This is to certify that the

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DISPATCHING POWER SYSTEM FOR PREVENTIVE AND CORRECTIVE VOLTAGE COLLAPSE PROBLEM IN A DEREGULATED POWER SYSTEM

presented by

Nasser Ahmed Alemadi

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Robert Schlueter
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Dispatching Power System for Preventive and Corrective Voltage Collapse Problem in a Deregulated Power System

By

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ABSTRACT

Dispatching Power System for Preventive and Corrective Voltage Collapse Problem in a Deregulated Power System

By

Nasser Ahmed Alemadi

Deregulation has brought opportunities for increasing efficiency of production and delivery and reduced costs to customers. Deregulation has also bought great challenges to provide the reliability and security customers have come to expect and demand from the electrical delivery system. One of the challenges in the deregulated power system is voltage instability. Voltage instability has become the principal constraint on power system operation for many utilities. Voltage instability is a unique problem because it can produce an uncontrollable, cascading instability that results in blackout for a large region or an entire country.

In this work we define a system of advanced analytical methods and tools for secure and efficient operation of the power system in the deregulated environment. The work consists of two modules; (a) contingency selection module and (b) a Security Constrained Optimization module.

The contingency selection module to be used for voltage instability is the Voltage Stability Security Assessment and Diagnosis (VSSAD). VSSAD shows that each voltage control area and its reactive reserve basin describe a subsystem or agent that has a unique voltage instability problem. VSSAD identifies each such agent. VS SAD is to assess proximity to voltage instability for each agent and rank voltage instability agents for each contingency simulated. Contingency selection and ranking for each

agent is also performed. Diagnosis of where, why, when, and what can be done to cure voltage instability for each equipment outage and transaction change combination that has no load flow solution is also performed.

A security constrained optimization module developed solves a minimum control solvability problem. A minimum control solvability problem obtains the reactive reserves through action of voltage control devices that VSSAD determines are needed in each agent to obtain solution of the load flow. VSSAD makes a physically impossible recommendation of adding reactive generation capability to specific generators to allow a load flow solution to be obtained. The minimum control solvability problem can also obtain solution of the load flow without curtailing transactions that shed load and generation as recommended by VSSAD. A minimum control solvability problem will be implemented as a corrective control, that will achieve the above objectives by using minimum control changes. The control includes; (1) voltage setpoint on generator bus voltage terminals; (2) under load tap changer tap positions and switchable shunt capacitors; and (3) active generation at generator buses. The minimum control solvability problem uses the VSSAD recommendation to obtain the feasible stable starting point but completely eliminates the impossible or onerous recommendation made by VSSAD.

This thesis reviews the capabilities of Voltage Stability Security Assessment and Diagnosis and how it can be used to implement a contingency selection module for the Open Access System Dispatch (OASYDIS). The OASYDIS will also use the corrective control computed by Security Constrained Dispatch. The corrective control would be computed off line and stored for each contingency that produces voltage instability. The control is triggered and implemented to correct the voltage instability in the agent experiencing voltage instability only after the equipment outage or operating changes predicted to produce voltage instability have occurred. The advantages and the requirements to implement the corrective control are also discussed.

This work is dedicated to my parents, my wife, and my children

ACKNOWLEDGMENTS

All thanks, Prayers and glories are due to ALLAH, the most gracious and most merciful, who taught humankind every thing they knew not.

I am deeply grateful and indebted to several people who helped by their effort and support in the development of this dissertation.

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This acknowledgment would be incomplete without recognizing the love and encouragement of my family. Great thanks are extended to my parents, brothers, and sisters for their continuous moral support, help, and prayers.

Most importantly, I would like to express my profound gratitude and greatest thanks to my great wife, Fawziya who stood by me and was a trusted friend and a compassionate partner in all my ups and downs during my graduate study in the U.S.A. Her emotional support, understanding, love and constant encouragement made my life much happier and my work much easier. I am also grateful to my daughters, Maha and Bashaer, and my son, Muhammad for their love, concern and patience.

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CHAPTER 1

Introduction

1.1 Description of the problem

Deregulation has brought great opportunities for increased efficiency of production and delivery and reduced cost to customers. Deregulation has also brought great challenges to provide the operating reliability and security that customers have come to expect and demand from electrical delivery system. In a deregulated environment, the transmission system will provide open access to all suppliers and electric energy customers. This competitive environment will force the generation and transmission companies to provide and sell their services under market conditions.

One of the challenges in a deregulated power system is voltage instability. System failure and blackouts already have been observed in Europe, Japan, Ontario Hydro, New York Power Pool, and lately two blackouts in the west of USA due to voltage instability. Voltage instability is one of the biggest concerns in operating and planning electric power systems before deregulation occurs. In a deregulated environment voltage collapse will become much more common. One of the reasons is that power is being transferred, wheeled, and interchanged through hundreds if not thousands of transactions. Other reasons for the voltage collapse are (1) real power is shipped along different paths in different directions than what they were designed for, (2) the rapid changes in power dispatch due to competition of selling power to different customers and the ability of these customers to change their generating company at their discretion, (3) the transmission and subtransmission system were built and compensated to provide stability and security for flow of power supplied from a known set of generators and delivered to a known set of loads, and (4) the absence of the knowledge that there is sufficient reactive reserve in each reactive reserve basins [1] due to the lack of knowledge that additional reactive supply may be necessary.

1.2 Motivation and Objective

Voltage instability is caused by exhaustion of the reactive supply on one or more generators in a subregion, that causes loss of control voltage instability in that subregion. Clogging voltage instability occurs when some subregion in the system can't obtain needed reactive supply because the network absorbs all the reactive power flowing to that subregion. Increasing transfer, wheeling, interchange of power on transmission lines, and the increasing demand for power can cause both clogging voltage instability and loss of control voltage instability. The power flow problem does not solve (no solution), or one or more eigenvalues of the Jacobian become negative as an indication of voltage instability. Q-V and P-V curves [2] are some of the traditional way of assessing proximity to voltage instability. The Q-V curve is used to test for voltage instability since it determines the maximum amount of reactive supply that can be added to a bus in order for the load flow to still have a solution. The P-V curve assesses the maximum real power transfer, wheeling, and interchange transactions in the system before the load flow no longer has a solution. Neither of the methods assesses the effects of equipment outage nor the kind of voltage instability (loss of control or clogging) that occurs, the cause of instability, and the cure for any voltage instability p

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instability problem for any particular equipment outage or operating change combination. Section 3.2 provides a review on what voltage instability is, when it occurs mathematically, and the $P-V$, $Q-V$ curve and minimum distance, minimum eigenvalue and minimum singular value proximity measures for voltage instability.

An Open Access System Dispatch is a controller proposed for implementation in the control centers, called Independent System Operators (ISO), of a deregulated power system. The objective, capabilities, and structure for this proposed Open Access System Dispatch are given in [15] but no concrete methodology is suggested for implementing it. The Open Access System Dispatch, as proposed, has a

- contingency selection module
- Security Constrained Optimization module

This thesis develops a set of optimization problems that will meet the requirements set forth for the Security Constrained Optimization module and use the Voltage Stability Security Assessment and Diagnosis (VSSAD), developed at Michigan State University, for the contingency selection module.

The contingency selection module is a very significant extension of current $P-V$, $Q-V$ curve, and minimum distance proximity measure tools because these measures only use continuous parameter changes and not the discontinuous changes in parameter changes. Discontinuous parameter changes are associated with equipment outage, large transactions of power between generating companies, or between generating companies and customers. The $P-V$ curves and minimum eigenvalue or minimum singular value proximity measures only assess one mode of instability for one particular eigenvalue at a time where several can experience instability and each is vulnerable to different equipment outage and transaction combinations. The contingency selection module indicates where, when, why, and corrective action (operating changes) for every mode of instability and for every equipment outage and operat-

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ing change that produces that particular mode of voltage instability. The analysis should also provide operating and security constraints for each mode of instability. The Voltage Stability Security Assessment and Diagnosis programs can provide all the above capabilities desired for the contingency selection module. The VSSAD is discussed in chapter 3 where its capabilities and advantages are discussed.

The proposed Security Constrained Optimization module is even further from current technology. The Security Constrained Optimization module utilizes constraints provided by a voltage stability analysis for voltage stability problems and dynamic security assessment for transient instability problems. The dynamic security assessment provides flow constraints on particular paths or interfaces and these constraints could be accommodated easily. Voltage stability constraints are not easy to obtain because there should be one for each mode of instability and possibly for each equipment outage and operating change combination that produces or threatens instability for that mode. The voltage stability assessment in VSSAD provides the structure for these constraints. There are also operating constraints that prevent thermal overload on each network branch and bus voltage limit operating constraints on every bus. There can also be security constraints associated with thermal overload on each branch, bus voltage limit violation on each bus, voltage instability of each mode of instability, and dynamic instability for each transient stability problem for every equipment outage and transaction combination that can cause any of these problems. Finding a feasible solution to the power system load flow model that satisfies all of these constraints is daunting. Optimization given all these constraints is even more difficult.

