Fast tuning procedures for emergency controls

using eigenvalue computations

By

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Chair

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Fast tuning procedures for emergency controls using eigenvalue computations

Abstract

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Remedial action schemes (RAS), also called, special protection schemes, are employed in large power systems for taking automatic corrective control actions in the event of double or multiple contingencies. Typical example of a RAS scheme would be tripping of generation and/or load following a two line outage to relieve excessive loading and to preserve system stability.

Unstable limit cycles play a crucial role in determining the transient stability margins of the power systems with weak interarea oscillatory modes. The western American power system WECC(Western Electricity Coordinating Council) is an example where the transient stability is closely related to the existence of unstable limit cycles under certain operating conditions. For these systems, fast computational procedures based on estimation of the damping of the interarea modes, can be used for assessing the RAS generation tripping amounts.

In order to concentrate on the factors that have the significant effect on RAS and to study the HVDC effect in power system transient stability, the thesis modifies the standard two-area test
system by adding a HVDC link parallel to the AC transmission, which allows us to carry out extensive stability studies using both transient stability simulation tools as well as eigenvalue tools.

Eigenvalue based rules are presented in the thesis and the results are illustrated on simulations of the phenomena in the Kundur two area test system which exhibits an interarea oscillatory mode.
## Table of Contents

ACKNOWLEDGEMENT ........................................................................................................ III

ABSTRACT................................................................................................................................ IV

LIST OF TABLES ................................................................................................................ IX

LIST OF FIGURES ............................................................................................................... X

CHAPTER 1  INTRODUCTION .................................................................................. 1

1-1 BACKGROUND ........................................................................................................ 1

1-2 LITERATURE REVIEW ........................................................................................ 3

1-3 SUMMARY ................................................................................................................ 5

CHAPTER 2  THEORY BACKGROUND .................................................................... 8

2-1 TWO IMPORTANT THEORIES ........................................................................... 8

2-1-1 Hopf bifurcation theory ............................................................................... 9

2-1-2 Center manifold theory ................................................................................. 11

2-2 UNSTABLE LIMIT CYCLE ................................................................................. 13

2-2-1 Comparison unstable limit cycle and unstable equilibrium point ............... 13

2-2-2 The relationship between ULC and small signal stability ......................... 14

2-2-3 The relationship between ULC and the damping ratio of the interarea mode 15
CHAPTER 6  CONCLUSIONS AND OUTLOOK .................................................67

6-1  CONCLUSIONS ..............................................................................................67

6-2  OUTLOOK ........................................................................................................67

REFERENCES ..........................................................................................................69

APPENDIX ...............................................................................................................72
List of Tables

Table 2- 1: ULC size vs interface power flow ................................................................. 18
Table 4- 1: Eigenvalue analysis for test system with and without HVDC ....................... 43
Table 5- 1: Effect of constant impedance load on generation tripping ......................... 52
Table 5- 2: Effect of constant current load on generation tripping ............................... 52
Table 5- 3: Effect of constant power load on generation tripping ................................ 52
Table 5- 4: Effect of nonlinear mixed load on generation tripping ............................... 52
Table 5- 5: Two kinds of RAS for special case .............................................................. 55
Table 5- 6: Effect of mixed load for different HVDC transfer ....................................... 63
List of Figures

Figure 2.1: Phase portrait of unstable limit cycle ................................................................. 15
Figure 2.2: Transient inside ULC converges to Xs .............................................................. 16
Figure 2.3: Transient on ULC maintains sustained oscillation ......................................... 16
Figure 2.4: Transient outside ULC diverges ...................................................................... 17
Figure 2.5: ULC size vs interarea damping ratio ................................................................ 18
Figure 4.1: HVDC link diagram .......................................................................................... 33
Figure 4.2: HVDC equivalent circuit .................................................................................. 33
Figure 4.3: Steady state converter control ......................................................................... 35
Figure 4.4: VDCOL steady state characteristic ................................................................. 37
Figure 4.5: Modified two-area study system ...................................................................... 38
Figure 4.6: Simple block diagram for rectifier side control mode ...................................... 39
Figure 4.7: Simple block diagram for inverter control ........................................................ 41
Figure 4.8: Interface power flow for AC line ..................................................................... 45
Figure 4.9: Rectifier power in MW .................................................................................... 45
Figure 4.10: DC voltage in kV ......................................................................................... 46
Figure 4.11: Rectifier alpha in degrees .............................................................................. 46
Figure 4.12: Inverter gamma in degrees ............................................................................ 47
Figure 5.1: Comparison for constant impedance load ......................................................... 56
Figure 5.2: Comparison for constant current load ............................................................... 57
Figure 5.3: Comparison for constant power load ............................................................... 57
Figure 5.4: Comparison for mixed-1 load ....................................................................... 58
Figure 5.5: Comparison for mixed-2 load ....................................................................... 58
Chapter 1  Introduction

1-1 Background

Power systems are large interconnected nonlinear systems that exhibit a wide area of dynamic performances. To maintain the security of the interconnected large system is always the overriding factor in the practical operation of a power system. Under normal conditions, the power system operates around a stable operating point. But after some contingency such as line outages, the system configuration can change. If such disturbances have reasonable amplitudes and decay quickly, the power system will survive the contingency and operate at a new steady state operating condition. Otherwise, the system trajectory can will be far away the nominal operating point and exhibit the unstable phenomena such as angle instability or voltage instability.

Dynamic security characterizes the ability of a power system to survive a set of credible contingencies with certain safety margin so that the system arrives at acceptable steady-state operating conditions after the contingencies. Usually, the security is addressed in two aspects: a) preventive actions applied to the pre-contingency system and b) corrective remedial actions (also termed special protection systems) taken following a credible contingency. Preventive actions usually restrict the tie-line interface power flows, the total generation output for certain plants or the angle difference across a particular path, which are conservative and can be costly. Therefore, corrective remedial
action schemes can lead to less conservative transfer limits than the preventive action schemes.

Reliability rules require that the power system be able to withstand all single contingencies or N-1 outages without any RAS (remedial action schemes). On the other hand, RAS schemes can be used effectively for mitigating N-2 outages or multiple contingencies. Remedial action schemes are triggered by the detection of the occurrence of a multiple contingency, and the RAS controller will then issue transfer trip signals to RAS control schemes. The RAS initiated controls include a) shedding remote generation, b) insertion or tripping of shunt and series capacitor/reactor banks, c) insertion of dynamic brakes, and d) load shedding.

Generator tripping and load shedding are two of most common control types for RAS, especially used for multiple line outages. In this case, the resulting higher power-flow on the remaining lines can push the system into transient instability unless the condition is corrected within the first swing of the transient response. Naturally, load tripping would be used as the last alternative if the other possible actions such as generation tripping or the insertion of shunt and series capacitor banks are not able to correct the problem. At the same time, we would like to minimize the amount of generation tripping that is initiated by the RAS scheme as an operations objective. Computing the minimum generation tripping amount to mitigate a contingency for a power system is nontrivial, since the tripping amount depends on various factors including the current operating conditions, the RAS controller action times, and the generator location. For the systems
limited by transient stability, the tripping amount and the RAS action times are especially sensitive.

1-2 Literature review

Traditionally, the RAS tripping amounts are developed from numerous time-consuming off-line simulations. Therefore, the results derived from conventional stability studies are not appropriate for on-line studies. On-line remedial action scheme problems have drawn many researchers attention during the last few decades and a variety of dynamic security assessment methods have been proposed in the literature.

Direct methods based on transient energy function (TEF) are the ones of the most prominent methods to evaluate the dynamic stability boundary. The second kick method, using energy concepts to determine the stability margin, belongs to TEF family. The basic idea [1-2] of this method is that the kinetic energy injected into the system by the second kick minus the value of the kinetic energy left in the system at the crest of potential energy hill, (PEBS crossing) should give the transient energy margin. This value should be adjusted for the potential energy change during the second kick. In this method, the computation of the potential energy, kinetic energy and corrected kinetic energy using time domain simulation is inevitable. And no modeling assumption is required for this method.

Another common method is EEAC (Extended equal area criterion) method [3], which was proposed based on the fact that the loss of synchronism in a power system is always
initiated from the splitting of the system into the following two parts: critical cluster of generators and rest of the system. This method is divided into three stages: at first stage the static method is incorporated with only one static transformation; at second stage the dynamic method is applied with several transformations, such as simplifying power system modeling and etc, to improve the accuracy; finally, the transformation is integrated with detailed time-domain simulations.

In [4], the authors applied data mining technique into the database, which covers the actual operating states collected over 5-year period for Hydor-Quebec, to find the relevant parameter and effective settings. Then a correlation analysis and the construction of regression trees are used to minimize the generation tripping amount.

Quite a large number of other methods for evaluating corrective actions have been proposed to study or improve the power system dynamic security. Inspired by using the neural network knowledge, a new method aim to calculate the minimal frequency and the load shedding is presented [5]. A new concept, called dynamic security region [6], is proposed to measure the system security using the time insecurity. By taking advantage of the generator’s angular swing and kinetic energy, Ota and Kitayama [7] presents the method to estimates the required tripping. Based on nonlinear programming methodology for evaluating load shedding during angle or voltage instability is reported in [8]. The dynamic security assessment practices for some utilities in North America have been reviewed in the literature [9-11].
1-3 Summary

The tuning of RAS initiated generation tripping amounts is an important problem for
the western American power system as well as for some Canadian utilities such as Hydro
Quebec. The motivation of this thesis, arising from a part of real-time control project
sponsored by Department of Energy, is to develop a robust remedial action scheme,
especially focusing on fast on-line computation of minimal generation tripping amount. It
is not easy to compute the minimal generation tripping amount since this tripping number
depend on various of operating conditions. The concept of ULC’s (unstable limit cycles)
gives us a comprehensive insight into RAS by describing how large the region of
attraction for the power system with weak interarea oscillatory modes. It is quite difficult
and time-consuming to locate the exact ULC’s size although ULC can anchor the
 transient stability boundary.

