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Coordinated static and dynamic reactive power planning against power system voltage stability related problems

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Coordinated static and dynamic reactive power planning against power system voltage stability related problems

by

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ABSTRACT

Power System, over the many years, has undergone dramatic revolution both in technological as well as structural aspects. With the ongoing growth of the electric utility industry, including deregulation in many countries; numerous changes are continuously being introduced to a once predictable system. In an attempt to maximally use the transmission system capacities for economic transfers, transmission systems are being pushed closer to their stability and thermal limits, with voltage instability becoming a major limiting factor. Insufficient reactive power support affects the reliable operation of electric power systems leading to voltage collapses as observed by the recent 2003 blackout. Among the many available solution options, installation of reactive power control devices such as MSCs, FACTS devices etc seem more viable. This is a typical long term planning problem that needs to consider both steady state as well dynamic condition of the power system after severe contingencies and use better informative indices for the planning process.

A mixed integer programming based algorithm is made use of in this work to develop a comprehensive tool to perform a coordinated planning of static and dynamic reactive power control devices while satisfying the performance requirements of voltage stability margin and transient voltage dip. The systematic planning procedure is illustrated on a large scale case study. The effectiveness of the planning algorithm is demonstrated using two separate planning problems, one where steady state planning is done exclusively against static voltage stability problems, and the other where a coordinated steady state and dynamic Var planning problem is solved.

The results of this work show the effectiveness of the developed planning tool to find a low cost optimal reactive power allocation solution to enable higher real power transfers and improve voltage stability. We envision the method developed will be a research grade tool for planning reactive control devices against voltage instability and will provide system planners a proper guide to find viable and economical planning solutions.

CHAPTER 1 INTRODUCTION

1.1 Introduction

In recent years, a variety of factors such as financial, regulatory, and environmental to mention a few, are forcing electric utilities to operate their systems in ways which make maximum use of transmission capability. This has lead to the full utilization of transmission facilities for economic transfers. Consequently the problem associated with voltage instability or voltage collapse has become the limiting constraint for an increasing number of systems, superseding rotor angle stability as the primary concern. This is evident from the many major system collapses due to voltage instability experienced in by utilities around the world. These network blackouts, which are usually triggered by system faults, occur from lack of reactive power support in heavily stressed conditions.

A number of techniques have been developed to study the problem of voltage instability with the growing concern and much industry attention given to investigating this phenomenon. As the techniques and tools become more mature, utilities are beginning to include voltage stability analysis as part of their routine planning and operation studies. However, well accepted criteria and study procedures do not yet exist. Currently, this analysis is mostly done by power flow program based simulation of an operating point in time several minutes following a disturbance. However, for practical purposes, it is not sufficient to merely understand and analyze voltage collapse mechanisms, but it is essential to also seek for effective and economically justified solutions to the problem. In general, voltage instability or collapse can be contained in a preventive or a corrective way. The preventive control is carried out before voltage instability actually occurs. While the corrective control is to stabilize an unstable power system, directing the system trajectory onto a new stable equilibrium point shortly after a severe contingency, such as tripping of a heavily loaded transmission line or outage of a large generating unit. The corrective control usually relates to system solvability. The work in this thesis is an attempt to include dynamic time domain simulation along with static power flow based tools to analyze a large scale system and take appropriate reactive power control actions in an economical way to counteract the static as well as dynamic voltage instability problems.

1.2 Available Solutions

The electric transmission system requires proper long-term planning to strengthen and expand transmission capability. Advanced technologies are paramount for the reliable and secure operation of power systems so as to accommodate continuously increasing transmission usage and long-distance power transactions. However, financial and market forces are, and will continue to, demand a more optimal and economical solutions for the power system problems. Some of the basic options for strengthening and expanding transmission are building/upgrading new transmission system; building new generation at strategic locations; and introducing additional control capabilities. Traditional solutions to upgrading the electrical transmission system infrastructure have been primarily in the form of new transmission lines, substations, and associated equipment. However, as experiences have proven over the past decade or more, the process to permit, site, and construct new transmission lines has become extremely difficult, expensive, time-consuming, and controversial [1]. Furthermore, the strategic siting of generation for purposes of transmission enhancement experiences hindrance since generation and transmission are owned and operated by separate organizations with the decentralization of power system market. In any case, if sufficient active power transmission capability already exists, further reactive compensation can be shown to be the most cost effective reinforcement option. So even though all of the above mentioned options will continue to exist as options in the future, the first two options have become less and less viable for addressing voltage security problems. There is significantly increased potential for application of additional power system control in order to strengthen and expand transmission in the face of growing transmission usage. The incentives for doing so are clear: there is little or no right-of-way, and capital investment is much less [2]. Although considerable work has been done in planning transmission in the sense of building new transmission system or new generation facilities [3], there has been little effort towards planning transmission control. As discussed before, the ability to consider these control devices in the planning process is a clear need to the industry [4], [5], [6], [7].

There are 3 types of control technologies that exist today: generation controls, power-electronic based transmission control, and system protection schemes (SPS). Of these, the first two exert continuous feedback control action; the third exerts discrete open-loop control action. Most of the times in real systems, the characteristics of certain area of the transmission system are such that the voltages immediately following a critical outage fall to such a degree that there is a risk of voltage collapse. The time delays required to ensure correct operation of SPS (MSC) devices means that they cannot be switched quickly enough to improve this aspect of the system voltage behavior. For this reason, any additional reactive compensation had to be of the fast responsive power electronics based devices. Power electronics based equipment, or Flexible AC Transmission Systems (FACTS), provide proven technical solutions to voltage stability problems. Especially, due to the increasing need for fast response for power quality and voltage stability, the shunt dynamic Var compensators such as Static Var Compensators (SVC) and Static Synchronous Compensators (STATCOM) have become feasible alternatives to a fixed reactive source, and therefore have received intensive interests [4]. Since power systems are already hybrid [2], and since good solutions may also be hybrid, assessment of control alternatives for expanding transmission must include procedures for gauging cost and effectiveness of hybrid control schemes.

1.3 Objective of this Work

Although a plethora of publications exist that describe voltage phenomena, a comprehensive methodology and satisfactory analysis and design tools that address the issue of optimally allocating static/dynamic VAR source mix is not readily available. A series of questions have been raised frequently by utility planners and manufacturers: what is the right mix, where is the right location and what is the right size for the installation of reactive power compensators considering technical and economic needs? Can the models, methods, and tools used for static Var planning be applied in dynamic Var planning?

The objective of this work is to develop criteria for the selection of the optimal mix and placement of static and dynamic VAR resources in large power systems with voltage stability constraints that answer all the above questions.

1.4 Organization of this Thesis

The rest of the thesis is organized as follows:

In chapter 2, a detailed literature survey of the topics relevant to this project has been presented. Definition and various theories of Voltage instability phenomenon have been presented. A brief account of secondary effects of voltage instability that lead to major voltage collapse situations is given. Then the effective system performance-criteria that are used for voltage stability assessment as well as control planning in this work are explained. The chapter also includes a section describing the various reactive power sources available that are divided into two types, namely static and dynamic. An account of the devices that are considered for this planning work has been given. Importance of Var/Voltage planning in today's environment has been stressed. The last section of the chapter includes a detailed literature review of the various works that have been done in the field of reactive power planning. The literatures are divided into two parts, namely the first variety that deal will steady state reactive power planning, and the second variety that deal with dynamic and coordinated static and dynamic Var planning methods.

In Chapter 3, a detailed account of the control planning tool developed in this project to find the optimal allocation of right mix of static and dynamic Var sources has been presented. The planning is done such that the proposed control solution, if implemented, should satisfy the minimum requirements for the steady state post contingency voltage stability margin and transient voltage dips. The chapter includes details of what device models a voltage stability base case should contain, what tools are used to assess the voltage stability of a power system for both steady state as well as dynamic system conditions, and how the performance indices that reflect the status of the system with respect to voltage stability are calculated. Then the important process of contingency analysis is explained. The last section of the chapter gives a detailed account of the control planning algorithm that has been used in this project. The control planning algorithm, which is basically a mixed-integer programming problem addresses three different planning problems. One corresponds to planning against steady state post contingency voltage instability, one corresponds to increasing the post contingency steady state voltage stability margin beyond certain minimum criteria as per the standards, and the last one corresponds to a coordinated planning of static and dynamic Var sources in order to satisfy minimum requirements for steady state voltage stability margin as well transient voltage dips. The developed planning tool was applied to a large-scale system.

In chapter 4, the results of the developed planning tool have been included. The chapter contains a description of the large-scale system and the process of obtaining the critical contingency list for the focus area of the system. Then the chapter gives a detailed account of each step involved in the comprehensive planning process leading to a final optimal solution. Two sets of solutions have been presented. The first one is for the planning problem against steady state voltage stability problem with purely static solution. The second problem deals with the coordinated static and dynamic solution for steady state as well transient voltage problems in the system. The obtained lowest cost solution was validated for its effectiveness.

Chapter 5 contains conclusion and scope for further improvement of the planning tool developed in the near future.

CHAPTER 2 LITERATURE REVIEW

2.1 Voltage Stability: Introduction

Over the past few decades, a greater importance has been felt to recognize Power System Stability issues for secure system operation. A major section of researchers have put onus on clearly understanding the different types of instability and how they are interrelated, as these stability problems can lead to system failure [8]. So in this context, it is essential to clearly define these stability problems, and have a consistent use of terminology for developing satisfactory system design and operating criteria, standard analytical tools, and study procedures. With this vision a Task Force, set up jointly by the CIGRE Study Committee 38 and the IEEE Power System Dynamic Performance Committee, addressed the issue of stability definition and classification in power systems from a fundamental viewpoint and closely examined the practical ramifications [9]. The report classified Power System Stability as shown in Figure 2.1.

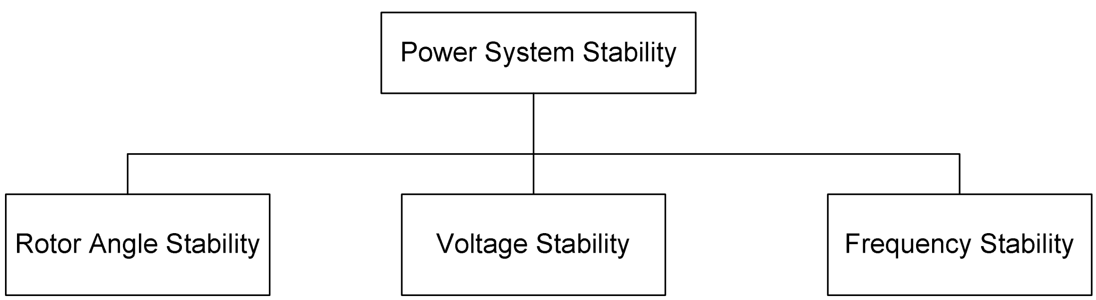


Figure 2.1 Classification of power system stability [9]

- Rotor angle stability refers to the capability of synchronous machines in an interconnected power system to remain in synchronism subjected to a disturbance.
- Voltage stability refers to the capability of a power system for maintenance of steady voltages at all buses in the system subjected to a disturbance under given initial operating conditions.

- Frequency stability refers to the capability of a power system for maintenance of steady frequency following a severe system upset resulting in a significant imbalance between generation and load.

According to that report, as power systems evolved through continuous growth in interconnections with increased operation in highly stressed conditions and use of new technologies and control, the historical focus on transient stability is being shifted to many different forms of system stability issues that have emerged such as frequency stability , voltage stability etc. However, voltage instability has been a major cause of several recent major power outages worldwide [8], [10], and it was one of several problems that led to the August 2003 blackout in the eastern US.

The same report [9] defines a voltage collapse as being the process by which voltage instability leads to a very low voltage profile in a significant part of the system. A voltage collapse may occur rapidly or more slowly, depending on the system dynamics. It may be caused by a variety of single or multiple contingencies. These may be the sudden removal of generation or a transmission element (a transformer or a transmission line), an increase of load without an adequate increase of reactive power, or the slow clearing of a system fault. Voltage collapse is more likely when transmission lines are heavily loaded.

2.2 Voltage Instability/Collapse: Theories

Several theories have been proposed to understand the mechanism of voltage instability. Voltage instability leading to collapse is system instability in that it involves many power system components and their variables at once. There are several system changes that can contribute to voltage collapse [11] such as increase in loading, generators or SVC reaching reactive power limits, action of tap changing transformers, load recovery dynamics and line tripping or generator outages. Most of the above mentioned system changes have a large effect on reactive power production or transmission. To discuss voltage collapse some notion of time scales is needed that accounts for fast acting variables of time scales of the order of seconds such as induction motors, SVCs to slow acting variables having long term dynamics in hours such as LTCs, load evolution etc.

A major factor contributing to voltage instability is the voltage drop that occurs when active and reactive power flow through inductive reactance of the transmission network; which limits the capability of the transmission network for power transfer and voltage support [9]. The power transfer and voltage support are further limited when some of the generators hit their field or armature current time-overload capability limits. Voltage stability is threatened when a disturbance increases the reactive power demand beyond the sustainable capacity of the available reactive power resources. The driving force for voltage instability is usually the loads. In response to a disturbance, power consumed by the loads tends to be restored by the action of motor slip adjustment, distribution voltage regulators, tap-changing transformers, and thermostats. Restored loads increase the stress on the high voltage network by increasing the reactive power consumption and causing further voltage reduction. A run-down situation causing voltage instability occurs when load dynamics attempt to restore power consumption beyond the capability of the transmission network and the connected generation. The above discussed phenomenon is a typical case caused by a cascade of power system changes.

The publication [12] provides a description of several factors that affect the mechanism of a voltage collapse. These factors are examined for a simple power system with its actual PV curves, shown in Figure 2.2, to briefly explain the voltage collapse phenomenon. It can be seen from this figure that, for a particular system and loads considered, the normal system can be stable with both resistive and motor loads at points where load curves and system curves intersect. However, when the system becomes stressed, with increased system reactance, it can only have a stable operating point with a resistive load. There is no intersection of system and load curves for the motor load since there is no stable operating point.

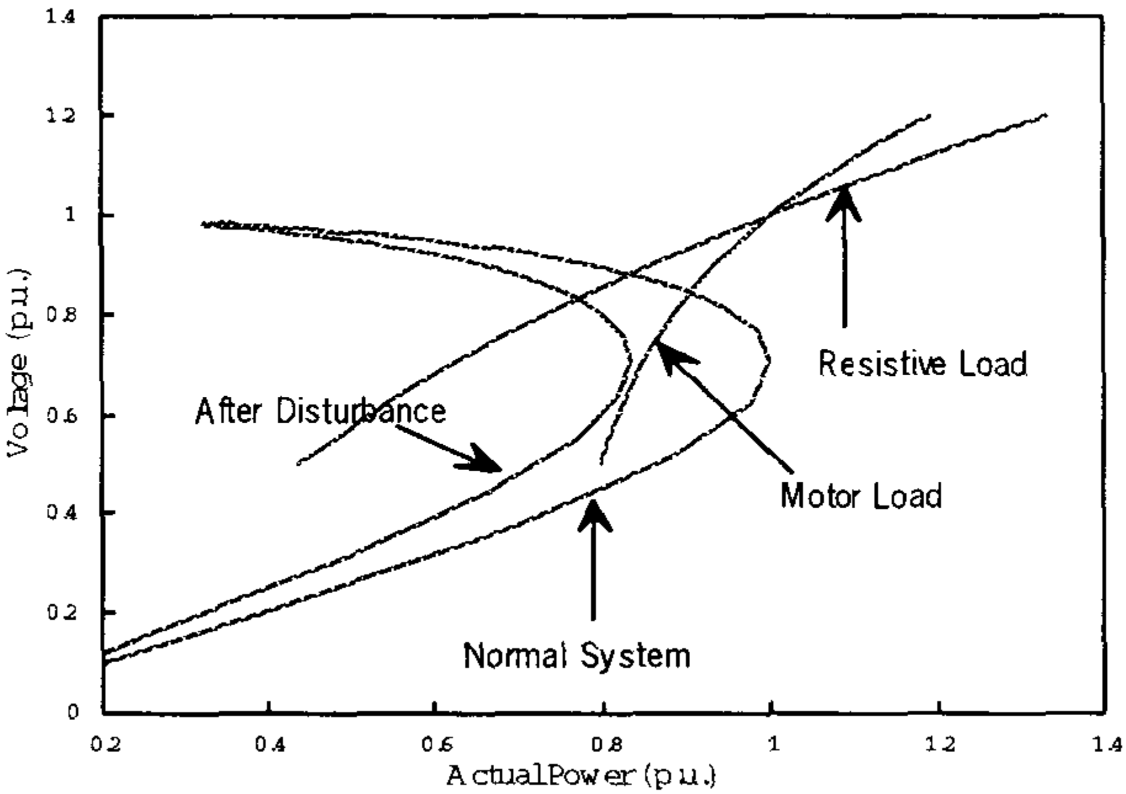


Figure 2.2 Stable and Unstable System Load Characteristics [12]

The above discussions give a physical sense of what the problem of voltage instability is, and shed importance on the requirement of good study techniques and models. It is recognized that the problem of low voltage and that of voltage stability is not the same, as the system can be still susceptible to voltage instability in spite of good pre-contingency and post-contingency voltage profiles due to various other reasons.

A more detailed explanation of voltage instability in terms of bifurcation theories are given in many literatures. Being an inherently nonlinear phenomenon, it is natural to use nonlinear methods such as bifurcation theory to consider voltage collapse and to devise ways of avoiding it. The main idea of such theories is to analyze the system at the threshold of stability. In [11], [13], a deeper look into bifurcation theories like saddle-node bifurcation, Hopf bifurcation and singularity-induced bifurcation are given. Such study gives a sense of how the system states like bus voltages, machine angles etc, which vary dynamically during system transients, change with respect to slow or gradual changes in system parameters like real power demands at system buses, which changes the system equations used. They also discuss how corrective/preventive measures can be devised.

2.3 Secondary Effects of Voltage Sag leading to Collapse

If the voltage drops to a point where some motors stall, the reactive power requirement increases quickly, and the rate of voltage decline can accelerate catastrophically [14], [15], [16]. Heavily loaded transmission lines during low voltage conditions can result in operation of protective relays causing other lines to trip in a cascading mode. A common scenario is a large disturbance such as a multi-phase fault near a load center that decelerates motor loads. Following fault clearing with transmission outages, motors draw very high current while simultaneously attempting to reaccelerate, and may stall if the power system is weak. Massive loss of load and possibly area instability and voltage collapse may follow. Investigating system response from the planning stage is vital to prevent a voltage collapse. A typical voltage recovery phenomenon following a disturbance is indicated in Figure 2.3.

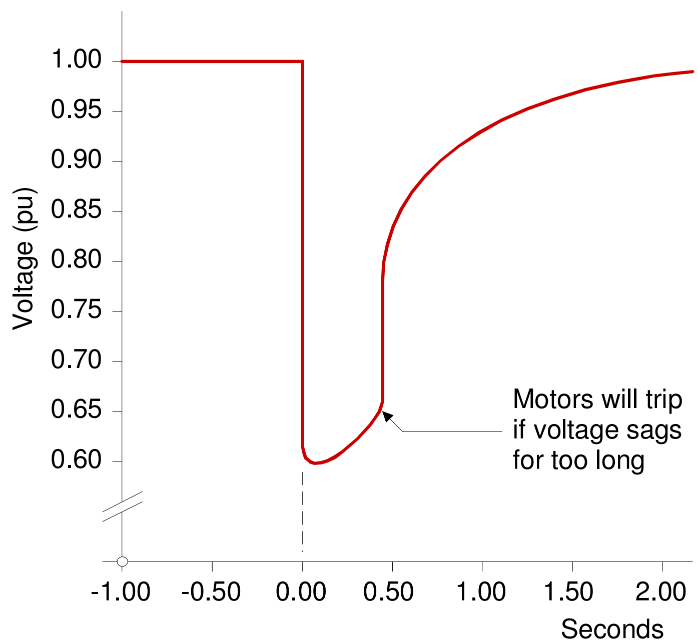


Figure 2.3 Possible Behavior of Voltage Recovery after a Disturbance [15]

There are several works [17] that have documented many short-term (few seconds) voltage collapse incidents with loss of load that have occurred in recent years. In all cases, adequate dynamic reactive power support was not available which resulted in a large loss of load.

2.4 Voltage Stability Planning Tools/Criteria

Concerns for voltage instability and collapse are prompting utilities to better understand the phenomenon so as to devise effective, efficient and economic solutions to the problem. Traditionally, voltage stability investigations have been based on steady-state analyses, using the power flow model. The system P-V curve and/or the sensitivity information derived from the power flow jacobian have been used to explain the basic concepts, and develop definitions and tests, of voltage stability. But the realization that voltage stability is a dynamic phenomenon has led to dynamic formulations of the problem and application of the dynamic analysis tools. It has been identified that the important issue is the modeling requirement and modeling adequacy of the various system components. Voltage stability is largely determined by load characteristics and the available means of voltage control. Motor loads are particularly hazardous from the viewpoint of voltage stability and require special consideration. The response speeds of these loads may be comparable to the speed of response of the voltage control equipment. A detailed modeling of their dynamic behavior along with that of the relevant voltage controls may, therefore, be necessary.

In this work, we focus on planning for systems only having the voltage stability problem. The proposed planning approach can be extended to consider other stability/security problems as well. In order to effectively plan against such stability problems, we need to identify proper performance criteria. Planning power systems is invariably performed under the assumption that the system is designed to maintain stability under a certain set of contingencies. There is currently a disturbance-performance table within the NERC (North American Electric Reliability Corporation)/WECC (Western Electricity Coordinating Council) planning standards [18] which provides minimum post-disturbance performance specifications for credible events. The post-disturbance performance criteria regarding voltage stability include:

- Minimum post-contingency voltage stability margin;
- Minimum transient voltage-dip criteria (magnitude and duration).

The rest of this section will introduce voltage stability margin and transient voltage dip. Voltage stability margin is defined as the amount of additional load in a specific pattern of load increase that would cause voltage instability as shown in Figure 1.2. The potential for contingencies such as unexpected component (generator, transformer, transmission line) outages in an electric power system often reduces the voltage stability margin [9], [19], [20].

Figure 2.4 shows the voltage stability margin under different operating conditions and controls.

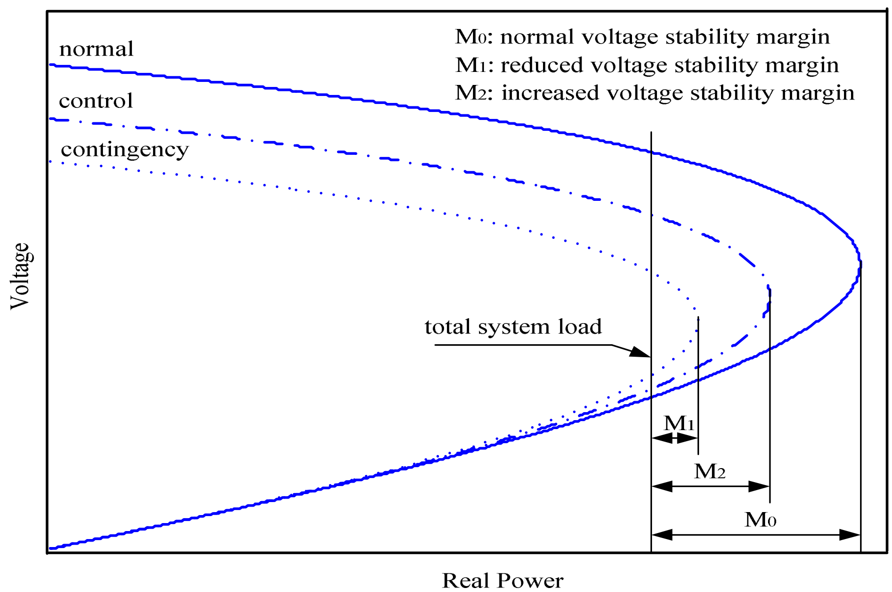


Figure 2.4 Voltage stability margin under different conditions [2]

Note that severe contingencies may cause the voltage stability margin to be negative (i.e. voltage instability). A power system may have the minimum post-contingency voltage stability margin requirement. For example, the NERC/WECC voltage stability criteria require that

- The post-contingency voltage stability margin must be greater than 5% for N-1 contingencies;

- The post-contingency voltage stability margin must be greater than 2.5% for N-2 contingencies;
- The post-contingency voltage stability margin must be greater than 0% for N-3 contingencies.

The above mentioned criterion equally applies to the system with all elements in service and the system with one element removed and the system readjusted. Appropriate power system control devices can be used to increase the voltage stability margin.

On the other hand, transient voltage dip is a temporary reduction of the voltage at a point in the electrical system below a threshold [14]. It is also called transient voltage sag. Excessive transient voltage dip may cause fast voltage collapse [7], [17]. In [21], it is stated that the needs of the industry related to voltage dips/sags for power system stability fall under two main scenarios. One is the traditional transient angle stability where voltage “swing” (i.e., dip/sag) during electromechanical oscillations is the concern. The other is “short-term” voltage stability generally involving voltage recovery following fault clearing where there is no significant oscillations, for which much greater load modeling detail is required with the fault applied in the load area rather than near generation. The two scenarios are different enough that a single criterion for angle stability voltage swing dip and for short-term voltage stability may not be appropriate. In [17], it is stated that many planning and operating engineers are insufficiently aware of potential short-term voltage instability, or are unsure on how to analyze the phenomena. Reliability criteria often does not address short -term voltage stability. In this work, we focus on the transient voltage dip after a fault is cleared.

In [21], information on transient voltage dip criteria following fault clearing related to power system stability was provided. Information was included from utilities, reliability councils, relevant standards, and industry-related papers. The WECC criteria on transient voltage dip are summarized in the following and will be used to illustrate the proposed control planning approach. The WECC transient voltage dip criteria are specified in a manner consistent with the NERC performance levels of (A) no contingency, (B) an event resulting in the loss of a single element, (C) event(s) resulting in the loss of two or more (multiple) elements, and (D) an extreme event resulting in two or more (multiple) elements removed or cascading out of service conditions, as follows:

- NERC Category A: Not applicable.
- NERC Category B: Not to exceed 25% at load buses or 30% at non-load buses. Not exceed 20% for more than 20 cycles at load buses.
- NERC Category C: Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.
- NERC Category D: No specific voltage-dip criteria.

The figure 2.5 below shows the WECC voltage performance parameters with the transient voltage dip criteria clearly illustrated [22]. Again, appropriate power system controls can be utilized to mitigate the post-contingency transient voltage dip problem.