In this thesis the voltage instability in the deregulated environment system will be investigated. We propose a secondary corrective control as being computed and updated every 5-30 minutes as part of the Open Access System Dispatch as discussed in [15]. The secondary control is actually precomputed for each equipment outage and operating change predicted to produce voltage instability at that update interval by th

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interval by the Voltage Stability and Security Assessment and Diagnosis [1]. This secondary control, called Open Access System Dispatch Security Constrained Optimization, would correct a specific mode of voltage instability (loss of control voltage or clogging) that is developing because the equipment outage and operating change combination predicted to produce the voltage collapse in the Voltage Stability and Security Assessment and Diagnosis (VSSAD) has occurred and been detected via the state estimators. The switching of capacitors, under load tap changer tap position adjustments, and generator excitation voltage set point changes are determined in an optimal fashion to eliminate the loss of control voltage or clogging instability on one or more subregions in a system for each specific equipment outage and operating change combination. This set of optimized control changes not only prevent or correct voltage instability in the subregion experiencing it but also prevent a cascading instability from producing loss of control voltage or clogging instability in the rest of the system. The Open Access System Dispatch Security Constrained Optimization is formulated to obtain a minimum set of control changes to achieve corrective control for any particular equipment outage and operating change, and also to posture the operating state and control settings on the whole system to help prevent voltage instability from occurring for any of the VSSAD predicted equipment outage and operating change combination. The minimum set of control changes for each specific equipment outage and operating change combination predicted by VSSAD to cause voltage instability would be stored, triggered, and implemented once the state estimator detects the occurrence of that equipment outage and operating change combination predicted to produce voltage instability by VSSAD. These control changes must be implemented by a local security controller with a sampling and control command update rate of 5-10 seconds. The emergency secondary voltage control would be used to insure stability and security of the system in case the control change cannot be determined for the secondary voltage control using switchable capacitors, under load tap changer tap position, and generator excitation control voltage set points as controls. An emergency secondary voltage control will change or curtail transaction and even curtail load if the secondary voltage control could not achieve stability and security of the system.

A review of the literature on the optimization used in dispatch of power systems is given in chapter 4. It discusses the security constrained economic dispatch and the reactive power dispatch problems that simplify the optimal power dispatch into two separate but coupled optimization problems. The difficulties in handling operating and security constraints is discussed. The Benders decomposition for solving a separate optimization problem for each equipment outage and operating change to correct all thermal, voltage, and voltage instability problems is discussed. Finally, the objectives, constraints, controls, and capability of the Security Constrained Optimization module developed in this thesis is given in section 4.4 . A discussion of the exact formulation is give in chapter 5 of this proposal and the development and testing of this module will be the principal subject of this thesis. The algorithms required to solve the security constrained optimization problems must be the most capable yet developed. There have been several developments over the last 15 years that have greatly improved the convergence rate and convergence robustness of algorithms. A review of optimization theory is given in chapter 2 to justify use of the Primal-Dual Logarithmic Barrier Interior Point Method to solve the security constrained optimization problems.

1.3 Literature Review

In the last three decades, a number of studies in electric power utilities have laid the groundwork for solving optimal power flow problems. The following is a brief literature review of some of the approaches which have been developed to solve the optimal disp

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optimal dispatch problems, and may represent a general overview of the research on this subject. Also, a comprehensive literature review of the optimal dispatch problems can be found in [29]

1.3.1 Optimal Power Flow

The classical economic dispatching problem first appeared in the early 50's [30, 31], where the objective and the nonlinear load flow constraints were approximated by some simpler equality linear constraints on total generation and load to avoid the need to use an iterative approach. These methods are simple and fast because the network model was limited to its simplest form.

In early 1960, the work of [32, 33] laid the groundwork of Optimal Power Flow (OPF) formulation. The work of Carpentier attempted a solution method which made use of Kuhn-Tucker necessary condition from nonlinear programming to obtain a set of equations that provide candidates for an optimal solution. The equations take into account the load flow equations and constraints on the state and control variables of the load flow model. In subsequent work, Carpentier [34] tries to solve the OPF problem by using the generalized reduced gradient method. Dommel and Tinney [35] attempted to solve the Kuhn-Tucker conditions using the gradient method with a penalty function to handle nonlinear inequality constraints. This work has the advantage of a fixed formulation. The work of Carpentier's and Dommel et al. was considered to be the most popular in the OPF research area for many years. In [36, 37] linear models were developed to approximate the first and the second order information of the objective function and constraints. These model approximation method were applied in several papers in the 1970's [38, 39, 40]. In [41], important improvement were proposed to make use of the fast decoupled load flow model and the sparsity technique. In the above methods, the convergence behavior, however, proved to be much more difficult and erratic than was initially anticipated. Other ifficulties inclu

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difficulties include; (a) the need for solving the load flow solution at each iteration which required significant computation and (b) ineffective handling of the inequality constraints so that convergence was problematic. In 1970's a Newton's technique method [42, 48, 49], was applied to the optimal power flow problem. This Newton method provided excellent local convergence properties, but its global convergence was still not guaranteed. The difficulty in handling inequality constraints was still a difficult and unsolved problem. The computation time remained high and thus it could not be implemented on large scale power system problems.

New methods proposed in 1980's [45, 46, 47], were based on Newton method. These Quasi Newton methods use an iterative scheme based on an approximation of the Hessian matrix, which is calculated at each iteration. These methods are useful only for problems of limited size because the reduced Hessian matrix must be updated at each iteration, and because they form a dense Hessian matrix. Burchett, et al. [48, 49] have reported the formulation and implementation of several methods of solving the optimal power flow problem. In [48], a Quasi Newton method is used for optimizing the subproblems which are transformed from the original problem. The nonlinear constraints are linearized by using the Newton Raphson Jacobian matrix. In [49] Burchett creates a sequence of quadratic subproblems from the exact analytical first and second derivative of the power flow equations and the nonlinear objective function. The dimension of the Hessian matrix was not fixed in these method and was updated at each iteration which makes the algorithm require significant computation for on-line implementation application in a power system control center.

Sun et al. [50] and later in [51] solve the classical OPF by decoupling the problem into active and reactive power problem using a Newton approach. The method uses Kuhn-Tucker optimality conditions, produces quadratic programming problems and uses sparsity techniques. The methods converge to the Kuhn-Tucker optimality conditions in few iterations if a set of binding inequality constraints is predetermined.

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The major challenge in Sun's algorithm is in identifying the binding inequality constraints. Some other authors have also used real-reactive decompositions of the OPF to solve the optimization problem using approaches that use [52] a linear programming method, [53] a quadratic programming method, or [54] a gradient method.

In 1984 a new method, called the Interior Point Method [27] was introduced for solving a linear programming problem. The Interior Point Method have been applied to solve large scale linear optimization problems [55]. Although, these method were first introduced into nonlinear programming by Fiacco and McCormick [56] in the early 70's, only recently has the theory matured to provide methods for solving nonlinear optimization problems [57, 18, 76].

1.3.2 Interior Point Method

The Interior Point Method has proven to be a feasible alternative for the solution of optimal power flow problems. In the last five years several papers were proposed to solve linear and nonlinear programming problems in power system using an Interior Point Method. Vargas, et at. [71] used a dual-affine scaling algorithm to solve a Security-Constrained Economic Dispatch problem by sequential linear programming. Pannambalam, et al. [72] used a dual-affine algorithm for the optimization of hydro scheduling operation which is a large scale linear programming problem. Both of the studies showed that the computational results favor the dual-affine algorithm in comparison to the MINOS simplex code. Lu,et al. [73] applied Karmarkar's algorithm to solve the linear contingency constrained security dispatch problem. Clements, et al. [74] applied a primal-dual logarithmic barrier interior point method to solve a power system state estimation problem using the Lagrangian function and the Hessian matrix. Momoh, et al. [14] presented an extended quadratic interior point method, based on an algorithm for improvement of initial point for solving linear and quadratic programming problems.

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The application of the interior point method algorithm to nonlinear optimal power flow problem consists of three crucial steps [75]. The first step consist of introducing the slack variables to transform the inequality constraints in to equality constraints and the use of Fiacco and McCormick's logarithmic barrier method [56] to add the slack variables to the objective function as soft constraints. Using Lagrangian function for optimization with equality constraints in the second step converts the constrained optimization problem to an unconstrained optimization problem. This almost eliminates the problem of handling inequality constraints. Finally, applying Newton's method to solve the Karush-Kuhn-Tucker (KKT) first optimality condition of the nonlinear unconstrained optimization problem provides quadratic convergence in primal and dual variables. Application of nonlinear programming worked by [57, 18, 76] uses the interior point method to solve optimal power flow problems.

In [57] primal-dual logarithmic barrier algorithm is directly applied to a nonlinear optimal power flow problem by using Pure Primal-Dual interior point algorithm that uses Newton's method to solve the Karush-Kuhn-Tucker optimality condition. Wu [57] also used Predictor-Corrector interior point algorithm to solve the nonlinear problem. Both methods were based on a method suggested by Mehrotra [77]. A similar algorithm was developed in parallel with the Wu's one by Granville [18] with a different application. Granville uses a Primal- Dual logarithmic barrier algorithm to solve reactive dispatch problem. Torres, et al. [76] applied Primal-Dual logarithmic barrier algorithm to solve a large scale nonlinear programming problem using both a rectangular and polar variables.