Hopf bifurcation theory proves that the size of ULC is directly proportional to the
positive damping ratio of the complex conjugate eigenvalues near the Hopf bifurcation
boundary. Furthermore, the damping ratio itself is also an important factor to describe the
post-fault transient stability boundary, especially for some large practical system having
interarea modes.

Motivated by these concepts, eigenvalue analysis, one of the most appropriate tools to
study small signal stability, is chosen as the main study tool while the traditional
nonlinear time domain simulation program acts as a complementary tool. In order to
concentrate on the factors that have the significant effect on RAS, this thesis constructs a small two-area system containing HVDC and AC transmission in parallel which ensure us to carry out extensive transient stability studies using both transient stability simulation tools as well as eigenvalue tools.

Based on the heuristic method, this thesis proposes a novel technique for fast computation of “minimal” generation tripping amounts associated with RAS schemes, from pre- and post-contingency eigenvalue computations. Different kinds of factors such as system operating conditions and RAS action times are important for computing the minimal tripping amounts to mitigate a double line outage contingency in the Kundur two area test system.

The main contributions in this thesis are listed as follows:

1) The standard two area test system is modified by adding a HVDC link parallel to the AC transmission line. Model validation shows that HVDC dynamic effect is consistent with its actual characteristic. General conclusions drawn from the test system will be helpful to study the large power system transient characteristics.

2) Based on estimation of the interarea modes’ damping ratio, this thesis presents a novel fast computational procedure to assess the minimal RAS generation tripping amounts. Effectiveness of this RAS is verified by different load types, and by changing AC as well DC transfer flows for the study system.

The thesis is organized as follows. The mathematical background related to Hopf bifurcation theory is described in Chapter 2. The fundamentals and formulations of small
signal stability analysis are stated in Chapter 3. In Chapter 4, the modified two area system and HVDC converter controls are presented for this system. The remedial action scheme based on eigenvalue analysis is then put forward and case studies are carried out in Chapter 5. In the last chapter, conclusions of this thesis are drawn and some future work is suggested.
Chapter 2  Theory Background

An overall understanding of unstable limit cycles (ULC’s) can provide us with a comprehensive overview of determining the transient stability for some power systems [12-16]. Also, based on Hopf bifurcation theory, the close relationship between the size of the ULC and the damping of the oscillatory mode is established in recent years [12,13]. Therefore, some fundamental concepts associated with the ULC and the damping ratio are reviewed. In the first section two important theories, Hopf bifurcation theory and center manifold theory, are described. The second part focuses on unstable limit cycle, the relationship between the unstable limit cycle and small signal stability is also presented.

2-1 Two important theories

Usually the power system can be described by a set of differential algebraic equations (DAE) as follows:

\[
\dot{x} = f(x, y, u) \quad (2.1)
\]

\[
0 = g(x, y, u) \quad (2.2)
\]

In the state space, the function \( f \) represents the power system dynamic equations, while \( g \) describes the power flow equations of the network. Linearizing the system matrix \( A \) at the equilibrium point \( (x_0, y_0, u_0) \), we can get the following equations:

\[
A = \left. \frac{\partial f}{\partial x} - \frac{\partial f}{\partial y} \left( \frac{\partial g}{\partial y} \right)^{-1} \frac{\partial g}{\partial x} \right|_{(x_0, y_0, u_0)} \quad (2.3)
\]
The feasibility region [16] is defined as the parametric region when the system matrix A has all negative real part eigenvalues. When the system matrix A has a pair of imaginary eigenvalues, denoted by Hopf bifurcation (also called zero damping mode in power system), the system is marginally stable that describes the feasibility boundary. Under such situations linear system theory fails to predict whether the system is small signal stable or not, since power system is a complicated nonlinear system. Usually Hopf bifurcation can be categorized as subcritical (nonlinear unstable), supercritical (nonlinear stable), or degenerate. The Hopf bifurcation theory provides us a useful tool to analyze the nonlinear behavior in analyzing the feasibility boundary.

2-1-1 Hopf bifurcation theory

When the system Jacobian matrix A has a simple pair of purely imaginary eigenvalues at the equilibrium point \((x_0, y_0, u_0)\), it is called Hopf bifurcation at \((x_0, y_0, u_0)\). The normal form of Hopf bifurcation can be expressed in polar coordinated form as:

\[
\begin{align*}
\dot{r} &= ar^3 + o(r^5) \\
\dot{\theta} &= \omega + o(r^2)
\end{align*}
\]

\[(2.4) \quad (2.5)\]

1) If the system matrix A has a simple pair of pure imaginary eigenvalues and has no other eigenvalues with zero real parts, then there exists a smooth curve for the equilibrium point with \(x(\mu_0) = x_0\).
2) If \( \lambda_1(\mu) = j\omega \) and \( \lambda_2(\mu) = \overline{\lambda_1(\mu)} \) are the two purely imaginary eigenvalues and \( \frac{d}{d\mu} \text{Re}(\lambda_1(\mu)) = d \neq 0 \), then there exists a locally invariant center manifold which is tangential to the eigenvectors associated with \( \pm j\omega \).

Under this condition, the original system can be transformed into:

\[
\begin{align*}
\dot{x}_s &= A_s x_s + o(2) \\
\dot{r} &= r(d\mu + ar^2) + o(4) \\
\dot{\theta} &= \omega + o(2)
\end{align*}
\]

(2.6) \hspace{1cm} (2.7) \hspace{1cm} (2.8)

Analyzing the coefficient factor \( a \), the modes for Hopf Bifurcation can be divided into two types: supercritical and subcritical Hopf bifurcation, which shows quite different transient behavior after Hopf bifurcation.

1) For \( a<0 \), then the Hopf bifurcation is supercritical and a stable limit cycle (SLC) exists around the small signal unstable equilibria.

2) For \( a>0 \), then the Hopf bifurcation belongs to the subcritical Hopf bifurcation. Subcritical Hopf bifurcation, rather than supercritical Hopf bifurcation, has an unstable limit cycle that bound the region of attraction around the small signal stable equilibria.

Therefore for subcritical Hopf, the ULC anchors the stability boundary associated with the poorly damped equilibrium point. ULC’s play a crucial role in determining whether the transient is stable or not after some contingencies for some power systems \([13,14]\).
2-1-2 Center manifold theory

Center manifold theory provides us a useful tool for studying the Hopf bifurcation by reducing the system dimension. If the reduced order system is stable, then the original full system is also stable, which is the main context of this theory.

Now, we describe the center manifold in a simple form. For two systems having the following forms:

\[ \dot{y} = A_1 y + g_1(y, z) \]  \hspace{1cm} (2.9)
\[ \dot{z} = A_2 z + g_2(y, z) \]  \hspace{1cm} (2.10)

Center Manifold Definition: If \( g_1 \) and are \( g_2 \) twice continuously differentiable and satisfy the following equation (2.11)

\[ g_r(0,0) = 0, \frac{\partial g_r}{\partial y}(0,0) = 0, \frac{\partial g_r}{\partial z}(0,0) = 0 \]  \hspace{1cm} (2.11)

In the above, \( A_1 \) is a \( c \times c \) matrix having eigenvalues with zero real parts, and \( A_2 \) is a \( s \times s \) matrix having eigenvalues with negative real parts.

Then an invariant manifold will be called a local center manifold for (2.9) and (2.10) if it can be locally be represented as follows:

\[ W^c(0,0) = \{(y, z) \in R^c \times R^s \mid z = h(y), |y| < \delta, h(0) = 0, Dh(0) = 0\} \]  \hspace{1cm} (2.12)

Here \( \delta \) is sufficiently small. We should note that the conditions \( h(0) = 0, Dh(0) = 0 \) imply that \( W^c(0,0) \) is tangent to center eigenspace at \( E^c \) at \((y, z) = (0, 0)\). The following two theorems are taken from Wiggins [17].
**Theorem 1**: There exists a $C^r$ center manifold for (2.9) and (2.10). The dynamics of these two equations restricted to the center manifold is, for a sufficiently small neighborhood, given by the following c-dimensional vector field

$$
\dot{u} = Au + f(u, h(u)), u \in \mathbb{R}^c
$$

(2.13)

**Theorem 2**: 1) Suppose the zero solution of (2.13) is stable (asymptotically stable) (unstable); then the zero solution of (2.9) and (2.10) is also stable (asymptotically stable) (unstable). 2) Suppose the zero solution of (2.13) is stable, then if $(y(t), z(t))$ is a solution of (2.9) and (2.10) with $(y(0), z(0))$ sufficiently small, there is a solution $u(t)$ of (2.13) such that as $t \to \infty$

$$
y(t) = u(t) + O(e^{-\gamma t})
$$

(2.14)

$$
z(t) = h(u(t)) + O(e^{-\gamma t})
$$

(2.15)

where $\gamma > 0$ is a constant.