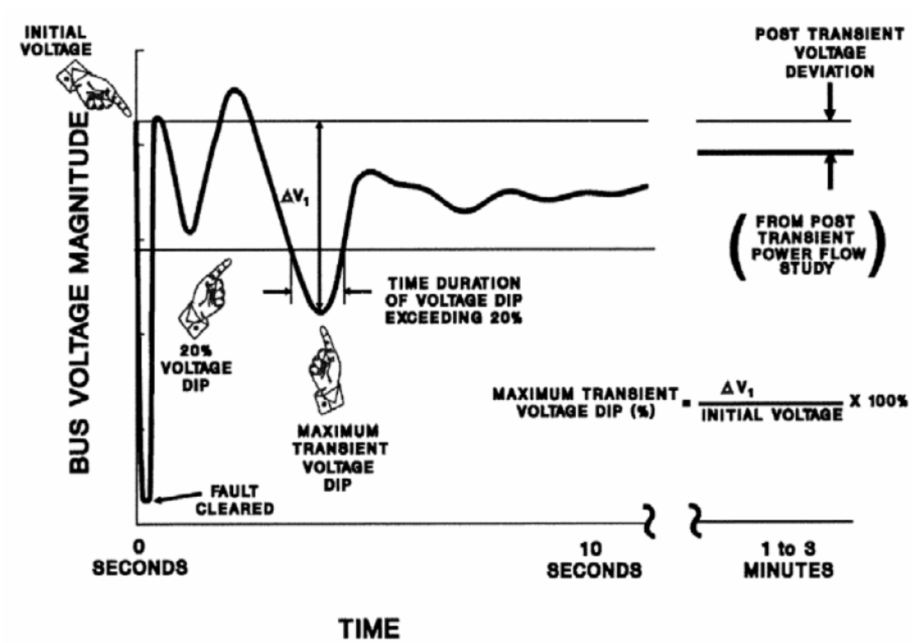


Figure 2.5 Voltage performance parameters for NREC/WECC planning standards [18]

It is mentioned in [23] that all the voltage stability criteria developed are mainly deterministic criteria. The Performance Levels used have been prepared based on historical average frequency of outages of various elements. It is perceived that establishment of voltage stability criteria is an evolutionary process that will require changes and enhancements as more experience is gained. Currently WECC is in the process of establishing probabilistic criteria which is directly related to the frequency and duration of outages. References [24], [25] are few efforts where the objective is to provide a risk-based approach to security assessment for a voltage stability constrained power system that are commensurate with the corresponding level of risk.

The voltage stability of a power system is greatly dependent upon the amount, location and type of reactive power sources available. If the reactive power support is far away, insufficient in size, or too dependent on shunt capacitors, a relatively normal contingency (such as a line outage or a sudden increase in load) can trigger a large system voltage drop. Hence there must be a proper allocation of reactive power support to support the power system under stressed conditions. Gradually, the importance of the VAR/voltage control planning problem has been felt.

2.5 VAR/Voltage Control

There are primarily three main variables that can be directly controlled in the power system to impact its performance. These are Voltage, Angle & Impedance [1]. One could also make the point that direct control of power is a fourth variable of controllability in power systems. With the establishment of "what" variables can be controlled in a power system, the next question is "how" these variables can be controlled. Several options are available to prevent voltage instability. Fast under-voltage load shedding (approximately one second time delay) is an option, but many residential air conditioner motors may still stall [12], [17]. Network reinforcements include new lines and transformers etc. But a number of studies done on the cost benefit analysis of investment on Reactive power control strategies and transmission re-enforcements over certain planning period do show that in most common cases reactive power control strategies look a viable and effective option [26], [27], [28]. The available reactive power control devices can be divided into two parts: namely conventional equipment and FACTS controller.

a) The Conventional equipments for enhancing Power system Control [1]:

- Series Capacitor (Controls impedance),
- Switched Shunt-Capacitor (MSC) and Reactor (Controls voltage),
- Transformer LTC (Controls voltage),
- Phase Shifting Transformer (Controls angle),
- Synchronous Condenser (Controls voltage),
- Special Stability Controls (voltage control but can often include direct control of power),
- Others (When Thermal Limits are involved) include re-conductoring, raising conductors, dynamic line monitoring, adding new lines, etc.

These devices are also called System protection schemes (SPS). MSCs have been used for post-contingency control [29], [30], [31], [32], [33].

b) The FACTS controllers for enhancing Power system Control [1], [26]:

- Static Synchronous Compensator (STATCOM) (Controls voltage),
- Static Var Compensator (SVC) (Controls voltage),
- Unified Power Flow Controller (UPFC),
- Convertible Static Compensator (CSC),
- Inter-phase Power Flow Controller (IPFC),
- Static Synchronous Series Controller (SSSC) (voltage, impedance, angle and power),
- Thyristor Controlled Series Compensator (TCSC) (Controls impedance),
- Thyristor Controlled Phase Shifting Transformer (TCPST) (Controls angle),
- Super Conducting Magnetic Energy Storage (SMES) (Controls voltage and power)

These are Power-electronic based transmission control devices [34].

The key to solving transmission system problems in the most cost-effective and coordinated manner is by employing a thorough systems analysis. This includes comparing the system benefits available by conventional equipment and from FACTS controllers. The conventional equipment exerts discrete open-loop control action; the FACTS controllers exert continuous feedback control action. While both static and dynamic Var resources belong to reactive (power) control devices, based on the response time, SVC and TCSC are often called dynamic Var resources, and MSC belongs to static Var resources. SVC and TCSC are effective countermeasures to increase voltage stability margin and to counteract transient voltage dip problems. However, much cheaper MSC is often sufficient for increasing voltage stability margin [32]. In the MSC family, mechanically switched shunt capacitors are usually cheaper than mechanically switched series capacitors while their effectiveness depends on characteristics of power systems.

As mentioned, SVC and TCSC can effectively mitigate transient voltage dip problems since they can provide almost instantaneous and continuously variable reactive power in response to grid voltage transients. In [1] it is shown that the speed of mechanical switches for conventional equipment solutions can be as fast as a couple of cycles of 60 (or 50) Hz. This speed of switching in itself may be fast enough to solve many power system constraints. Although there is a vast improvement in switching time from mechanical to power electronic based solutions (Figure 2.6 illustrates that the speed of power electronics switches is a fraction of a cycle), the main benefit that FACTS controller solutions provide is the "cycling/repeatability" and "smooth control" that accompanies the power electronic based switching. In other words, a mechanically switched based (conventional) solution is usually a "one and done" or "on or off" impact to the power system in the time frame needed for power system stability, whereas the power electronic based solution can provide a smooth, continuous, and/or repeatable option for power system control.

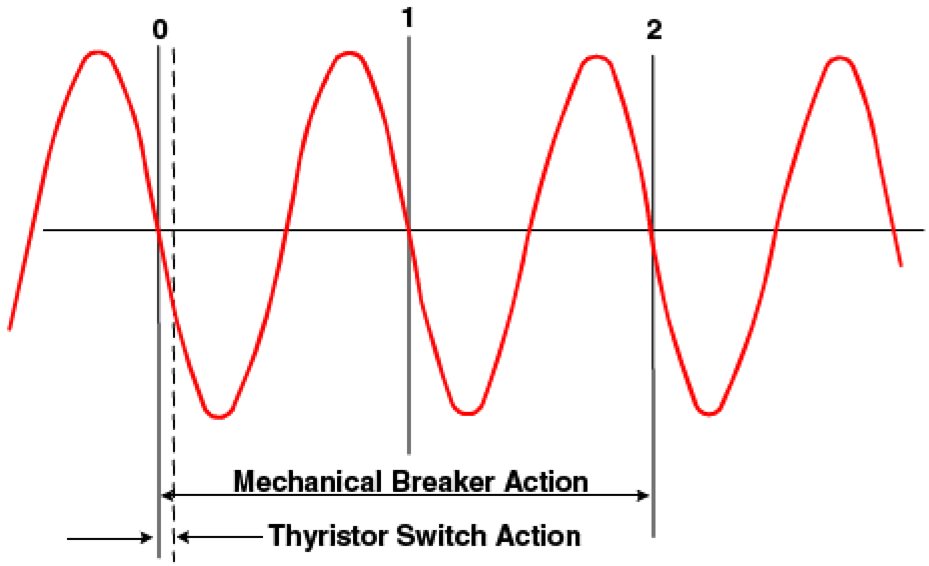


Figure 2.6 Illustration of the speed of power system control [1]

A cost comparison of static and dynamic Var resources is presented in Table 2.7 [20], [28], [35], [36]. The final selection of a specific reactive power control devices should be based on a comprehensive technical and economic analysis.

Table 2.1 Cost comparison for reactive power control devices

	Static Var		Dynamic var	
	Mechanically switched shunt capacitor	Mechanically switched series capacitor	SVC	TCSC
Variable cost ($ million/100 MVar)	0.41	0.75	5.0	5.0
Fixed cost ($ million)	1.3	2.8	1.5	1.5

The advantages achieved in the overall control planning can be qualitatively realized through metrics like effective use of transmission corridors, improved power system stability, reliability and system security, flexibility in siting new generation, elimination or deferral of the need for new transmission etc. However, for justifying the costs of implementing added power system control and for comparing conventional solutions to FACTS controllers, more specific metrics of the benefits to the power system are often required that can quantify the advantages of control planning. Such metrics include Transient Stability Criteria, Power System Oscillation Damping (Minimum damping ratio), long term Voltage Stability Criteria such as minimum voltage collapse margins and Q-V reactive power criteria with minimum margins, short term Dynamic Voltage Criteria such as minimum transient voltage dip/sag criteria (Magnitude and duration) etc.

Each of the above-listed items can usually be measured in terms of a physical quantity such as power transfer through a critical transmission interface, power plant output, and/or area or region load level as discussed in the previous section. This allows for a direct quantification of the benefits of adding power system control and provides a means to compare such benefits by the various solution options considered, whether they are conventional or FACTS based. As mentioned earlier our study is limited to planning against voltage instability problems. So the criteria for long term and short term voltage stability problems are only considered for planning. The problem of finding the optimal allocation of static and dynamic Var sources belongs to the Reactive Power Planning (RPP) or Var planning category.

2.6 Reactive Power Control Planning

Reactive power planning (RPP) involves optimal allocation and determination of the types and sizes of the installed Var compensators to cover normal, as well as, contingency conditions. The planning process aims at providing the system with sufficient Var compensation to enable the system to be operated under a correct balance between security and economic concerns. In [37] detailed information on how reactive power planning problem is typically formulated along with many computational techniques to solve the problem is given. Traditionally, the locations for placing new Var sources were either simply estimated or directly assumed by engineering judgment. However in this work, we propose to develop an optimization methodology for selecting the optimal size and placement of static as well as dynamic VAR sources for a specific system, which is a typical long term planning problem. Rigorous solution to this problem is extremely complex because of its large solution space, large number of contingencies, difficulty in evaluating the performance of candidate solutions, and lack of efficient mathematical solution techniques [38].

Essentially, Reactive Power control strategy is a large-scale mixed integer nonlinear optimization with a large number of variables and uncertain parameters. Solution techniques have evolved over many years. There are no known ways to solve such Nonlinear Programming Problems (NLP) exactly in a reasonable time. Generally, the reactive power planning problem can be formulated as a mixed integer nonlinear programming problem to minimize the installation cost of reactive power devices plus the system real power loss or production cost under the normal and contingency conditions subject to a set of power system equality and inequality constraints. Initially, due to lack of proper knowledge of voltage instability mechanism, as well as lack of good models of dynamic Var devices, Var re-enforcements were restricted to capacitor placement problem. In many cases capacitor placement was done to improve the voltage profile under normal and contingency cases [39]. Then as and when it was found that voltage stability problems are quite different from that of system low voltage problems, many literatures focused on Var planning in terms of capacitor allocation problems to mitigate voltage stability problem using new power system voltage stability indices. There were many literatures with proposals on new and better computational techniques to solve the reactive power planning problem, which can be broadly classified into conventional methods such as Generalized Reduced Gradient (GRG), Newton's Approach, and Successive Quadratic Programming (SQP) etc, and heuristic methods such as Simulated Annealing (SA), Genetic Algorithms (GA), and Tabu Search (TS) etc [40]. Later with the advent of FACTs devices, and better modeling and computational techniques, reactive power planning included allocation of both static and fast acting dynamic devices to mitigate voltage stability problem, while the performance measures or criteria considered were still static. Then with the growing awareness of short term voltage stability issues like voltage dips/sags, dynamic stability criteria were also included in the planning of reactive power compensation for power system voltage stability.

There are a few references which address static VAR planning to increase voltage stability margin. Obadina et. al. in [41] developed a method to identify reactive power control that will enhance voltage stability margin. The RPP problem was formulated in two stages. The first stage involved a nonlinear optimization problem which minimizes the amount of reactive supply. The solution of the first stage is the minimum amount of VARs that needs to be installed in order to satisfy voltage levels and the security constraint. The second stage employed a mixed-integer linear program to minimize the number of VAR supply locations while maintaining system voltages within specified limits, and maintaining a security margin greater than (or equal to) security margin specified. The planning procedure also considers contingencies, where the most severe contingency case with the smallest value of security margin was chosen. The work in [42] introduces the application of genetic based algorithm in reactive power planning problem to find optimal allocation of capacitors to solve voltage instability issues. The work brings out the effectiveness of genetic algorithm in RPP and suggests the use of sensitivity information from the CPF to plan against voltage collapse. The method developed in [43] uses a knowledge and algorithm-based approach to VAR planning in a transmission system. This heuristic VAR Planning method involves two intelligent modules to determine locations and sizes of new compensators considering contingencies and voltage collapse problems in a power system. An expert system module analyzes the operating conditions of a power system and suggests one or more of the P-V. Q-V and S-V curves for use in assessing the voltage collapse problem. A second expert system module suggests control actions with the existing VAR controllers, their sizes and locations for the installation of new compensators. In [44], the effect of static compensation on voltage stability boundary was investigated. A typical class of voltage instability cases which correspond to static bifurcations of power flow equations was considered. For these cases minimum singular values of Jacobian matrix and total generated reactive power were calculated as indicators of stability margin, and sensitivity methods were used for static shunt reactive support allocation. Ajjarapu, et. al. in [45] introduced a method of identifying the minimum amount of shunt reactive power support which indirectly maximizes the real power transfer before voltage collapse is encountered. A relaxation strategy that operates with a predictor-corrector optimization scheme was utilized to determine the maximum system loading point. The sensitivity of the voltage stability index derived from the continuation power flow (CPF) was used to select weak buses to locate shunt reactive power devices. A sequential quadratic programming algorithm was adopted to solve for the optimization problem with the objective function as minimizing the total reactive power injection at the selected weak buses. Overbye et. al. in [46] address the practical problem of power flow cases which have no real solution, proposed an algorithm for determining the best control allocation to restore such cases to solvability. The degree of un-solvability of a power system case was quantified using the distance in parameter space between the desired operating point and the closest solvable point. The sensitivities of this measure to system controls were then used to determine the best control actions to restore the case to solvability. The dynamic consequences of loss of solution should the severe contingency occur, and the maximum allowable time frame for control intervention were also calculated using energy methods. Chen, et. al. in [47] presented a weak bus oriented reactive power planning to counteract voltage collapse. The algorithm identifies weak buses by right singular vector of the power flow Jacobian matrix. Then the identified weak buses are selected as candidate shunt reactive power control locations. The smallest singular value is used as the voltage collapse proximity index. The optimization problem is formulated to maximize the minimum singular value. Simulated annealing is applied to search for the final optimal solution. Chang, et. al. in [48] presented a hybrid algorithm based on simulated annealing, the Lagrange multiplier, and the fuzzy performance index method for optimal reactive power control allocation. The proposed procedure has three identified objectives: maximum voltage stability margin, minimum system real power loss, and maximum voltage magnitudes at critical points. The work in [49] presents a genetic-algorithm (GA) based method to determine the optimal siting of Flexible AC Transmission System (FACTS) controller. It was quoted that the advantage of GA is the solving ability of multi-objective problem. However, the drawback is the time consuming problem for large system. In [50], a new and comprehensive method for optimal reactive power planning (ORPP) against voltage collapse is given. The problem has the objectives of optimally siting and sizing new capacitors at prospective locations such that the transmission loss is minimized, an acceptable voltage profile is obtained, and the voltage stability is improved. To plan against collapse, modal analysis is used to generate a participation-factor-based voltage collapse sensitive index (VCSI). VCSI is used to rank and select the best few prospective buses to site new capacitors. Using fuzzy models, all the violated load bus voltage constraints are fuzzified and their enforcements are maximized. The nonlinear programming problem of ORPP is solved in the successive multi-objective fuzzy LP framework. In [51], a new methodology for fast determination of optimal location of SVC based on system loadability and contingency analysis is presented. Continuation power flows combined with Eigen value analysis of power system were used as tools for choosing the location of SVC based on the loading margin. To value the effect of contingencies on the performance of the system a new index in terms of voltage stability margin was proposed. The effectiveness of the placement of SVC was also obtained in terms of similar index. To analyze the response of different systems without considering the cost of SVC, a norm was proposed. This norm compared the performance of power systems based on loadability margin, contingencies and "flatting" of voltage profiles. Vaahedi, et. al. in [52] evaluated the existing optimal VAR planning/OPF tools for voltage stability constrained reactive power control planning. A minimum cost reactive power support scheme was designed to satisfy the minimum voltage stability margin requirement given a pre-specified set of candidate reactive power control locations. The problem formulation does not include the fixed VAR cost. The obtained results indicated that OPF/VAR planning tools can be used to address voltage stability constrained reactive power control planning. Additional advantages of these tools are: easier procedures and avoidance of engineering judgment in identifying the reactive power control amount at the candidate locations. Xu, et. al. in [53] used conventional power flow methods to assess the voltage stability margin. The methods scale up entire system load in variable steps until the voltage instability point is reached. The modal analysis of power flow Jacobian matrix was used to determine the most effective reactive power control sites for voltage stability margin improvement. Mansour, et. al. in [54] presented a tool to determine optimal locations for shunt reactive power control devices. The tool first computes the critical modes in the vicinity of the point of voltage collapse. Then system participation factors are used to determine the most suitable sites of shunt reactive power control devices for transmission system reinforcement. Granville, et. al. in [55] described an application of an optimal power flow [56], solved by a direct interior point method, to restore post-contingency equilibrium. The set of control actions includes rescheduling of generator active power, adjustments on generator terminal voltage, tap changes on LTC transformers, and minimum load shedding. Feng, et. al. in [57] identified reactive power controls to increase voltage stability margin under a single contingency using linear programming with the objective of minimizing the control cost. This formulation is suitable to the operational decision making problem. The fixed cost of new controls is not included in the formulation. Yorino, et. al. in [58] proposed a mixed integer nonlinear programming formulation for reactive power control planning which takes into account the expected cost for voltage collapse and corrective controls. The Generalized Benders Decomposition technique was applied to obtain the solution. The convergence of the solution can not be guaranteed because of the non-convexity of the optimization problem. The proposed model does not include the minimum voltage stability margin requirement. The work done in [59] proposes two effective ways to increase the voltage stability margin of power systems by finding optimal allocation of shunt and series reactive power compensation. This work proposes a methodology of locating switched shunt and series capacitors to endow them with the capability of being reconfigured to a secure configuration under a set of prescribed contingencies. A new method based on forward/backward search on a graph representing discrete configuration of switches is used to find optimal locations of new switch controls. Specifically, the sensitivity of voltage stability margin with respect to susceptance of shunt capacitors and the reactance of series capacitors is used in the candidate control location selection. In [33] a new optimization based algorithm to plan the minimum amount of switched shunt and series capacitors to restore the voltage stability of a power system after severe contingencies was proposed. Through parameterization of severe contingencies, the continuation method is applied to find the critical point. Then, the backward/forward search algorithm with linear complexity proposed in [59], is used to select candidate locations for switched shunt and series capacitors. Next, a mixed integer programming formulation is proposed for computing locations and amounts of switched shunt and series capacitors to withstand a planned set of contingencies. A linear programming formulation is utilized to further refine the compensation amounts. The work in this thesis is based on this approach.

All the above mentioned literatures deal with static VAR planning to increase voltage stability margin. Some of them contributed to the application of new computational techniques in Var planning. There is another group of literatures, though very limited, that are about dynamic VAR planning or coordinated static and dynamic VAR planning that also addresses transient voltage performance. The work in [60] done in 1978, presents one of the earlier attempts to come up with a comprehensive planning method for coordinated static and dynamic reactive compensation in power systems so as to maintain voltages in acceptable ranges during contingencies. The methodology allows the addition of further VAR compensation as may be economically justified. Reactive compensation considered consists of conventional shunt reactive compensation, synchronous condensers, as well as variable shunt reactive control devices called static VAR control devices. This work combines VAR optimization with static as well as with dynamic system performance evaluations. But this work was not in voltage stability point of view, and the dynamic stability criteria didn't include transient voltage behavior. Donde et. al. [61] presented a method to calculate the minimum capacity requirement of an SVC to satisfy the post-fault transient voltage recovery (which is a specific case of transient voltage dip) requirement. Given the required transient voltage recovery time, the SVC capacity is calculated by solving a boundary value problem using numerical shooting methods. The report [23] presented a Q-V analysis based procedure for the use by system planners to determine the appropriate mixture of static and dynamic VAR sources at a certain bus. First, the intersection of the required minimum voltage and the post-fault Q-V curve considering the short-term exponential load characteristic determines the dynamic VAR requirement. Then, the intersection of the required minimum voltage and the post-fault Q-V curve with load modeled as constant power less the dynamic VAR requirement identified in the previous step is the needed amount of static VAR. An approach was presented in [6], [62], and [63] to identify static and dynamic reactive power compensation requirements for an electric power transmission system. First, optimal power flow techniques were used to determine the best locations for reactive power compensation. Then, Q-V analysis with the constant power load model was utilized to find the total amount of reactive compensation at identified locations. Finally, iterative time domain simulations were performed to determine a prudent mix of static and dynamic VAR sources. Kolluri et. al. presented a similar method in [64] to obtain the right mix of static and dynamic VAR sources in a utility company's load center. All of the coordinated methods mentioned above use a sequential procedure to allocate static and dynamic VAR sources. In [28] a systematic approach in the determination of a cost-effective FACTS solution against transmission vulnerabilities considering transient voltage dip criteria is developed. The analysis in that work presents an example of economic assessment of FACTS investment against several possible short term and long term alternatives. The result is a priority list of possible solutions for the short-term and long-term along with their respective capital cost and/or yearly cost, and a quantification of risk when applicable. The work in [40] categorizes the literature relevant to optimal allocation of shunt dynamic Var source SVC and STATCOM, based on the voltage stability analysis tools used. Those tools discussed in the paper include static voltage stability analysis ones such as P-V and V-Q curve analysis, continuation power flow (CPF), optimization methods (OPF), modal analysis, saddle-node bifurcation analysis, and dynamic voltage stability analysis ones such as Hopf bifurcation analysis and time-domain simulation. A detailed account of various works that has been done for the past 20 years in the dynamic Var planning is given.

2.7 Summary

A review of all the related literatures was done in this chapter. The first section had the importance of studying this voltage stability/voltage collapse phenomenon, as well its mechanism. Then a brief account of some of post-contingency power system criteria was given which will be used in the planning procedure suggested in this work. A section was presented discussing about various static and dynamic Var devices that exist, and their relative merits/demerits. It was noted that Var control planning problem is one of the vital planning problems for modern power system security. The various work done towards optimal Var planning to counter voltage stability problems was discussed.

As seen, plenty of publications exist that describe voltage phenomena and discuss planning static and dynamic Var resources separately to mitigate voltage stability problem. But a comprehensive methodology and satisfactory analysis and design tools that addresses the issue of a coordinated static/dynamic VAR source planning is not readily available. So this work is an attempt to develop one such tool. The primary idea of this work is based on the work done by Haifeng et. al. in [2], [33], [59], [65] which culminated in [38] on planning reactive power control for transmission enhancement. A summary of the planning procedure described in [38] and the relevant changes done to it to accommodate for this work is presented in the next chapter.

CHAPTER 3 REACTIVE POWER PLANNING TOOL

3.1 Introduction

The concerns for voltage stability have motivated the development of some study guidelines [23], [66] based on which several tools are being developed. These tools help to examine for any serious concerns with system voltage stability during planning and operational studies, with the help of some security indices and criteria. The methods adopted usually depend largely on the utilities' experience, policies, and regulatory requirements. There are cases where if studies show that voltage instability may occur when reactive reserves on specific generators reach certain values, then the utility may use such measures as direct indicators of voltage security. The success of any such method depends on the understanding of the mechanism of voltage instability for the particular system under a wide variety of possible conditions including a variety of contingencies. Moreover, it takes a lot of effort to devise planning tools that consider performance criteria that also encompass transient characteristic of system voltages, and can also accommodate a large number of contingencies for planning. The work described in this thesis, which is based on [38] is an endeavor to develop one such long term reactive power planning tool to find optimal allocation of static and dynamic Var sources that considers both static as well as dynamic voltage stability performance criteria, there by improving both post-contingency steady state as well as short term dynamic characteristics of system voltage.

We explicitly target the planning of reactive power controls, i.e., reactive power devices intended to serve as control response for contingency conditions. Thus the system real power loss or production cost is a less important consideration for decision making. A coordinated planning of different types of Var resources to achieve potential economic benefit is done in this work. The proposed planning algorithm based on [38] has following assumptions:

- No new transmission equipment (lines and transformers) is installed, and that generation expansion occurs only at existing generation facilities. This assumption creates conditions that represent the extreme form of current industry trend of relying heavily on control to strengthen and expand transmission capability without building new transmission or strategically siting new generation.

- Existing continuous controllers: The power system has an existing set of continuous controllers that are represented in the model, including controls on existing generators.
- Candidate controllers: Candidate controllers include mechanically switched shunt/series capacitors or SVC or coordinated use of any of these in combination.

The proposed reactive power control planning approach requires few basic steps like establishing a voltage stability base case, performing contingency analysis, and planning reactive power control satisfying the planning requirements as shown in the Fig. 3.1.