1.3.3 Voltage Instability

Voltage instability has become the principle constraint on power system operation for many utilities [58]. Many blackouts have affected the Pennsylvania, New Jersey, Maryland Interconnection, the Western System Coordinating Council

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(WSCC) system, Florida, France, Sweden and Japan. In the 1980's several author [59, 60, 61, 62, 87] investigated the voltage instability problems. These investigation provided some knowledge of the development, propagation, and some factors causing voltage instability. Despite the knowledge gained, voltage collapse scenarios still suffer from a lack of knowledge of modelling and understanding of the problem.

Recently, voltage instability has received an increasing attention [63, 64, 65]. The work in these articles and in the report [66] have been done to study the bifurcations that have been found to be one of the primary causes for voltage instability in a differential algebraic power system model. It has been shown that bifurcation sequences occur in a differential algebraic model that can include saddle- node [67, 68], Hopf [69], and chaotic[70] bifurcation. Instability in the dynamics can occur before the bifurcation occurs in the algebraic model [3]. Furthermore, Schlueter at al. [9] show that saddle-node bifurcation in a differential algebraic model at equilibrium is a bifurcation in the load flow model that includes both the algebraic submodel and differential submodel at equilibrium. In [11] a bifurcation subsystem method is defined that identifies the subsystem that not only experiences but produces the voltage instability observed in the load flow model in a differential algebraic model. Schlueter in [11] determines the conditions for bifurcation to occur in each bifurcation subsystem that can experience voltage instability in load flow model. Two eigenvalue estimates that bound the bifurcating eigenvalue associated with the bifurcation subsystem were derived. The two conditions for a bifurcation subsystem to exist are that bifurcation occurs nearly simultaneously in the subsystem and full system models. The two eigenvalue estimates are shown to respectively measure satisfaction of these bifurcation subsystem conditions. The theory provides theoretical justification of the diagnostic procedures in the voltage stability security assessment and diagnostic (VSSAD) methods.

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complete in describing the modeling required to perform voltage stability as well as some of the algebraic model based methods for assessing proximity to voltage instability. Taylor [24] provides a tutorial review of voltage stability, the modeling needed, and simulation tools required to perform a planning study on a particular utility or system. Van Cutsen and Vournaś [25] provide the only dynamical system discussion of voltage instability and also, show the various dynamics that play a role in producing voltage instability.

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CHAPTER 2

Interior Point Method

A review of optimization theory in general and the interior point algorithms since optimization is central to the development of the preventive and corrective controls proposed in chapter 4 and 5 of the thesis. The focus of this discussion is to justify use of an interior point algorithm as well as the particular algorithm used in the thesis. The interior point algorithm can be divided in to three main methods: the affine-scaling method (Primal affine and Dual affine); the projective method such as Karmarkar's algorithm; and the path-following method and the potential-reduction method, which both use the Primal-Dual algorithms. We use in this thesis the Primal-Dual interior point method that is based on use of a barrier function in the performance index. The Primal-Dual interior point method has been particularly successful in practice. The bound on the number of iterations is on the order of $O(\sqrt{n}\,l)$, whereas in the affine-scaling method the bound on the number of iterations for both the Primal affine and the Dual affine is on the order of $O(nl^2)$ [26], where n is the number of nodes and l is a measure of the length of the input data for the problem. The projective method has not been as successful as the other two interior point method. Furthermore, it appears to be slower and less robust in computational tests. Computational experiments [75, 77, 78, 79] showed that Primal-Dual algorithms also performed better than the other interio

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other interior point methods on theoretical and practical problems. The Primal Dual performed better than the Simplex method on large-scale linear programming problems. This chapter briefly reviews the linear and nonlinear programming and then the Primal-Dual algorithm of the Interior Point Method will explained in detailed.

2.1 Linear Programming

A Linear programming problem has a linear objective function with the linear equality and inequality constraints. The linear programming problem has the form [26].

$$\left.\begin{array}{ll} Minimize & F(x) = c^T x \\ subject\ to & Ax = b \\ & x \geq 0 \end{array}\right\} \tag{2.1}$$

with $b \geq 0$. *Here* x *and* c *are vectors of length* n, b *is vector of length* m, *and* A *is an* $m \times n$ *matrix called the constraint matrix.*

The feasible region of a linear programming problem is defined by its linear performance index and its linear constraints that forms a convex set. A point x is a solution to the problem if it satisfies the equality constraints, and the columns of the constraint matrix corresponding to the linear components of x are linearly independent [26]. The point x it is a feasible solution (extreme point) if it satisfies the equality constraints and non negativity constraints, and it is an optimal solution if it minimizes $F(x)$ over all feasible x. The Simplex method is a classical method for solving a linear programming written in the standard form. It is an iterative method that moves from one feasible solution (extreme point) to another as long as the objective function improves. At each iteration the components of feasible solution x are separated into two vectors, one consisting of all zero components which are called th

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are called the $n-m$ nonbasic variables x_N , and the other consisting of nonzero components, which are called the m basic variables x_B. The test for optimality is then performed to see if there exist any feasible decent direction. An exchange between some components of basic variables x_B and nonbasic variables x_N will take place when a feasible solution moves from one extreme point to an adjacent extreme point.

The simplex method moves from one set of binding constraints $x_i = 0 \quad i \in I_j$ to another $x_i = 0 \quad i \in I_{j+1}$ looking for an optimal set of binding constraints that characterize the optimal solution. The difficulty with the simplex algorithm is that the procedure does not guarantee convergence to the optimal solution because there is no direct convergent search for the set of binding constraints.

2.2 Nonlinear Programming

A Nonlinear programming problem has a nonlinear objective function and nonlinear constraints. The problem that can be written in the general form [26]

$$\left.\begin{array}{ll} \textit{Minimize} & F(x) \\ \textit{subject to} & G_i(x) = 0; i \in E \\ & H_i(x) \geq 0; i \in I \end{array}\right\} \tag{2.2}$$

where:

$x \in R^{m \times n}$ *is the vector of decision variable that include both control and state variables, that is* $x = [U \; X]$

$U \in R^m$ *is the vector of control variables*

$X \in R^n$ *is the vector of state variables*

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The solution to the constrained problem is a local solution. However, the local solution is also global solution if the objective function is convex function and the feasible region is convex. Unlike a linear programming where the feasible movement from a point to a nearby point along a feasible direction, the movements of a nonlinear case will be made along a feasible curve. Four important methods of nonlinear programming solution techniques are commonly used:

1. Primal Method
2. Dual Method
3. Penalty Function Method
4. Barrier Function Method
5. Interior Point Method

and are discussed in the following subsection of this section.

2.2.1 Primal Method

The problem(2.2) is known as the primal problem since it directly searches for x. Often a $\mathcal{L}$agrangian is formed

$$\mathcal{L}(x, \lambda, \mu) = F(x) - \sum_{i \in E} \lambda_i G_i(x) - \sum_{i \in I} \mu_i H_i(x) \tag{2.3}$$

where λ and μ are $\mathcal{L}$agrange multiplies.

Kuhn Tucker conditions for the optimal solution requires

$$\frac{\partial \mathcal{L}(x, \lambda, \mu)}{\partial x} = 0 \tag{2.4}$$

$$\frac{\partial \mathcal{L}(x, \lambda, \mu)}{\partial \lambda} = G(x) = 0 \tag{2.5}$$

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$$\mu_i H_i(x) = 0 \; ; \; i = 1, 2, \cdots, I \tag{2.6}$$

$$\mu_i \geq 0 \tag{2.7}$$

The condition (2.6) is the complementary slackness condition and states either μ_i or $H_i(x)$ must be zero.

The determination of x and λ can be determined for any value of μ that satisfies (2.7) either by solving the gradient equations (2.4 , 2.5) analytically or by a Newton Method that requires finding a Hessian matrix $\mathcal{L}_{xx}(x, \lambda, \mu)$. The difficulty with this primal method is that there is no direct convergent search for μ and no assurance of feasibility $[\ x\ ;\ G_i = 0\ \forall\ i \in E,\ H_i \geq 0\ \forall\ i \in I]$.

2.2.2 Dual Method

The dual problem is a $min - max$ problem

$$max_{\lambda,\mu}\left[min_x\left[\mathcal{L}(x, \lambda, \mu)\right]\right] \tag{2.8}$$

that optimizes on both λ, μ and x. Thus there can be convergence in μ as well as x and λ. If the performance index $F(x, u)$ is convex and the constraints $H_i(x, u)$ are concave, the solution to the dual is the solution to the primal [26]. There can be a duality gap between the primal solution and dual solution if the problem is not a convex programming problem. Another condition for lack of a duality gap requires the Hessian

$$\frac{\partial^2 \mathcal{L}(x, \lambda, \mu)}{\partial x^2} \tag{2.9}$$

to be defined at all value of (x, λ, μ) and be positive definite at (x^*, λ^*, μ^*) which is dual feasible.