In this subsection, two important background theories for analyzing ULC’s are described. Hopf bifurcation theory provides us the theory foundation for unstable limit cycle, while the center manifold theory provides us a useful tool to reduce the state space dimension, which have a great effect for locating the unstable limit cycles.
2-2 Unstable limit cycle

2-2-1 Comparison unstable limit cycle and unstable equilibrium point

Energy function methods have been considered the most efficient methods for DSA in the last several decades because of their ability of producing stability margin index [9]. The roles of ULS in analyzing RAS have been recognized recently [12-16]. Comparison of these two kinds of methods, there are some similarities between them, such as they both can be used to assess the transient stability properties of the post-fault initial condition. Similar to the behavior of a saddle point in the case of a UEP, trajectories can converge to ULC along certain directions while diverging in other directions [12-14]. The collection of all trajectories converging to an unstable limit cycle is called its stable manifold.

While looking at the properties of these two methods, a lot of differences can be found between them. Unstable equilibrium points (UEP’s) are defined as the solution to a set of nonlinear equations, while unstable limit cycles are represented as a closed trajectory of the underlying differential equation model [12-14].

Another difference between them is that the energy function methods have some limitation in terms of the model assumptions. Using classical power system models to represent the power system dynamics, energy function methods assume that the stability boundary for the post-fault operating point is strictly anchored by unstable equilibrium points. But in practice, real power system should take into account different power
system models, especially for full descriptions of generator electromagnetics and control
devices etc, which cannot be fully captured by the energy function methods. Under these
operating conditions, unstable limit cycles (ULC’s) may be a better tool for describing
the stability boundary than UEP’s.

2-2-2 The relationship between ULC and small signal stability

In power system dynamics, sustained oscillations are usually associated with limit
cycles. Usually, sustained oscillations mean that the limit cycles are stable. But when a
small disturbance is put on an unstable limit cycle and it will move away from the limit
cycle, the system will become unstable.

Here a qualitative phase portrait of ULC is shown in Figure 2.1 to illustrate its basic
characteristic. Xs denotes the stable equilibrium point. If the initial point is on the exact
unstable limit cycle, the system will maintain sustained oscillations, which means ULC
itself is a closed trajectory. If a small perturbation moves the initial condition ‘inside’ the
ULC, such as $\gamma_1$ in Figure 2.1, the trajectory will approach the stable equilibrium point
Xs and the oscillations are seen to decrease in amplitude. On the other hand, if the
perturbation moves the initial condition ‘outside’ the ULC, such as $\gamma_2$ in Figure 2.1, the
trajectory will tend away from the unstable limit cycle as time increases and the
oscillations are increasing amplitude, described by $V_2$. In this case, the equilibrium point
within unstable limit cycle is small signal stable, while the unstable limit cycles anchors
the stability boundary separating the region of attraction from changing trajectories.
2-2-3 The relationship between ULC and the damping ratio of the interarea mode

Locating the exact ULC’s in detail power system models provides us a useful platform for studying the power system transient stability boundary for post-contingencies. We can approximate the ULC’s size by reclosing the lines after some line outages, which gives us a way to evaluate whether the operating point is inside or outside the ULC. Consider the Kundur two-area system [21-22], Figures 2.2-2.4 represent the qualitative
plots for different reclosing time, which show the presence of ULC on the transient stability boundary.

**Figure 2.2:** Transient inside ULC converges to Xs

**Figure 2.3:** Transient on ULC maintains sustained oscillation
Figure 2.4: Transient outside ULC diverges

For a single line outage, if the reclosing time is 19.09sec, as shown in Figure 2.2, the operating point is inside the ULC, the trajectory will converge to the stable equilibrium point, which is denoted by $\gamma_1$ in Figure 2.1. When the reclosing time is above 19.095 sec, the trajectory will diverge, represented by $\gamma_2$ in Figure 2.1. The size of ULC represented by the bus-7 voltage magnitude is from 0.86 to 1.125.

If we can calculate the exact ULC size, it will give us the implication on how large the region of attraction is for the operating point. Unfortunately, it is difficult and highly time-consuming to approximate the exact unstable limit cycles since many power system parameters have important effects on the size of unstable limit cycle. But the size of ULC has a close relationship with damping ratio: the size of the ULC is directly proportional to the positive damping level of the associated complex conjugate eigenvalues, when the damping factor is small and positive and when the Hopf bifurcation is “subcritical” [17].
It is generally believed that under poorly damped conditions if the system is more stressed, the system will have poorer damping ratio, which means that the size of attraction of the region will shrink and the system will exhibit more weakness to disturbances, as shown in Figure 2.5 and Table 2.1. These results corroborate the simulation results shown in the literature [13,14]. Since the size of ULC is closely associated with the interarea damping ratio, it inspires us to use interarea damping ratio to develop the remedial action scheme.

Table 2-1: ULC size vs interface power flow

<table>
<thead>
<tr>
<th>Power flow (MW)</th>
<th>Post-fault damp</th>
<th>Upper value Bus-7</th>
<th>Lower value Bus-7</th>
</tr>
</thead>
<tbody>
<tr>
<td>350</td>
<td>0.0188</td>
<td>1.15</td>
<td>0.74</td>
</tr>
<tr>
<td>380</td>
<td>0.0142</td>
<td>1.15</td>
<td>0.80</td>
</tr>
<tr>
<td>400</td>
<td>0.0094</td>
<td>1.125</td>
<td>0.86</td>
</tr>
<tr>
<td>420</td>
<td>0.0035</td>
<td>1.07</td>
<td>0.95</td>
</tr>
<tr>
<td>425</td>
<td>0</td>
<td>1.02</td>
<td>1.02</td>
</tr>
</tbody>
</table>

Figure 2.5: ULC size vs interarea damping ratio
Chapter 3  Small Signal Stability

In some power systems such as the western American interconnection WECC, interarea oscillatory modes are significant in determining the stability properties of the system. Clearly, the small-signal stability of a power system requires that all the modes have positive damping. From the theory background of chapter 2, it is indicated that unstable limit cycles, ULC’s associated with poorly damped interarea modes, can anchor the transient stability boundary of the system (just like unstable equilibrium points or UEP’s). Then, the size of the ULC is directly proportional to the positive damping level of the associated complex conjugate eigenvalues, when the damping factor is small and positive and when the Hopf bifurcation is “subcritical” [13,14].

By itself, the damping ratio of interarea modes can be an important factor for evaluating the system stability margin, especially for the large systems having interarea modes, such as WECC system. Therefore we try to find the relative change in the damping ratios of the interarea mode between the pre-fault and the post-fault systems to develop a rule for the RAS generation tripping amount. The eigenvalue computations are also fast even for large systems, and hence, the method is targeted towards online implementations. In our study, EPRI SSSP (Small Signal Stability Analysis) program [18] is chosen as the main study tool and traditional nonlinear time domain simulation program ETMSP (Extended Transient and Midterm Stability Program) [19] is also used
in our study as a complementary tool to verify the results. The following material of small signal stability in this chapter is presented from [21].

3-1 Overview of small signal stability

3-1-1 State equation and linearization

To describe the power system dynamic performance, differential equations can be expressed as a set of n first order nonlinear ordinary differential equations. These can be represented in the state-variable form as the vector equations:

\[ \dot{x}_i = f_i(x_1, x_2, \ldots, x_n; u_1, u_2, \ldots, u_r) \quad i = 1,2,\ldots,n \]  \hspace{1cm} (3.1)

where \( n \) is the order of the system and \( r \) is the number of inputs.

We can also write these equations in another form, vector-matrix form:

\[ x = f(x,u) \]  \hspace{1cm} (3.2)

where

\[
\begin{bmatrix}
  x_1 \\
  x_2 \\
  \vdots \\
  x_n \\
\end{bmatrix}
\begin{bmatrix}
  u_1 \\
  u_2 \\
  \vdots \\
  u_r \\
\end{bmatrix}
\begin{bmatrix}
  f_1 \\
  f_2 \\
  \vdots \\
  f_n \\
\end{bmatrix}
\]

The column vector \( x \) is referred to as the state vector, \( x_i \) as the state variables. The column vector \( u \) is the vector of inputs to the system.

\[ y = g(x,u) \]  \hspace{1cm} (3.3)

where
The column vector $y$ is the vector of inputs, and $g$ is the vector of nonlinear functions relating state and input variables to output variables.

The equilibrium point or singular point is the point whose trajectory’s speed is zero. From the mathematical view, it must satisfy the following equation:

$$f(x_0, u_0) = 0$$  \hspace{1cm} (3.4)

where $x_0$ is the state vector $x$ at the equilibrium point, $u_0$ is the input vector corresponds to the equilibrium point.

For a linear system, if the system is non-singular, the system only has one equilibrium point. Based on Lyapunov theory, if a small signal linear model is valid near an equilibrium state and it is stable, then there is a region containing the equilibrium state with which the nonlinear system is stable. From this concept, we can linearize the system model within the neighborhood of the equilibrium point.

We expand the nonlinear equation in terms of perturbations form these equilibrium values; that is, we let

$$x = x_0 + \Delta x \text{ and } u = u_0 + \Delta u$$

The nonlinear function can be expressed in terms of Taylor’s series expansion, neglecting the second and higher order powers, we get

$$\Delta x = A\Delta x + B\Delta u$$ \hspace{1cm} (3.5)
\[ \Delta y = C \Delta x + D \Delta u \]  

(3.6)

Here, \( \Delta x \) is the \( n \) state vector increment, \( \Delta y \) is the \( m \) output vector increment, \( \Delta u \) is the \( r \) input vector increment, \( A \) is the \( n \times n \) state matrix, \( B \) is the \( n \times r \) input matrix, \( C \) is the \( m \times n \) output matrix and \( D \) is the \( m \times r \) feed-forward matrix.