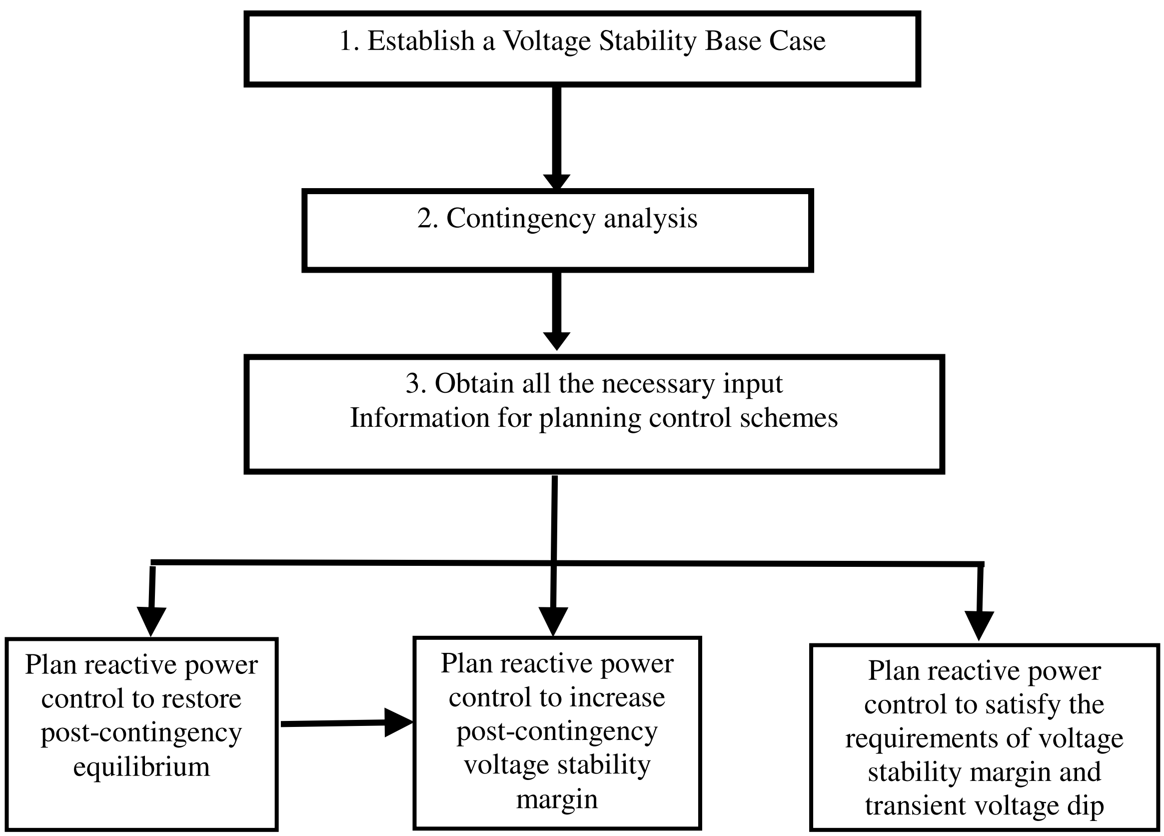


Figure 3.1 Basic steps of the planning process

Figure 3.1 gives a broader idea of the planning tool, while there are many intermediate stages involved in performing the planning task such as obtaining sensitivity information, selecting candidate locations for planning etc. So the next few sections would give a detailed account of successive stages involved in performing a voltage stability assessment and planning against them. Section 3.2 contains information about the various system and device models, and their related data is used to build a voltage stability base case. Section 3.3 presents the system performance criteria that serve as voltage stability indices and section 3.4 gives an account of various tools used to perform the various analyses on the test system. Contingency analysis forms the vital component of any long term planning tool, which is described in section 3.5. Section 3.6 gives detail of the Var resources used for planning and methods to obtain sensitivities of performance measures with respect to these devices. Section 3.7 discusses about the selection of initial candidate locations. Final section 3.8 concludes the chapter.

3.2 Establishing a Base Case

A pre-contingency steady state base case is required for the voltage stability study to be performed. Usually, the base case is generated under real-time sequence control (State estimator solution), or via an already recorded power flow solution for study purposes by the utility. While preparing this base case, there is the vital issue of the extent of system network data representation. There are two types of network models that will have to be represented, namely internal and external models. The degree of detail for the internal (study area) and external systems representation depends upon the type of study being done. Even if ideally the entire interconnected system including both the internal and external systems should be represented in as much as detail as possible, in reality some form of system reduction may be necessary to keep the size of the system manageable. The onus on reduction techniques for voltage stability studies is to retain the same reactive power demand-supply characteristics for the original system and the reduced system [11]. It is also essential to properly model all the devices that are important for the system voltage stability. The next section describes the modeling requirements of the internal network and the various devices in the power system.

3.2.1 Modeling Requirements

The internal model includes representation of lines, generators, transformers, loads, DC converters and shunt/series devices etc. The main purpose is to be able to adequately represent the switching operations in contingencies and possible remedial action schemes. The related data include connectivity/topology information for lines, transformers, shunt/series devices and generating units. Additional information like limits on bus voltages for each voltage level for normal and emergency operation, zone data etc are very useful for system analysis purposes.

Power system device modeling requirements depend on the kind of study being done. Usually system device representation is done with the static models. In the case of dynamic analyses, dynamic models of devices have to be included. Dynamic studies done with static models will give forth to dubious results.

3.2.1.1 Static Device Models

- *Transmission lines* represented as pi-sections, possibly with unsymmetrical line charging; accompanying data include line pi-section impedances/admittances data; line thermal limit both normal and emergency.
- *Transformers* represented as pi-sections whereby the various impedance/admittance components may be explicit functions of tap settings; three winding transformers must be properly modeled The data needed are transformer pi-section data including tap settings and transformer limits under normal/emergency cases
- *Phase-shifting transformers* by complex tap ratios, allowing both shift in angle and change in voltage magnitude;
- *Generators* as real-power source together with a reactive power capability curve as a function of terminal voltage; The required generator static data include minimum and maximum

ratings, nominal terminal voltage and reactive power capability curve as a function of terminal voltage

- *Shunt elements* by their impedance/admittance and Static Var compensators by static gain and maximum/minimum limits
- *Loads* by ZIP model, i.e., as a combination of constant impedance (Z), constant current (I), and constant real/reactive injection (P) components; The data necessary are default ZIP load partition ratios at nominal voltage, load limits and default power factors

3.2.1.2 Dynamic Device Models

- *Machine* mechanical dynamic equation (swing with damping) and machine electrical dynamic equations; machine mechanical parameters such as inertia constant and damping co-efficient and machine electrical parameters such as transient/sub-transient reactances and time constants etc are required. Saturation model data is also very vital.
- *Excitation systems* of various types; the data for each model available in standard power system stability analysis programs such as EPRI's ETMSP, PTI's PSS/E etc are used in most cases.
- *Governor systems* of various types; Again the necessary data for each model are usually available in standard power system stability analysis programs such as EPRI's ETMSP etc.
- *Load* modeling is very vital for performing a voltage stability study. As mentioned earlier big motor loads generally affect the voltage recovery process after voltage sag has been incepted due to system faults, and in many occasions due to extended voltage sag secondary effects such as stalling of sensitive motors or switching of protective devices etc might happen that might lead to massive load disruption. So, it is very vital to represent large, small and trip induction motor loads, slow thermostatically driven loads (heating/cooling) etc in various combinations.

Apart from the above, models for selected prime mover, power system stabilizers, and control devices such as SVC etc are required. Apart from the standard device models, user defined models are also included while building the dynamic case. In addition to all the system/device data required for the models discussed, other system data include convergence parameters such as threshold and maximum iteration counts for static power flow studies, and also various other solution parameters used for the dynamic time domain simulation.

Once the voltage stability base case is ready, next system analysis has to be performed to check the severity of the contingencies that need planning. So the next vital step in the planning procedure is contingency analysis. Voltage stability of the power system should be assessed based on voltage security criteria of interest to, and accepted by, the utility. There are many criteria or indices such as Mvar reserve in different parts of the system, limits on post-contingency voltage declines, sensitivity factors, Eigenvalues, Tangent Vector Index, FSQV (based on summation of diagonal elements of power system jacobian) [67], VSMI (based on the relationship between voltage stability and the angle difference between sending and receiving end buses) [68] etc. As mentioned in the previous chapter the performance criteria used in this work are post-contingency voltage stability margin and transient voltage dip magnitude/duration, which are most basic and widely accepted in the industrial environment. Usually the prediction/estimation of these performance measures for long term planning studies is based on simulation, rather than actual tests. The next section presents the important tools and techniques, namely linear sensitivities, used for performing contingency analysis and system control planning against steady state as well as dynamic voltage stability related issues in any system.

3.3 Voltage Stability Analysis Tools and Methods

There are two general types of tools for voltage stability analysis, namely Static and dynamic [69]. Static analysis is based on the solution of conventional or modified powerflow equations, while dynamic analysis uses time-domain simulations to solve nonlinear system differential algebraic equations. While dynamic analysis provides the most accurate replication of the time responses of the power system, it is expensive in terms of CPU time and engineering requirements. Moreover, the sensitivities obtained in the case of steady state analysis [54] (modal analysis etc.) provide much more information on the relationship between system/control parameters and voltage stability. So many analytical methodologies have been proposed and are currently used for the study of voltage stability problem using static tools [40]. However, with the advent of trajectory sensitivity techniques sensitivity information from the dynamic analysis can be obtained that can be used for the planning process concerned with transient voltage dip issues. It is also seen in recent years that new software package like DigSILENT employ fast dynamic simulation techniques (Quasi-Dynamic) striking a good compromise between speed and accuracy [70]. Such improvement in dynamic analysis has proved to be useful for detailed study of specific voltage collapse situations, coordination of protection and time dependent action of controls.

Anyways in our study, time domain simulation together with static voltage stability analysis tools such as Continuation Power flow techniques and modal analysis are used to plan optimal mix of static and dynamic Var resources against voltage stability issues. There are plenty of references that include details about continuation power [71], [72], [73], [74] and time domain simulation and the various application of these tools. The next section presents details on how these two tools are used to obtain the sensitivity information [13], [75] that will be used for both contingency analysis as well as control planning against system steady state (post-contingency stability margin) and dynamic (transient voltage dip) voltage stability related issues.

3.3.1 Steady State Sensitivity Information

The sensitivity of security margins refers to how much the security margin changes for a small change in system parameters such as P and Q bus injections, regulated bus voltages, Bus shunt capacitance, Line series capacitance etc. Sensitivity computation is used for two major purposes, Contingency Ranking and evaluating Control Action Effectiveness [76]. The details of how contingency ranking and evaluation of the control action's effectiveness or rather selection of the most effective control action will be given in later sections. This section presents the theory behind calculation of margin sensitivities.

3.3.1.1 Voltage Stability Margin Sensitivity

Let the steady state of the power system satisfying a set of equations in the vector form be,

$$F(x, p, \lambda) = 0 \tag{3.1}$$

where, x is the vector of state variables, p is any parameter in the power system steady state equations such as demand and base generation or the susceptance of shunt capacitors or the reactance of series capacitors, the state vector, and λ denotes the system load/generation level called the scalar bifurcation parameter. The system reaches a state of voltage collapse, when λ hits its maximum value (the nose point of the system PV curve), and the value of the bifurcation parameter is equal to λ^*. For this reason, the system equation at equilibrium state is parameterized by this bifurcation parameter λ as shown below.

$$P_{li} = (1 + K_{lpi}\lambda) P_{li0} \tag{3.2}$$

$$Q_{li} = (1 + K_{lqi}\lambda) Q_{li0} \tag{3.3}$$

$$P_{gj} = (1 + K_{gj}\lambda) P_{gj0} \tag{3.4}$$

where, P_{li0} and Q_{li0} are the initial loading conditions at the base case corresponding to λ=0. K_{lpi} and K_{lqi} are factors characterizing the load increase pattern (stress direction). P_{gj0} is the real power generation at bus *j* at the base case. K_{gj} represents the generator load pick-up factor.

When system parameters are changed, the total transfer capability will probably increase or decrease. Reference [13] explains margin sensitivity in the framework of DAE formulation,

$$\dot{x} = F(x, y, p) \tag{3.5}$$

$$0 = G(x, y, p) \tag{3.6}$$

where x are the state variables $x \in R^n$; y are the algebraic variables $y \in R^m$; p are the independent variables or parameters $p \in R^l$; f are the differential equations $f : R^n * R^m * R^l \rightarrow R^n$; and g are the algebraic equations $g : R^n * R^m * R^l \rightarrow R^m$.

$$\frac{\partial \lambda}{\partial P} = \frac{(w_F^T, w_G^T)\begin{pmatrix} F_P \\ G_P \end{pmatrix}}{(w_F^T, w_G^T)\begin{pmatrix} F_\lambda \\ G_\lambda \end{pmatrix}} \quad (3.7)$$

where w are the left Eigen vectors of the Jacobian at the nose point.

Once $\partial\lambda/\partial P$ is computed, we will first get the bifurcation parameter estimation as

$$\Delta\lambda = \frac{\partial \lambda}{\partial P}\Delta P \quad (3.8)$$

For a power system model using ordinary algebraic equations, the bifurcation point sensitivity with respect to the control variable p_i evaluated at the saddle-node bifurcation point is

$$\frac{\partial \lambda^*}{\partial p_i} = -\frac{w^* F_{p_i}^*}{w^* F_\lambda^*} \quad (3.9)$$

where w is the left eigenvector corresponding to the zero Eigen value of the system Jacobian F_x, F_λ is the derivative of F with respect to the bifurcation parameter λ and F_{p_i} is the derivative of F with respect to the control variable parameter p_i.

This margin sensitivity gives the first order partial derivative in the Taylor series expansion of λ as a nonlinear function of P, which describes the hypersurface $\sum$. The bifurcation parameter sensitivity will allow us to know, when some parameters are varied, how the system will move along the hypersurface $\sum$ in the vicinity of the current instability point denoted by λ_*.

The voltage stability margin can be expressed as [38]

$$M = \sum_{i=1}^{n} P_{li}^* - \sum_{i=1}^{n} P_{li0} = \lambda^* \sum_{i=1}^{n} K_{lpi} P_{li0} \quad (3.10)$$

The sensitivity of the voltage stability margin with respect to the control variable at location i, S_i, is

$$S_i = \frac{\partial M}{\partial p_i} = \frac{\partial \lambda^*}{\partial p_i} \sum_{i=1}^{n} K_{lpi} P_{li0} \quad (3.11)$$

The discussed concept is depicted in Fig. 3.2 below.

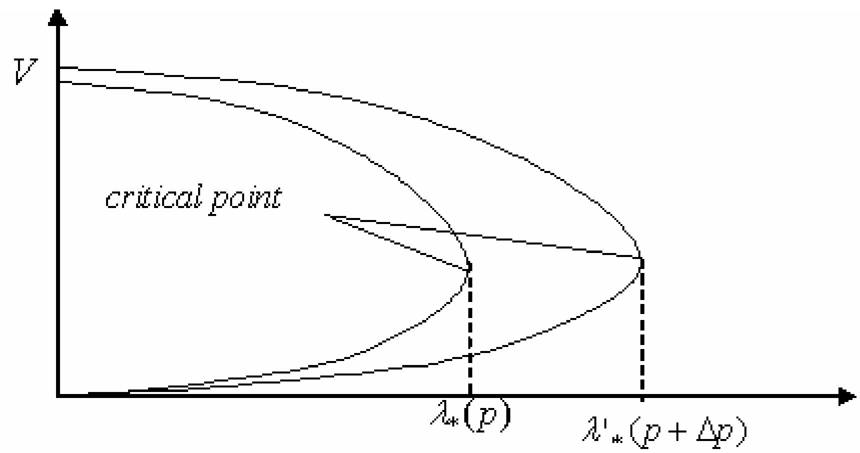


Figure 3.2 Transfer margin change with the change of parameter, p [13]

References [77], [78], [79] first derived these margin sensitivities for different changing parameters. Sensitivity formulae with respect to many parameters such as generator exciter gain, governor parameter, line susceptance, shunt capacitance etc are given in [13].

3.3.2 Transient Voltage Sensitivities

In the case of coordinated static and dynamic Var planning, sensitivity information about voltage dip and duration with respect to reactive compensation parameter is also necessary apart from the steady state voltage stability margin sensitivities. As mentioned in previous chapter, SVC is an effective means to mitigate transient voltage dip by providing dynamic reactive power support. The SVC is modeled as shown in the figure 3.3, with a non-windup limit on the SVC output, constraining the SVC susceptance output B [38]. The power system model when the SVC output reaches the limit is different from that of when the SVC output is within the limit, as at the limits SVC becomes non-controllable and is equivalent to a shunt capacitor. Hence, the ability of an SVC to mitigate transient voltage dip depends on the SVC's capacitive limit (size) B_{svc}. Dynamic reactive power support increases with B_{svc}, but so does the SVC cost.

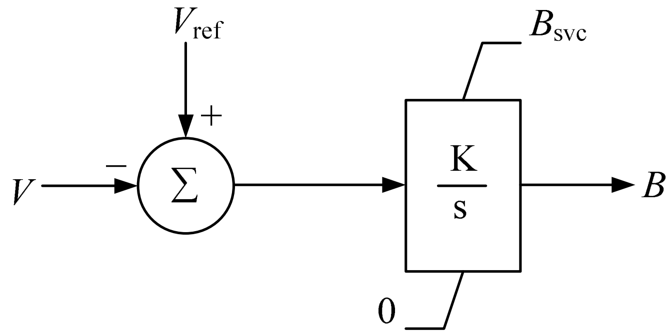


Figure 3.3 Static VAR compensator model [38]

The response of a power system is hybrid when studying large disturbances. In order to derive the sensitivities of the voltage dip time duration and the maximum transient voltage dip to the SVC capacitive limit, the hybrid system nature of a power system needs to be considered. The sensitivities of the voltage dip time duration and the maximum transient voltage dip to the SVC capacitive limit are derived based on the concept of trajectory sensitivities of hybrid systems presented in [38]. The trajectory sensitivities provide a way of quantifying the variation of a trajectory resulting from (small) changes to parameters and/or initial conditions.

3.3.2.1 Sensitivity of Voltage Dip Time Duration to SVC Capacitive Limit

The sensitivity of the voltage dip time duration to the SVC capacitive limit is the change of the voltage dip time duration for a given change in the SVC capacitive limit.

Let, $\tau^{(1)}$ - the time at which the transient voltage dip begins after a fault is cleared, and

$\tau^{(2)}$ - the time at which the transient voltage dip ends, as shown in Fig. 3.4 below.

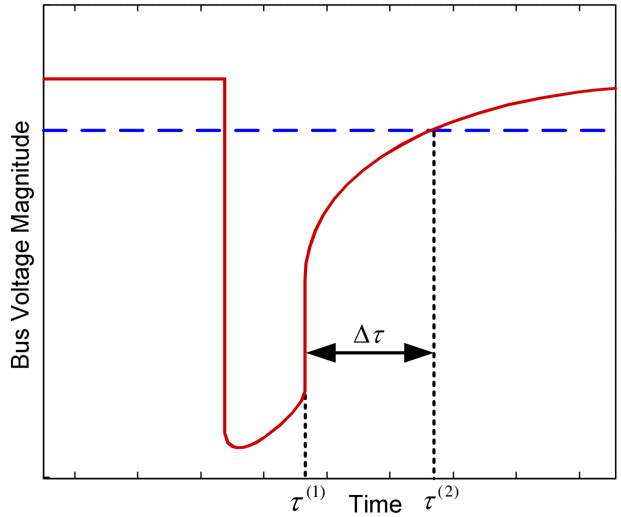


Figure 3.4 Slow voltage recovery after a fault [38]

Then the time duration of the transient voltage dip τ_{dip} is given by

$$\tau_{\mathrm{dip}} = \tau^{(2)} - \tau^{(1)} \tag{3.12}$$

Thus, the sensitivity of the voltage dip time duration to the capacitive limit of an SVC, S_τ, is

$$S_\tau \equiv \frac{\partial \tau_{dip}}{\partial B_{\mathrm{svc}}} = \frac{\partial(\tau^{(2)} - \tau^{(1)})}{\partial B_{\mathrm{svc}}} = \frac{\partial \tau^{(2)}}{\partial B_{\mathrm{svc}}} - \frac{\partial \tau^{(1)}}{\partial B_{\mathrm{svc}}} = \tau^{(2)}_{B_{\mathrm{svc}}} - \tau^{(1)}_{B_{\mathrm{svc}}} \tag{3.13}$$

where $\tau^{(1)}_{B_{\mathrm{svc}}}$ and $\tau^{(2)}_{B_{\mathrm{svc}}}$ are calculated based on trajectory sensitivity computations. Numerical details are given in [38]. It is noted that the hypersurface s(x,y) of the system state trajectory is defined by $0.8V_i(0) - V_i(t)$ when calculating $\tau^{(1)}_{B_{\mathrm{svc}}}$, and is defined by $V_i(t) - 0.8V_i(0)$ when calculating $\tau^{(2)}_{B_{\mathrm{svc}}}$ where V_i is the voltage at load bus i (as 20% dip magnitude is the WECC criteria). If the bus voltage recovery is too slow after a fault is cleared, then we may consider $\tau^{(1)}$ to be equal to the time at which the fault is cleared and therefore, $\tau^{(1)}_{B_{\mathrm{svc}}} = 0$ and $S_\tau = \tau^{(2)}_{B_{\mathrm{svc}}}$.

3.3.2.2 Sensitivity of Maximum Transient Voltage Dip to SVC Capacitive Limit

The maximum transient voltage dip V_{dip} after the fault is cleared is defined as

$$V_{\mathrm{dip}} = \frac{V_0 - V_{\min}}{V_0} \times 100\% \tag{3.14}$$

where V_0 is the pre-fault voltage, and V_{min} is the minimum voltage magnitude during the transient voltage dip.

The sensitivity of the maximum transient voltage dip to the SVC capacitive limit, S_V, is the change of the maximum transient voltage dip for a given change in the SVC capacitive limit

$$S_V \equiv \frac{\partial V_{dip}}{\partial B_{\mathrm{svc}}} = -(\frac{\partial V_{\min}}{\partial B_{\mathrm{svc}}})/V_0 = -(\frac{\partial V}{\partial B_{\mathrm{svc}}}\Big|_{t=t_{\mathrm{max\_dip}}})/V_0 \tag{3.15}$$

where t_{max_dip} is the time when the maximum transient voltage dip (minimum voltage magnitude) occurs after the fault is cleared, $\partial V/\partial B_{svc}$ is the voltage trajectory sensitivity to the SVC capacitive limit. These trajectory sensitivity calculations are given in [38], which are used in this work.

3.3.2.3 Numerical Approximation

It is mentioned in [38] that the trajectory sensitivities and the transient voltage dip sensitivities require the computation of integration of a set of high dimension differential algebraic equations which is very tedious for a larger power system. The computation burden of obtaining the sensitivities is minimal when an implicit numerical integration technique such as trapezoidal integration is used to generate the trajectory. An alternative to calculate the sensitivities is using numerical approximation

$$S_\tau = \frac{\partial \tau_{\mathrm{dip}}}{\partial B_{\mathrm{svc}}} \approx \frac{\Delta \tau_{\mathrm{dip}}}{\Delta B_{\mathrm{svc}}} = \frac{\tau_{\mathrm{dip}}(B_{\mathrm{svc}} + \Delta B_{\mathrm{svc}}) - \tau_{\mathrm{dip}}(B_{\mathrm{svc}})}{\Delta B_{\mathrm{svc}}} \tag{3.16}$$

and

$$S_V = \frac{\partial V_{\mathrm{dip}}}{\partial B_{\mathrm{svc}}} \approx \frac{\Delta V_{\mathrm{dip}}}{\Delta B_{\mathrm{svc}}} = \frac{V_{\mathrm{dip}}(B_{\mathrm{svc}} + \Delta B_{\mathrm{svc}}) - V_{\mathrm{dip}}(B_{\mathrm{svc}})}{\Delta B_{\mathrm{svc}}} \tag{3.17}$$

The above procedure requires repeated runs of simulation of the system model for the SVC capacitive limits B_{svc} and $B_{svc}+\Delta B_{svc}$. The sensitivities are then given by the change of the voltage dip time duration or the maximum transient voltage dip divided by the SVC capacitive limit change ΔB_{svc}. This procedure is easier to implement for a large power system, even though the computation cost may be greater than direct calculation of the sensitivities when large numbers of sensitivities are desired.

Forthcoming sections will explain how this preliminary analysis on the base case and the obtained sensitivity information are used to identify critical contingencies and how reactive power planning is done for those critical contingencies that affect the static as well as dynamic voltage stability criteria.

3.4 Contingency Analysis

A contingency consists of one or more events occurring simultaneously or at different instants of time, with each event resulting in a change of the state of one or more power system elements. A contingency may be initiated by a small disturbance, a fault, or a switching action like breaker opening/closing, generator tripping, etc. Generally these undesirable events do affect a power system's voltage stability. In the immediate aftermath of a contingency, necessary corrective control actions are to be taken to ensure the system does not become voltage unstable, or become vulnerable to voltage instability with the minimum criteria being violated. So the task of contingency analysis plays a vital role in planning against voltage instability issues in a power system.

Traditionally, analysis of contingencies is done by simulating each contingency on the base-case model of the power system using the tools described in the previous section, i.e., CPF based tool and the time domain simulation to assess the voltage stability of a system. Then the calculated post-contingency state of the system is checked for performance criteria violations, i.e., post-contingency voltage stability margin and transient voltage dip characteristics, and a list of critical contingencies is formed that violate the minimum stability criteria. The planning is done only for these selected critical contingencies. In our study, contingency analysis is done for the more probable contingencies, i.e., the N-1 and N-G-T. The single contingency test (N-1) covers the loss of any single item of generation or transmission equipment at any time. Since it is plausible that at any time, one of the generators could be off line, for any number of reasons, an overlapping single contingency (line contingency) and generator outage N-G-T is also investigated. Care must be exercised in this case to account for the system readjustment after the first outage (G) and before the actual contingency (T), for creating a new base case with one element out-of service.

Even if the above process of analyzing the critical contingencies seems to be straightforward in principle, this task that takes significant time in a voltage stability assessment study. When performed for a larger system, it is impractical and unnecessary to analyze in detail the impact of every conceivable contingency. Generally, only a limited number of contingencies might impose actual threat to voltage stability and these might be quite different from the contingencies critical for transient stability, thermal overload, or voltage decline. It is required therefore to select a credible list of contingencies that would affect the voltage stability and analyze only those in detail for planning purposes. This process of filtering the critical contingencies to be analyzed, so that overall computation may be reduced, is known as contingency screening.