There are two popular algorithms for solving the primal problem. The gradient determi

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determines a gradient of $\mathcal{L}(x, \lambda, \mu)$ with respect to x and λ. The generalized reduced gradient method (GRG) reduces the dimension of the primal problem by using the equality constraints $G(x) = 0$ to solve for the state variables and thus eliminate these equality constraints and the $\mathcal{L}$agrange multipliers associated with the equality constraints $\frac{\partial \mathcal{L}}{\partial x}$ that contain λ. The Newton Method solves (2.4, 2.5) using the Newton Rapheson Method for solving nonlinear equations is a second method for solving the primal problem. The Newton Method requires computing the Hessian $\frac{\partial^2 \mathcal{L}}{\partial z^2}$ where $z^T = (x^T, \lambda^T)$ and thus assures quadratic convergence in z to a solution.

The reduced gradient method and Newton Method do not optimally search for the subset of optimal binding constraints that either satisfy $x_{i_{min}} = x_i$ or $x_{i_{max}} = x_i$ and the vector μ as the dual algorithm does. There is no assurance of convergence to an optimal set of binding constraints and the GRG and Newton Method often do not converge on large nonlinear problems such as the Reactive Dispatch Problem. It is desired that one should find feasibility and quadratic convergence in selecting the binding constraints and parameters μ. There are several approaches to assuring feasibility. The penalty function method and the barrier function method are two popular approaches and they are now discussed.

2.2.3 Penalty Function Method

The penalty function method have been used over the past three decades to solve the nonlinear constrained problem. The main idea behind the penalty function method is to transfer the constrained problem into a single unconstrained problem or a sequence of unconstrained problems, with the introduction of a penalty whenever a constraint is violated. The penalty function is only applied when the solution is infeasible. The penalty function penalizes the lack of satisfaction of a particular inequality constraint, but has no value if the constraint is satisfied. The penalty function is placed into the objective function via a penalty parameter that can be used to insure that the penalty is suffici

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is sufficiently large to correct violation of any inequality constraint. A suitable penalty function must also incur a penalty for violation that increases dramatically with the magnitude of the violation, which forces the solution toward the feasible region. To motivate use of penalty function, consider the following problem (here we repeat problem of eq: 2.2):

$$\left.\begin{array}{ll} Minimize & f(x) \\ subject\ to & G_i(x) = 0; i \in E \\ & H_i(x) \geq 0; i \in I \end{array}\right\} \tag{2.10}$$

The performance index function with penalty for nonlinear problem(2.10) is

$$f(x) = F(x) + \mu\psi(x) \tag{2.11}$$

and $\psi(x)$ is referred to as the penalty function. The following unconstrained problem is expressed as

$$\left.\begin{array}{ll} Minimize & F(x) + \mu\psi(x) \\ subject\ to & x \in R^n \end{array}\right\} \tag{2.12}$$

where μ is a large positive penalty parameter, and $\psi(x)$ is continuous penalty function.

$\psi(x)$ is a continuous function that penalizes any violation of constraints, with the property that

$$\left.\begin{array}{ll} \psi(x) = 0 & if\ x\ is\ feasible \\ \psi(x) > 0 & otherwise \end{array}\right\} \tag{2.13}$$

and is defined in the general form:

$$\psi(x) = 1/3\ g(x)^T g(x) + \sum_{i \in I} minimum\ \{0, h_i(x)\} \tag{2.14}$$

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The solution can be obtained to be arbitrarily close to feasible region of the original problem by choosing μ to be sufficiently large. The parameter μ is increased after each iteration until the resulting solution is feasible. The main advantage of using the penalty function method is that each iteration is not required to be strictly feasible. On the other hand, the penalty function method will force the iteration toward feasible set boundary, but not necessarily and not generally toward the optimal solution. The penalty function method also suffers from a problem of ill conditioning. As the penalty parameter increases ($\mu \longrightarrow \infty$) to enforce feasibility, the Hessian matrix of the auxiliary function will become ill-conditioned near the solution, causing the unconstrained problem to become increasingly difficult to solve.

The penalty function method at least achieves feasibility of solution for problems with a large number of equality and inequality constraints. Adding a penalty function is a simple method for guaranteeing feasibility and for some penalty function can guarantee quadratic convergence to a feasible solution when μ is large. However, if $\mu \to \infty$ to enforce feasibility the penalty function appears as a infinitely high wall around the feasible set that assures feasibility. The ill conditioning of the Hessian makes it very difficult to find an optimal solution within the feasible set since the objective function appears nearly flat over the feasible region compared to the penalty function produced wall. There can be some searching for the optimal solution within the feasible region but often no convergence to an optimal solution.

2.2.4 Barrier Function Method

The barrier function method uses a barrier function to transform a constrained problem to a series of unconstrained problems just as a penalty function method does. The barrier function method requires starting from a feasible solution and adding the barrier functions to prevent leaving the feasible region. The barrier function method is

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$$\begin{aligned} &Minimize && \Theta(\mu) && (2.15)\\ &subject\ to && \mu > 0 && (2.16) \end{aligned}$$

where

$\Theta(\mu) = inf_{x,\lambda}\left\{f(x) - \lambda^T G_i(x) + \mu B(x)\right\}$ *and* $x \in \{H(x) \geq 0\ , G(x) = 0\}$.

The barrier function is one that approaches infinity as the boundary of $\{x\ ;\ H_i(x) \geq 0\}$ is approached from the interior. Possible barrier function are

$$B_1(x) = \sum_{i=1}^{N} \frac{1}{H_i(x)} \tag{2.17}$$

$$B_2(x) = -\sum_{i=1}^{\infty} \ln\{H_i(x)\} \tag{2.18}$$

The optimization of $\Theta(\mu)$ occurs for values of decreasing μ that allow the solution x_k to approach the boundary of the set $\{x\ ;\ H_i(x) \geq 0\}$. The barrier function cause the Hessian to experience serious ill conditioning and round off error when μ is small but when μ is large these problems disappear.

The barrier method finds a feasible solution at every iteration rather than at the final iteration. The barrier function ill conditioning problem increases as μ decreases with a barrier function method just like penalty function ill conditioning problem increase as feasibility is starting to be assured. The barrier function can optimize within the feasible solution region that grows as μ decreases. The ill conditioning of the Hessian matrix rules out use of an unconstrained method whose convergence depends on the condition number of the Hessian matrix. Therefore Newton type methods are usually the choice. The Newton equations are also sensitive to the ill conditioning of the Hessian matrix. The numerical errors can result in poor search directions. The ill conditioning of the barrier led to their abandonment in the early 1970s. Interest in barrier fu

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barrier function method was renewed in 1984 with the announcement of Karmarkar's method [27]for linear programming and the discovery that this method is a special case of the barrier method (No ill conditioning occurs in a linear program which has a unique solution.) Recently specialized algebraic techniques have been developed that compute a numerically stable approximate solution to the Newton equations.

2.2.5 Interior Point Method

The interior point algorithm for nonlinear programming problems are motivated out of Karmarkar's algorithm for linear programming problems. The interior point algorithm in contrast to simplex algorithm (and nonlinear programming algorithms such as Newton and GRG) do not move from one set of binding constraints to another. The interior point algorithm moves from point to point interior to a feasible region. A primal-dual interior point algorithm is now formulated for the problem

$$\begin{aligned} \mathit{Minimize} \quad & F(z) && (2.19)\\ s.t. \quad & G(z) = 0 && (2.20)\\ & l \leq z \leq u && (2.21) \end{aligned}$$

The problem is first reformulated by introducing the slack variables s_1 and s_2 and the barrier function

$$\begin{aligned} \mathit{Minimize} \quad & F(z) - \mu \sum_{j=1}^{n} \ln(s_{1j}) - \mu \sum_{j=1}^{n} \ln(s_{2j}) && (2.22)\\ \mathit{subject\ to} \quad & G(z) = 0 && (2.23)\\ & z - s_1 = l && (2.24)\\ & z + s_2 = u && (2.25)\\ & s_1, s_2 \geq 0 && (2.26) \end{aligned}$$

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The $\mathcal{L}$agrangian is

$$\mathcal{L} = F(z) - \lambda^T G(z) - \Pi_1(z - s_1 - l) - \Pi_2(z + s_2 - u) - \mu \sum_{j=1}^{n} \ln(s_{1j}) - \mu \sum_{j=1}^{n} \ln(s_{2j}) \quad (2.27)$$

where λ, Π_1 *and* Π_2 *are the dual variables.*

The first order necessary conditions are

$$\nabla F(z) - \mathcal{J}^T(z)\lambda - \Pi_1 - \Pi_2 = 0 \quad (2.28)$$

$$G(z) = 0 \quad (2.29)$$

$$z - s_1 - l = 0 \quad (2.30)$$

$$z + s_2 - u = 0 \quad (2.31)$$

$$\mu e - S_1 \Pi_1 = 0 \quad (2.32)$$

$$\mu e - S_2 \Pi_2 = 0 \quad (2.33)$$

where:

$\nabla F(z)$ *is gradient of* $F(z)$

$\mathcal{J}(z)$ *is Jacobian of* $G(z)$

λ *are the* $\mathcal{L}$*agrange multipliers* $\in R^m$ *where* m *is the number of equality constraints*