3-1-2 Eigenvalues and Stability Analysis

Eigenvalue and eigenvector are important concepts in small signal stability. For a matrix, the eigenvalue is defined as follows:

\[ A \phi_i = \lambda_i \phi_i \]  

(3.7)

For a non-trivial solution, it can be written:

\[ \det(A - \lambda I) = 0 \]  

(3.8)

The solution of (3.8), the vector \( \phi_i \) is the right eigenvector corresponds to the eigenvalue \( \lambda_i \). Similarly, we can define the left eigenvector \( \psi_i \) associated with the eigenvalue \( \lambda_i \) in this way:

\[ \psi_i A = \lambda_i \psi_i \]  

(3.9)

The normalized right and left eigenvector have the following property:

\[ \psi_i \phi_j = 0 \quad i \neq j \]  

(3.10)

\[ \psi_i \phi_i = 1 \quad i = j \]  

(3.11)

The eigenvalues for \( A \) matrix may be real or complex. If \( A \) is real, the complex eigenvalues always occur in conjugate pairs, such as \( \lambda = \sigma \pm j \omega \) form.
We can use the eigenvalues to study the small signal stability of the operating point $(\delta, \omega)$. It is known that the system is locally stable if all of the eigenvalues are on the left-hand side of the imaginary axis of the complex plane; otherwise, if at least one of the eigenvalues appears on the right of this axis, the corresponding modes are said to be unstable. This is confirmed by looking at the time dependent characteristic of the oscillatory modes corresponding to each eigenvalue $\lambda_i$, given by $e^{\lambda_i t}$. The latter part shows that a real eigenvalue corresponds to a nonoscillatory mode. If the real part of eigenvalue is negative, the mode decays over time. The magnitude is related to the time of decay: the larger the magnitude, the faster the decay. If the real part eigenvalue is positive, the mode is said to have aperiodic instability.

On the other hand, the conjugate-pair complex eigenvalues $(\sigma \pm j\omega)$ correspond to oscillatory modes. A pair with a positive $\sigma$ represents an unstable oscillatory mode since eigenvalues yield an unstable time response of the system. In contrast, a pair with a negative $\sigma$ represents a desired stable oscillatory mode. Eigenvalues associated with an unstable or poorly damped oscillatory mode are also called dominant modes since their contribution dominates the time response of the system. It is clear that the necessary property of the system is for all of the eigenvalues to be in the left-hand side of the complex plane.

Other useful information, such as the oscillatory frequency and the damping factor, can be provided using eigenvalue analysis.

The frequency of the oscillation in Hertz is given by
The damping ratio is given by
\[ \xi = \frac{-\sigma}{\sqrt{\sigma^2 + \sigma^2}} \]  

These concepts are also very important indexes that can be used to analysis power system dynamic performance. In modern power system systems, many system stability problems result from the insufficient damping of system oscillation. For instance, the August 10, 1996 WECC system blackout failure was caused by the small-signal instability of the 0.25 Hz COI mode.

3-1-3 Modal Matrix and Participation Factors

In order to express the properties of eigenvalue analysis more sufficiently, Modal matrix and participation factor are induced as follows:

\[ \phi = [\phi_1, \phi_2, \ldots, \phi_n] \]

\[ \psi = [\psi_1^T, \psi_2^T, \ldots, \psi_n^T]^T \]

\[ \Lambda = \text{diagonal matrix with eigenvalues as diagonal elements} \]

The relationships (3.6) and (3.9-3.10) can be written in a compact form as

\[ A\phi = \phi\Lambda \]  

\[ \psi\phi = I \]

The time domain response can be written by

\[ x(t) = \sum_{i=1}^{n} \phi_i c_i e^{\lambda_i t} \]
where coefficient \( c_i \) is determined by the initial condition, modal matrix \( \phi \) can be derived by the definition. It is known that this sum represents a contribution of specific mode to the system response. And the entries of the right eigenvector \( \gamma_i \) determine the activity level of each state only when one mode is excited. The left eigenvector defines a linear combination of the original state into a single variable only related to the \( ith \) mode.

To solve this problem, the concept of participation matrix is defined as follows:

\[
p_i = \begin{bmatrix}
    p_{i1} \\
    p_{i2} \\
    \vdots \\
    p_{in}
\end{bmatrix} = \begin{bmatrix}
    \phi_{i1} \psi_{r1} \\
    \phi_{i2} \psi_{r2} \\
    \vdots \\
    \phi_{in} \psi_{rn}
\end{bmatrix}
\]

\( \phi_{ki} = \) the element on the \( kth \) row and \( ith \) column of the modal matrix \( \phi \)

\( \psi_{ik} = \) the element on the \( ith \) row and \( kth \) column of the modal matrix \( \psi \)

It is shown that the participation factor is independent of a particular choice of elements associated with state \( x \).

From the above description, the fundamental concept of small signal stability is presented. Once the oscillatory modes have been identified and the modal matrices constructed, eigenvalue analysis can be performed to find the specific rotor-angle modes that provide the largest contribution to the low frequency oscillations. Next, based on the right and left eigenvectors in conjunction with the participation factor, the rotor-angle modes can be identified. Finally, the mode shape of the rotor-angle modes is used to examine whether this particular mode is of local or interarea mode.
3-2 Formulation for multi-machine system

The small signal stability program is the same as the concept. It needs formulation of the state equation involving the development of linearized equations about an operating point and at the same time elimination of all variables other than the state variables. The formulation of the state equations requires a systematic procedure for treating the wide range of devices, which include transmission networks, loads, excitation systems and prime mover models, HVDC links.

The dynamic equations are expressed in the state space form:

\[
\begin{align*}
\dot{X}_d &= A_d X_d + B_d \Delta V_d + B_r \Delta V_r \\
\Delta i_d &= C_d X_d - Y_d \Delta V_d - Y_r \Delta V_r
\end{align*}
\]

(3.17) (3.18)

where

- $X_d$ is the state of devices
- $A_d$ is the device state matrix
- $\Delta V_d$ is the change of the voltage at the terminals of the device
- $\Delta V_r$ is the change of the voltage at the terminals remote from the site
- $B_d$ and $B_r$ are the matrices relating the respective changes in voltages to the rates of change of the states
- $\Delta i_d$ is the change in the current injected by the device into its network terminal
- $C_d$ is the matrix relating the change in device current to the device states.
\( Y_d \) and \( Y_r \) are the matrices relating the change in device current to the changes in the device voltage and the remote voltage respectively.

### 3-2-1 Static load model for SSSP

The characteristic of load model play a very significant role in eigenvalue analysis, the static load model is presented in this part.

For constant impedance load, the shunt admittance to ground representing the load is computed as

\[
G_L = \frac{P_{L0}}{V_0^2} \tag{3.19}
\]

\[
B_L = -\frac{Q_{L0}}{V_0^2} \tag{3.20}
\]

where

- \( P_{L0} \): initial value of the active component of load
- \( Q_{L0} \): initial value of the reactive component of load
- \( V_0 \): initial value of the bus voltage magnitude

For nonlinear load, the voltage dependent characteristics are represented as

\[
P_L = P_{L0} \left( \frac{V}{V_0} \right)^m \tag{3.21}
\]

\[
Q_L = Q_{L0} \left( \frac{V}{V_0} \right)^n \tag{3.22}
\]

\( V \) is the magnitude of the bus voltage given by

\[
V = \sqrt{V_R^2 + V_I^2}
\]
The $R$ and $I$ components of the loads are

$$i_R = P_L \frac{v_R}{V^2} + Q_L \frac{v_I}{V^2}$$

$$i_I = P_L \frac{v_I}{V^2} - Q_L \frac{v_I}{V^2}$$

Linearizing, we can get

$$\begin{bmatrix} \Delta i_R \\ \Delta i_I \end{bmatrix} = \begin{bmatrix} G_{RR} & B_{RI} \\ -B_{IR} & G_{II} \end{bmatrix} \begin{bmatrix} \Delta V_R \\ \Delta V_I \end{bmatrix}$$  \hspace{1cm} (3.23)

where

$$G_{RR} = \frac{P_{L_0}}{V_0^2} \left[ (m - 2) \frac{V_R^{0}}{V_0^2} + (n - 2) \frac{V_I^{0}}{V_0^2} \right]$$

$$B_{RI} = \frac{P_{L_0}}{V_0^2} \left[ (m - 2) \frac{V_R^{0} V_I^{0}}{V_0^2} + (n - 2) \frac{V_I^{0} V_R^{0}}{V_0^2} \right]$$

$$B_{IR} = -\frac{P_{L_0}}{V_0^2} \left[ (m - 2) \frac{V_R^{0} V_I^{0}}{V_0^2} + (n - 2) \frac{V_I^{0} V_R^{0}}{V_0^2} \right]$$

$$G_{II} = \frac{P_{L_0}}{V_0^2} \left[ (m - 2) \frac{V_I^{0}}{V_0^2} + 1 \right] - \frac{Q_{L_0}}{V_0^2} \left[ (n - 2) \frac{V_R^{0} V_I^{0}}{V_0^2} \right]$$

3-2-2 HVDC model for SSSP

HVDC link is another important factor that we should consider in the stability problem since HVDC control modes have some deep impact on practical power system dynamic performance. In general, the converter is modeled as one point connected to the DC network and at another point to the AC system and AC/DC converter has the standard structure. On the other hand, the equipments and their associated controls vary from one manufacture to another, as well as from one application to another. These variations are not only parametric but also structural. Due to these reasons, for small signal stability
HVDC can be represented by two ways: for dc network and converter model using standard forms while for control model using user-defined models that can match the flexibility in the controls.