3.4.1 Contingency Screening

The process of contingency screening is of immense value in forming a list of critical contingencies that would have an adverse effect on post contingency voltage stability margin. The margin sensitivity described in section 3.3.1.1 can be used for this purpose [78]. The CPF program is used to locate the nose point of the base case, and consequently the normalized left eigenvector of the nose point Jacobian will provide us the margin sensitivity with respect to bus real and reactive power injections, which is in accordance with the linear calculation of margin sensitivity presented in section 3.3.1.1.

For transmission line outages, the change in voltage stability margin is estimated as

$$\Delta L = w_i^p * P_i + w_i^q * Q_i + w_j^p * P_j + w_j^q * Q_j \tag{3.18}$$

where P and Q are the pre-contingency real and reactive power injections to the outaged line, i and j indicate the buses connected by the outaged line, and w_i^p represents the scaled left eigenvector component corresponding to real power balance at bus I and w_i^q corresponds to the reactive power.

For generator outages, the resulting change in voltage stability margin is estimated as

$$\Delta L = w_i^p * \Delta P_i + w_i^q * \Delta Q_i \tag{3.19}$$

where ΔP_i and ΔQ_i are the change of the real and reactive power output of the outaged generator respectively.

Then the contingencies are ranked from most severe to least severe according to the value of the estimated change in voltage stability margin. Once the above mentioned contingency screening is done and a ranked list of severe contingencies is obtained, the next step is to analyze these selected contingencies in detail. So this lessens the burden of performing contingency analysis by giving a clear indication of the critical contingencies that need to be assessed in detail. As mentioned earlier this screening process is valid to rank the contingencies that have steady state voltage stability issues. In the case of transient voltage dip issues, it is necessary to run time domain simulations for every conceivable contingency in order to analyze them. But by combining the critical contingency list obtained from steady state analysis, some engineering judgment, and some prior knowledge of the test system, one can zero in on the critical contingencies that might have severe transient voltage dip problems.

Now the contingencies which cause insufficient voltage stability margin and/or excessive transient voltage dip problems are identified using accurate methods. In the case of static analysis, we evaluate each contingency from the selected severe contingency list starting from the most severe one using the accurate CPF program and stop testing after encountering a certain number of sequential contingencies that have the voltage stability margin greater than or equal to the required minimum criteria. In order to find the contingencies having excessive transient voltage dip problems, the time domain simulation is used. A program has been developed in PSS/E[1], the software used for dynamic study, to automate the time domain simulation for every critical contingency and identify buses that violate transient voltage dip criteria under those contingencies.

[1] PSS/E is the acronym for **P**ower **S**ystem **S**imulator for **E**ngineering tool (PSS™E), which is the standard Siemens offering for electrical transmission analysis that has become one of the most comprehensive, technically advanced, and widely used commercial programs of its type.

Once the critical contingencies are identified, the control planning is performed by formulating a mixed integer linear program like the one proposed in [38]. The optimization routine would require certain input in order to determine an optimal allocation solution. So the next section summarizes the necessary input information required in order to plan control schemes.

3.5 Inputs for Planning Control Schemes

Various input required for planning control schemes include:

- System performance indices for the critical contingencies that need reactive power control planning
- Sensitivity information
- Cost information of the control devices
- Initial candidate location to lessen the computational burden

3.5.1 System Performance Indices

After a thorough analysis of the power system using various tools, we identify a set of critical contingencies that violate specific pre-determined performance criteria. In our case, the criteria are post-contingency steady state voltage stability margin, and transient dip magnitude/duration. The control planning algorithm (MIP optimization module) uses these performance indices under every contingency to plan reactive support according to the severity of each contingency.

3.5.2 Sensitivity Information

As discussed before, the planning algorithm developed in [38] in determining the desired reactive power control locations is mainly based on the sensitivity of the performance indices with respect to reactive support. The sensitivity information does help the planner to optimally allocate the reactive resources which would maximally benefit the system. The sensitivities are obtained as described in the section 3.3.1 and section 3.3.2. This work considers MSC and SVC as the two reactive power devices to mitigate the static and dynamic voltage stability problems respectively. But, it should be understood that the described planning method may be applied to the other types of compensators as well such as series compensators, STATCOM etc, as the centre point of the method is to find the sensitivity of the performance indices with respect to these devices. Care should be taken to properly model the considered device in the planning procedure.

3.5.3 Control Device Cost Information

Cost information is needed to find the total investment cost for system reliability. The objective function of the optimization is to minimize this installation cost. So it is vital to properly model this information which would consider all the necessary information such as the voltage level, geographical location etc. There are not many literatures available that give an exact quantification of cost for every device at various voltage levels. But a good idea can be obtained from the literatures [20], [28], and [36]. The output of the optimization routine very much depends on this modeling of the cost function. It is also to be noted that the optimization is flexible enough to handle any change in the objective function formulation with respect to cost modeling.

The cost in this work is modeled similar to the one in [20]. The total cost of the reactive power device has two components as mentioned in section 2.5. Fixed installation cost in $ and the variable operating cost in $/Mvar. So the input to the control planning algorithm must include this cost information for every candidate location considered for the Var planning.

3.5.4 Initial Candidate Location

For reactive power control planning in large scale power systems, the pre-selection of the candidate locations for installing new reactive power control devices is important, as it reduces the computation burden to solve the MIP/MINLP problem while guaranteeing the existence of feasible solutions to the optimization problem. Moreover, if an effective way of choosing the initial candidate location is there, then the size of the power system under analysis does not matter, as the optimization routine does not involve the full size but only those candidate locations. Usually, candidate control locations are chosen only based on the engineering judgment. There is no guarantee that the selected candidate control locations are sufficient to provide sufficient reactive power support for all pre-defined contingencies. Moreover the practice could result in solutions that are not economically justified.

The work in [38] develops a backward/forward search algorithm to select candidate locations of reactive power controls while satisfying power system performance requirements. But this work does not employ this method because very high computational efficiency, available in the CPLEX MIP solver renders it unnecessary, even with a large set of candidate control locations of the order of 200. Described below is a method that uses sensitivity information and binary search technique to pre-select [38] the best candidate locations for the planning process.

Pre-selection of candidate location:

Choose an initial set of switch locations using the bisection approach for each identified contingency possessing unsatisfactory voltage stability margin and transient voltage dip criteria according to the following 3 steps:

1. Rank the feasible control locations according to the numerical value of margin sensitivities in descending order with location 1 having the largest margin sensitivity and location *n* having the smallest margin sensitivity.
2. Estimate the voltage stability margin with top half of the switches included as

$$M_{est}^{(k)} = \sum_{i=1}^{\lfloor n/2 \rfloor} X_{i\max}^{(k)} S_i^{(k)} + M^{(k)} \tag{3.20}$$

where $M_{est}^{(k)}$ is the estimated voltage stability margin and $\lfloor n/2 \rfloor$ is the largest integer less than or equal to *n/2*. If the estimated voltage stability margin is greater than the required value, then reduce the number of control locations by one half, otherwise increase the number of control locations by adding the remaining one half. Similarly estimate the transient voltage dip duration and magnitude using sensitivity information starting from the top half of the switches until reaching the exact number of switches required.

3. Continue in this manner until we identify the set of control locations that satisfies the voltage stability margin requirement and transient voltage dip criteria. Do this for every identified

critical contingency.

4. Obtain the final candidate control locations as the union of the results for each identified contingencies found in step 3.

3.6 Control Planning Algorithm

There are three different control planning algorithms proposed in [38], each addressing different planning problems. The first problem formulation deals with planning for cases with voltage instability (a), i.e., to take corrective action that brings the voltage stability margin to 0 after a severe disturbance results in negative stability margin. The second problem formulation is to increase the post contingency steady state voltage stability margin to satisfy the minimum system performance criteria with control planning under many contingencies simultaneously (b). Both (a) and (b) can be achieved with static Var devices. The third planning problem addressed is a coordinated planning of static and dynamic Var resources against problems related to both post contingency steady state voltage stability margin and transient voltage dips (c).

A brief description of each method is given in this section. This section is more or less a summary of the planning work done in [38]. The optimization formulation proposed in [38] is the backbone of the work in this thesis. A common feature of the planning procedures for all three problems (a), (b) and (c) is that they are done in two stages. The first stage involves solving the original MIP problem to find the optimal allocation of Var devices. Since the planning procedure uses linear sensitivity information, it is very likely that there are some contingencies that might require additional iterations when the obtained control solution from original MIP is updated in the system and validated. So the second stage involves solving an updated MIP problem to refine the control amount in case some contingencies violate the minimum system performance criteria even after the system up-grade with additional control resources. Figure 3.5 shows the general flow of planning procedure for every planning problem with successive MIP to refine the control amount.

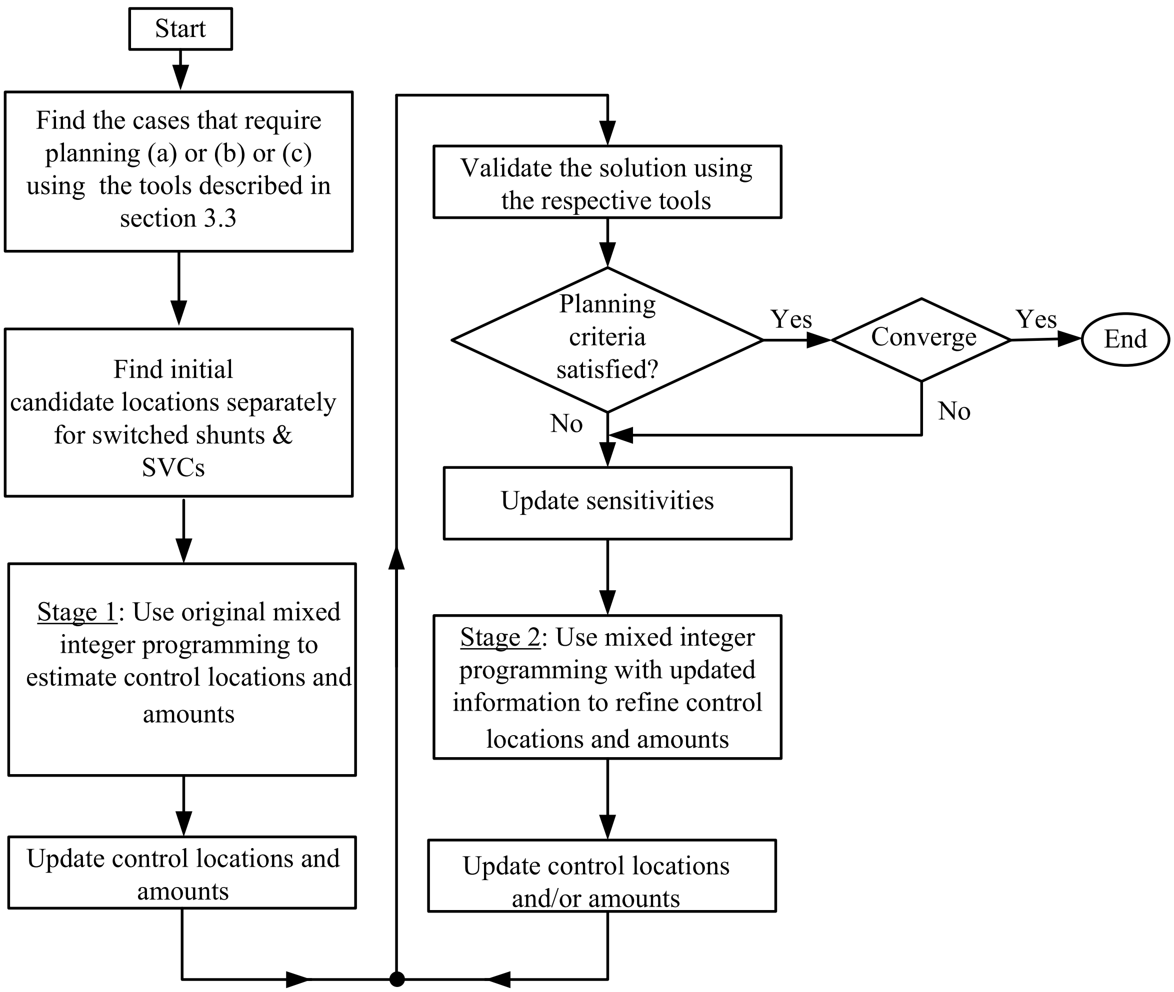


Figure 3.5 Flowchart of planning procedure with successive MIP

The result of the implementation of this planning method on New England 39 bus system was presented in [38]. The work in this thesis is the application of this planning algorithm to a large scale power system. Detail of the entire work done to develop a comprehensive voltage stability assessment tool is given in the next chapter with the application on a larger system of more than 16,000 buses. Necessary changes to the planning procedure described in [38] have been made according to the application requirements of a larger system and assumptions considered in this work.

3.6.1 Planning Problem (a): Corrective Planning against Voltage Instability

Voltage instability is one of the major threats to power system operation. Severe contingencies such as tripping of heavily loaded transmission lines or outage of large generating units can cause voltage instability when no new equilibrium of the power system exists (negative voltage stability margin) after contingencies. There are very many options to restore equilibrium such as redispatch of generation, blocking tap-changing transformers, load shedding etc [11]. In the face of loss of equilibrium, switched shunt and series capacitors are generally effective control [38].

In this work, an approach similar to [38] for planning minimum amount of switched shunt capacitors to restore the voltage stability under severe contingencies is implemented. Through parameterization of severe contingencies, the continuation method is applied to find the critical point. Then, with a set of initial candidate locations for switched shunt capacitors, a mixed integer programming formulation has been proposed for estimating locations and amounts of switched shunt capacitors to withstand a planned set of contingencies. A sequence of MIP with updated information is utilized to further refine the control locations and amounts. Because the problem formulation is linear, it is scalable and at the same time provides good solutions.

3.6.1.1 Contingency Analysis via Parameterization and Continuation

This section discusses a technique used in [38] to plan for certain severe contingency cases when a power system may lose equilibrium, and corrective control planning has to be done. For such a case, the techniques of contingency parameterization and continuation can be used for planning corrective reactive power controls to restore equilibrium. There are basically two common types of contingencies that cause voltage instability. One is branch type of contingency such as the outage of transformers or transmission lines. The other is node type of contingency such as the outage of generators or shunt reactive power compensation devices. The contingency parameterization for both types of contingencies is as follows.

Parameterization of Branch Outage

The set of parameterized power flow equations at bus i for the outage of branch br connecting bus i to bus m is as follows

$$\begin{cases} P_i^{inj} - V_i \sum_{j \in L(i), j \neq m} V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) - V_i V_m (G_{im}^{new} \cos\theta_{im} + B_{im}^{new} \sin\theta_{im}) \\ -V_i^2 G_{ii}^{new} - P_{im}(V_i, V_m, \lambda) = 0 \\ Q_i^{inj} - V_i \sum_{j \in L(i), j \neq m} V_j (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) - V_i V_m (G_{im}^{new} \sin\theta_{im} - B_{im}^{new} \cos\theta_{im}) + V_i^2 B_{ii}^{new} \\ -Q_{im}(V_i, V_m, \lambda) = 0 \end{cases} \tag{3.21}$$

where $L(i) = \{j : Y_{ij} \neq 0,\ j \neq i\}$ is the set of buses that are directly connected to bus i through transmission lines, $G_{ij}+jB_{ij}$ is the (i, j) element of the bus admittance matrix, $G_{ii}+jB_{ii}$ is the ith diagonal element of the bus admittance matrix, θ_{ij} is the voltage angle difference between bus i and bus j, V_i and V_j are voltage magnitude of bus i and bus j respectively, $G_{ii}^{new} + jB_{ii}^{new}$ is the new kth diagonal element of the bus admittance matrix and $G_{im}^{new} + jB_{im}^{new}$ is the new (i, m) element of the bus admittance matrix after branch br has been removed from the system, P_i^{inj} and Q_i^{inj} are real power and reactive power injections at bus i. $P_{im}(V_i, V_m, \lambda)$ and $Q_{im}(V_i, V_m, \lambda)$ are defined as follows:

$$P_{im}(V_i, V_m, \lambda) = (1-\lambda)\{V_i V_m (G_{im}^{br} \cos\theta_{im} + B_{im}^{br} \sin\theta_{im}) + V_i^2 G_{ii}^{br}\} \tag{3.22}$$

$$Q_{im}(V_i, V_m, \lambda) = (1-\lambda)\{V_i V_m (G_{im}^{br} \sin\theta_{im} - B_{im}^{br} \cos\theta_{im}) - V_i^2 B_{ii}^{br}\} \tag{3.23}$$

The case of λ=0 represents the original set of power flow equations before the contingency. The case of λ=1 represents the new set of power flow equations with branch *br* removed.

<u>Parameterization of Generator Outage</u>

The parameterized power flow equation at bus *i* for the outage of the generator at that bus is as follows:

$$\begin{cases} P_{gi}(1-\lambda) - P_{di} - V_i \sum_{j \in L(i)} V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) - V_i^2 G_{ii} = 0 \\ Q_{gi}(1-\lambda) - Q_{di} - V_i \sum_{j \in L(i)} V_j (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) + V_i^2 B_{ii} = 0 \end{cases} \tag{3.24}$$

where P_{gi} and P_{di} are generator real power output and load real power respectively, and Q_{gi} and Q_{di} are generator reactive power output and load reactive power respectively. For a generator of PV type,

Q_{gi} is the reactive power output under the normal operating condition.

The real power generation loss P_{gi} due to generator outage can be reallocated among the available generators. Let ΔP_{gz} be the specified real power increase of available generator z after the faulted generator i is removed from the system.

The parameterized power flow equation at generator bus z for the outage of the generator at bus i is as follows:

$$P_{gz} + \lambda \Delta P_{gz} - P_{dz} - V_z \sum_{j \in L(i)} V_j (G_{zj} \cos\theta_{zj} + B_{zj} \sin\theta_{zj}) - V_z^2 G_{zz} = 0 \tag{3.25}$$

The case λ=0 represents the power flow equations before contingency. The case of λ=1, represents the power flow equations after the generator at bus i is shut down.

Continuation Method

The parameterized set of equations representing steady state operation of a power system under N-k contingency (where $k \geq 2$) can be represented as in equation 3.1. In this case λ is the scalar uncontrollable bifurcation parameter that parameterizes the simultaneous outage of k components. Specifically, when λ=0, the set of parameterized steady state equations represents the one before contingency. On the other hand, when λ=1, the set of parameterized steady state equations is the one after all faulted k components are removed from the system.

The continuation method can be used to find the critical point associated with a contingency precisely and reliably. In addition, the sensitivity information obtained as a by-product of the continuation method is useful for reactive power control planning. During the continuation process, λ is increased from 0 to 1 as shown in Figure 3.6 below. If there is a stable operating point after a contingency, the continuation method can find this point with $\lambda^* = 1$. If there is no power flow solution following a contingency, the continuation method will obtain a critical point with $\lambda^* < 1$.

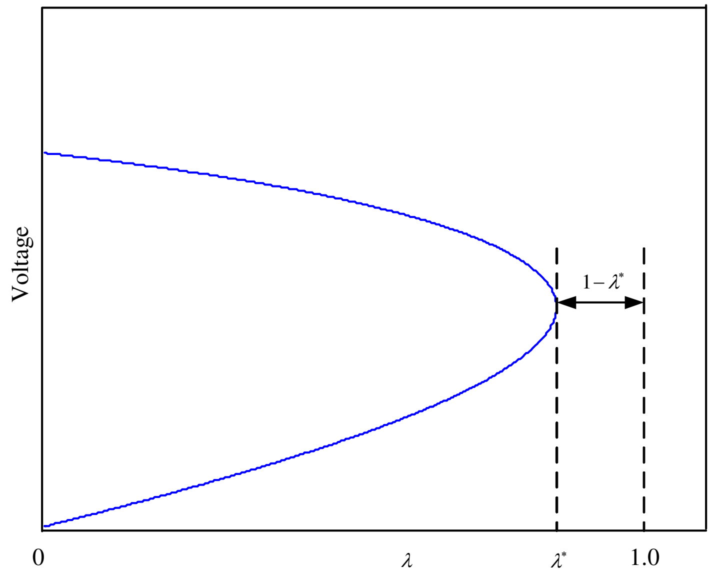


Figure 3.6 Bifurcation curve obtained by the continuation method

Mathematically, the continuation method finds the critical point if the following conditions are satisfied:

$$F(x^*, p^*, \lambda^*) = 0 \tag{3.26}$$

$$w^* F_x^* = 0,\ w^* \neq 0 \tag{3.27}$$

where w^* is the left eigenvector corresponding to the zero Eigen value of the singular Jacobian F_x^*, (x^*, p^*, λ^*) is the critical point.

Once the critical point is found by the continuation method, the sensitivity of the bifurcation parameter with respect to the control variable p evaluated at the critical point is

$$\frac{\partial \lambda^*}{\partial p} = -\frac{w^* F_p^*}{w^* F_\lambda^*} \tag{3.28}$$

where F_λ^* is the derivative of F with respect to the bifurcation parameter λ evaluated at the critical point and F_p^* is the derivative of F with respect to the control variable p evaluated at the critical point. The bifurcation parameter sensitivity is used to plan cost-effective reactive power controls against voltage collapse.

3.6.1.2 Formulation for Corrective Control Planning

After the initial set of candidate locations for switched shunt capacitors are found using a method such as bisection method described in section 3.5, they used in the planning algorithm as the decision variables. A mixed integer programming (MIP) to estimate control locations and amounts is formulated. The MIP minimizes control installation cost while restoring equilibrium (i.e. the bifurcation parameter at the critical point λ^* is greater than or equal to one):

Minimize $$J = \sum_{i \in \Omega_1} (C_{vi} B_i + C_{fi} q_i) \tag{3.29}$$

Subject to $$\left(\sum_{i \in \Omega_1} S_i^{(k)} B_i^{(k)} \right) + \lambda^{*(k)} \geq 1, \forall k \tag{3.30}$$

$$0 \leq B_i^{(k)} \leq B_i, \forall k \tag{3.31}$$

$$B_{i\min} q_i \leq B_i \leq B_{i\max} q_i \tag{3.32}$$

$$q_i = 0,1 \tag{3.33}$$

The decision variables are $B_i^{(k)}$, B_i, and q_i.

Here,

- C_f is fixed installation cost and C_v is variable cost of switched shunt or series capacitors,
- B_i is the size (susceptance) of the switched shunt capacitor at location i,
- q_i=1 if location i is selected for reactive power control expansion, otherwise, q_i=0,
- the superscript k represents the contingency under which there is no equilibrium,
- Ω_1 is the set of candidate locations to install switched shunt capacitors,
- $B_i^{(k)}$ is the size of the shunt capacitor to be switched on at location i under contingency k,
- $S_i^{(k)}$ is the sensitivity of the bifurcation parameter with respect to the susceptance of the shunt

capacitor at location i under contingency k,

- $\lambda^{*(k)}$ is the bifurcation parameter evaluated at the critical point under contingency k and without controls,

- $B_{i\min}$ is the minimum size of the switched shunt capacitor at location i,
- $B_{i\max}$ is the maximum size of the switched shunt capacitor at location i.

The output of the MIP is the control locations and amounts for all k contingencies and the control location and amount. For each concerned contingency, the identified controls are switched in, and λ^* is recalculated to check if an equilibrium is restored. However, because we use the linear sensitivity to estimate the effect of the variations of control variables on the value of the bifurcation parameter at the critical point, there may be contingencies that have λ^* less than one after the network configuration is updated according to the results of the MIP. The control locations and/or amounts can be further refined by solving a second-stage mixed integer programming with updated information. In the successive MIP, we use updated sensitivity at each iteration.

3.6.1.3 Formulation of MIP with Updated Information

The successive MIP is formulated to minimize the total control installation cost subject to the constraint of equilibrium restoration, as follows:

Minimize
$$J = \sum_{i\in\Omega_1} (C_{vi}\overline{B}_i + C_{fi}\overline{q}_i) \tag{3.34}$$

Subject to
$$\left(\sum_{i\in\Omega_1} \overline{S}_i^{(k)}(\overline{B}_i^{(k)} - B_i^{(k)})\right) + \overline{\lambda}^{*(k)} \geq 1, \forall k \tag{3.32}$$

$$0 \leq \overline{B}_i^{(k)} \leq \overline{B}_i, \forall k \tag{3.35}$$

$$B_{i\min}\overline{q}_i \leq \overline{B}_i \leq B_{i\max}\overline{q}_i \tag{3.36}$$

$$\overline{q}_i = 0,1 \tag{3.37}$$

The decision variables are $\overline{B}_i^{(k)}$, $\overline{B}_i$, and $\overline{q}_i$.

Here,

- $\overline{B}_i$ is the new size of the switched shunt capacitor at location i,

- $\overline{q}_i$'s are new binary control location variables,
- $\overline{S}_i^{(k)}$ is the updated sensitivity of the bifurcation parameter with respect to the susceptance of the switched shunt capacitor at location i under contingency k,
- $\overline{B}_i^{(k)}$ is the new size of the switched shunt capacitor at location i under contingency k,
- $\overline{\lambda}^{*(k)}$ is the updated bifurcation parameter evaluated at the critical point under contingency k.

The above successive MIP will end until all concerned contingencies have satisfactory voltage stability margin and there is no significant movement of the decision variables from the previous MIP solution. The effectiveness of the method is illustrated by applying it to a large-scale system.

3.6.2 Planning Problem (b): Preventive Control planning against voltage instability

The previous section presented an optimization-based method of planning reactive power control in electric power transmission systems to restore equilibrium under severe contingencies. In this section, planning problem to increase voltage stability margin under certain contingencies that is prone to voltage instability is addressed. The voltage stability margin of the system under these contingencies is increased to meet certain the prescribed minimum criteria in order to keep the system secure. An optimization formulation similar to the previous section is used here. Instead of considering only the most severe contingency or considering several contingencies sequentially the proposed planning method considers multiple contingencies simultaneously.

3.6.2.1 Formulation of Original Mixed Integer Programming

Again the solution has two stages, first to solve original MIP, and then to update if criteria are not met. The MIP minimizes the total control installation cost while increasing the voltage stability margin to a required percentage x for each concerned contingency.