Π_1 *and* Π_2 *are the* $\mathcal{L}$*agrange multipliers* $\in R^n$ *where* n *is the number of state and control variables*

S_1 *and* S_2 *are diagonal matrices whose diagonal elements are* s_{1j} *and* s_{2j} *respectively and they are* $\in R^{nxn}$

$e = [1, 1, \cdots, 1]^T \in R^n$

The Newton equations are generated by taking derivatives of the equations (2.28 - 2.33) with respect to $z, \lambda, \Pi_1, \Pi_2, s_1,$ and s_2 to produce a solution for these variables. These conditions are given in chapter 4 when the interior point

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algorithm for the OASYDIS is given. This primal- dual problem is thus quadratically convergence in both primal and dual variables. The value of μ is chosen based on the duality gap which in this case is equal to

$$S_1^T \Pi_1 - S_2^T \Pi_2 \tag{2.34}$$

and [28] selects

$$\mu = \frac{S_1^T \Pi_1 - S_2^T \Pi_2}{n^2} \tag{2.35}$$

where n *is number of variables.* In [18] μ is selected as

$$\mu = \frac{S_1^T \Pi_1 - S_2^T \Pi_2}{\beta n^2} \tag{2.36}$$

where $\beta > 1$ *specified by the user.* The control path or barrier trajectory is $z(\mu)$: $\mu > 0$, along this barrier trajectory. If an affine search algorithm were used and the problem was linear, the primal z and dual Π_i and S_i search direction are orthogonal along the barrier trajectory. This linear programming primal-dual can converge in $\sqrt{n}$ iteration. It is not as clear that the convex nonlinear programming barrier trajectory has such desirable quadratic convergent properties in both the primal and dual orthogonal directions. It is certainly anticipated that the primal-dual logarithmic barrier interior point algorithm is rapidly convergent in both the primal and dual directions. The primal-dual logarithmic barrier interior point algorithm is used in this thesis.

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2.3 Primal-Dual Interior Point Method

To apply the Primal-Dual algorithm we consider the problem stated here in the following form [80]:

$$\left.\begin{array}{ll} Minimize & f(x) \\ Subject\ to: & g(x) = 0 \\ & h_{min} \leq h(x) \leq h_{max} \\ & x_{min} \leq x \leq x_{max} \end{array}\right\} \tag{2.37}$$

Using slack variables to transform the inequality constraints into equality constraints, the problem of (2.37) can be transformed to:

$$\left.\begin{array}{ll} Minimize & f(x) \\ Subject\ to: & g(x) = 0 \\ & h(x) + S_{h1} = h_{max} \\ & S_{h1} + S_{h2} = h_{max} - h_{min} \\ & x + S_{x1} = x_{max} \\ & S_{x1} + S_{x2} = x_{max} - x_{min} \\ & S_{x1}, S_{x2}, S_{h1}, S_{h2} \geq 0 \end{array}\right\} \tag{2.38}$$

These nonnegative slack variables $S_{x1}, S_{x2}, S_{h1}, S_{h2}$ in (2.38) are eliminated by adding the barrier penalties to the objective function (Fiacco and McCormick's method). The where m

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resulting problem with the barrier penalties is defined as:

$$\left.\begin{array}{lll} Minimize & f(x) - \mu\sum_{i=1}^{m}\ln(S_{h1}) - \mu\sum_{i=1}^{m}\ln(S_{h2}) & \\ & \quad -\mu\sum_{j=1}^{n}\ln(S_{x1}) - \mu\sum_{j=1}^{n}\ln(S_{x2}) & \\ Subject\ to: & g(x) = 0 & (a) \\ & h_{max} - h(x) - S_{h1} = 0 & (b) \\ & h_{max} - h_{min} - S_{h1} - S_{h2} = 0 & (c) \\ & x_{max} - x - S_{x1} = 0 & (d) \\ & x_{max} - x_{min} - S_{x1} - S_{x2} = 0 & (e) \end{array}\right\} \tag{2.39}$$

where m and n are the number of inequality constrained function and the number of the primal variable that have lower and upper bound respectively, μ is a positive interior point barrier parameter that decreases to zero iteratively.

Based on Fiacco and McCormick's theorem [56], the solution of (2.39) $x(u_k)$ approaches the local optimal solution x^* of (2.37) as μ decreases towards zero.

We now consider the $\mathcal{L}$agrangian function to transform the constrained problem (2.39) into unconstrained problem. The $\mathcal{L}$agrangian function is given as:

$$\begin{aligned} \mathcal{L}(x,\lambda) &= f(x) - \lambda_g^T g(x) \\ &\quad -\lambda_{h1}^T[h_{max} - h(x) - S_{h1}] - \lambda_{h2}^T[h_{max} - h_{min} - S_{h1} - S_{h2}] \\ &\quad -\lambda_{x1}^T[x_{max} - x - S_{x1}] - \lambda_{x2}^T[x_{max} - x_{min} - S_{x1} - S_{x2}] \\ &\quad -\mu\sum_{i=1}^{m}\ln(S_{h1}) - \mu\sum_{i=1}^{m}\ln(S_{h2}) \\ &\quad -\mu\sum_{j=1}^{n}\ln(S_{x1}) - \mu\sum_{j=1}^{n}\ln(S_{x2}) \end{aligned} \tag{2.40}$$

where $\lambda_g \in R^n$ are the $\mathcal{L}$agrangian multipliers of constraints (2.39-a). $\lambda_{h1}, \lambda_{h2} \in R^m$ and $\lambda_{x1}, \lambda_{x2} \in R^n$ are the $\mathcal{L}$agrangian multipliers of constraints (2.39-b), (2.39-c) and (2.39-d), (2.39-e) respectively.

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The $\mathcal{L}$agrange multipliers are the dual variables. The dual problem can be formed using the $\mathcal{L}$agrangian duality concept [80]. Therefore we can state the dual problem in the following form:

$$\left.\begin{array}{lll} Minimize & \mathcal{L}(x,\lambda) & \\ Subject\ to: & \nabla_x \mathcal{L}(x,\lambda) & = 0 \\ & \nabla_{S_{h1}} \mathcal{L}(x,\lambda) & = 0 \\ & \nabla_{S_{h2}} \mathcal{L}(x,\lambda) & = 0 \\ & \nabla_{S_{x1}} \mathcal{L}(x,\lambda) & = 0 \\ & \nabla_{S_{x2}} \mathcal{L}(x,\lambda) & = 0 \end{array}\right\} \tag{2.41}$$

The relationship of the primal problem and the dual problem can also be found in [80].

The local minimizer (x^*, λ, S^*) of (2.37- 2.41) is given in terms of the stationary point of $\mathcal{L}$, which satisfies the KKT conditions, also known as the first-order necessary conditions. The KKT conditions are defined as following :

$$\begin{array}{lclcl} \nabla_x \mathcal{L} & = & \nabla f(x) - \nabla g(x)^T \lambda_g + \nabla h(x)^T \lambda_{h1} + \lambda_{x1} & = & 0 \\ \nabla_{\lambda_g} \mathcal{L} & = & -g(x) & = & 0 \\ \nabla_{\lambda_{h1}} \mathcal{L} & = & -h_{max} + h(x) + S_{h1} & = & 0 \\ \nabla_{\lambda_{h2}} \mathcal{L} & = & -h_{max} + h_{min} + S_{h1} + S_{h2} & = & 0 \\ \nabla_{\lambda_{x1}} \mathcal{L} & = & -x_{max} + x + S_{x1} & = & 0 \\ \nabla_{\lambda_{h2}} \mathcal{L} & = & -x_{max} + x_{min} + S_{x1} + S_{x2} & = & 0 \\ \nabla_{S_{h1}} \mathcal{L} & = & \lambda_{h1} + \lambda_{h2} - \mu S_{h1}^{-1} e & = & 0 \\ \nabla_{S_{h2}} \mathcal{L} & = & \lambda_{h2} - \mu S_{h2}^{-1} e & = & 0 \\ \nabla_{S_{x1}} \mathcal{L} & = & \lambda_{x1} + \lambda_{x2} - \mu S_{x1}^{-1} e & = & 0 \\ \nabla_{S_{x2}} \mathcal{L} & = & \lambda_{x2} - \mu S_{x2}^{-1} e & = & 0 \end{array} \tag{2.42}$$

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where $\nabla f(x)$ is the gradient of the performance index and $\nabla g(x)$, $\nabla h(x)$ are the gradient of the equality and inequality constraints respectively, λ are the $\mathcal{L}$agrangian multipliers of constraints (2.39), S_{h1}, S_{h2}, S_{x1}, and S_{x2} are diagonal matrices in $\in R^{nxn}$ whose diagonal elements are $s_{h1_j}, s_{h2_j}, s_{x1_j}$, and s_{x2_j} respectively. $e \in R^n$, $e = [1, 1, ..., 1]^T$