The dynamic equations for DC network and user-defined control model [20]:

\[ X_{dc} = A_{dc}X_{dc} + B_{dc} \Delta E_0 + B_{\alpha} \Delta \alpha \]  
(3.24)

\[ \Delta i_{ac} = AK X_{dc} + Y_{dc0} \Delta E_0 + AK_{\alpha} \Delta \alpha \]  
(3.25)

where

\( X_{dc} \) is the state of dc network
\( A_{dc} \) is the dc network state matrix
\( B_{dc} \) and \( B_{\alpha} \) are the matrices describing the interaction between the commutation voltage change \( \Delta E_0 \) and the converter firing angle changes \( \Delta \alpha \) respectively and the rate of change of \( X_{dc} \)

\( AK_{c} \) and \( BK_{c} \) are the matrices describing the influence of the dc network of and converter firing angle change respectively on the converter ac current change \( \Delta i_{ac} \)

\( Y_{dc0} \) is the effective commutating bus admittance matrix

The dynamic equations for user-defined models are slightly different from the previous one

\[ X_{c} = A_{c}X_{c} + B_{c} \Delta V_{b} \]  
(3.26)

\[ \Delta y_{b} = C_{c}X_{c} - D_{c} \Delta u_{b} \]  
(3.27)

\[ \Delta u_{b} = AK_{c} \Delta y_{b} + BK_{c} \Delta u_{0} \]  
(3.28)
\[
\Delta \alpha = CK_c \Delta y_b
\]  
(3.29)

\[
\Delta u_0 = CGx_{dc} + BG_1 \Delta i_{ac} + BG_2 \Delta v_{ac} + BG_3 \Delta v_r + BG_a \Delta \alpha
\]  
(3.30)

where

- \( X_c \) is the state of devices
- \( A_c \) is the device state matrix
- \( B_c \) is the matrix describing the interaction between the control block input changes \( \Delta u_b \) and controller states.
- \( C_c \) and \( D_c \) are the matrices describing the influence of the controller state and control block input changes respectively on the control block output changes \( \Delta y_b \).
- \( AK_c \) and \( BK_c \) are the matrices describing the influence of the controller block output changes and control block input changes \( \Delta u_0 \) respectively on the control block input changes.
- \( CK_c \) is the matrix describing the influence of the controller block output changes on the converter firing angle changes.
- \( CG \) is the matrix describing the influence of the dc network states on the controllers input changes.
- \( BG_1 \) and \( BG_a \) are the matrices describing the influence of the converter ac current changes and converter firing angle changes respectively on the controller inputs changes.
- \( BG_2 \) and \( BG_3 \) are the matrices describing the influence of the converter at LT bus voltage change \( \Delta v \) and remote bus voltage changes respectively on the controllers’ inputs \( \Delta v_r \) changes.
Chapter 4 The Modified Two Area Study System

The tuning of RAS initiated generation tripping amounts is an important problem for the western American power system as well as for some Canadian utilities such as Hydro Quebec. In general, a large practical power system, such as WECC system, is chosen to study the power system dynamic performance. But the complexity of the large system adds the difficulty of analysis, and at the same time it may also obscure the fundamental nature of the problem. Therefore, we start with a small system in this thesis, since it enables us to focus on the factors that have the significant effects on RAS.

Except for its complexity, WECC system is also a classical example of low frequency interarea mode oscillation problem (0.25 Hz). The simple two area system [21-22] has a somewhat similar topology as the WECC system in terms of sending and receiving areas and is a good candidate for getting insight into the mechanisms of the 0.25 Hz WECC modes. The Kundur’s system also has the mixture of interarea and local modes, which matches our research requirement. Furthermore, this system is small enough to carry out extensive stability studies using both transient stability simulation tools as well as eigenvalue tools, so that the results can be compared.

It has been noted that under certain conditions, HVDC lines may contribute to oscillatory modes and voltage collapse phenomena during transient stability studies [24.26]. Therefore, in order to analyze HVDC effect on dynamics, the former test system
is adjusted by adding a HVDC line parallel to the HVAC lines between the two areas. Since the modified two-area system has the similar topology as WECC large power system, it is believed that the general conclusions drawn from the modified two-area system will be helpful for us to study the large power system transient characteristics.

Therefore, in this chapter, three parts are described as follows. First basic knowledge of HVDC is described; second model of converter control and the modified two-area test system are presented; third sample simulation results for the study system are analyzed.

4-1 Overview of HVDC concepts

HVDC technology has been widely used in the past few decades, especially for transmission of large amounts of power over long distances among several different asynchronous systems, etc.

In order to provide the efficient and secure operation, various control modes are used in practice. In this subsection, the fundamental principles of HVDC controls are described [21,25]. Figures 4.1 and 4.2 represent the simple HVDC link and its equivalent circuit.
The current form rectifier to inverter is

$$I_d = \frac{V_{d0}\cos \alpha - V_{d0}\cos \gamma}{R_{cr} + R_L - R_{cr}} = \frac{V_{d0}(\cos \alpha + \cos \gamma)}{2R_c}$$ \hspace{1cm} (4.1)$$

The power at rectifier terminal and inverter terminal are:

$$P_{dr} = V_{d_r}I_d$$ \hspace{1cm} (4.2)$$

$$P_{di} = V_{d_i}I_d = P_{dr} - R_LI_d^2$$ \hspace{1cm} (4.3)$$

The power factors at rectifier and inverter terminal are:
\[
\cos \phi_r \approx \frac{V_{dr}}{V_{dr0}} \\
\cos \phi_i \approx \frac{V_{di}}{V_{di0}}
\] (4.4)
(4.5)

Then several features should be considered for selecting control types:

1) Prevention of large fluctuation in direct current so as to avoid damage to the valves and other equipments.

2) Keeping power factors as high as possible, which is based on several factors, such as reduce stress in valves, minimize the required current rating, minimize the voltage drop at the ac terminal and etc.

3) Keeping direct voltage at the sending side as its rated value as possible in order to minimize losses for a given power.

4) Prevention of commutation failure of the inverters.

The actual controls not only satisfy these four features but also should consider other operating conditions, such as voltage and reactive support. Here, some common control types are discussed below, as shown in Figure 4.3

Under normal operation, the rectifier controls constant current (CC) while the inverter operates sets the dc current with constant extinction angle (CEA). The inverter characteristic is a line given by

\[
V_d = V_{d0r} \cos \gamma + (R_L - R_c) I_d
\] (4.6)
Figure 4. 3: Steady state converter control

Usually the commutation resistance $R_{ci}$ is somewhat greater than the line resistance $R_L$, the line CD has a small negative slope.

Due to the finite gain of the current regulator, the constant current (CC) control has a negative slope, which is represented by the line AB. The intersection of rectifier and inverter is the point E.

$$\cos \phi = 0.5 \times [\cos \alpha + \cos(\alpha + \gamma)] \quad (4.7)$$

From the equation of power factor, in order to maintain the power factor as high as possible, the delay angle $\alpha$ and extinction angle $\nu$ should be kept as low as possible. In reality, we choose the minimum $\alpha$ about $15^\circ$ to ensure the adequate voltage across the
valve before firing. In the similar way, for the minimum extinction angle $\nu$, a value of $15^\circ$ - $18^\circ$ is accepted to prevent commutation failure. When it reaches the minimum $\alpha$ voltage can’t increase and rectifier will operate at the constant ignition angle (CIA). Therefore, the controls for rectifier side have two types: one segment AB represents the constant current control; the other segment FA means the constant ignition angle control.

If the inverter voltages decreases, it operate at the new condition represented by XZB. The new inverter characteristic does not intersect with the rectifier characteristic, and the HVDC system will run down. As a solution to this problem, the inverter is also provided with a constant current control represented by GH. The actual inverter characteristic is represented by DGH: one of GD (CEA) and GH (CC).

The difference between the current command of the rectifier and that of the inverter is called the current margin and is denoted by $\Delta I_m$. It is generally 10% to 15% of the rated current so that the two constant current lines do not cross each other in spite of error of current measurement or other causes.

Under normal operating conditions, the rectifier controls the direct current and the inverter controls the direct voltage. They intersect at point E, which is shown in Figure 4.3. When the rectifier side voltage drops as indicated by XYZ, the new intersection point is Y. At this operating condition, the control modes for rectifier and inverter have reversed: the inverter controls the direct current and the rectifier regulates the direct voltage, which is called mode shift.
In practice other factors, especially for some severe cases, should be taken into account to ensure HVDC operate safely. The VDCOL (Voltage-dependent current-order limit) control is one of the most important controls used in reality. The VDCOL characteristics may be a function of the ac commutating voltage or the dc voltage. The steady-state characteristic with VDCOL is shown in Figure 4.4.

VDCOL add to three more elements for the converter control.

1) To prevent thermal damage to valves, the maximum current limit is set as 1.2 to 1.3 times as the normal value.

![Figure 4.4: VDCOL steady state characteristic](image-url)
2) In case of low value of current, the overlap is small. Then the jumps for direct voltage at the beginning and end of commutation may merge to a large value, causing the valve damage. So it needs to set a minimum current limit.