Minimize $$J = \sum_{i \in \Omega_1} (C_{vi} B_i + C_{fi} q_i) \tag{3.38}$$

Subject to $$\sum_{i\in\Omega_1} S_i^{(k)} B_i^{(k)} + M^{(k)} \geq xP_{l0}, \forall k \tag{3.39}$$

$$0 \leq B_i^{(k)} \leq B_i, \forall k \tag{3.40}$$

$$B_{i\min} q_i \leq B_i \leq B_{i\max} q_i \tag{3.41}$$

$$q_i = 0,1 \tag{3.42}$$

The decision variables are $B_i^{(k)}$, B_i, and q_i. All the variables are the same as defined in the previous section 3.6.1.2, except for some new variables.

- x is an arbitrarily specified voltage stability margin in percentage
- P_{l0} is the forecasted system load
- $M^{(k)}$ is the voltage stability margin under contingency k and without controls

Here, we may increase the voltage stability margin for those contingencies that resulted in voltage instability (which are now compensated) to the required value along with other contingencies having insufficient voltage stability margin to meet the minimum criteria. In order to minimize the total installation cost of switched shunt capacitors, the previously identified switched shunt capacitors can be utilized to increase the voltage stability margin for other contingencies.

The output of the mixed integer-programming problem is the control locations and amounts for all k contingencies and the combined control location and amount. Then the network configuration is updated by switching in the controls under each contingency. After that, the voltage stability margin is recalculated using CPF to check if sufficient margin is achieved for each concerned contingency. In this case of the criteria being not satisfied due to usage of linear sensitivity information, the control locations and/or amounts are further refined by re-computing margin sensitivities (with updated network configuration) under each concerned contingency, and solving a second-stage successive MIP with updated information, as described in the next subsection.

3.6.2.2 Formulation of MIP with Updated Information

The successive MIP is formulated to minimize the total control installation cost subject to the constraint of the voltage stability margin requirement, as follows:

Minimize
$$J = \sum_{i \in \Omega_1} (C_{vi} \overline{B}_i + C_{fi} \overline{q}_i) \tag{3.43}$$

Subject to
$$\left(\sum_{i \in \Omega_1} \overline{S}_i^{(k)} (\overline{B}_i^{(k)} - B_i^{(k)}) \right) + \overline{M}^{(k)} \geq x P_{l0}, \quad \forall k \tag{3.44}$$

$$0 \leq \overline{B}_i^{(k)} \leq \overline{B}_i, \forall k \tag{3.45}$$

$$B_{i\min} \overline{q}_i \leq \overline{B}_i \leq B_{i\max} \overline{q}_i \tag{3.46}$$

$$\overline{q}_i = 0,1 \tag{3.47}$$

The decision variables are $\overline{B}_i^{(k)}$, $\overline{B}_i$, and $\overline{q}_i$.

Here, all the variables are the same as defined in the previous section 3.6.1.3, except for some new variables.

- $\overline{M}^{(k)}$ is the updated voltage stability margin under contingency *k*.

The above successive MIP will end until all concerned contingencies have satisfactory voltage stability margin and there is no significant movement of the decision variables from the previous MIP solution. The effectiveness of the method will be illustrated by applying it to a large-scale system in next chapter.

3.6.3 Planning Problem (c): Coordinated Control Planning

The previous section presented an optimization-based method for planning reactive power controls in electric power transmission systems to satisfy the voltage stability margin requirement under a set of contingencies. This section uses a similar optimization formulation that uses sensitivity information to solve the problem of coordinated allocation of static and dynamic Var resources. The last two sections had sensitivity of loading margin with respect to static shunt reactive sources (MSCs). This section includes the usage of sensitivity information of transient voltage dip magnitude and duration with respect to dynamic Var source like SVC. While many existing methodologies determine static and dynamic Var support sequentially, this method simultaneously determines the optimal allocation of static and dynamic VAR sources to satisfy the requirements of long-term voltage stability margin and transient voltage dip [38].

3.6.3.1 Formulation of Original Mixed Integer Programming

After finding the candidate locations for mechanically switched shunt capacitors and SVCs, a mixed integer program (MIP) is used that minimizes the total installation cost of mechanically switched shunt capacitors and SVCs while satisfying the requirements of voltage stability margin and transient voltage dip.

Minimize $$J = \sum_{i\in\Omega}[C_{vi\_\mathrm{shunt}}B_{i\_\mathrm{shunt}} + C_{fi\_\mathrm{shunt}}q_{i\_\mathrm{shunt}} + C_{vi\_\mathrm{svc}}B_{i\_\mathrm{svc}} + C_{fi\_\mathrm{svc}}q_{i\_\mathrm{svc}}] \tag{3.48}$$

Subject to $$\sum_{i\in\Omega} S_{M,i}^{(k)}[B_{i\_\mathrm{shunt}}^{(k)} + B_{i\_\mathrm{svc}}^{(k)}] + M^{(k)} \geq M_{\mathrm{r}},\ \forall k \tag{3.49}$$

$$\sum_{i\in\Omega_{\mathrm{svc}}} S_{\tau,n,i}^{(k)}B_{i\_\mathrm{svc}}^{(k)} + \tau_{\mathrm{dip},n}^{(k)} \leq \tau_{\mathrm{dip},n,\mathrm{r}},\ \forall n,k \tag{3.50}$$

$$\sum_{i\in\Omega_{\mathrm{svc}}} S_{V,n,i}^{(k)}B_{i\_\mathrm{svc}}^{(k)} + V_{\mathrm{dip},n}^{(k)} \leq V_{\mathrm{dip},n,\mathrm{r}},\ \forall n,k \tag{3.51}$$

$$0 \leq B_{i\_\mathrm{shunt}}^{(k)} \leq B_{i\_\mathrm{shunt}},\ \forall k \tag{3.52}$$

$$0 \leq B_{i\_\mathrm{svc}}^{(k)} \leq B_{i\_\mathrm{svc}},\ \forall k \tag{3.53}$$

$$B_{i\min\_\mathrm{shunt}}q_{i\_\mathrm{shunt}} \leq B_{i\_\mathrm{shunt}} \leq B_{i\max\_\mathrm{shunt}}q_{i\_\mathrm{shunt}} \tag{3.54}$$

$$B_{i\min\_\mathrm{svc}}q_{i\_svc} \leq B_{i\_\mathrm{svc}} \leq B_{i\max\_\mathrm{svc}}q_{i\_\mathrm{svc}} \tag{3.55}$$

$$q_{i\_\mathrm{shunt}}, q_{i\_\mathrm{svc}} = 0,1 \tag{3.56}$$

The decision variables are $B_{i\_\mathrm{shunt}}^{(\mathrm{k})}$, $\mathrm{B}_{\mathrm{i\_shunt}}$, $\mathrm{q}_{\mathrm{i\_shunt}}$, $B_{i\_\mathrm{svc}}^{(\mathrm{k})}$, $\mathrm{B}_{\mathrm{i\_svc}}$, and $\mathrm{q}_{\mathrm{i\_svc}}$.

Variable definition follows:

- $\mathrm{C}_{\mathrm{f\_shunt}}$ is fixed installation cost and $\mathrm{C}_{\mathrm{v\_shunt}}$ is variable cost of shunt capacitors,
- C_{f_svc} is fixed installation cost and C_{v_svc} is variable cost of SVCs,

- B_{i_shunt}: size of the shunt capacitor at location i,
- B_{i_svc}: size of the SVC at location i,
- q_{i_shunt}=1 if the location i is selected for installing shunt capacitors, otherwise, q_{i_shunt}=0,
- q_{i_svc}=1 if the location i is selected for installing SVCs, otherwise, q_{i_svc}=0,
- the superscript k represents the contingency causing insufficient voltage stability margin and/or excessive transient voltage dip problems,
- Ω_{shunt}: set of candidate locations to install shunt capacitors,
- Ω_{svc}: set of candidate locations to install SVCs,
- Ω: union of Ω_{shunt} and Ω_{svc},
- $B^{(k)}_{i\_\text{shunt}}$: size of the shunt capacitor to be switched in at location i under contingency k,
- $B^{(k)}_{i\_\text{svc}}$: size of the SVC at location i under contingency k,
- $S^{(k)}_{M,i}$: sensitivity of the voltage stability margin with respect to the shunt susceptance at location i under contingency k,
- $S^{(k)}_{\tau,n,i}$: sensitivity of the voltage dip time duration at bus n with respect to the size of the SVC at location i under contingency k,
- $S^{(k)}_{V,n,i}$: sensitivity of the maximum transient voltage dip at bus n with respect to the size of the SVC at location i under contingency k,
- $M^{(k)}$: voltage stability margin under contingency k and without controls,
- M_r: required voltage stability margin,
- $\tau_{\text{dip},n}{}^{(k)}$: time duration of voltage dip at bus n under contingency k and without controls,
- $\tau_{\text{dip},n,\text{r}}$: maximum allowable time duration of voltage dip at bus n,
- $V_{\text{dip},n}{}^{(k)}$: maximum transient voltage dip at bus n under contingency k and without controls,
- $V_{\text{dip},n,\text{r}}$: maximum allowable transient voltage dip at bus n,
- $B_{i\text{min\_shunt}}$: minimum size of the shunt capacitor at location i,

- $B_{i\max\_shunt}$: maximum size of the shunt capacitor at location i,
- $B_{i\min\_svc}$: minimum size of the SVC at location i, and
- $B_{i\max\_svc}$: maximum size of the SVC at location i.

Note that SVCs can also be used to increase the voltage stability margin. The output of the mixed integer-programming problem is the reactive compensation locations and amounts for all concerned contingencies and the combined reactive compensation location and amount. Then the network configuration is updated by including the identified reactive power support under each contingency. After that, the voltage stability margin is recalculated using CPF to check if sufficient margin is achieved for each concerned contingency. Also, time domain simulations are carried out to check whether the requirement of the transient voltage dip performance is met. This step is necessary because the power system model is inherently nonlinear, and the mixed integer programming algorithm uses linear sensitivities to estimate the effect of variations of reactive support levels on the voltage stability margin and transient voltage dip. So if need be, the reactive compensation locations and/or amounts can be further refined by re-computing sensitivities (with updated network configuration) under each concerned contingency, and solving a second-stage mixed integer programming problem, as described in the next subsection.

3.6.3.2 Formulation of MIP with Updated Information

The successive MIP problem is formulated to minimize the total installation cost of mechanically switched shunt capacitors and SVCs subject to the constraints of the requirements of voltage stability margin and transient voltage dip, as follows:

$$\text{Minimize} \quad J = \sum_{i\in\Omega}[C_{vi\_\text{shunt}}\overline{B}_{i\_\text{shunt}} + C_{fi\_\text{shunt}}\overline{q}_{i\_\text{shunt}} + C_{vi\_\text{svc}}\overline{B}_{i\_\text{svc}} + C_{fi\_\text{svc}}\overline{q}_{i\_\text{svc}}] \tag{3.57}$$

$$\text{Subject to} \quad \sum_{i\in\Omega}\overline{S}^{(k)}_{M,i}[(\overline{B}^{(k)}_{i\_\text{shunt}} - B^{(k)}_{i\_\text{shunt}}) + (\overline{B}^{(k)}_{i\_\text{svc}} - B^{(k)}_{i\_\text{svc}})] + \overline{M}^{(k)} \geq M_{\text{r}},\ \forall k \tag{3.58}$$

$$\sum_{i\in\Omega_{svc}}\overline{S}^{(k)}_{\tau,n,i}(\overline{B}^{(k)}_{i\_\text{svc}} - B^{(k)}_{i\_\text{svc}}) + \overline{\tau}^{(k)}_{\text{dip},n} \leq \tau_{\text{dip},n,\text{r}},\ \forall n,k \tag{3.59}$$

$$\sum_{i\in\Omega_{svc}} \overline{S}_{V,n,i}^{(k)}(\overline{B}_{i\_\mathrm{svc}}^{(k)} - B_{i\_\mathrm{svc}}^{(k)}) + \overline{V}_{\mathrm{dip},n}^{(k)} \le V_{\mathrm{dip},n,\mathrm{r}}, \forall n,k \tag{3.60}$$

$$0 \le \overline{B}_{i\_\mathrm{shunt}}^{(k)} \le \overline{B}_{i\_\mathrm{shunt}}, \forall k \tag{3.61}$$

$$0 \le \overline{B}_{i\_\mathrm{svc}}^{(k)} \le \overline{B}_{i\_\mathrm{svc}}, \forall k \tag{3.62}$$

$$B_{i\,\mathrm{min\_shunt}}\,\overline{q}_{i\_\mathrm{shunt}} \le \overline{B}_{i\_\mathrm{shunt}} \le B_{i\,\mathrm{max\_shunt}}\,\overline{q}_{i\_\mathrm{shunt}} \tag{3.63}$$

$$B_{i\,\mathrm{min\_svc}}\,\overline{q}_{i\_\mathrm{svc}} \le \overline{B}_{i\_\mathrm{svc}} \le B_{i\,\mathrm{max\_svc}}\,\overline{q}_{i\_\mathrm{svc}} \tag{3.64}$$

$$\overline{q}_{i\_\mathrm{shunt}}, \overline{q}_{i\_\mathrm{svc}} = 0,1 \tag{3.65}$$

The decision variables are $\overline{B}_{i\_\mathrm{shunt}}^{(k)}$, $\overline{B}_{i\_\mathrm{shunt}}$, $\overline{q}_{i\_\mathrm{shunt}}$, $\overline{B}_{i\_\mathrm{svc}}^{(k)}$, $\overline{B}_{i\_\mathrm{svc}}$ and $\overline{q}_{i\_\mathrm{svc}}$.

Variable definition follows:

- $\overline{B}_{i\_\mathrm{shunt}}$: new size of the shunt capacitor at location *i*,
- $\overline{B}_{i\_\mathrm{svc}}$: new size of the SVC at location *i*,
- $\overline{q}_{i\_\mathrm{shunt}}$ and $\overline{q}_{i\_\mathrm{svc}}$ are new binary location variables for shunt capacitors and SVCs,
- $\overline{S}_{M,i}^{(k)}$: updated sensitivity of the voltage stability margin with respect to the shunt susceptance at location *i* under contingency *k*,
- $\overline{S}_{\tau,n,i}^{(k)}$: updated sensitivity of the voltage dip time duration at bus *n* with respect to the size of the SVC at location *i* under contingency *k*,
- $\overline{S}_{V,n,i}^{(k)}$: updated sensitivity of the maximum transient voltage dip at bus *n* with respect to the size of the SVC at location *i* under contingency *k*,
- $\overline{B}_{i\_\mathrm{shunt}}^{(k)}$: new size of the shunt capacitor at location *i* under contingency *k*,
- $\overline{B}_{i\_\mathrm{svc}}^{(k)}$: new size of the SVC at location *i* under contingency *k*,
- $\overline{M}^{(k)}$: updated voltage stability margin under contingency *k*,

- $\overline{\tau}_{\text{dip},n}^{(k)}$: updated time duration of voltage dip at bus *n* under contingency *k*, and
- $\overline{V}_{\text{dip},n}^{(k)}$: updated maximum transient voltage dip at bus *n* under contingency *k*.

The above successive MIP will end until all concerned contingencies have satisfactory voltage stability margin and transient voltage response and there is no significant movement of the decision variables from the previous MIP solution. The effectiveness of the method will be illustrated in a large-scale system in next chapter.

3.6.4 Common Features of Planning Problems (a), (b) and (c)

- The optimization formulation is to minimize the total installation cost including fixed cost and variable cost of new controls while satisfying the voltage stability margin requirement under contingencies.
- The voltage stability margin and the transient voltage dip magnitude/duration sensitivities with respect to control variables are used in the optimization problem formulation according to what the problem address.
- The above developed optimization formulation does not directly involve complex steady state and dynamic power system models. Instead, it uses the corresponding sensitivity information.
- The branch-and-bound and primal-dual interior-point methods are used to solve the optimization problem.
- Because the optimization formulation is linear, it is fast, yet it provides good solutions for large-scale power systems compared with nonlinear optimization formulations.
- For k contingencies that need planning and n pre-selected candidate control locations, there are n (k+2) decision variables and k+3n+2kn constraints. Since the number of candidate control locations can be limited to a relative small number even for problems of the size associated with practical power systems by pre-selecting the initial set of locations, the computational burden for solving the above MIP is not excessive.

3.7 Summary

The chapter gives detail of the various stages involved in the making of a coordinated control-planning tool against voltage stability problems. The tools and methods described in this chapter gives us the list of critical contingencies that affect post contingency steady state voltage stability margin and transient voltage profile, and calculate the performance indices under those contingencies. An initial set of candidate control locations are selected using the calculated margin sensitivities and transient voltage dip duration/magnitude sensitivities. These inputs are fed to the control-planning module, which is essentially a MIP program, to optimally plan the reactive resource allocation. The proposed mixed integer programming based algorithm addresses the following three different planning problems:

1. To calculate reactive control locations and amounts to restore equilibrium under a set of severe contingencies;
2. To increase post contingency voltage stability margin under a set of contingencies; and
3. To coordinate planning of static and dynamic Var resources while satisfying the performance requirements of voltage stability margin and transient voltage dip.

The planned reactive power controls are capable to serve as control response for contingencies. The optimal solution obtained from first stage planning is validated for every contingency with their respective control strategy, and if the problems are unresolved a successive planning problem is solved until the performance indices do not violate. The following chapter includes the results of the entire planning process implemented on the Eastern interconnection system with more than 16000 buses.

CHAPTER 4 APPLICATION TO LARGE SCALE SYSTEM

4.1 Introduction

This chapter illustrates the results of the reactive power planning method described in previous chapter using a large-scale model. The result of the method is a cost effective solution to plan optimal mix of static and dynamic reactive power sources.

All the required data for the study, i.e., power flow base case data, and the dynamic files including the models for generator and load systems, and the various parameter settings for the dynamic simulation, were obtained from a utility. This study targeted a subsystem of the utility's control area, henceforth referred to as the "study area."

The contingencies considered for the study are the more probable ones, i.e., N-1 and N-G-T. The objective is to identify a minimum cost mix of static and dynamic Var resources that results in satisfactory voltage stability and transient voltage dip performance for all considered contingencies. The voltage stability criteria used was that steady state voltage stability margin must be no less than 5% of total load, and transient voltage dip must not exceed 20% of the initial voltage for more than 20 cycles.

CPF based PV analysis and time domain simulation are the tools used to study the steady state and dynamic system performances respectively. The sensitivity information of the system performance with respect to the reactive control device is important in order to optimally allocate the reactive resources. Matlab programming and PTI PSS/E power flow and dynamics packages are the software tools used for this work. The steady state analysis is done in Matlab, while the dynamic voltage stability analysis is done using PTI PSS/E. The coordinated planning algorithm is done in Matlab which input like control device cost information, static and dynamic sensitivity information etc from earlier analysis. The analysis and planning program is done in Matlab exploiting its capability to perform vectorized computations and sparse matrix functions in order to optimize performances in an endeavor to develop this research grade planning tool. Although we choose to use Matlab and PSS/E, it should be pointed out that the general procedure presented here is equally applicable using other static and dynamic analysis packages and programming tools, provided they incorporate appropriate modeling and solution methods.

It is important to note here that a data conversion module was built that converted the system raw data (the base case as given by the utility) that is in PTI format to a format that was understandable by Matlab. This data format conversion module is a vital component of this work, as the entire system analysis and planning has been done using program modules developed in Matlab. The conversion module includes tasks such as careful modeling of 3-winding transformer data, switched shunt data etc., checking system topology, checking for any islanding etc, so that the utility's base case is transported without any errors into Matlab environment from PSS/E for further system analysis. This data format conversion module, which is a by product in the overall endeavor to develop a long term reactive power planning tool against voltage stability issues, is one of the very important contributions of this work, as this kind of conversion modules are very useful in any work where a research grade tool is being developed or any sophisticated analysis are done as part of any research effort where Matlab is the very commonly used programming tool. With minimal modifications to the conversion module, it can be made to convert any data format such as IEEE common data format, WECC format etc into a format readable by Matlab.

This chapter is organized as follows. Section 4.2 summarizes the basecase power flow model and the particular stress direction used in the illustration. Section 4.3 reports the results of a contingency selection process used in the study. Sections 4.4 and 4.5 illustrate the planning procedure implemented assuming that only voltage stability is of concern. Section 4.6 extends these results for the case when both voltage stability and transient voltage dip are of concern.

4.2 Basecase and Stress Direction

A summary of the base case used for the study is provided in Table 4.1. Information specific to the study area is provided in a separate column. It was assumed that this basecase represented the topology and loading conditions for which a reactive power plan is desired.

Table 4.1 Summary of the basecase

#	Total	Study Area	External to Study Area
Buses	16173	2069	14104
Generators	2711	239	2472
Transformers	7261	463	6798
Pgen (MW)	603798.9	37946.7	565852.2
P (load) (MW)			
[Const. P,	591927.2	30065.2	561862
Const. I,	100.3	0	100.3
Const. Z]	116.4	0	116.4
Q (load) (MVar)			
[Const. Q,	208138.8	9067.6	199071.2
Const. I,	26.4	0	26.4
Const. Z]	125	0	125

As described in Chapters 3, continuation power flow (CPF) is used to analyze the steady state performance characteristics of the system. CPF requires an assumption of a stress direction depicting a future power loading or transfer pattern in the system. To this end, the area of interest is divided into 88 different zones, which are grouped into 6 Market zones (MZ) as shown in the Table 4.2 below.

Table 4.2 Market Zones within the Study Area

Market Zones	Zones
MZ1	100 - 104; 200 – 204; 501 - 504; 600 - 603; 701
MZ2	105 - 109; 111-112; 205 - 209; 211 - 212; 306; 312; 505 - 508; 511 - 512;
MZ3	110 ; 140 - 152; 161; 210; 240 - 252; 310; 410; 451; 510; 540 - 552; 561; 650 - 651; 750; 850; 938
MZ4	120 - 122; 220 – 222; 322; 422; 521; 720 - 721; 820 - 821
MZ5	123 - 130; 223 – 230
MZ6	160; 162 - 163; 261 - 262; 462; 560; 562 - 563; 939

These 6 market zones represent 6 different stress directions typically studied by planning engineers, with the stress direction Sink characterized by the set of loads inside the zones, and the stress direction Source characterized by generators outside of these zones, but within the study area. The CPF scales the Sink loads upwards with corresponding increase to the Source generators to find the collapse point (nose of the PV curve). Increased load is allocated to the source generators in proportion to each generator's rating while enforcing generator reactive power limits.

Voltage instability analysis using CPF-based contingency screening was performed on the basecase and for all credible contingencies under these six different stress directions. The list of credible contingencies included all possible N-1 and N-G-T contingencies in the study area. The number of such contingencies was 2268 N-1 contingencies (2100 branch contingencies and 168 generator contingencies) and all possible combinations (2100*168=352,800) for N-G-T contingencies.

Results indicated only the stress direction corresponding to the MZ1 region was found to have post contingency steady state voltage stability related problems. As a result, we studied only MZ1 to determine reactive resources and the corresponding static vs. dynamic mix, so as to limit the work while appropriately illustrating the approach. Table 4.3 below provides the voltage instability performance measure for the basecase conditions.

Table 4.3 Performance measure for basecase conditions

Base case load in the MZ1 sink (MW)	Critical point (MW)	Stability margin (%)
2073	2393	15.43657

4.3 Contingency Analysis for Market Zone 1

As stated in Section 4.2, contingency screening indicated voltage instability problems occur only in MZ1. This section describes the contingency screening performed in order to identify those contingencies that drive the need for additional reactive resources in MZ1.

The 5% voltage stability margin requirement described in Section 4.1 means for MZ1 (with 2073 MW load) that 103 MW should be the minimum load margin, for both N-1 and N-G-T contingencies.

Contingencies that violate this criterion are used in the ensuing reactive power planning analysis.

Modeling of N-1 generator contingencies and N-G-T contingencies requires special considerations, as follows:

- N-1 Generator contingencies: Remaining generators within the study area pick up the loss of generation in proportion to their MVA rating. The system slack bus compensates only for losses.
- N-G-T contingencies: The generator outage is simulated first consistent with the comment made in the previous bullet. Then, based on the assumption that the interevent time is long enough (e.g., at least 15 minutes), system adjustments (switched shunts, taps, and area interchange) are made, and the second contingency is then simulated.

The result from contingency screening process shows a total of 82 contingencies that either violated voltage instability margin criteria or led to voltage instability (negative stability margin). The 82 contingencies included 2 N-1 contingencies corresponding to the two critical generator outages at buses 97451 (G1LEWIS) and 97452 (G2LEWIS). The remaining 80 contingencies were N-G-T contingencies, with a set of 40 line contingencies repeating themselves under the two critical generators being outaged separately.

Full CPF analysis was performed on the 82 contingencies identified in the screening process, using both our Matlab code, with results verified using PSS/E. This resulted in elimination of 26 of the contingencies due to the fact that CPF indicated post-disturbance performance for these 26 satisfied all criteria. The remaining 56 contingencies therefore comprised the set that would drive subsequent reactive power planning. These 56 contingencies are summarized in Table 4.4.

All of the selected 56 contingencies were N-G-T (none of the N-1 contingencies had any post-contingency margin violation problem). These 56 N-G-T contingencies either resulted in voltage instability (rows 1-7), or they violated loading margin criteria (rows 8-28), as indicated in the right-hand columns of Table 4.4.