The above set of equation can be solved using Newton's method since it is inherently nonlinear. The solution of $f(x)$ is usually approximated by a single iteration of Newton's method, since the Newton's direction is the only means to follow the central path parameterized by [76]. The following iterative equation is obtained

$$[W] \begin{bmatrix} \Delta x \\ \Delta\lambda_g \\ \Delta\lambda_{h1} \\ \Delta\lambda_{h2} \\ \Delta\lambda_{x1} \\ \Delta\lambda_{x2} \\ \Delta S_{h1} \\ \Delta S_{x2} \\ \Delta S_{x1} \\ \Delta S_{x2} \end{bmatrix} = - \begin{bmatrix} \nabla_x \mathcal{L} \\ \nabla_{\lambda_g} \mathcal{L} \\ \nabla_{\lambda_{h1}} \mathcal{L} \\ \nabla_{\lambda_{h2}} \mathcal{L} \\ \nabla_{\lambda_{x1}} \mathcal{L} \\ \nabla_{\lambda_{x2}} \mathcal{L} \\ \nabla_{S_{h1}} \mathcal{L} \\ \nabla_{S_{h2}} \mathcal{L} \\ \nabla_{S_{x1}} \mathcal{L} \\ \nabla_{S_{x2}} \mathcal{L} \end{bmatrix} \tag{2.43}$$

where $[W]$ is an augmented matrix which will be defined later.

at each iteration (k, we solve the system of equations (2.43) for determining the Newton's search direction $\Delta x, \Delta\lambda_g, \Delta\lambda_{h1}, \Delta\lambda_{h2}, \Delta\lambda_{x1}, \Delta\lambda_{x2}, \Delta S_{h1}, \Delta S_{h2}, \Delta S_{x1}$

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and ΔS_{x2}), then a new approximation to all variables is obtained as follows :

$$\left.\begin{aligned} x^{(k+1)} &= x^{(k)} + \alpha \Delta x \\ \lambda_g^{(k+1)} &= \lambda_g^{(k)} + \alpha \Delta \lambda_g \\ \lambda_{h1}^{(k+1)} &= \lambda_{h1}^{(k)} + \alpha \Delta \lambda_{h1} \\ \lambda_{h2}^{(k+1)} &= \lambda_{h2}^{(k)} + \alpha \Delta \lambda_{h2} \\ \lambda_{x1}^{(k+1)} &= \lambda_{x1}^{(k)} + \alpha \Delta \lambda_{x1} \\ \lambda_{x2}^{(k+1)} &= \lambda_{x2}^{(k)} + \alpha \Delta \lambda_{x2} \\ S_{h1}^{(k+1)} &= S_{h1}^{(k)} + \alpha \Delta S_{h1} \\ S_{h2}^{(k+1)} &= S_{h2}^{(k)} + \alpha \Delta S_{x2} \\ S_{x1}^{(k+1)} &= S_{x1}^{(k)} + \alpha \Delta S_{x1} \\ S_{x2}^{(k+1)} &= S_{x2}^{(k)} + \alpha \Delta S_{x2} \end{aligned}\right\} \tag{2.44}$$

where the scaler $\alpha \in [0,1]$ *is the step length parameter chosen to preserve the feasibility of all the variables.*

At every iteration step we reduce the barrier parameter μ and solve the problem to insure fast convergence instead of taking several iteration steps with fixed μ.

2.3.1 Predictor-Corrector Interior Point Algorithm

Mehrotra [77]developed another procedure called the Predictor - Corrector Primal Dual Interior Point Method. In this procedure he generates correction terms to the current estimate, the new corrected point can then be substitute into KKT conditions

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(2.42) directly, to obtain;

$$[W]\begin{bmatrix} \Delta x \\ \Delta\lambda_g \\ \Delta\lambda_{h1} \\ \Delta\lambda_{h2} \\ \Delta\lambda_{x1} \\ \Delta\lambda_{x2} \\ \Delta S_{h1} \\ \Delta S_{x2} \\ \Delta S_{x1} \\ \Delta S_{x2} \end{bmatrix} = \begin{bmatrix} -\nabla_x\mathcal{L} \\ -\nabla_{\lambda_g}\mathcal{L} \\ -\nabla_{\lambda_{h1}}\mathcal{L} \\ -\nabla_{\lambda_{h2}}\mathcal{L} \\ -\nabla_{\lambda_{x1}}\mathcal{L} \\ -\nabla_{\lambda_{x2}}\mathcal{L} \\ \mu S_{h1}^{-1}e - \lambda_{h1} - S_{h1}^{-1}\Delta S_{h1}\Delta\lambda_{h1} \\ \mu S_{h2}^{-1}e - \lambda_{h1} - \lambda_{h2} - S_{h2}^{-1}\Delta S_{h2}(\Delta\lambda_{h1} + \Delta\lambda_{h2}) \\ \mu S_{x1}^{-1}e - \lambda_{x1} - S_{x1}^{-1}\Delta S_{x1}\Delta\lambda_{x1} \\ \mu S_{x2}^{-1}e - \lambda_{x1} - \lambda_{x2} - S_{x2}^{-1}\Delta S_{x2}(\Delta\lambda_{x1} + \Delta\lambda_{x2}) \end{bmatrix} \tag{2.45}$$

The main difference between the Predictor-Corrector Primal Dual and the Pure Primal Dual algorithms is the presence of the nonlinear terms in the right hand side of (2.45). The Predictor-Corrector method take an affine step to approximately solve (2.45) where the barrier parameter is set to zero and the nonlinear terms are dropped.

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The affine step is consists of the solution of the system:

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[W]\begin{bmatrix} \Delta x \\ \Delta\lambda_g \\ \Delta\lambda_{h1} \\ \Delta\lambda_{h2} \\ \Delta\lambda_{x1} \\ \Delta\lambda_{x2} \\ \Delta S_{h1} \\ \Delta S_{x2} \\ \Delta S_{x1} \\ \Delta S_{x2} \end{bmatrix} = - \begin{bmatrix} \nabla_x \mathcal{L} \\ \nabla_{\lambda_g} \mathcal{L} \\ \nabla_{\lambda_{h1}} \mathcal{L} \\ \nabla_{\lambda_{h2}} \mathcal{L} \\ \nabla_{\lambda_{x1}} \mathcal{L} \\ \nabla_{\lambda_{x2}} \mathcal{L} \\ \lambda_{h1} \\ \lambda_{h1} + \lambda_{h2} \\ \lambda_{x1} \\ \lambda_{x1} + \lambda_{x2} \end{bmatrix} \tag{2.46}
$$

The solution of the affine step is then used to estimate the barrier parameter and to approximate the nonlinear terms in (2.45). Finally, the actual new search direction can be solved for using (2.45).

2.4 Computational Implementation

The outline for the Optimal Power Flow algorithm may be summarized as the following:

Step 1: Initialization.

In this step we solve for the initial point (starting point) of the OPF problem. The starting point in IPM need to strictly satisfy the nonnegativity condition. However, a strictly feasible starting point is not required. An interior point algorithm will perform better if the starting point is defined in systematic way. In this study we will estimate the starting point as given by the load flow solution for the primal variables x^0. Starting with the load flow solution not only will insure the feasibility and solvability

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ability of the power balance equations, but also the nonnegativity conditions. The slack variables of the primal problem can be chosen arbitrarily; so that

$$S_{h1}^{0} + S_{h2}^{0} = h_{max} - h_{min} \tag{2.47}$$

$$S_{x1}^{0} + S_{x2}^{0} = x_{max} - x_{min} \tag{2.48}$$

the dual variables of the $\mathcal{L}$agrange multiplier of the equality constraints, λ_g, can be set to zero, the other dual variables can be solved for using the following equations,

$$\lambda_{h1}^{0} = \mu S_{h1}^{-1} e \tag{2.49}$$

$$\lambda_{h2}^{0} = \mu S_{h2}^{-1} e - \mu S_{h1}^{-1} e \tag{2.50}$$

$$\lambda_{x1}^{0} = \mu S_{x1}^{-1} e \tag{2.51}$$

$$\lambda_{x2}^{0} = \mu S_{x2}^{-1} e - \mu S_{x1}^{-1} e \tag{2.52}$$

Step 2: Forming the Newton's system.

The process of forming the Newton's system of equations (2.43) involves evaluation of the gradient vectors, and the Hessian and Jacobian matrices. The elements of these vectors and matrices are computed and can be found in [76]. However in practice implementation of these vectors and matrices are not actually formed. The augmented Hessian matrix W and the primal and dual variables are rearranged in a way described by the rearranged Hessian matrix, incremental variable vector, and the mism

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$$\begin{bmatrix} \mu S_{h1}^{-2} & 0 & 0 & 0 & 0 & 0 & I & 0 & 0 & 0 \\ 0 & \mu S_{h1}^{-2} & 0 & 0 & 0 & 0 & I & I & 0 & 0 \\ 0 & 0 & \mu S_{h1}^{-2} & 0 & I & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & \mu S_{h1}^{-2} & I & I & 0 & 0 & 0 & 0 \\ 0 & 0 & I & I & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & I & 0 & 0 & 0 & 0 & I & 0 \\ I & I & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & I & 0 & 0 & 0 & 0 & 0 & 0 & \nabla h(x) & 0 \\ 0 & 0 & 0 & 0 & 0 & I & 0 & \nabla h(x)^T & H_x & -\nabla g(x)^T \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\nabla g(x) & 0 \end{bmatrix} \tag{2.53}$$

Step 3: Computing the Newton's search direction.