3) The most important feature is voltage-dependent current-order limit HVDC converter consumes reactive power equal to 50-60% of the transferred power.

Under low voltage conditions, HVDC will need more reactive power than normal case, in turn it will further depresses the AC system voltage and aggravates the situations. If the ac system is weak, the voltage collapse may take place.

### 4-2 The modified two area system and HVDC control

In the second part, HVDC control modeling and the modified two-area study system are illustrated.

![Modified two-area study system](image-url)

**Figure 4.5: Modified two-area study system**
In order to get the similar topology as the WECC (Western Electricity Coordinating Council) system, we construct the test system by adding a bipolar dc line parallel to the ac line between the two areas, as shown in the Figure 4.5. The dc link is represented as a monopolar link with a voltage rating of 500KV.

Since HVDC control types range from a wide area, ETMSP HVDC data blocks are used to build the converter control. The simple diagram of the rectifier control is shown in Figure 4.6. The detail block diagram is listed in appendix.

The rectifier operates in power control mode, which means that HVDC will maintain transferred dc power constant from the rectifier side to the inverter side.

![Figure 4.6: Simple block diagram for rectifier side control mode](image)
From Figure 4.6, we can see that the transferred power and voltage values are derived from the dc line. The current reference signal, $I_{ref}$, is computed by the power order, $P_{ord}$, by the rectifier dc voltage, $V_{dc}$. Then the VDCOL characteristic is a function of the dc voltage and dc current. If the rectifier side dc voltage drops below 80% about the rate valve (500kV), the control mode will switch to the constant current control. The output dc current will passes through a limit block that corresponds to the concept of VDCL current limit. For the minimal current limit is set as the current margin, 10%-15% of the rated current. The actual reference current signal ($I_{act}$) minimizes the desired value ($I_{set}$), and then we get the adjusted current order ($I_{adj}$). A proportional plus integral controller is used to control the direct line current. Since this PI control contains the nonlinear gain characteristics, it can also have a good effect on reducing the commutation failure. The ignition delay angle is limited between 5° and 120°. The minimum ignition angle is chosen to ensure that sufficient voltage across the value before firing. Then the final output signal is used to control the ignition angle [22].

The inverter controls are more complicated than that of rectifier side. It has two types of control modes: constant current control and constant extinction angle control. Under normal conditions, the inverter tries to maintain dc voltage by operating at the minimum extinction angle control. The rectifier minimal firing angle is set as 15° while the minimum extinction angle is 17°. The inverter voltage control is valid until it does not reach the minimum extinction angle. Otherwise, the mode shift will happen. The inverter on constant extinction angle control can be illustrated by the following equation:
\[
\cos \alpha = \frac{6X_c I_d}{\pi V_{d0}} - \cos \gamma
\]  

(4.8)

The HVDC block (Figure 4.7) is the same as this equation: obtaining commutation reactance, dc voltage and current from inverter side, then minimizing \( \cos \gamma \). The constant extinction angle control will ensure that \( \cos \alpha \) corresponds to a condition with \( \gamma \) constant. Since for inverter side, it has cosine function. Then before getting the output signal \( \alpha \), it needs the arc-cosine function to revert the signal, which is a slightly different from the rectifier control.

![Simple block diagram for inverter control](image)

Figure 4.7: Simple block diagram for inverter control

The inverter also has a current control mode similar to that the rectifier, but it is normally ineffective since its reference value lower than that of the rectifier (the current
margin is 10-15% about the rated current valve). Only when the rectifier cannot maintain constant current control and the current decreases by more than the current margin the inverter current control can take effect. This can be seen from the simple block diagram of inverter control, which has a selection function, shown in Figure 4.7.

4-3 Test case for HVDC of two-area system

HVDC models are very complex and many user-defined blocks are built to model the control modes. Therefore, Model validation is needed to ensure that HVDC dynamic effect is consistent with its actual characteristic. At the same time, steady and dynamic performances of without and with HVDC are compared.

MASS and ETMSP simulation programs are used in the test system. The study system, as shown in Figure 4.5, comprises a two-area, four detailed generator models and a parallel HVDC line between buses 8 and 9. The total 400MW of power flow is transferred from area-1 to area-2, and 200MW power is transferred by HVDC line. All generators are imbedded with exciters, governors and PSS. For the HVDC rectifier side using constant power and firing angle control, the inverter side using constant current and extinction angle control. The load models for bus 7 and bus 9 are nonlinear mixed types: 25% current, 50% power, and 25% impedance load.
4.3.1 **Eigenvalue analysis for the test system**

For this system, 72 user-defined blocks are used to represent HVDC control dynamic characteristics. But this system is still small enough to represent all state modes, such as eigenvalues, eigenvector and participation factors. Since we just concentrate on interarea and local modes, the rotor angle modes associated with the synchronous generators are listed in Table 4.1, without HVDC and with HVDC.

Due to adding HVDC link, case B has 65 modes while case A has 60 modes. The damping ratio and frequency for these two cases are quite similar, especially for local area modes. Case B has a slightly poorer interarea mode’s damping ratio than case A. This is because HVDC will consume about 50-60% of the reactive power transferred, at certain cases, it may present unfavorable load characteristic to the power system. At the same time, as a frequency insensitive load HVDC line may produce negative damping torque at generator. This is why under some conditions, the system having HVDC may detrimental effect on the damping of the interarea mode.

**Table 4- 1: Eigenvalue analysis for test system with and without HVDC**

<table>
<thead>
<tr>
<th>Control Mode</th>
<th>Eigenvalue /Frequency (f), Damping ratio (d)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Interarea mode</td>
<td>Area1 local mode</td>
<td>Area2 local mode</td>
</tr>
<tr>
<td>Without HVDC</td>
<td></td>
<td>-0.7012+j4.1745</td>
<td>-2.0200+j8.4169</td>
<td>-2.0857+j8.7443</td>
</tr>
<tr>
<td>(Case A)</td>
<td></td>
<td>f=0.6644,d=0.1656</td>
<td>f=1.3396, d=0.2334</td>
<td>f=1.3917, d=0.2320</td>
</tr>
<tr>
<td>Having HVDC</td>
<td></td>
<td>-0.6684+j4.2504</td>
<td>-1.9909+j8.3336</td>
<td>-2.0713+j8.7092</td>
</tr>
<tr>
<td>(Case B)</td>
<td></td>
<td>f=0.6765,d=0.1599</td>
<td>f=1.3263,d=0.2324</td>
<td>f=1.3861,d=0.2314</td>
</tr>
</tbody>
</table>
4-3-2 Time domain simulation for the test system

To verify the HVDC control mode effectiveness, time domain simulation is provided using ETMSP program. For this system, assuming three-phase fault close to bus 9 on a circuit between bus 8 and 9 at 1.0 sec, cleared at 1.08 sec. Time domain simulation results for AC tie line power, rectifier side power, dc voltage, rectifier alpha, inverter gamma are shown in Figure from 4.8 to 4.12.

From the simulation result, we can see that unlike AC system transient disturbance, DC system response is much faster than the AC system. DC system recovers from the disturbance with decreasing power or shutting down. For this three-phase fault between the rectifier and inverter, the dc voltages for inverter and rectifier sides decrease. As the voltage drops, it will lead to current increase for dc line and at the same time temporarily reduce the transferred power, which is illustrated in Figure 4.9. Under this condition, VDCOL have a great effect on recovering the system from fault. It will limit the current order and prevent the further deterioration of AC system under low voltage. As noted, if the fault lasts a longer time or more severe than this one, the dc voltage will reduce 10% to 15% and repeated commutation failures will take place, which will cause the converter block although it does not happen in the sample test. After about 1 or 2 cycles clearing the fault, the system state will approach the steady state before the fault. These simulation results are consistent with the theory parts, which proves that the test system with HVDC is effect in representing the power system dynamic characteristics.
Figure 4.8: Interface power flow for AC line

Figure 4.9: Rectifier power in MW
Figure 4.10: DC voltage in kV

Figure 4.11: Rectifier alpha in degrees
Figure 4.12: Inverter gamma in degrees
Chapter 5 Remedial Action Schemes and Simulations

5-1 Remedial action scheme tuning procedures based on eigenvalue analysis

Using heuristic arguments noted in previous section, we present a new remedial action scheme based on the damping ratio of interarea oscillatory modes. This scheme assumes that we know what kind of contingency has occurred, such as line outage, etc., and proceeds to decide how much generation tripping would need to be initiated.

Based on extensive studies, the following rules have been developed for the two area test system. We would like to emphasize that the specific numbers in the rules would need to be tuned for other systems, and the criteria would likely have to be strengthened for application to large systems such as the WECC. However, the rules proposed below outline the general philosophy of the proposed computational procedure, which we support with several simulations on the two-area system. We will assume static load models for the loads in the system with typical mixed load types.