Table 4.4 Critical Contingencies

S.No	Transmission Line From	To	Bus Name From	To	Zone From	To	Base KV	Stability / Index (Margin in %) LEWIS Gen#1 -97451	LEWIS Gen # 2 -97452
1	97463	97467	4OAKRIDG	4PORTER	102	104	138	Voltage Instable	Voltage Instable
2	97478	97721	6JACINTO	CHJC_SER	104	105	230	Voltage Instable	Voltage Instable
3	97567	97714	6PORTER	6CHINA	104	105	230	Voltage Instable	Voltage Instable
4	97691	97717	8CYPRESS	8HARTBRG	105	105	500	Voltage Instable	Voltage Instable
5	97714	97716	6CHINA	6SABINE	105	105	230	Voltage Instable	Voltage Instable
6	97714	97721	6CHINA	CHJC_SER	105	105	230	Voltage Instable	Voltage Instable
7	53526	97513	CROCKET7	7GRIMES	999	100	345	Voltage Instable	Voltage Instable
8	97461	97464	4LEWIS	4PANORAM	103	100	138	1.495417	1.784853
9	97514	97526	4GRIMES	4MAG AND	100	100	138	2.411963	2.556681
10	97513	97546	7GRIMES	7FRONTR	100	100	345	2.556681	2.701399
11	97689	97714	6AMELIA	6CHINA	106	105	230	2.990835	3.135552
12	97690	97697	4CYPRESS	4HONEY	105	105	138	2.990835	3.135552
13	97455	97463	4METRO2	4OAKRIDG	102	102	138	3.28027	3.424988
14	97510	97526	4SOTA 1	4MAG AND	100	100	138	3.28027	3.424988
15	97493	97758	4MENARD	4BRAGG	101	105	138	3.617945	3.617945
16	97532	97627	4HICKORY	4EASTGAT	104	105	138	3.617945	3.762663
17	97697	97758	4HONEY	4BRAGG	105	105	138	3.617945	3.907381
18	97508	97510	4NAVSOTA	4SOTA 1	100	100	138	3.907381	3.907381
19	97532	97533	4HICKORY	4NEWCANY	104	104	138	3.907381	3.907381
20	97627	97723	4EASTGAT	6L533TP8	105	105	138	3.907381	4.052098
21	97632	97723	4ADAYTON	6L533TP8	105	105	138	3.907381	4.052098
22	97717	97916	8HARTBRG	8NELSON	105	112	500	3.907381	4.052098
23	97490	97493	4GULFLIV	4MENARD	101	101	138	3.95562	4.052098
24	97692	97706	4CHEEK	4SO.BMT.	106	105	138	4.196816	4.341534
25	97518	97685	4CAMDEN	4DEER 1	101	105	138	4.245055	4.486252
26	97487	97514	4MT.ZION	4GRIMES	101	100	138	4.486252	4.63097
27	97490	97494	4GULFLIV	4POCO 1	101	101	138	4.486252	4.63097
28	97633	97692	4BDAYTON	4CHEEK	105	106	138	4.63097	4.823927

4.4 Reactive Resources to Restore Equilibrium

The first step in the planning process is to identify reactive resources necessary to ensure all contingencies result in equilibrium, i.e., have positive loading margin. The approach taken in this step is consistent with that described in Chapter 3. It is possible to find operational solutions for restoring post-contingency equilibrium, e.g., using load shedding. Our planning approach restores equilibrium by identifying an amount and location of reactive resources *just* sufficient to restore equilibrium.

Since these contingencies are N-G-T, a base case with a generator removed is solved; the branch to be outaged is then parameterized as described in Section 3.6.1.1 of chapter 3. The parameterized system equations are then used to simulate the branch contingency and identify the necessary reactive resources for that contingency. This process can require several iterations, as the use of linear sensitivities at the bifurcation point does not guarantee an optimal solution on the first attempt. The parameterization is done for every branch contingency under the N-G base case, and the bifurcation parameter and its sensitivities are obtained for each case.

The mixed integer programming (MIP) optimization problem used to identify the investment solution to the equilibrium restoration problem requires candidate locations, margin sensitivity information at those locations, reactive resource cost information for each voltage level, and amount of additional margin for each contingency. We describe procedures for obtaining the candidate locations (in Subsection 4.4.1), the cost information (in Subsection 4.4.2), and the required margin (in Subsection 4.4.3).

4.4.1 Candidate Location Selection

The obtained bifurcation parameter sensitivities with respect to shunt capacitance (dλ/dB) under each contingency are used to select the candidate location set for planning reactive control. In this work, the bifurcation parameter sensitivity is converted into loading margin sensitivity; i.e., dM/dB, where M is the loading margin. The candidate locations under each contingency are obtained by ranking all the study area buses in descending order of the dM/dB under each contingency.

Table 4.5 below indicates the top 20 candidate locations in descending order of dM/dB for the top seven most severe contingencies that resulted in voltage instability (and therefore require equilibrium restoration), when generator at 97451 is outaged. Bus numbers that are in bold font are 138 KV buses. The bus numbers in regular fonts are 69 KV buses.

Table 4.6 below shows the top 20 candidate locations in descending order of dM/dB for the top seven most severe contingencies (as listed in Table 4.4) that resulted in voltage instability (and therefore require equilibrium restoration), when generator at 97452 is outaged. Bus numbers that are in bold font are 138 KV buses. The bus numbers in regular fonts are 69 KV buses.

Table 4.5 Candidate location set for N-G-T, where Gen at 97451 is outaged

	Contingency Number						
Rank	# 1	# 2	# 3	# 4	# 5	# 6	# 7
1	**97463**	97511	97504	97504	97511	97511	97516
2	**97457**	97504	97511	97511	97525	97504	97517
3	**97455**	97525	97523	97503	97516	97501	97523
4	**97468**	97523	97525	97500	97502	97500	97511
5	**97544**	97516	97517	97524	97517	97503	97525
6	97504	97517	97516	97523	97523	97524	**97457**
7	97511	97502	97524	97525	97504	97523	**97455**
8	97500	97524	97500	97517	97524	97525	97503
9	97501	97500	97503	97516	97527	97517	97504
10	97524	97501	97502	97505	97500	97516	97500
11	97523	97503	97501	97502	**97506**	97502	**97464**
12	97502	97505	97505	**97506**	97501	97505	97524
13	97525	97527	**97506**	97501	97505	**97506**	97501
14	97517	**97506**	97527	97527	97503	97527	97505
15	97516	**97507**	**97507**	**97507**	97515	**97507**	97527
16	97505	97515	**97455**	**97455**	**97507**	**97457**	97502
17	**97506**	**97457**	**97463**	**97468**	**97457**	97452	**97506**
18	97527	**97455**	**97468**	**97463**	**97455**	**97464**	**97507**
19	**97507**	**97508**	97562	**97457**	**97522**	**97455**	97515
20	**97464**	**97457**	**97457**	97569	**97509**	**97468**	**97514**

Table 4.6 Candidate location set for N-G-T, where Gen at 97452 is outaged

	Contingency Number						
Rank	# 1	# 2	# 3	# 4	# 5	# 6	# 7
1	**97463**	97511	97504	97504	97511	97511	97511
2	**97457**	97525	97511	97511	97525	97525	97516
3	**97455**	97516	97500	97503	97516	97504	97517
4	**97468**	97517	97524	97500	97504	97516	97523
5	97504	97523	97503	97524	97517	97517	97525
6	**97544**	97504	97523	97523	97523	97523	**97457**
7	97511	97501	97525	97525	97524	97502	**97455**
8	97501	97502	97517	97517	97502	97524	97504
9	97525	97524	97516	97516	97500	**97506**	97503
10	97523	97500	97502	97505	97503	97527	97500
11	97516	97503	97505	97502	97505	97500	97524
12	97517	97527	**97506**	**97506**	97527	97501	97505
13	97502	97505	**97463**	97527	**97506**	97505	97501
14	97524	**97506**	97501	97501	97501	97503	**97464**
15	97500	97515	**97455**	**97507**	97515	**97507**	**97506**
16	97503	**97507**	97527	**97455**	**97507**	97515	97527
17	97505	**97509**	**97468**	**97468**	**97457**	**97457**	97502
18	**97506**	**97455**	**97457**	**97463**	**97455**	**97522**	97515
19	97527	**97508**	**97544**	**97457**	**97468**	**97508**	**97468**
20	**97507**	**97457**	**97465**	**97544**	**97463**	**97510**	**97507**

It is observed that buses at 69 kV transmission level are generally more effective to increasing load margin than buses at 138 kV. But care should be taken not to over-compensate these buses as they might lead to excessive voltage magnitudes. To address this issue, an iterative approach was introduced where the optimization solution is found, which is the investment solution, and then each operational solution (as indexed by parameter *k* in the formulations of Chapters 3) corresponding to each contingency *k* is implemented for each post-contingency solution. For any bus having post-contingency voltage exceeding 1.06 pu, a maximum shunt MVAR constraint is developed, and the optimization is re-run with that constraint included. This procedure begins with a default set of MVAR constraints on each bus according to voltage level, as indicated in Table 4.7.

Table 4.7 Maximum shunt compensation at various voltage levels

Bus Base Voltage (KV)	Maximum Shunt capacitance amount (MVar)
69	30
100	75
115	120
138	150
230	200
345	300
500	300

While the maximum shunt capacitance amount at 138 KV buses is 150 Mvar, some of the buses which are connected to the very sensitive low voltage 69 KV buses are constrained to have a maximum shunt capacitance amount of 75 Mvar under these set of contingencies, as it was found that more Mvar on those 138 KV buses resulted in unacceptable post-contingency over-voltages. Buses 97506 (4BRYAN), 97507 (4COLSTTA), 97522 (4TABULAR) are examples of such 138 KV buses.

In order to ensure that all good reactive resource locations are included, we selected the top 50 candidate control locations for each contingency from the ranked list of sensitivities. (Tables 4.5 and 4.6 show such a list, but in order to conserve space, Tables 4.5 and 4.6 provide only the top 20 locations for each contingency). The final set of candidate locations was obtained as a union of all the locations for all critical contingencies considered for the equilibrium restoration problem. The union of all the candidate locations provided an initial set of 64 candidate location buses (many locations were in the ranked lists of more than one contingency), as shown in Table 4.8.

However, it was also found that mixed integer programming (MIP) optimization software we are using (CPLEX) is so efficient that reduction in the number of locations is unnecessary beyond a point. It is estimated that reasonable MIP running time can be obtained for up to 500 candidate locations, well in excess of what a standard planning problem might require.

Table 4.8 Initial candidate control location set - stage1 MIP for planning problem # 1

S No	Bus #	Bus Name	Base KV		S No	Bus #	Bus Name	Base KV
1	97453	4DOBBIN	138		33	97507	4COLSTTA	138
2	97454	4WALDEN	138		34	97508	4NAVSOTA	138
3	97455	4METRO2	138		35	97509	4SPEEDWY	138
4	97457	4LONGMIR	138		36	97510	4SOTA 1	138
5	97458	4CONAIR	138		37	97511	2TESCO	69
6	97459	4CONROE	138		38	97512	4PEE DEE	138
7	97460	4CRYSTAL	138		39	97513	7GRIMES	345
8	97461	4LEWIS	138		40	97514	4GRIMES	138
9	97462	5L523T58	138		41	97515	2CALVERT	69
10	97463	4OAKRIDG	138		42	97516	2HEARNE	69
11	97464	4PANORAM	138		43	97517	2TXHEARN	69
12	97465	4PLANTAT	138		44	97519	4GEORGIA	138
13	97466	4SHEAWIL	138		45	97522	4TUBULAR	138
14	97467	4PORTER	138		46	97523	2APLHERN	69
15	97468	4GOSLIN	138		47	97524	2IN.AT$T	69
16	97469	4APRILTX	138		48	97525	2HUMBHRN	69
17	97470	4LFOREST	138		49	97526	4MAG AND	138
18	97471	4CANEYCK	138		50	97527	2SINHERN	69
19	97480	L558T485	138		51	97533	4NEWCANY	138
20	97481	4CEDAR	138		52	97538	8LNG 413	138
21	97482	4CINCINT	138		53	97539	4WDHAVN	138
22	97483	4GOREE	138		54	97540	4EVGRN	138
23	97484	4HUNTSVL	138		55	97544	4ALDEN	138
24	97486	4WYNTEX	138		56	97545	4LACON	138
25	97487	4MT.ZION	138		57	97546	7FRONTR	345
26	97488	4TEMCO	138		58	97551	4CEDHILL	138
27	97500	2INDEPEN	69		59	97554	GRMXF	345
28	97502	2ANAVSOT	69		60	97555	4BISHOP	138
29	97503	2SOMERVL	69		61	97566	4TAMINA	138
30	97504	2BRYAN B	69		62	97567	6PORTER	230
31	97505	2BRYAN A	69		63	97570	4DRYCRK	138
32	97506	4BRYAN	138		64	97721	CHJC_SER	230

4.4.2 Control Cost Information

As discussed in the previous chapters a cost model similar to what has been mentioned in [20] has been used, where the investment cost of shunt capacitor is modeled as two components: fixed installation cost and variable operating cost. Table 4.9 indicates that while the operating cost in \$/MVar is constant for all the voltage levels; the fixed cost varies at different voltage levels with the installation cost at highest voltage level the highest.

Table 4.9 Cost formulation at various voltage levels

Cost Information[2]		
Bus Base Voltage level (KV)	Fixed Cost (Million $)	Variable Cost (Million $/MVar)
69	0.025	0.41
100	0.05	0.41
115	0.07	0.41
138	0.1	0.41
230	0.28	0.41
345	0.62	0.41
500	1.3	0.41

4.4.3 Required Margin

In the case of severe contingencies that lead to voltage instability, the performance index is load margin. The bifurcation parameter λ must reach 1 or in other words, the load margin must be 0 in order to simulate the line contingency. So planning is done until that criterion is solved, so that sufficient reactive resource is obtained that can withstand such a severe contingency and not result in voltage instability.

The amount of margin necessary under each contingency needed is input to the optimization model so that sufficient amount of capacitor can be switched in to restore solvability. The expression for computing the amount of load margin ΔLM needed under a particular contingency is:

$$\Delta LM = w_i^p * P*_i + w_i^q * Q*_i + w_j^p * P*_j + w_j^q * Q*_j \tag{4.1}$$

[2] Cost information at 230 KV and 500 KV levels are given in [20], extrapolated to get the cost information at the other voltage levels.

where P^* and Q^* are the real and reactive power injections at the parameterized branch at the pre-contingency[3] operating point, i and j indicate the buses connected by the parameterized branch that has to be finally removed, and w_i^p is the scaled left eigenvector component corresponding to the real power at bus i, *and* w_i^q is the scaled left eigenvector component corresponding to the reactive power at bus i.

4.4.4 Optimal Allocation

After obtaining all the necessary inputs such as critical contingencies, the bifurcation sensitivities, amount of increase in load margin, cost information etc, the final step in the planning is to solve the MIP optimization with the objective of minimizing the total reactive resource allocation cost while satisfying the required constraint of having enough load margin for each contingency, which is 0 in our case indicating power system solvability. The optimization problem is solved iteratively, as a result of the fact that we utilize linear sensitivities to characterize nonlinear relationships. The result from the first iteration is provided in Table 4.10.

Table 4.10 Optimal allocation from first iteration for equilibrium restoration problem

Bus No	Name	Base KV	Amount if (p.u) of B (or p.u. Q injection)						
			Generator outage at bus 97451						
			# 1	# 2	# 3	# 4	# 5	# 6	# 7
97457	4LONGMIR	138	1	1	0.65	0.775	0.6	1	1.5
97455	4METRO2	138	0	0	0	0	0	0	0.88
			Generator outage at bus 97452						
			# 1	# 2	# 3	# 4	# 5	# 6	# 7
97457	4LONGMIR	138	0.95	1	0.65	0.775	0.627	1	1.5
97455	4METRO2	138	0	0	0	0	0	0	0.7

The solution provided in Table 4.10 was validated according to the following procedure. For each N-G-T contingency, the generation outage was simulated, with automatic readjustments (switched shunts, taps, and tie line control) enabled. All such adjustments were then frozen, and the branch

[3] For an N-G-T contingency, the operating point for which this calculation is done is the one corresponding to after the generator outage but before the branch outage.

outage was simulated with automatic readjustments disabled, but with the Table 4.10 planning solution modeled for the particular branch contingency.

Following this validation procedure, it was observed that all contingencies do solve for the solution provided in Table 4.10, except the contingency 7 (345 KV tie line from area 151 EES to 520 CESW) under both generator outages. To address this unsolved contingency, a second optimization iteration was performed using updated sensitivities and cost information. In performing this iteration, we desire to determine how much *additional* reactive compensation is needed at each bus, relative to the solution identified in the first iteration. Therefore, the fixed costs are made 0 for buses receiving reactive compensation in the previous iteration, since it is assumed that the fixed cost of installation is already incurred for these locations. Buses 97457 and 97455 are such buses. Furthermore, for these buses receiving reactive compensation in the previous iteration, the maximum compensation amount needs to be adjusted to ensure the compensation will not exceed the actual maximum amount.

The bifurcation parameter sensitivities for the capacitor re-enforced system are obtained for the branch contingency under each generator outage that needs further compensation. Then the initial set of candidate locations are again found, and the optimal reactive power solution is computed. The result from the second optimization iteration is updated to the first optimization to get the updated amount of compensation that is provided in Table 4.11.

Table 4.11 Optimal allocation from second iteration for equilibrium restoration problem

Bus	Base KV	Amount of per unit susceptance, B (or p.u. Q injection)	
		Contingency # 7 (Gen at 97451)	Contingency # 7 (Gen at 97452)
97455 4METRO2	138	1.15	1.10

So the final result for the equilibrium restoration problem, to restore power system solvability for contingencies resulting in voltage instability (contingencies 1-7 in Table 4.4) is provided in Table 4.12. The total investment cost for this solution is 1.2865 M $.

Table 4.12 Final optimal allocation solution for equilibrium restoration

Bus	Base KV	Amount if (p.u) of B (or p.u. Q injection)
97457 4LONGMIR	138	1.5
97455 4METRO2	138	1.15

4.5 Reactive Resources to Increase Voltage Stability Margin

After the reactive power planning has been done to restore the equilibrium under those contingencies that result in voltage instability, the loading margin under those contingencies is just above 0, in violation of the margin criteria (in this case, 5%). Along with these contingencies, there are also other contingencies that did not require equilibrium restoration but are in violation of the margin criteria. So the problem addressed in this section involves finding a minimum cost solution to plan reactive control to increase the voltage stability margin to at least 5% under a given set of contingencies, none of which satisfy the margin requirement. The approach taken in this step is consistent with that described in Chapter 3.

4.5.1 First Iteration Optimization

As in the second iteration of the equilibrium restoration problem described in Subsection 4.4.4, it is necessary to modify input data for buses receiving reactive compensation in previous steps, i.e., fixed costs should be 0, and the maximum compensation amount needs to be adjusted to ensure the compensation will not exceed the actual maximum amount. This was done for buses 97457 4LONGMIR and 97455 4METRO2. Once the initial set of candidate locations is found, the margin sensitivities at every candidate location and the voltage stability margin under every contingency are provided as input to the MIP optimizer to identify the optimal reactive compensation necessary to satisfy the margin criteria for all identified contingencies.

It is determined from a first optimization run, and confirmed by simulation, that for all contingencies which did not result in voltage instability (i.e., those contingencies that are stable but violated margin criteria, which are rows 8-28 in Table 4.4), the solution to the equilibrium restoration problem provides enough additional reactive support to ensure all of these contingencies satisfy the margin criteria. That is, the optimal solution of the equilibrium restoration problem, placing capacitors at locations 97457 4LONGMIR and 97455 4METRO2, increases margin for these less severe contingencies above 5%. So no further planning for reactive resources is needed for these contingencies. However, the contingencies that were voltage unstable (rows 1-7 of Table 4.4), now having equilibrium *just* restored and therefore margin *just* exceeding 0, require additional margin to satisfy the 5% (103 MW) criteria.

The candidate location set for this planning problem was found out following a similar approach to what was described earlier for the equilibrium restoration optimization problem. The required margin for each contingency was set to satisfy the 5% requirement. Results of this first iteration optimization which is updated to the earlier amount at every location are provided in Table 4.13.

Table 4.13 Optimal allocation from first iteration to increase margin

Bus No	Name	Base KV	Amount if (p.u) of B (or p.u. Q injection)						
			Generator outage at bus 97451 & 97452						
			# 1	# 2	# 3	# 4	# 5	# 6	# 7
97457	4LONGMIR	138	1.5	1.5	1.2	0.775	1.5	1.5	1.5
97455	4METRO2	138	0	0.55	0.7	0	0.45	0.7	1.5
97464	4PANORAM	138	0.45	0	0	0.65	0	0	0.7

To validate the solution of Table 4.13, all contingencies that addressed (rows 1-7 of Table 4.4) were tested via simulation after updating the system with the respective amount of compensation under any contingency identified by MIP. It was determined that none of them satisfied the minimum margin criterion. We therefore performed a second iteration (successive MIP) to increase margin for these contingencies.

4.5.2 Successive Iteration Optimization

The second iteration optimization to increase margin uses margin sensitivities from the system reinforced by the reactive resources identified in the first iteration optimization. Candidate locations were again the same as the candidate locations used in the equilibrium restoration process. The amount obtained from the second iteration was good enough for contingencies 1-6 that the minimum criteria were satisfied, except for contingency 7 under both the generator outages. Then another successive MIP was performed to plan further for this particular contingency. This procedure was carried out till the minimum steady state stability criteria were satisfied under all the contingencies.

Table 4.14 Final solution for optimal allocation to increase margin

No	Transmission Line		Bus Name		KV	Capacitor Allocation (Mvar)			
	From	To	From	To		97457	97455	97464	97544
1	97463	97467	4OAKRIDG	4PORTER	138	1.5	0	1.5	0.25
2	97478	97721	6JACINTO	CHJC_SER	230	1.5	1.5	0.75	0
3	97567	97714	6PORTER	6CHINA	230	1.2	1.5	0	0.85
4	97691	97717	8CYPRESS	8HARTBRG	500	1.0	1.2	1.25	0
5	97714	97716	6CHINA	6SABINE	230	1.5	1.5	0.5	0
6	97714	97721	6CHINA	CHJC_SER	230	1.5	1.5	0.9	0
7	53526	97513	CROCKET7	7GRIMES	345	1.5	1.5	1.5	1
8	97461	97464	4LEWIS	4PANORAM	138	0.3	0	0	0
9	97514	97526	4GRIMES	4MAG AND	138	0.65	0	0	0
10	97513	97546	7GRIMES	7FRONTR	345	0.85	0	0	0
11	97689	97714	6AMELIA	6CHINA	230	0.68	0	0	0
12	97690	97697	4CYPRESS	4HONEY	138	0.65	0	0	0
13	97455	97463	4METRO2	4OAKRIDG	138	0.57	0	0	0
14	97510	97526	4SOTA 1	4MAG AND	138	0.55	0	0	0
15	97493	97758	4MENARD	4BRAGG	138	0.52	0	0	0
16	97532	97627	4HICKORY	4EASTGAT	138	0.45	0	0	0
17	97697	97758	4HONEY	4BRAGG	138	0.52	0	0	0
18	97508	97510	4NAVSOTA	4SOTA 1	138	0.5	0	0	0
19	97532	97533	4HICKORY	4NEWCANY	138	0.4	0	0	0
20	97627	97723	4EASTGAT	6L533TP8	138	0.5	0	0	0
21	97632	97723	4ADAYTON	6L533TP8	138	0.5	0	0	0
22	97717	97916	8HARTBRG	8NELSON	500	0.5	0	0	0
23	97490	97493	4GULFLIV	4MENARD	138	0.5	0	0	0
24	97692	97706	4CHEEK	4SO.BMT.	138	0.47	0	0	0
25	97518	97685	4CAMDEN	4DEER 1	138	0.35	0	0	0
26	97487	97514	4MT.ZION	4GRIMES	138	0.4	0	0	0
27	97490	97494	4GULFLIV	4POCO 1	138	0.4	0	0	0
28	97633	97692	4BDAYTON	4CHEEK	138	0.4	0	0	0

Table 4.14 provides the final solution after updating the solution obtained from all the successive

optimizations. This solution is the final solution of the steady state planning problem to ensure the system satisfies margin criteria for all contingencies. The total investment cost is 2.665 M $.

4.5.3 Optimal Allocation Solution for Static VAR Planning

This section presents results for optimal allocation of MSCs to solve steady state voltage instability issues in the study area. The method described in the previous chapter was implemented on the large scale power system for contingencies that lead to voltage instability or have post-contingency voltage stability margin less than the minimum criteria. The method selected 4 buses in the subsystem to solve the voltage instability problems in that area. All N-1 and N-G-T contingencies for 6 different stress directions were considered.

The final optimal solution depends to a great deal on the list of contingencies considered. If only contingencies 5, 6 and 8-28 are considered (these are contingencies that violate stability margin but exclude contingencies that result in voltage instability), then the final solution includes three 69 KV buses and two 138 KV buses with the total cost being 1.3 M$, as shown in Table 4.15.

Table 4.15 Final solution for static Vars considering subset of contingencies

Bus No	Bus Name	Base KV	Amount of p.u. Q injection
97501	2CALDWEL	69	0.25
97504	2BRYAN B	69	0.25
97511	2TESCO[4]	69	0.25
97506	4BRYAN	138	1
97507	4COLSTTA	138	0.732

In validating the solution of Table 4.15 we observe that although this solution has acceptable loading margins, it results in post-contingency voltage magnitudes of 1.15 at the three 69 kV buses where we have located reactive compensation, clearly unacceptable. To adjust for this, one would need to tighten the maximum reactive compensation allowable at these buses and resolve the MIP.

[4] Sometimes it is observed that there are a number of candidate locations that have same cost and similar margin sensitivities forming a cluster of locations where any location is equally effective. In such cases the planner can consider other factors like geographic location, limitation on maximum size that can be installed at those locations, etc., before making the final decision. In this case capacitor re-enforcement at buses 97502, 97522, 97525, 97511 are almost equally effective.

We do not make this adjustment here because Table 4.15 is illustrative only, i.e., it was obtained for only a subset of contingencies.

Table 4.16 below shows the final solution when all contingencies were considered. The solution satisfies reliability criteria for the set of line contingencies under both sets of generator outages, i.e., all 56 N-G-T cases listed in the contingency list of Table 4.4. The voltage stability margin for all considered contingencies is now at least 5%, and the total investment cost is 2.665 M \$. It is interesting to note that the post-contingency high voltage problem observed for the solution of Table 4.15 does not occur for the solution of Table 4.16. This is due to the fact that the solution of Table 4.16 contains no 69 kV buses (which have greater voltage magnitude sensitivity to reactive injection than the 138 kV buses). The reason the solution of Table 4.16 contains no 69 kV buses is that the contingencies for which it is developed require a significantly high amount of reactive resource. The discrete nature of the MIP favors 138 kV buses in this case because, despite the lower cost per unit Q for 69 kV buses, it would require too many of them to satisfy the loading margin (since 69 kV buses have tighter maximum Q constraints than do 138 kV buses in order to avoid high voltage problems), incurring the high fixed cost for each additional 69 kV bus. This is a reasonable and satisfying feature of the MIP.

Table 4.16 Final solution for static vars considering all contingencies

Bus No.	Bus Name	Base KV	Amount of p.u. Q injection
97457	4LONGMIR	138	1.5
97455	4METRO2	138	1.5
97464	4PANORAM	138	1.5
97544	4ALDEN	138	1

The results show the effectiveness of the method to find optimal allocation of static compensation against post contingency steady state voltage instability problems. In the next section, we present results to develop a coordinated control plan against steady state as well dynamic voltage stability problems to optimally allocate a mix of static and dynamic Var sources.