Good algorithm performance requires an efficient computation of the Newton's system. The major computational effort in this algorithm is to solve large, sparse, and symmetrical system of equations. Most of the work in the primal dual algorithm is in the solution of system of this form

$$\begin{bmatrix} H_x & -\nabla g(x)^T \\ -\nabla g(x) & 0 \end{bmatrix} \begin{bmatrix} x \\ y \end{bmatrix} = \begin{bmatrix} V \\ W \end{bmatrix} \tag{2.54}$$

Symbolic factorization and optimal ordering schemes need to be performed only once at the beginning and can then be used for all iterations [80], since the sparse structure of the system of (2.54) can always be preserved.

Step 4: Barrier parameter and determining the step length.

A critical step in the primal dual algorithm is the choice of the barrier parameter, μ. The value of μ is estimated based on the predicted decrease of the duality gap for the li

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for the linear programming problems [75, 77, 79]. The duality gap is defined as the difference between the primal and dual objective functions. In nonlinear programming problems the complementary gap is used to estimate the duality gap instead of the the real duality gap because of the inability of having some of the nonnegativity conditions satisfied and because of some infeasibility of the primal and dual variables. We choose the barrier parameter as given by Wu et al. [57] for the predictor-corrector primal-dual interior point algorithm,

$$\mu = \left(\frac{g\tilde{a}p}{gap}\right)^2 \left(\frac{g\tilde{a}p}{2(n+m)}\right) \tag{2.55}$$

where $g\tilde{a}p$ is the complementary gap when we consider updating the variables in (2.45) and gap is also a complementary gap that approximates the duality gap. The variables gap and $g\tilde{a}p$ are given as the following:

$$\begin{aligned} gap &= (\lambda_{h1} + \lambda_{h2})^T S_{h1} + \lambda_{h2}^T S_{h2} + (\lambda_{x1} + \lambda_{x2})^T S_{x1} + \lambda_{x2}^T S_{x2} & (2.56) \\ g\tilde{a}p &= \left[\lambda_{h1} + \lambda_{h2} + \tilde{\alpha}(\Delta\tilde{\lambda_{h1}} + \Delta\tilde{\lambda_{h2}})\right]^T (S_{h1} + \tilde{\alpha}\Delta\tilde{S_{h1}}) + \\ & \quad (\lambda_{h2} + \tilde{\alpha}\Delta\tilde{\lambda_{h2}})^T (S_{h2} + \tilde{\alpha}\Delta\tilde{S_{h2}}) + \\ & \quad \left[\lambda_{x1} + \lambda_{x2} + \tilde{\alpha}(\Delta\tilde{\lambda_{x1}} + \Delta\tilde{\lambda_{x2}})\right]^T (S_{x1} + \tilde{\alpha}\Delta\tilde{S_{x1}}) + \\ & \quad (\lambda_{x2} + \tilde{\alpha}\Delta\tilde{\lambda_{x2}})^T (S_{x2} + \tilde{\alpha}\Delta\tilde{S_{x2}}) & (2.57) \end{aligned}$$

where,

$$\begin{aligned} \tilde{\alpha} &= Min\left\{1, \frac{(\lambda_{h1} + \lambda_{h2})}{(\Delta\tilde{\lambda_{h1}} + \Delta\tilde{\lambda_{h2}})}, \frac{\lambda_{h2}}{\Delta\tilde{\lambda_{h2}}}, \frac{(\lambda_{x1} + \lambda_{x2})}{(\Delta\tilde{\lambda_{x1}} + \Delta\tilde{\lambda_{x2}})}, \frac{\lambda_{x2}}{\Delta\tilde{\lambda_{x2}}}, \right. \\ & \quad \left. \frac{S_{h1}}{\Delta\tilde{S_{h1}}}, \frac{S_{h2}}{\Delta\tilde{S_{h2}}}, \frac{S_{x1}}{\Delta\tilde{S_{x1}}}, \frac{S_{x2}}{\Delta\tilde{S_{x2}}}\right\} & (2.58) \end{aligned}$$

for those

$(\Delta\tilde{\lambda_{h1}} + \Delta\tilde{\lambda_{h2}}), \Delta\tilde{\lambda_{h2}}, (\Delta\tilde{\lambda_{x1}} + \Delta\tilde{\lambda_{x2}}), \Delta\tilde{\lambda_{x2}}, \Delta\tilde{S_{h1}}, \Delta\tilde{S_{h2}}, \Delta\tilde{S_{x1}}, \Delta\tilde{S_{x2}} \leq 0$

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The step length α is chosen to preserve the feasibility of all the problem variables and is determined as

$$\alpha = Min\left\{1, \frac{\sigma(\lambda_{h1}+\lambda_{h2})}{(\Delta\lambda_{h1}+\Delta\lambda_{h2})}, \frac{\sigma\lambda_{h2}}{\Delta\lambda_{h2}}, \frac{\sigma(\lambda_{x1}+\lambda_{x2})}{(\Delta\lambda_{x1}+\Delta\lambda_{x2})}, \frac{\sigma\lambda_{x2}}{\Delta\lambda_{x2}}, \frac{\sigma S_{h1}}{\Delta S_{h1}}, \frac{\sigma S_{h2}}{\Delta S_{h2}}, \frac{\sigma S_{x1}}{\Delta S_{x1}}, \frac{\sigma S_{x2}}{\Delta S_{x2}}\right\} \tag{2.59}$$

for those

$(\Delta\lambda_{h1}+\Delta\lambda_{h2}), \Delta\lambda_{h2}, (\Delta\lambda_{x1}+\Delta\lambda_{x2}), \Delta\lambda_{x2}, \Delta S_{h1}, \Delta S_{h2}, \Delta S_{x1}, \Delta S_{x2} \leq 0$ and σ is chosen to be less than 1. A typical value is $\sigma = 0.9995$.

Step 5: Update variables and check for convergence.

The new approximation value to the primal and dual variables are then estimated using (2.44) and then the convergence check is performed. The convergence check and the stopping criteria for linear programming problems are usually defined in terms of the relative duality gap [76]. For nonlinear problems the iteration procedures are terminated as both the relative complementary gap and the mismatches of the KKT conditions are sufficiently small[57]. The stopping criteria for the nonlinear problems are as follows;

$$\frac{gap^*}{1+|dobj|} < \varepsilon_1 \tag{2.60}$$

and

$$|the\ \ largest\ \ mismatch\ \ of\ \ KKK| \leq \varepsilon_2 \tag{2.61}$$

where dobj is the dual objective function value and ε_1*, and* ε_2 *are the tolerance values.*

The problem solution is said to have converged when (2.60) and (2.61) reach their tolerance values, the optimal solution is found, and the algorithm stops.

Step 6:

If the solution is not found then set the iteration index $k = k + 1$ and start a new iteration from step 3.

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CHAPTER 3

Voltage Stability Security Assessment and Diagnosis

3.1 Introduction

Voltage instability is a very complex phenomena. Use of mid-term transient stability models and simulation tools are required if a reasonably accurate simulation of equipment outage or operating change induced voltage instability events is to be possible. These models require differential equation models of turbine energy systems, generators, excitation systems, network controls, and load as well as algebraic equation of the network [3]. The network models must include the transmission network, subtransmission network, and some aggregated representation of the distribution network over a fairly large geographical region to accurately simulate such events. Finally, one must have an excellent mid-term simulation tool that can accommodate such a large model.

Screening for all the subregions that can experience voltage instability as well as the operating changes, equipment outages, and equipment outage and operating changes combinations that can produce voltage instability in each region requires use of a computationally fast simulation tool. A simpler model and a computationally fast simulation tool is needed since the computation per equipment outage and operating change combination using a mid-term transient simulation tool can be quite large and since there are a huge number of equipment outages and operating changes to be studied. Load flow has been found to be a remarkably accurate tool for assessing voltage instability despite its many modeling, algorithmic, and control shortcomings.

Voltage Stability Security Assessment and Diagnosis (VSSAD) should determine most if not all equipment outage, operating changes, and all the contingencies that cause voltage instability. VSSAD can also determine the cause of the voltage instability in terms of lack of reactive supply on specific reactive sources or an inability to deliver reactive supply to the specific region experiencing voltage collapse. It can also indicate what operating condition changes and control changes could be made in order to prevent the voltage instability from occurring when contingency and operating condition changes combination predicted by the state estimator to cause collapse occurs.

Voltage Stability Security Assessment and Diagnosis (VSSAD) method is used to find voltage collapse regions and subregions that have unique voltage collapse problem, the reactive reserve basins protecting each voltage collapse region and subregion from voltage collapse. The VSSAD method simulates all the contingencies that are most likely to occur and than find out all the single and double equipment outage contingencies, that are responsible for voltage collapse in each voltage collapse region and subregion, and the voltage collapse region that are most vulnerable to voltage instability for contingency.