A) If the pre-contingency damping ratio of the interarea mode is above 3% and the corresponding post-contingency damping ratio is above 0.5%, no remedial action scheme is needed for this condition.
B) For normal cases, when the pre-contingency damping ratio is between 1.5% and 3%, and the post-contingency damping ratio is from 0.5% to −1.5%, remedial action scheme is necessary in the form of tripping generation in the sending area or/and load shedding in the receiving area. The minimal tripping amount is calculated based on the damping ratio difference between the pre-contingency and post-contingency damping levels of the interarea mode. The tripping amount is evaluated as \( P_{\text{trip}} = \mu^* \Delta d \). Here, \( \Delta d \) denotes the difference in damping levels of the interarea mode between the pre-contingency and post-contingency power-flow conditions, and is stated as a percentage. The parameter \( \mu \) is defined as a “droop” like ratio of MW to % change in damping,

\[
\mu = \frac{\text{MW}}{0.1\% \text{(damping ratio)}}
\]  

(5.1)

In other words, \( \mu \) states how many MW’s of generation will be tripped for each 0.1% change in the damping levels. The parameter \( \mu \) is expected to be a constant for a specific system, and the ratio is somewhat different according to the load types and HVDC transfer amounts. But for a specific kind of load and fixed HVDC transfer amount, this ratio \( \mu \) is an approximate constant value for the post-fault damping ratio between −1.5% and 0.5%. The coefficient factor \( \alpha \) is between 0 and 1, and is introduced to tune the tripping amount for varied HVDC loading conditions. Then the minimal tripping amount is represented by

\[
P_{\text{trip}} = \alpha^* \mu^* \Delta d
\]  

(5.2)
If the operating condition such as the type of loads is known in advance, an appropriate coefficient factor $\alpha$ is chosen to obtain a better correction to the previous value; Otherwise $\alpha$ is set as 1, which gives a conservative value.

Action time (or response time) is another important factor that should be taken into account for determining the minimal tripping. The action time is assumed to be between 0.1 sec and 0.25 sec. If the action time exceeds that limit, the tripping amount needs to increase correspondingly. In the test results, we will see that the case of purely constant power loads is a very special case in being the most severe in terms of stability constraints, and the heuristic rules stated above need to be modified somewhat for handling this special case.

C) If the pre-contingency damping ratio is below 1.5% (poorly positively damped) or if the post-contingency damping ratio is less than $-1.5\%$ (strong negative damping), we need to trip generation at the sending area, and also shed load at the receiving area simultaneously. In this case, the response time is very important. The quicker the RAS action, the smaller the minimal tripping amount and the better the stability performance.

5-2 Test case results

In this section, we will use the Kundur two-area test system to analyze the different factors related to the remedial action scheme.

The study system is shown in chapter 4. The MW power flow is normally from area 1 to area 2. All generators are modeled with exciters and governors. One PSS is included at
generator 1. Contingencies associated with the transmission path are of primary concern in marking RAS decisions. For the HVDC, the rectifier side is represented using constant power and firing angle control, while the inverter side uses constant current and extinction angle control.

5-2-1 Load parameter effects on generator tripping

In this subsection, we list the effect of several types of loads on the tripping amount and the action time.

- Constant impedance load (Table 5.1)
- Constant current load (Table 5.2)
- Constant power load (Table 5.3)
- Mixed load-1: 25% constant current, 50% constant power, 25% constant impedance load (Table 5.4)

HVDC line transfers a fixed 200MW from Area 1 to Area 2. Double lines outages (one of the circuits between buses 7-8, another is one of the circuit between buses 8-9) happen at 1.0 second. RAS action studied here is the tripping of partial generation at Generator 2. The results for minimal tripping amounts are computed using repeated simulations of the contingency in ETMSP.
Table 5-1: Effect of constant impedance load on generation tripping

<table>
<thead>
<tr>
<th>Power flow (MW) (impedance)</th>
<th>Pre-fault damping ratio</th>
<th>Post-fault damping ratio</th>
<th>RAS (tripping gen2-2) Damping ratio(f)/ trip amount(MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.2 sec</td>
</tr>
<tr>
<td>340</td>
<td>3.05%</td>
<td>0.77%</td>
<td>0</td>
</tr>
<tr>
<td>360</td>
<td>2.75%</td>
<td>0.18%</td>
<td>21</td>
</tr>
<tr>
<td>380</td>
<td>2.44%</td>
<td>-0.46%</td>
<td>56</td>
</tr>
<tr>
<td>400</td>
<td>2.12%</td>
<td>-1.11%</td>
<td>84</td>
</tr>
<tr>
<td>410</td>
<td>1.95%</td>
<td>-1.45%</td>
<td>105</td>
</tr>
</tbody>
</table>

Table 5-2: Effect of constant current load on generation tripping

<table>
<thead>
<tr>
<th>Power flow (MW) (current)</th>
<th>Pre-fault damping ratio</th>
<th>Post-fault damping ratio</th>
<th>RAS (tripping gen2-2) Damping ratio(f)/ trip amount(MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.2 sec</td>
</tr>
<tr>
<td>340</td>
<td>1.81%</td>
<td>0.60%</td>
<td>0</td>
</tr>
<tr>
<td>360</td>
<td>1.90%</td>
<td>0.45%</td>
<td>21</td>
</tr>
<tr>
<td>380</td>
<td>1.92%</td>
<td>0.16%</td>
<td>49</td>
</tr>
<tr>
<td>400</td>
<td>1.87%</td>
<td>-0.24%</td>
<td>77</td>
</tr>
<tr>
<td>420</td>
<td>1.74%</td>
<td>-0.79%</td>
<td>112</td>
</tr>
<tr>
<td>440</td>
<td>1.54%</td>
<td>-1.46%</td>
<td>147</td>
</tr>
</tbody>
</table>

Table 5-3: Effect of constant power load on generation tripping

<table>
<thead>
<tr>
<th>Power flow (MW) (power)</th>
<th>Pre-fault damping ratio</th>
<th>Post-fault damping ratio</th>
<th>RAS (tripping gen2-2) Damping ratio(f)/ trip amount(MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.2 sec</td>
</tr>
<tr>
<td>370</td>
<td>3.15%</td>
<td>1.29%</td>
<td>0</td>
</tr>
<tr>
<td>390</td>
<td>3.34%</td>
<td>0.07%</td>
<td>35</td>
</tr>
<tr>
<td>410</td>
<td>3.22%</td>
<td>-1.40%</td>
<td>77</td>
</tr>
<tr>
<td>420</td>
<td>3.03%</td>
<td>-2.35%</td>
<td>84</td>
</tr>
</tbody>
</table>

Table 5-4: Effect of nonlinear mixed load on generation tripping

<table>
<thead>
<tr>
<th>Power flow (MW) (mixed)</th>
<th>Pre-fault damping ratio</th>
<th>Post-fault damping ratio</th>
<th>RAS (tripping gen2-2) Damping ratio(f)/ trip amount(MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.2 sec</td>
</tr>
<tr>
<td>360</td>
<td>1.76%</td>
<td>0.62%</td>
<td>0</td>
</tr>
<tr>
<td>380</td>
<td>1.89%</td>
<td>0.39%</td>
<td>28</td>
</tr>
<tr>
<td>400</td>
<td>1.92%</td>
<td>0.00%</td>
<td>63</td>
</tr>
<tr>
<td>420</td>
<td>1.86%</td>
<td>-0.59%</td>
<td>98</td>
</tr>
<tr>
<td>440</td>
<td>1.69%</td>
<td>-1.33%</td>
<td>140</td>
</tr>
</tbody>
</table>
We note the following observations from Tables 5.1-5.4.

1) The damping levels of the interarea mode have a close relationship with the system stability. For double line outages, when the post-fault damping ratio is below certain value (say 0.5%), the transfer demand exceeds the transfer capacity and the system is transient unstable without a rapid remedial action scheme. Under such conditions, as the interface MW power flow increases, the damping ratio decreases and tripping amount increase at the same time. This is because, as the damping ration decreases towards zero, the size of the ULC becomes smaller [13,14], and hence, the associated region of attraction for transient stability also decreases in size. Therefore, for the same RAS action time, more amount of generation should be tripped to maintain the system stable after the contingency.

2) The ratio $\mu$ can be used to describe the generation tripping ratio per damping change. For certain kind of load, this ratio is nearly a constant value. For example, for the constant impedance load, the ratio $\mu$ is about 5 MW/0.1%; for constant current load, the ratio $\mu$ is about 5 MW/0.1%; for constant power load, the ratio $\mu$ is about 2 MW/0.1%; and for mixed type of load, this ratio $\lambda$ is about 5 MW/0.1%. If the type of load is unknown before the contingency, we can use a conservative value 5.5 MW/0.1% for $\mu$. In the next subsection B, the conservative value of 5.5 MW per 0.1% change in damping levels is used for computing the RA tripping amount from eigenvalue computations.

3) The action time is also an important factor for deciding the minimal generation tripping amount, especially for the constant power load. Usually this action time should
be within 0.25 sec. If the response time is slow for some reason, and if the fact is also known to the RAS controller, the tripping amounts should be increased correspondingly. When the action time is 1.0 sec, we need to use a $\mu$ value of about 7.5 MW per 0.1% damping change, as compared to a $\mu$ value of 5.5 MW per 0.1% damping change for the 0.25 sec action time. This observation is not always valid for the severe condition of a purely constant power load; for constant power load, when the response time is above 0.5 sec, tripping generator at Generator 2 alone is not enough to keep the system stable after the double line outage, for interface power flow is 420MW. This can be explained by two reasons: one is that constant power load is very sensitive; another reason is that HVDC link is parallel to the AC link and the DC link consumes about 40%-50% reactive power of comparable MW power it transfers. When double-line outage occurs, the AC voltage at converter sides will decrease and it also causes the decrease of reactive power supply for the HVDC link, possibly leading to commutation failures.