4.6 Coordinated Reactive Resource Planning for Static and Dynamic Problems

The dynamic data includes dynamic models for generators, exciter and governor systems. An appropriate load model is used for detailed voltage stability analysis in the control area, where load at every bus is portioned as 50% motor load and 50% ZIP load with the motor loads further split into three different kinds, i.e., large, small, and trip motors (1/3 each). The ZIP model for the remaining 50% load is modeled as 50% constant impedance and 50% constant current for P load and 100% constant impedance for Q load. Time domain simulation is used to study the system dynamic performance. The sensitivity information of the system performance (dip magnitude and duration) with respect to the reactive control device (SVC) is important in order to optimally allocate the reactive resources. PTI PSS/E dynamics package is the software tool used for this work.

4.6.1 Contingency Screening and Analysis

The contingency set for our study was chosen as the contingencies that lead to steady state post contingency voltage instability. These contingencies (top 7 contingencies in Table 4.4) were the ones which resulted in relatively low bus voltages even after installing the static reactive resources of Section 4.5.

These contingencies were all N-G-T. These contingencies were simulated by removing a generator, resolving the power flow case, and then running time domain simulation for the circuit outage. Time domain simulations were run by applying a 3-phase fault at t=0 at one end of the transmission circuit and then clearing the fault and the circuit at 6 cycles (t = 0.1s). The simulation was run for about 3 sec to detect any of the following transient voltage problems:

1. Slow voltage recovery problem: voltage recovery time (time taken to reach 80% of initial voltage after fault has been cleared) > 20 cycles, i.e., 0.333s.
2. Transient voltage dip magnitude problem: after the voltage recovery has taken place, i.e., dip magnitude > 25% of initial voltage.
3. Transient voltage dip duration problem: voltage dip of > 20% of initial voltage with a dip

duration of > 20 cycle.

A slow voltage recovery problem can lead to tripping of induction motors. So it is very important to prevent the voltage recovery problem. The nature of this problem demands a fast acting Var source. Hence static Var compensators (SVCs) must be employed. Yet, there may also be static voltage problems to which SVCs can contribute. Hence an optimal combination of SVCs and static capacitors is desired, to address both post contingency voltage instability and transient voltage dip problems. Chapter 3 develops the procedure, which is now applied to a larger system.

When time domain simulation was done to analyze all 7 severe contingencies, it was found that none of them resulted in transient voltage dip magnitude and duration problem (transient after voltage recovery). But all the contingencies lead to a slow voltage recovery due to the presence of induction motor loads. This slow voltage recovery resulted in the tripping of induction motor at the respective buses. The following summarizes results of each contingency. In each case, the contingency is identified, the buses having low voltage dips below 20% of initial voltage and recovery time exceeding 20 cycles are identified, and the recovery time is given.

Contingency 1

Generator at 97451 or 97452 is outaged and the transmission line between buses 97463-97467 is tripped due to fault. Table 4.17 lists those buses resulting in transient voltage dip violation.

Table 4.17 Buses resulting in transient voltage dip violation for contingency 1

Bus Number	Bus Name	Recovery time	Cycles
97463	4OAKRIDG	0.841	50.46
97455	4METRO2	0.771	46.26
97468	4GOSLIN	0.694	41.64
97544	4ALDEN	0.614	36.84

Contingency 2

Generator at 97451 or 97452 is outaged and the transmission line between buses 97478-97721 is tripped due to fault. Table 4.18 lists those buses resulting in transient voltage dip violation.

Table 4.18 Buses resulting in transient voltage dip violation for contingency 2

Bus Number	Bus Name	Recovery time	cycles	Bus Number	Bus Name	Recovery time	cycles
97468	4GOSLIN	0.495	29.7	97482	4CINCINT	0.386	23.16
97544	4ALDEN	0.492	29.52	97484	4HUNTSVL	0.386	23.16
97455	4METRO2	0.491	29.46	97527	2SINHERN	0.385	23.1
97463	4OAKRIDG	0.467	28.02	97530	4WALKER	0.385	23.1
97460	4CRYSTAL	0.439	26.34	97481	4CEDAR	0.384	23.04
97521	4JEFCON	0.439	26.34	97485	L558TP91	0.384	23.04
97520	4FWPIPE	0.438	26.28	97555	4BISHOP	0.382	22.92
97456	4SECURTY	0.436	26.16	97536	4RIVTRIN	0.381	22.86
97458	4CONAIR	0.436	26.16	97486	4WYNTEX	0.379	22.74
97462	5L523T58	0.436	26.16	97503	2SOMERVL	0.378	22.68
97459	4CONROE	0.435	26.1	97454	4WALDEN	0.377	22.62
97542	4JAYHAWK	0.428	25.68	97512	4PEE DEE	0.377	22.62
97466	4SHEAWIL	0.424	25.44	97480	L558T485	0.376	22.56
97457	4LONGMIR	0.421	25.26	97500	2INDEPEN	0.373	22.38
97475	4CLVELND	0.421	25.26	97516	2HEARNE	0.373	22.38
97464	4PANORAM	0.42	25.2	97517	2TXHEARN	0.372	22.32
97461	4LEWIS	0.418	25.08	97524	2IN.AT$T	0.37	22.2
97465	4PLANTAT	0.418	25.08	97525	2HUMBHRN	0.37	22.2
97545	4LACON	0.418	25.08	97528	4GULFTRN	0.369	22.14
97471	4CANEYCK	0.416	24.96	97535	4CARLILE	0.369	22.14
97543	4PECHCK#	0.414	24.84	97501	2CALDWEL	0.368	22.08
97476	4JACINTO	0.413	24.78	97523	2APLHERN	0.367	22.02
97538	8LNG 413	0.413	24.78	97566	4TAMINA	0.367	22.02
97539	4WDHAVN	0.41	24.6	97467	4PORTER	0.366	21.96
97479	4SHEPERD	0.407	24.42	97552	4ONLASKA	0.363	21.78
97488	4TEMCO	0.407	24.42	97502	2ANAVSOT	0.36	21.6
97540	4EVGRN*	0.407	24.42	97474	4HIGHTWR	0.355	21.3
97453	4DOBBIN	0.406	24.36	97522	4TUBULAR	0.355	21.3
97519	4GEORGIA	0.403	24.18	97537	4STALEY	0.354	21.24
97478	6JACINTO	0.402	24.12	97492	4BLANCHD	0.352	21.12
97551	4CEDHILL	0.402	24.12	97509	4SPEEDWY	0.352	21.12
97483	4GOREE	0.397	23.82	97511	2TESCO	0.352	21.12
97515	2CALVERT	0.396	23.76	97508	4NAVSOTA	0.351	21.06
97534	4SPLENDR	0.396	23.76	97487	4MT.ZION	0.344	20.64
97470	4LFOREST	0.394	23.64	97491	4LIVSTON	0.344	20.64
97531	4APOLLO	0.391	23.46	97477	4TARKING	0.343	20.58
97495	4RICH 1	0.39	23.4	97504	2BRYAN B	0.34	20.4
97469	4APRILTX	0.386	23.16	97553	4BLDSPRG	0.34	20.4

Contingency 3

Generator at 97451 or 97452 is outaged and the transmission line between buses 97567-97714 is tripped due to fault. Table 4.19 lists those buses resulting in transient voltage dip violation.

Table 4.19 Buses resulting in transient voltage dip violation for contingency 3

Bus Number	Bus Name	Recovery time	cycles
97455	4METRO2	0.36	21.6
97468	4GOSLIN	0.36	21.6
97544	4ALDEN	0.353	21.18
97463	4OAKRIDG	0.344	20.64

Contingency 4

Generator at 97451 or 97452 is outaged and the transmission line between buses 97691-97717 is tripped due to fault. Table 4.20 lists those buses resulting in transient voltage dip violation.

Table 4.20 Buses resulting in transient voltage dip violation for contingency 4

Bus Number	Bus Name	Recovery time	cycles
97468	4GOSLIN	0.394	23.64
97455	4METRO2	0.392	23.52
97544	4ALDEN	0.392	23.52
97463	4OAKRIDG	0.377	22.62
97515	2CALVERT	0.376	22.56
97459	4CONROE	0.357	21.42
97527	2SINHERN	0.357	21.42
97462	5L523T58	0.355	21.3
97458	4CONAIR	0.354	21.24
97465	4PLANTAT	0.347	20.82
97539	4WDHAVN	0.343	20.58
97516	2HEARNE	0.337	20.22
97551	4CEDHILL	0.337	20.22
97482	4CINCINT	0.336	20.16
97457	4LONGMIR	0.335	20.1
97517	2TXHEARN	0.335	20.1
97530	4WALKER	0.335	20.1
97481	4CEDAR	0.334	20.04

Contingency 5

Generator at 97451 or 97452 is outaged and the transmission line between buses 97714-97716 is tripped due to fault. Table 4.21 lists those buses resulting in transient voltage dip violation.

Table 4.21 Buses resulting in transient voltage dip violation for contingency 5

Bus Number	Bus Name	Recovery time	cycles	Bus Number	Bus Name	Recovery time	cycles
97468	4GOSLIN	0.781	46.86	97532	4HICKORY	0.415	24.9
97455	4METRO2	0.78	46.8	97503	2SOMERVL	0.412	24.72
97544	4ALDEN	0.764	45.84	97516	2HEARNE	0.412	24.72
97463	4OAKRIDG	0.743	44.58	97517	2TXHEARN	0.41	24.6
97459	4CONROE	0.605	36.3	97484	4HUNTSVL	0.409	24.54
97462	5L523T58	0.582	34.92	97525	2HUMBHRN	0.408	24.48
97465	4PLANTAT	0.57	34.2	97481	4CEDAR	0.406	24.36
97458	4CONAIR	0.563	33.78	97500	2INDEPEN	0.406	24.36
97551	4CEDHILL	0.543	32.58	97542	4JAYHAWK	0.406	24.36
97539	4WDHAVN	0.517	31.02	97482	4CINCINT	0.405	24.3
97566	4TAMINA	0.502	30.12	97485	L558TP91	0.405	24.3
97467	4PORTER	0.501	30.06	97530	4WALKER	0.405	24.3
97533	4NEWCANY	0.485	29.1	97555	4BISHOP	0.405	24.3
97461	4LEWIS	0.484	29.04	97523	2APLHERN	0.404	24.24
97470	4LFOREST	0.484	29.04	97524	2IN.AT$T	0.402	24.12
97545	4LACON	0.484	29.04	97512	4PEE DEE	0.401	24.06
97464	4PANORAM	0.481	28.86	97486	4WYNTEX	0.4	24
97457	4LONGMIR	0.48	28.8	97501	2CALDWEL	0.4	24
97466	4SHEAWIL	0.479	28.74	97536	4RIVTRIN	0.4	24
97520	4FWPIPE	0.47	28.2	97480	L558T485	0.397	23.82
97469	4APRILTX	0.469	28.14	97502	2ANAVSOT	0.39	23.4
97538	8LNG 413	0.469	28.14	97511	2TESCO	0.385	23.1
97460	4CRYSTAL	0.468	28.08	97522	4TUBULAR	0.384	23.04
97521	4JEFCON	0.468	28.08	97508	4NAVSOTA	0.38	22.8
97471	4CANEYCK	0.464	27.84	97509	4SPEEDWY	0.38	22.8
97454	4WALDEN	0.456	27.36	97528	4GULFTRN	0.378	22.68
97488	4TEMCO	0.455	27.3	97535	4CARLILE	0.378	22.68
97540	4EVGRN*	0.455	27.3	97475	4CLVELND	0.371	22.26
97456	4SECURTY	0.447	26.82	97537	4STALEY	0.371	22.26
97519	4GEORGIA	0.446	26.76	97552	4ONLASKA	0.369	22.14
97453	4DOBBIN	0.443	26.58	97504	2BRYAN B	0.368	22.08
97567	6PORTER	0.443	26.58	97479	4SHEPERD	0.362	21.72
97515	2CALVERT	0.442	26.52	97487	4MT.ZION	0.358	21.48
97531	4APOLLO	0.439	26.34	97495	4RICH 1	0.353	21.18
97483	4GOREE	0.435	26.1	97505	2BRYAN A	0.351	21.06
97543	4PECHCK#	0.432	25.92	97492	4BLANCHD	0.35	21

<u>*Contingency 6*</u>

Generator at 97451 or 97452 is outaged and the transmission line between buses 97714-97721 is tripped due to fault. Table 4.22 lists those buses resulting in transient voltage dip violation.

Table 4.22 Buses resulting in transient voltage dip violation for contingency 6

Bus Number	Bus Name	Recovery time	cycles	Bus Number	Bus Name	Recovery time	cycles
97468	4GOSLIN	0.942	56.52	97474	4HIGHTWR	0.48	28.8
97455	4METRO2	0.938	56.28	97477	4TARKING	0.48	28.8
97544	4ALDEN	0.93	55.8	97484	4HUNTSVL	0.476	28.56
97463	4OAKRIDG	0.894	53.64	97485	L558TP91	0.474	28.44
97459	4CONROE	0.818	49.08	97482	4CINCINT	0.473	28.38
97462	5L523T58	0.81	48.6	97530	4WALKER	0.473	28.38
97458	4CONAIR	0.801	48.06	97503	2SOMERVL	0.472	28.32
97465	4PLANTAT	0.793	47.58	97516	2HEARNE	0.472	28.32
97460	4CRYSTAL	0.774	46.44	97481	4CEDAR	0.471	28.26
97521	4JEFCON	0.774	46.44	97517	2TXHEARN	0.47	28.2
97456	4SECURTY	0.772	46.32	97536	4RIVTRIN	0.47	28.2
97520	4FWPIPE	0.769	46.14	97525	2HUMBHRN	0.468	28.08
97551	4CEDHILL	0.767	46.02	97555	4BISHOP	0.468	28.08
97542	4JAYHAWK	0.76	45.6	97500	2INDEPEN	0.466	27.96
97475	4CLVELND	0.749	44.94	97486	4WYNTEX	0.464	27.84
97539	4WDHAVN	0.731	43.86	97512	4PEE DEE	0.464	27.84
97476	4JACINTO	0.723	43.38	97523	2APLHERN	0.464	27.84
97534	4SPLENDR	0.715	42.9	97480	L558T485	0.463	27.78
97466	4SHEAWIL	0.71	42.6	97524	2IN.AT$T	0.462	27.72
97531	4APOLLO	0.708	42.48	97528	4GULFTRN	0.46	27.6
97543	4PECHCK#	0.672	40.32	97535	4CARLILE	0.46	27.6
97566	4TAMINA	0.664	39.84	97501	2CALDWEL	0.459	27.54
97467	4PORTER	0.652	39.12	97552	4ONLASKA	0.455	27.3
97471	4CANEYCK	0.649	38.94	97502	2ANAVSOT	0.451	27.06
97461	4LEWIS	0.637	38.22	97567	6PORTER	0.448	26.88
97545	4LACON	0.636	38.16	97522	4TUBULAR	0.447	26.82
97478	6JACINTO	0.614	36.84	97511	2TESCO	0.444	26.64
97464	4PANORAM	0.604	36.24	97509	4SPEEDWY	0.443	26.58
97457	4LONGMIR	0.593	35.58	97492	4BLANCHD	0.442	26.52
97470	4LFOREST	0.572	34.32	97508	4NAVSOTA	0.442	26.52
97538	8LNG 413	0.57	34.2	97491	4LIVSTON	0.435	26.1
97479	4SHEPERD	0.568	34.08	97537	4STALEY	0.43	25.8
97469	4APRILTX	0.542	32.52	97553	4BLDSPRG	0.426	25.56
97488	4TEMCO	0.539	32.34	97504	2BRYAN B	0.425	25.5
97540	4EVGRN*	0.539	32.34	97487	4MT.ZION	0.419	25.14
97519	4GEORGIA	0.526	31.56	97489	4ISRAEL	0.414	24.84
97454	4WALDEN	0.522	31.32	97494	4POCO 1	0.413	24.78
97533	4NEWCANY	0.519	31.14	97510	4SOTA 1	0.407	24.42
97453	4DOBBIN	0.518	31.08	97505	2BRYAN A	0.405	24.3
97495	4RICH 1	0.517	31.02	97532	4HICKORY	0.404	24.24
97483	4GOREE	0.513	30.78	97506	4BRYAN	0.374	22.44
97515	2CALVERT	0.506	30.36	97529	4MAGROVE	0.337	20.22

Contingency 7

Generator at 97451 or 97452 is outaged and the transmission line between buses 53526-97513 is tripped due to fault. Table 4.23 lists those buses resulting in transient voltage dip violation.

Table 4.23 Buses resulting in transient voltage dip violation for contingency 7

Bus Number	Bus Name	Recovery time	cycles
97515	2CALVERT	0.366	21.96
97527	2SINHERN	0.343	20.58

Table 4.24 ranks the 7 contingencies based on their severity, where severity is quantified in terms of worst-case recovery times. It can be expected that the most severe contingencies will drive the amount of dynamic Vars needed.

Table 4.24 Contingency ranking in terms of worst-case recovery times

Contingency No	Bus Numbers		Bus Names		kV	Rank
	From	To	From	To		
1	97463	97467	4OAKRIDG	4PORTER	138	2
2	97478	97721	6JACINTO	CHJC_SER	230	4
3	97567	97714	6PORTER	6CHINA	230	6
4	97691	97717	8CYPRESS	8HARTBRG	500	7
5	97714	97716	6CHINA	6SABINE	230	3
6	97714	97721	6CHINA	CHJC_SER	230	1
7	53526	97513	CROCKET7	7GRIMES	345	5

4.6.2 Candidate Locations for SVC

As indicated by the tables above, there are quite a number of buses having transient voltage dip violations. Many of these buses have induction motor load connected to them that trip under these conditions. The following criteria were used to identify candidate locations for SVCs to mitigate this problem:

1. Buses for which one or more contingencies result in:
    - the bus being among the top 5 worst voltage dips and
    - the bus has induction motor load that trips

2. Buses must have high voltage stability margin sensitivity so that they can also increase the stability margin when installed; this criterion provides that most of the buses that were part of the steady state solution to increase the post contingency steady state voltage stability margin are candidate SVC locations.

Application of the above criteria resulted in a list of candidate locations as given in Table 4.25.

Table 4.25 Candidate SVC locations

Candidate Bus	Name	Zone	KV
97455	4METRO2	102	138
97468	4GOSLIN	102	138
97544	4ALDEN	102	138
97457	4LONGMIR	103	138
97464	4PANORAM	100	138
97459	4CONROE	103	138
97463	4OAKRIDG	102	138

4.6.3 Sensitivities

To compute the optimal mix of static and dynamic Vars, we must obtain the sensitivity of recovery time to the SVC capacity. The sensitivity calculation is described in Section 3.3.2. For every candidate location considered at least two time domain simulation solutions are obtained, one with SVC having capacity of B1 Mvar and another with SVC having capacity of B2 Mvar. Then the difference in voltage dip recovery time is obtained, and the sensitivity is calculated per equation (3.2).

The first time domain simulation was run with an SVC capacity of 300 Mvar. It was observed that the top 5 buses in the list of candidate location in Table 4.25 had a better effect on voltage recovery under most of the contingencies than the last two. So, the last two were dropped from the list to reduce computation. Then another set of time domain simulations was run with SVC capacity limit being 150 Mvar for the first 5 candidate locations. Sensitivities were then computed for every bus voltage dip change under every contingency. The table below shows the sensitivity of SVC placement at buses 97455, 97468 and 97544 on the bus voltage characteristics of buses 97463, 97455, 97468, 97544 (most severe voltage dip buses) for contingency 1. Similarly sensitivities can be calculated for all the affected bus voltages with respect to SVC placement under every contingency.

Table 4.26 Recovery time sensitivity ($\Delta\tau_i$recovery/ΔB_jSVC) for Contingency 1

SVC placement bus (j)	Bus (i) for which recovery time is measured			
	97463	97455	97468	97544
97455	0.1947853	0.180272	0.149442	0.129305
97468	0.1847081	0.177179	0.149262	0.131107
97544	0.1738613	0.158503	0.142828	0.129502

4.6.4 Stage 1 Optimization

The obtained sensitivities along with the performance measures in terms of dip duration violation are used in the MIP optimization to find the optimal allocation of dynamic Vars. To find the optimal mix of static and dynamic Var sources to mitigate both steady state and dynamic voltage stability issues, we also input voltage instability margin sensitivities with respect to MSCs and SVCs at every bus along with the list of contingencies that require margin stability increase. The result of the stage 1 MIP optimization is given in Table 4.27.

Table 4.27 Result of first iteration stage 1 MIP optimization

Contingency						SVC (pu MVAR)	
No.	Bus Number		Bus Name		kV	At 97455 4METRO2	At 97568 4GOSLIN
	From	To	From	To			
1	97463	97467	4OAKRIDG	4PORTER	138	3	0.85
2	97478	97721	6JACINTO	CHJC_SER	230	3	0.8
3	97567	97714	6PORTER	6CHINA	230	3	0.7
4	97691	97717	8CYPRESS	8HARTBRG	500	1.7	0
5	97714	97716	6CHINA	6SABINE	230	3	1.5
6	97714	97721	6CHINA	CHJC_SER	230	3	1.53
7	53526	97513	CROCKET7	7GRIMES	345	3	0.95

Although the stage 1 MIP optimization is formulated to admit both capacitors and SVCs in finding a minimum cost solution which satisfies both voltage instability requirements and transient voltage dip requirements, we obtain here a solution which does not select shunt capacitor at all, i.e., the solution provided by the MIP optimization selects only SVC. Investigation indicates the reason for this is that the transient voltage dip problems are so severe that the amount of SVC required to solve them is also sufficient to mitigate the voltage stability problems.

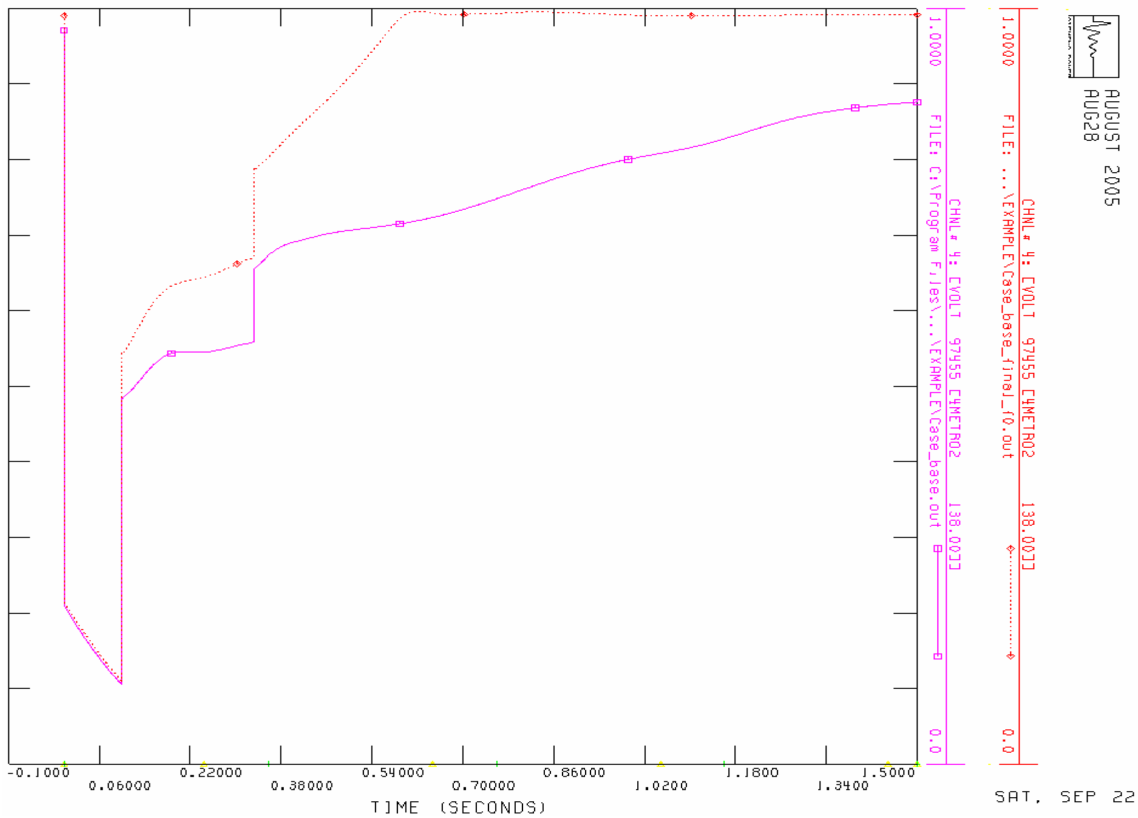
Stage 1 optimization is designed to identify a solution for post contingency voltage instability (finding equalibria) and transient voltage dip violations. Once a stage 1 solution is identified, then another MIP optimization stage, stage 2, is performed to increase voltage stability margin beyond 5% as necessary. Before doing that, however, we performed simulations to validate the obtained solution.

It was found that the SVCs placed at the two buses do solve the steady state voltage instability, and in fact increase the post contingency stability margin well beyond 5% margin requirement. Post contingency voltage stability margin after placing the two SVCs is provided in Table 4.28.

Table 4.28 Voltage instability margin for stage 1 solution

Contingency						Stability Margin (%)
No	Bus Numbers		Bus Names		kV	
	From	To	From	To		
1	97463	97467	4OAKRIDG	4PORTER	138	9.64
2	97478	97721	6JACINTO	CHJC_SER	230	9.16
3	97567	97714	6PORTER	6CHINA	230	9.4
4	97691	97717	8CYPRESS	8HARTBRG	500	8.68
5	97714	97716	6CHINA	6SABINE	230	9.4
6	97714	97721	6CHINA	CHJC_SER	230	8.92
7	53526	97513	CROCKET7	7GRIMES	345	5.1

When time domain simulations were done to validate, it was found that contingencies 1, 2, 5, 6, and 7 still had buses that violated the minimum recovery time requirement, resulting in tripping of some motors. To illustrate effect of the first iteration stage 1 solution, Figure 4.1 compares voltage at bus 97455 with and without the SVC solution from the first iteration stage 1 optimization. Although the SVCs improve the voltage, recovery time still exceeds 20 cycles.



Legend: Pink – Voltage profile before SVC placement;
Red – Voltage profile after SVC placement

Figure 4.1 Bus 97455 voltage profile under contingency 1 with SVC after stage 1 MIP

For additional comparison, Figure 4.2 shows the five most severe bus voltage plots for contingency 2 without SVCs, and Figure 4.3 shows plots for these same buses for contingency 2, but with the SVCs from the first iteration stage 1 optimization. We observe significant improvement in Figure 4.3 relative to Figure 4.2, but voltage dip recovery time still exceeds 20 cycles.

To further illustrate, Figure 4.4 compares, for contingency 3, bus voltage plots with and without SVCs, and it also provides SVC outputs. The SVCs placed at buses 97455 and 97468 produced an output of 290 Mvar and 75 Mvar respectively, and it is seen that in this case the transient voltage dip recovery problem has been solved. Plots for the other contingencies are similar and so are not provided.

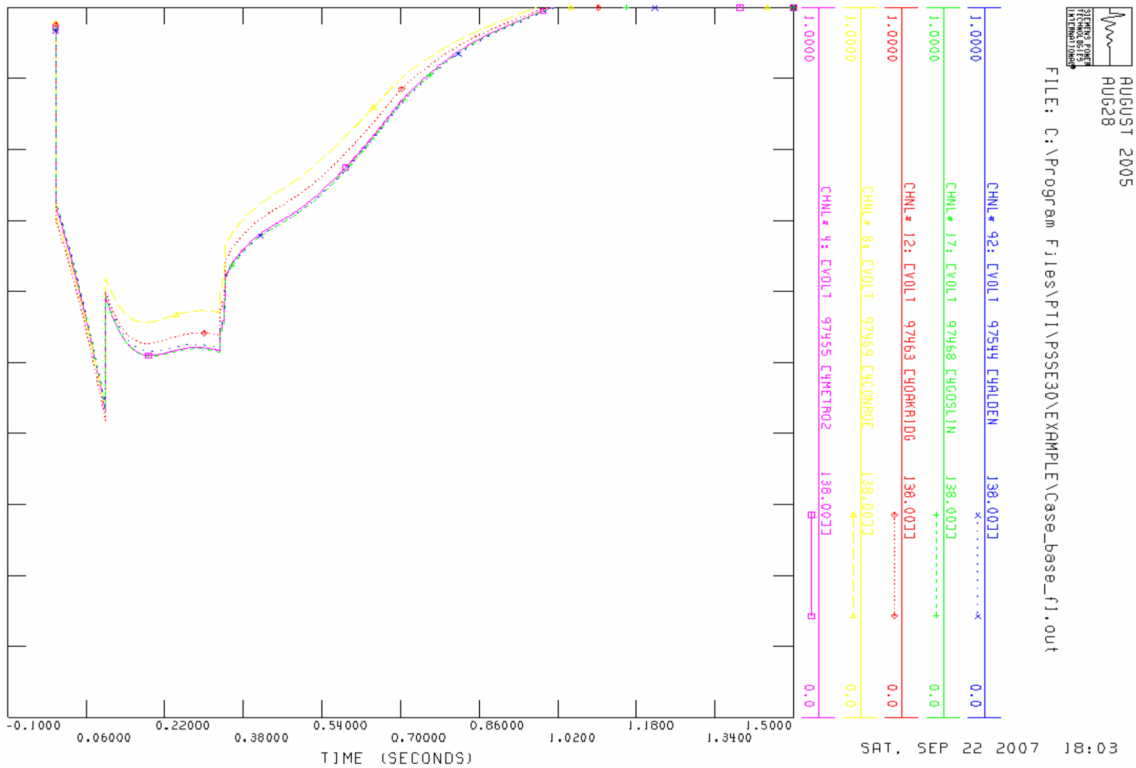


Figure 4.2 Voltage profiles of some buses under contingency 2 without SVC

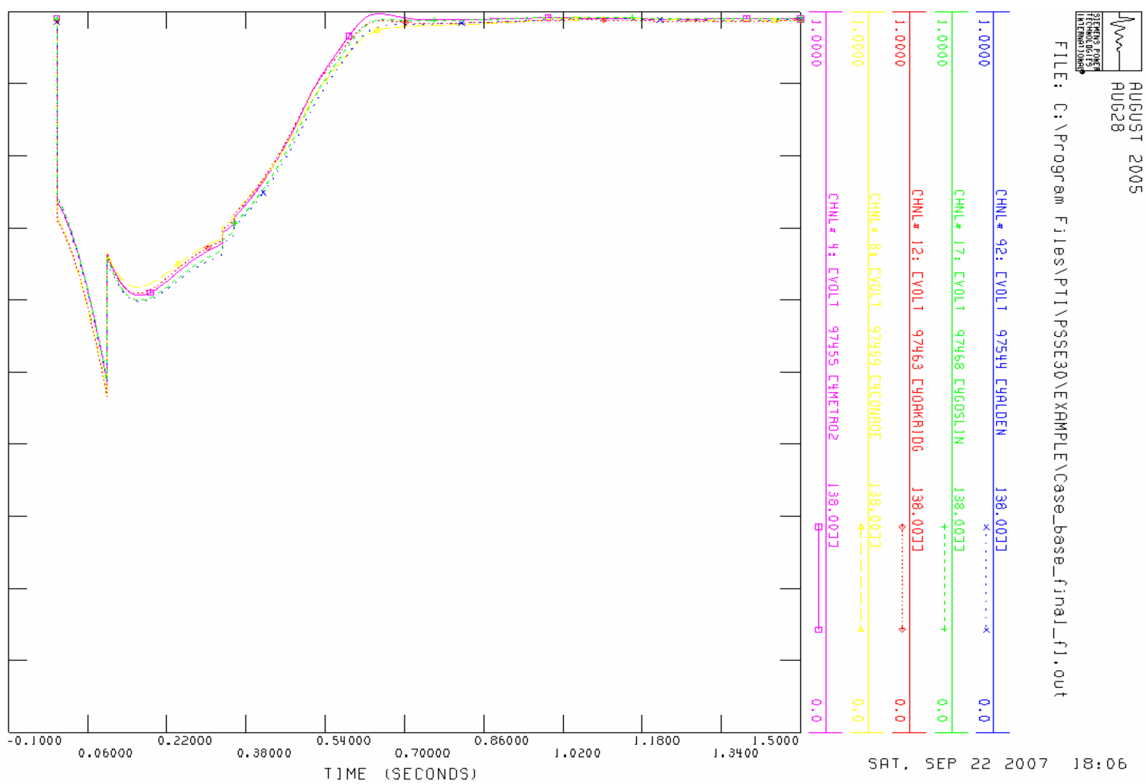
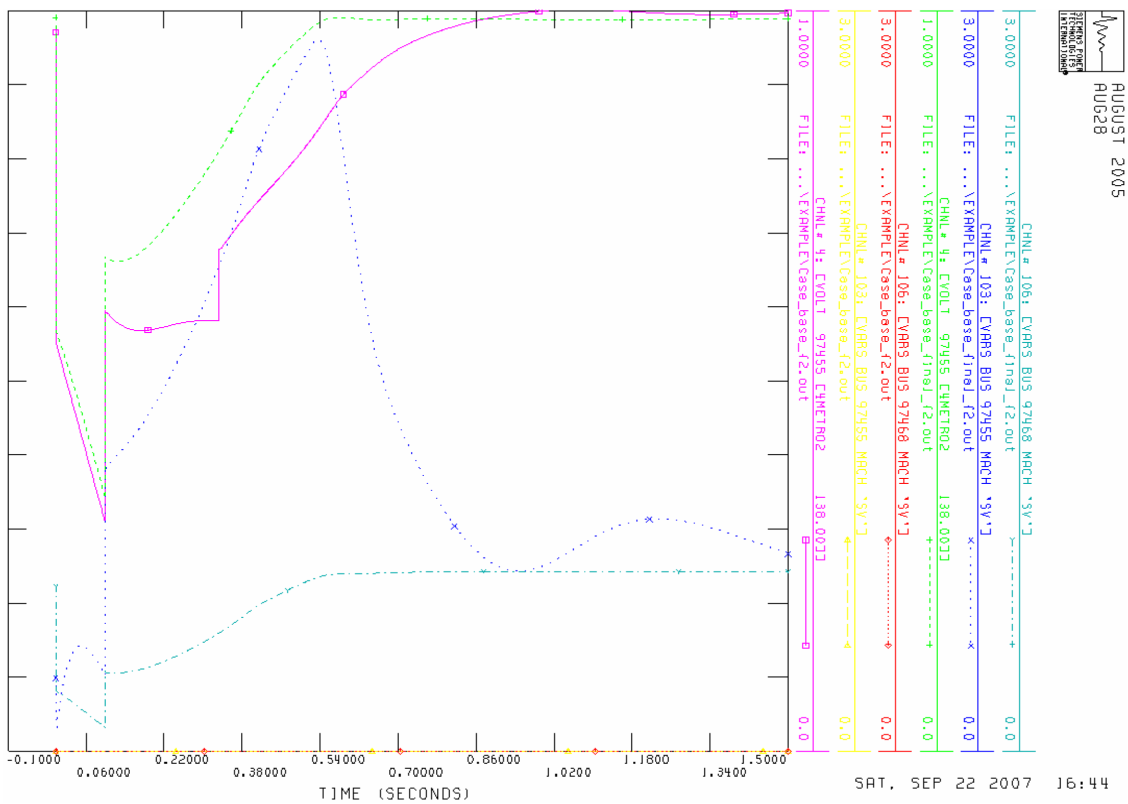


Figure 4.3 Voltage profiles of some buses under contingency 2 with SVC after Stage 1 result



Legend: Pink – voltage before control; Green – Voltage after SVC placement; Dark blue – SVC output at bus 97455; Light blue – SVC output at Bus 97468.

Figure 4.4 Voltages under contingency 3 before and after first iteration SVC placement

4.6.5 Successive Optimization

As indicated in Figure 4.1 and Figure 4.3, voltage dip recovery time for some buses is insufficient, even after implementing the SVC solution from the first iteration stage 1 optimization. So a second iteration of stage 1 optimization is required. In the second iteration of the stage 1 optimization, we fixed bus 97455 SVC at its maximum capacity of 3 p.u since the first iteration solution (Table 4.27) indicates this is required. We direct the second iteration stage 1 optimization to optimize between SVC placement at the next two most desirable buses, which are buses 97468 and 97544. Thus, we provide voltage dip sensitivities only for these two buses (there was not much difference between the old and new sensitivities). The result of the second iteration stage 1 MIP optimization is given in Table 4.29. After validation, it was found that none of the contingencies had any voltage dip problems with the two SVCs placed at buses 97455 and 97468[5]. Given that the first iteration of stage 1 optimization resulted in sufficient voltage stability margin, and we have added Var resources in the second iteration of stage 1 optimization, there is no need to check voltage stability margin for this solution. And so the solution of Table 4.29 represents the final solution.

Table 4.29 Result of second iteration stage 1 MIP optimization

Contingency						SVC (pu MVAR) 97568, 4GOSLIN (amount includes MIP 1 solution)
No	Bus Numbers		Bus Names		kV	
	From	To	From	To		
1	97463	97467	4OAKRIDG	4PORTER	138	2.65
2	97478	97721	6JACINTO	CHJC_SER	230	2.7
3	97567	97714	6PORTER	6CHINA	230	Not considered for MIP 2
4	97691	97717	8CYPRESS	8HARTBRG	500	Not considered for MIP 2
5	97714	97716	6CHINA	6SABINE	230	2.7
6	97714	97721	6CHINA	CHJC_SER	230	2.85
7	53526	97513	CROCKET7	7GRIMES	345	2.1

To illustrate the effect of the second iteration stage 1 optimization, Figure 4.5 and Figure 4.6 compares bus voltages at buses 97455, 97459, 97463, 97468, and 97544 under contingency 1 for the case of no SVC and the case of the SVC solution from the second iteration stage 1 optimization, showing significant improvement. Voltage recovery time for the buses in Figure 4.6 is within 20 cycles.

[5] It is to be noted that the Bus 97544 also has good sensitivities that are almost close to Bus 97468's. Buses 97459, 97463, 97457, 97464 do form another group of buses that have a very good influence on bus voltages to solve the voltage dip problems. So any other technical or non-technical constraint could well make the planner interested in these buses that are capable of solving the transient dip problems at an equal or only slightly higher cost.

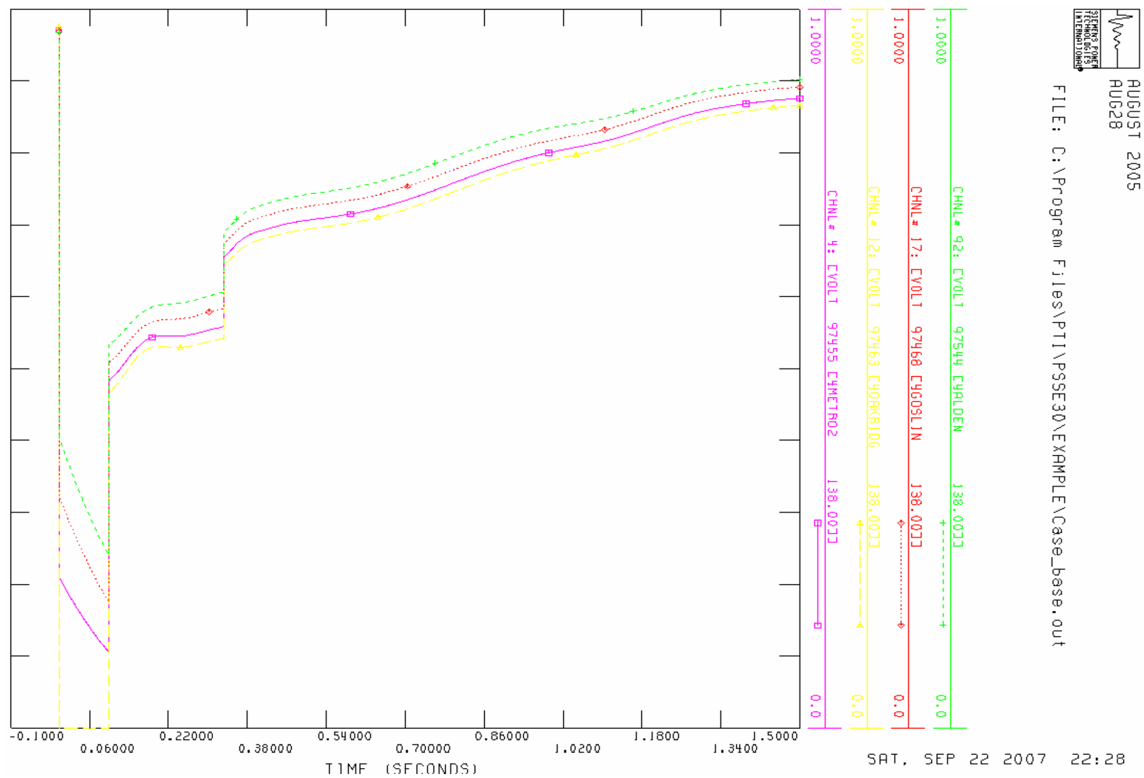


Figure 4.5 Bus voltages under contingency 1 without any SVCs

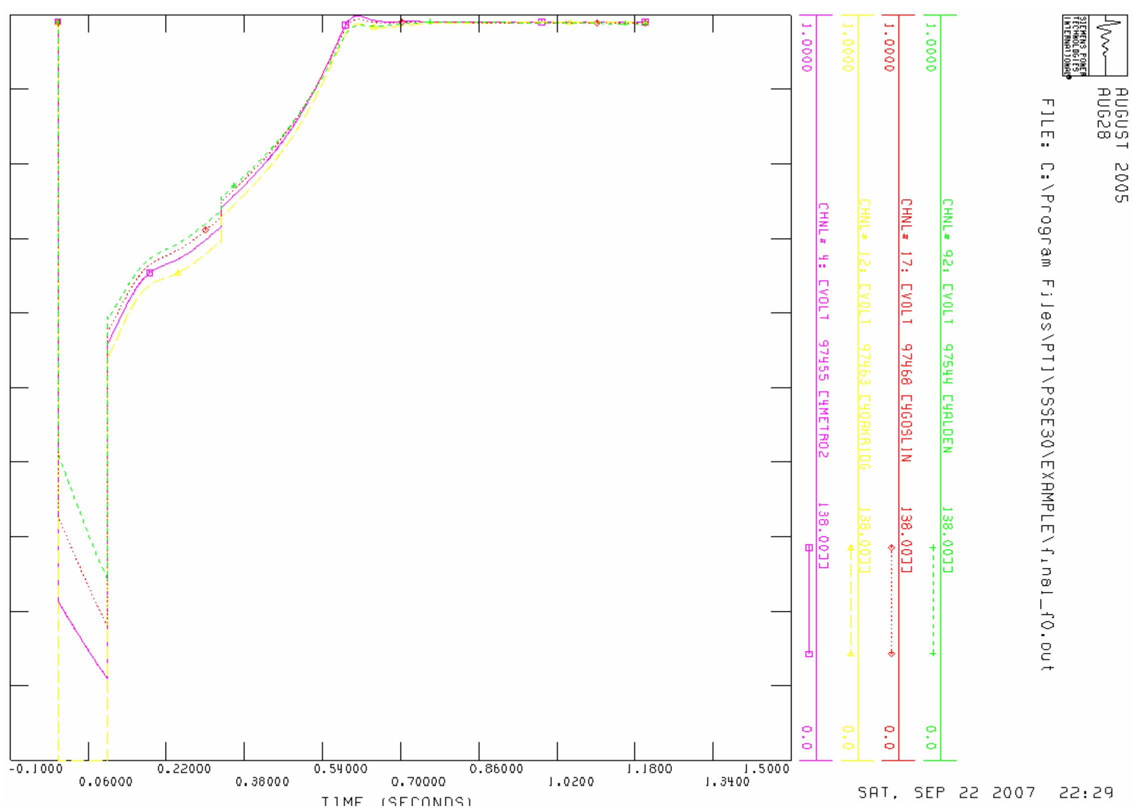
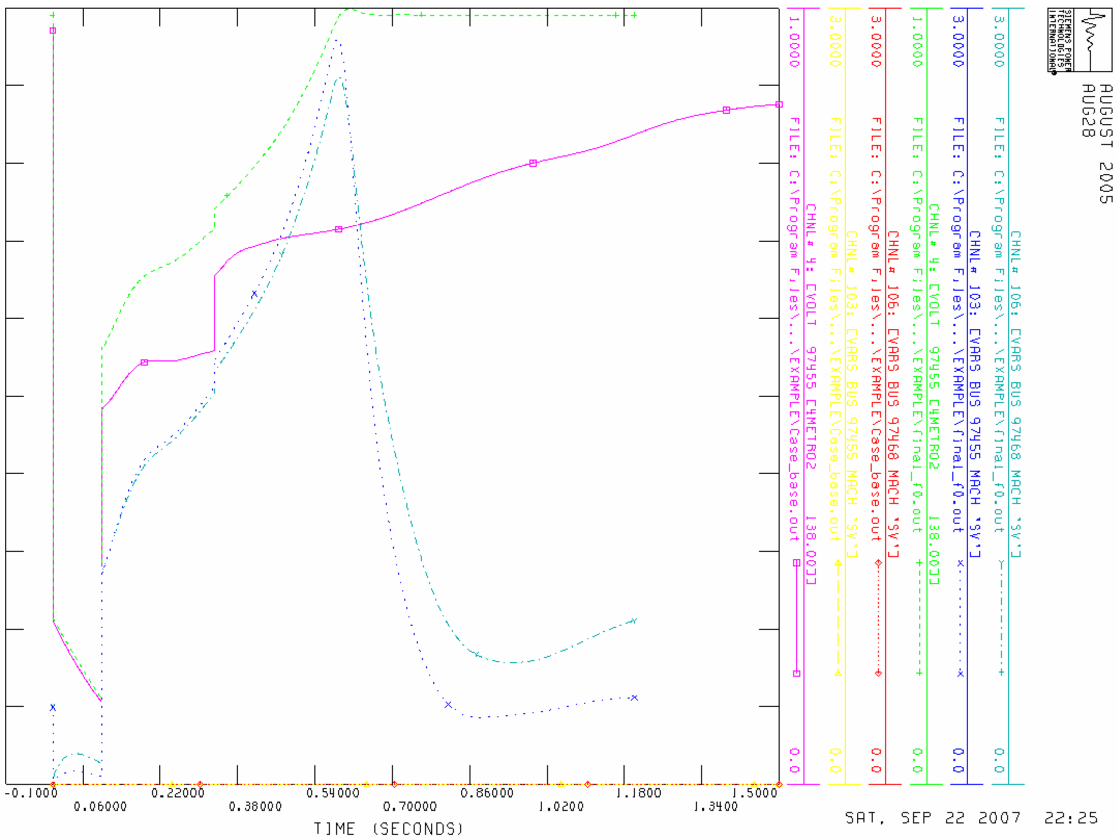


Figure 4.6 Bus voltages under contingency 1 for SVC solution of 2nd iteration optimization

Figure 4.7 shows the improved voltage profile at Bus 97455 under contingency 1 after implementing the SVC solution from the second iteration of stage 1 optimization. Figure 4.7 also shows the output of the two SVCs. The SVC peak output at bus 97455 is about 290 Mvar, and that of bus 97468 is about 270 Mvar.



Legend: Pink – Voltage profile before SVC placement; Green – Voltage profile after SVC placement; Dark Blue – SVC output at Bus 97455; Light Blue – SVC output at Bus 97468

Figure 4.7 Bus 97455 voltage profile under contingency 1 with final SVC allocation

4.7 Summary

The first part of this chapter performed a study to determine least cost reactive resources to satisfy constraints imposed only by voltage instability for a subsystem of a large interconnection. Critical contingencies inside the subsystem that cause voltage instability were considered. In this work, only static Var solutions were considered. The final result was given in Table 4.16, repeated below for convenience, and cost 2.665 M $ under the cost assumptions used for this study.

Bus No.	Bus Name	Base KV	Amount of p.u. Q injection
97457	4LONGMIR	138	1.5
97455	4METRO2	138	1.5
97464	4PANORAM	138	1.5
97544	4ALDEN	138	1

The second part of this chapter performed a *coordinated* planning for static and dynamic Var sources was done for the same subsystem, to plan against voltage instability problems as well as transient voltage dip issues. Critical contingencies inside the subsystem that cause voltage instability and/or that cause transient voltage dip problems were considered. The transient dip problems were so severe that the solution required a lot of SVC, which meant there was no role for capacitors. Several transient voltage profile plots under different contingencies were shown to present the effectiveness of the solution. The final solution was attained through a successive MIP planning algorithm. A second iteration of the stage 1 MIP optimization was needed as some of the contingencies still had voltage dip problems following the first iteration stage 1 solution implementation. Table 4.30 below shows the final solution for the coordinated planning problem. No capacitors[6] are required. The total cost is 32.25 M $ under the cost assumptions used for this study.

Table 4.30 Final Solution

Bus	Base KV	Amount if (p.u) of B (or p.u. Q injection)
97455 4METRO2	138	3.0
97468 4GOSLIN	138	2.85

[6] There can be cases, when the required SVC to mitigate the transient dip problems might be less, and they might still not solve the steady state voltage stability margin violation problems. So in that case Capacitors can be an effective addition to the solution.

CHAPTER 5 CONCLUSION

5.1 Conclusion

This project developed a practical approach to plan an optimal mix of static and dynamic reactive power controls against voltage stability related issues. The work has been motivated by the need for better planning tools that address the alarming increase in concerns shown by the utility around the world to counteract the major power outages caused by voltage instability. The long term planning tool devised in this work uses a power-flow based static tool to calculate post-contingency steady state voltage stability margins for all the identified critical contingencies. For system dynamic studies, PSS/E time-domain simulation tool is used to analyze the transient voltage dip characteristics after few selected critical system faults leading to severe contingencies. The results and sensitivity information from both the study is used together for the coordinated planning problem. The entire planning process was implemented on the Eastern interconnection system with the results presented in the previous chapter.

The following presents important features of the entire Planning tool against voltage instability:

1. Mature MIP software packages such as CPLEX are used that can accommodate larger candidate locations for planning.
2. The method is very effective in dealing with voltage stability requirements under multiple contingencies; which include contingencies that create both static as well as dynamic stability problems.
3. It is only during contingency analysis that we must deal with the full size of the power system. Since the optimization formulation is linear that uses linear sensitivity information, it is fast, and provides good solutions for large-scale power systems that can be validated.

4. The method provides a systematic way to determine the optimal mix of static and dynamic VAR resources.
5. The total cost of reactive power control devices can be reduced by the proposed simultaneous optimization formulation.

The specific contributions of this research are summarized as follows:

1. Implementation of a systematic algorithm of coordinated planning of static and dynamic VAR resources developed in the work [38] on a larger real time system satisfying the performance requirements of voltage stability margin and transient voltage dip. This work is the first of its kind where a coordinated planning proposal has been applied to a large-scale system. Simulation results on a large-scale system indicate that the algorithm is effective to determine the optimal mix of static and dynamic VAR resources. The total installation cost of reactive power control devices can be reduced using the proposed simultaneous optimization formulation.
2. The coordinated planning tool developed is a semi-automated one, in that the interface between the two programming tool, namely PSS/E and Matlab requires manual intervention. The entire planning work described for steady state in the first half of chapter 4 is fully automatic, in that once the base case is input, system analysis, sensitivity calculations, and subsequent steady state planning is done automatically.
3. As a by-product to this planning tool, a data format conversion code was developed that converts PTI PSS/E '.raw' data format into a format understandable and useable by Matlab.

5.2 Scope for Improvements

1. *Consideration of Hopf Bifurcation:* This research uses ODE (Ordinary differential equation) model for power system representation. If DAE (differential algebraic equation)

model is used for power system representation with the algebraic equations for machine, governor, excitation system models etc., then the sensitivity information from this new jacobian of the system will be useful to plan against Hopf bifurcation.

2. *Consideration of operational constraints:* Operational constraints or security measures like line loading, Bus voltage magnitude can also be considered for planning. Right now, the algorithm used in this work does consider Bus voltage magnitude as a constraint for planning while fixing the maximum amount of compensation that can be done at any Bus. But a better implementation of this feature would be to obtain the sensitivities of the Bus voltage magnitudes with respect to the compensation at any bus and use this as one of the constraints while planning. The same holds true for including any other system stability consideration for planning.

3. *Consideration of other reactive control devices:* The planning algorithm can be extended to include other reactive power control devices such as STATCOM, UPFC etc. The only requirement is the exact modeling of these devices for the study, and calculation of sensitivity information for performance indices with respect to these devices.

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