4) For double line outages, if the post-fault damping ratio is under $-1.5\%$, tripping generator at the sending area may not keep the system stable after certain contingency. In this case, the system may need generation tripping and load shedding at the same time, especially for the constant power load. For instance, when the pre-fault flow is 460 MW, in order to maintain the system stable after double line outage, we need to trip generation at Generator 2 and also shed load at Bus 7 simultaneously, as shown in Table 6 for the constant power load. Such complex RAS schemes will be discussed in a later paper.
Table 5-5: Two kinds of RAS for special case

<table>
<thead>
<tr>
<th>Power flow (MW)</th>
<th>Pre-fault damping ratio</th>
<th>Post-fault damping ratio</th>
<th>Damping /trip amount trip gen2-2 &amp; load shed</th>
</tr>
</thead>
<tbody>
<tr>
<td>460</td>
<td>1.66%</td>
<td>-6.72%</td>
<td>0.2 sec 105 (gen) 71 (load) 140 (gen) 53 (load)</td>
</tr>
</tbody>
</table>

5-2-2 Comparison of actual and calculated values

In the previous subsection, Tables 5.1-5.4 listed the minimal tripping amounts, which are necessary for stabilizing the system, and these values were computed using extensive simulations of transient stability runs using ETMSP. In this subsection, we will compare the ETMSP based results with the eigenvalue based heuristic algorithm proposed in Section 5.1. For checking the effectiveness of the fast computational procedure, actual (ETMSP) and calculated (eigenvalue based) minimal tripping amounts for different kinds of loads are plotted in Figure 5.1 to 5.4. If the load type is well known ahead of the contingency, we can set a proper coefficient $\alpha$ a priori to better tune the computed values. Even if the load type is unknown, we can still get a feasible value, although the computed value is conservative as we see from Figures.

The typical load type for a realistic power system is a mixed type instead of the basic types: pure constant impedance, pure constant power or pure constant current. The constant power type is not shown here since the rules need to be modified a little bit for this special case, and a purely constant power load is not realistic. Instead, we study two other two types of mixed load effect, as shown in Figures 5.5 and 5.6.
- Mixed load-2: 50% constant current, 25% constant power, and 25% constant impedance load.

- Mixed load-3: 25% constant current, 25% constant power, and 50% constant impedance load.

We observe that the computed values match well with the ETMSP based minimum tripping amounts, even though the computed values are consistently more conservative as compared to the ETMSP results.

![Graph showing comparison for constant impedance load](image)

**Figure 5.1:** Comparison for constant impedance load
Figure 5.2: Comparison for constant current load

Figure 5.3: Comparison for constant power load
Figure 5.4: Comparison for mixed-1 load

Figure 5.5: Comparison for mixed-2 load
5-2-3 PSS location effect on RAS

The effect of PSS location on RAS is investigated in this subsection. The assumptions are the same as the section 5-2-1 except that PSS are added at generator 1 and 4. When the transfer power amount is close to 550MW, the system will become unstable without any remedial action. Because of PSS effect, the transfer limit is higher than the previous case.

The remedial action scheme can be applied to this case in the same way. For mixed type load (25% current, 50% power, 25% impedance load), the comparison of actual and calculated valve is listed in Figure 5.7.
5-2-4 Variations of HVDC transfers

It is well known that HVDC plays an important role in power system transient stability [9]. In this subsection, the HVDC MW flow is varied to study the impact on the double HVAC line outages contingency. In order to focus on the HVDC effect, AC line power flow is kept at a fixed value (190MW) while the DC flow is increased. Other assumptions are the same as the subsection 5-2-1. Three types of mixed effect on the tripping amount are listed in Figure 5.8-5.10 and Table 5-7. The results, shown in Figure 5.8-5.10 and Table 5-7, lead to the following conclusions:

1) When the HVDC transfer amount increases, the total interface transfer limit increases at the same time. However, even as the interface power increases, the AC line
outage does not impact on stability as much as for the increase in AC MW flows studied in subsection 5-2-1. This is consistent with the general notion that DC power flow is more tolerant of AC line outages with regards to AC system stability.

2) The difference between the damping ratios of the interarea mode for the pre-fault and post-fault cases increases as the DC power flow increases, which means that our proposed RAS scheme trips more MW’s of generation, thus becoming more conservative. We can again use the ratio $\mu$ to represent the generation tripping amount. In reality, the ratio $\mu$ can be decreased a little while HVDC transfer amount increases. Using a constant value for $\mu$ (say 5.5) will give us a conservative estimate of the tripping amount as shown in Figure 5.8.
Figure 5.8: Comparison for mixed-1 load

Figure 5.9: Comparison for mixed-2 load
Figure 5.10: Comparison for mixed-3 load

Table 5-6: Effect of mixed load for different HVDC transfer

<table>
<thead>
<tr>
<th>Power flow (MW) (DC flow)</th>
<th>Pre-fault damping ratio %</th>
<th>Post-fault damping ratio %</th>
<th>RAS damping ratio/trip amount (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>390 (200)</td>
<td>1.92%</td>
<td>0.21%</td>
<td>0.73%</td>
</tr>
<tr>
<td>410 (220)</td>
<td>2.10%</td>
<td>0.14%</td>
<td>0.80%</td>
</tr>
<tr>
<td>430 (240)</td>
<td>2.22%</td>
<td>0.04%</td>
<td>0.89%</td>
</tr>
<tr>
<td>450 (260)</td>
<td>2.31%</td>
<td>-0.10%</td>
<td>0.94%</td>
</tr>
<tr>
<td>470 (280)</td>
<td>2.38%</td>
<td>-0.27%</td>
<td>0.98%</td>
</tr>
<tr>
<td>490 (300)</td>
<td>2.40%</td>
<td>-0.49%</td>
<td>0.99%</td>
</tr>
</tbody>
</table>

5-2-5 High HDC transfer cases

The effect of various power flows on AC and DC links is investigated in this subsection. Except that HVDC line transfers 300 MW not 200 MW from Area 1 to Area
2, other assumptions keep the same as the subsection 5-2-1. For double line outages, when the transfer power amount is close to 470MW, the system will become unstable without any remedial action.

The remedial action scheme can be applied to this case in the same way. In order to compare with normal DC transfer cases, we choose the same ratio $\mu$ 5.5 MW/0.1% although the actual ratio $\mu$ is about 5, a slightly smaller than the chosen value. It is observed that different HVDC transfer has some effect on the ratio: the higher HVDC transfer, the smaller value for the ratio. The comparison of actual and calculated value is listed in Figure 5.11. It is shown that calculated value is a little large than the actual one.

![Figure 5.11: Comparison of mixed-1 load](image-url)
5-2-6 Partial loss of HVDC contingency

The purpose of these tests is to show the fundamental effects of HVDC transfer power change on RAS. Under normal operations, HVDC line transfers fixed value (200MW or 300MW) from Area 1 to Area 2. At 1.0 sec HVDC transfer power will decrease to 50MW. During this process, we keep the same control modes for converter and inverter sides. In order to transfer the same amount power after DC power change, within a short period time AC lines will compensate the power that DC lines have lost and AC lines become more stressed or even beyond its stability-limited operation constraints.

![Graph showing the effect of DC transfer from 200MW to 50MW](image)

Figure 5.12: Effect for DC transfer from 200MW to 50MW
To avoid the whole system collapse, tripping generation at sending area would be initiated under a RAS scheme. Based on the same rule, we can get the minimal generation tripping amount. Figure 5.12 and 5.13 show that the comparison of actual and calculated values.
Chapter 6  Conclusions and Outlook

6-1  Conclusions

Using heuristic methods, this thesis presents a novel remedial action scheme, especially for choosing the minimal generation tripping amount, based on analyzing the relationship between the damping levels of the interarea mode for the pre-contingency and post-contingency power-flow scenarios. Effectiveness of this remedial action scheme is verified by comparing the results with those of transient stability studies using ETMSP. The results have been tested for different load types, and by changing AC as well DC transfer flows. The simulation results indicate that this remedial action scheme can provide a credible tripping amount although for certain cases, such as for the constant power load, the results are conservative.

Due to its simplicity and ease of implementation, this remedial action scheme is a useful tool for mitigating severe contingencies for on-line security assessment.

6-2  Outlook

The main objective of this project is to develop fast on-line computational procedures for tuning the remedial action schemes under diverse operating conditions. Extending the results of this paper for a realistic large system promises to be a challenging task. Specifically, the method needs to be modified to handle a number of interarea modes, and
also for handling UEP’s on the transient stability boundary. These results can eventually be used for wide-area control schemes such as the one in proposed [27] for on-line modification of the generation tripping amounts and the tuning of other control parameters.
References


Appendix

A. Block Diagrams of Dynamic Control Devices

Synchronous Generator

\[ R_a = 0.0025, \; X_d = 1.8, \; X_q = 1.7, \; X_{d}' = 0.3, \; X_{q}' = 0.55, \; X_{d}'' = 0.25, \; X_{q}'' = 0.25 \]
\[ T_{d0}' = 8.0s, \; T_{q0}' = 0.4s, \; T_{d0}'' = 0.03s, \; T_{q0}'' = 0.05s, \; H_{1,4} = 6.175, \; H_{2,3} = 6.5 \]

![Figure A. 1: IEEE G3 Mechanical-Hydraulic Governor Model](image-url)
Figure A. 2: IEEE DC1A Excitation System Model

Figure A. 3: IEEE PSS1A Power System Stabilizer Model
Figure A. 4: HVDC rectifier side block diagram