3.2 Voltage Stability Overview

Voltage stability is the ability of a power system to preserve the voltage of an operation equilibrium under normal condition and to maintain an acceptable voltage at all buses after being subjected to a disturbance. A system will start to lose stability and enters the state of instability when a disturbance, changes in system operating condition, or increase in load demand causes a progressive and spreading drop in voltage. The incapability of the power system to meet the reactive power demand is the main cause of voltage instability. The drop in voltage results in (a) reducing shunt capacitive reactive supply and (b) increasing magnetic field due to increased current flow that together increase the network reactive losses. The increased network losses result in (1) reducing reactive power flow to the region that needs the most reactive supply and (2) exhaustion of the reactive reserves on generators, synchronous condensers, or SVC's causing loss of voltage control that result in further voltage drop and further increase in network reactive losses.

Voltage collapse has been studied in a load flow (algebraic) and in a differential algebraic model. It has been shown that bifurcation sequences occur in a differential algebraic model that can include saddle node, Hopf, singularity induced, or algebraic bifurcation. Instability in the dynamics can occur before the bifurcation affects the algebraic model. It has been shown that saddle node bifurcation in a differential algebraic model at equilibrium is a bifurcation in the load flow model that includes the algebraic model and differential model at equilibrium [81]. In other cases, the bifurcation solely in the algebraic model has no affects on generator dynamics (algebraic bifurcation) or alternately in the algebraic model that produces very rapid changes in generator dynamics(singularity induced bifurcation). The bifurcation in the algebraic equations is almost always associated with the ultimate blackout even when saddle node or Hopf bifurcation initiates the instability that results in blackout [3]

This thesis will only discuss the voltage stability problems in an algebraic model, $f(x, \underline{P})$ where x is the n dimension state of the model and is of the same dimension as $\underline{f}(x, P)$ and p is an m vector of parameters that can change and produce bifurcation or instability if p changes continuously. The implicit function theorem can indicate when solutions exists and the solutions are unique.

Theorem (Implicit function theorem)[4]

Let $\mathbf{f} = (\mathbf{f}_1, \cdots, \mathbf{f}_n)$ be a vector valued function defined on an open set $\mathbf{S}$ in $\mathbf{R}^{\mathbf{n}+\mathbf{k}}$ with values in $\mathbf{R}^{\mathbf{n}}$. Suppose $\mathbf{f} \in \mathbf{C1}$ on $\mathbf{S}$. Let $(\mathbf{x}_0; \mathbf{p}_0)$ be a point in $\mathbf{S}$ for which $\mathbf{f}(\mathbf{x}_0; \mathbf{p}_0) = \mathbf{0}$ and for which the $n \times n$ determinant $\mathbf{det}[\mathbf{f}_{\mathbf{x}}(\mathbf{x}_0; \mathbf{p}_0)] \neq \mathbf{0}$. Then there exists a k-dimensional open set $\mathbf{P}_0$ containing $\mathbf{p}_0$ and one, and only one, vector-valued function $\mathbf{g}$, defined on $\mathbf{P}_0$ and having values in $\mathbf{R}^{\mathbf{n}}$, such that

a) $\mathbf{g} \in \mathbf{C1}$ on $\mathbf{P}_0$,

b) $\mathbf{g}(\mathbf{p}_0) = \mathbf{x}_0$,

c) $\mathbf{f}(\mathbf{g}(\mathbf{p}); \mathbf{p}) = \mathbf{0}$ for every $\mathbf{p}$ in $\mathbf{P}_0$.

When the Jacobian is nonsingular the implicit function theorem indicates there exist solutions that are unique for all $p_0 \in P_0$. When a solution exists, the system may be stable or unstable depending on whether there are any non positive eigenvalues of the Jacobian $f_x(x_0, p_0)$. However, when no solution exists the system is considered unstable and this singularity of load flow Jacobian can be used to detect voltage instability. When the $det[f_x(x_0, p_0)]$ is zero or the Jacobian $f_x(x_0, p_0)$ is singular, the implicit function theorem does not provide any information but it may imply no solution $x_0 = x(p_0)$ exists at these values of p_0 or there are multiple solutions $x_{0_i}(p_0)$, Both can be true as will be noted later. A number of indices have been developed to test

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test for load flow bifurcation when p is changed in some direction n

$$p = p_0 + kn \tag{3.1}$$

via change in k until $det[f_x(x^*, p^*)] = 0$. The indices come from tracking the minimum eigenvalue $\lambda_i^*(k)$ using

$$f_x(x(k), p(k))\underline{u}_i(k) = \lambda_i(k)\underline{u}_i(k) \tag{3.2}$$

where $\lambda_i^*(k) = min_i[\lambda_i(k)]$

or the minimum singular value $\sigma_i^*(k)$ obtained using

$$f_x(x(k), p(k))^T f_x(x(k), p(k)) = W_\sigma(k)\Sigma(k)V_\sigma^T(k) \tag{3.3}$$

where $\Sigma(k) = diag[\sigma_1(k), \sigma_2(k), \cdots, \sigma_n(k)]$ *and* $\sigma_i^*(k) = min_i[\sigma_i(k)]$

The singular values $\sigma_i(k)$ are the eigenvalues of

$$f_x(x(k), p(k)) f_x^T(x(k), p(k)) \tag{3.4}$$

and satisfy

$$f_x(x(k), p(k))v_i(k) = \sigma_i(k)w_i(k) \tag{3.5}$$

$$w_i^T(k) f_x(x(k), p(k)) = \sigma_i(k)v_i^T(k) \tag{3.6}$$

where $v_i(k)$ *and* $w_i(k)$ *are the right and the left singular vectors of* $\sigma_i(k)$ *and are columns of matrices* $V_\sigma(k)$ *and* $W_\sigma(k)$ *above.*

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The minimum singular value and minimum eigenvalue are just two of many sensitivity based indices or measures of proximity to voltage instability.

The $Q-V$ and $P-V$ curve are particular scalar ($m=1$) proximity measures where

(1) for a $Q-V$ curve the direction $\underline{n}$ vector is a unit vector where the voltage at a bus i is the only nonzero element, k is the real valued negative number that starts at zero and decreases, and $-Q_i(V_i)$ is the reactive load that is added at bus i for each value of V_i. The curve $Q_i(V_i)$ is the reactive injection at bus i obtained by changing the bus type from a load bus to a generator bus reducing the voltage V_i until $Q_i(V_i)$ reaches a minimum at $V_{i_{min}}$ with maximum added load $-Q_i(V_{i_{min}}) = -Q_{i_{min}} \geq 0$. The value of $(V_{i_{min}}, Q_{i_{min}})$ defines the minimum of the $Q-V$ curve when $\frac{\partial Q_i}{\partial V_i} = 0$, that corresponds to the bifurcation point (x^*, p^*).

(2) The $P-V$ curve can add active power load at a bus i or at several load buses simultaneously

$$p = p_0 + kn_{load} \tag{3.7}$$

and pick up that power at several generators

$$g = g_0 + kn_{gen} \tag{3.8}$$

where n *is made up of* n_{gen} *and* n_{load} *and both are participation vectors where* $\sum_{\forall i} n_i = 1$.

A $P-V$ curve can also result in transfer power from one set of generators g^* to another set of generators $\hat{g}$

$$g^* = g_0^* + kn^* \tag{3.9}$$

$$\hat{g} = \hat{g}_0 - k\hat{n} \tag{3.10}$$

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Note n_{gen}, n_{load}, n^*, and $\hat{n}$ are unit vectors where one or more elements are nonzero and $\sum n_i = 1$. The $P-V$ curve plots voltage at some bus i for change in $k = P_{system}$ where it represents system power load change or $k = P_{transfer}$ represents the total power transfer change.

Optimization based methods have been used to calculate $Q-V$ and $P-V$ curves in [5]. These scalar optimization based methods optimize performance index Q_i to produce a $Q-V$ curve with load flow equality constraints

$$f(x, p, u) = 0 \tag{3.11}$$

and inequality constraints on voltage controls u. These controls can include under load tap changer tap position, switchable shunt capacitor susceptance, and possibly generator excitation control set points. The $P-V$ curve computed by load flow for varying $k = P_{system}$ or $P_{transfer}$ has all or most of these controls fixed. The $P-V$ curve would optimize P for a particular transfer or wheeling transaction with the same load flow model, same controls u and inequality constraints on controls u. The particular transfer or wheeling transaction is defined via specification of n_{gen}, n_{load}, n^* and $\hat{n}$. In [6], a scalar optimization based method to maximize the reactive power margin when n can be a unit vector with several nonzero elements. The generalized $Q-V$ curve allows added reactive load at several buses in the participation factor normal direction rather than just one as in a typical load flow based $Q-V$. The approach used in [6] eliminates the active power and phase angle relationship, using active power generation as control, and imposes reactive power limits on the generators. Dobson[7] is first to develop a vector optimization based method that optimizes the normal direction vector n and the loading factor k, which are assumed to be positive real numbers. This paper computes load power at which saddle node bifurcation occurs, that represent the worst case load power parameter variati

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variation. The proximity measure $|P^* - P_0|$ to saddle node bifurcation, where P_0 and P^* represent the current load power and the critical load power respectively, was first noted in this paper [7].

All of these methods [5, 6, 7] assess bifurcation in a single mode due to continuous scalar or vector parameter variation. The methods are thus not applicable to assessing proximity to collapse for equipment outage or transactions that are modeled by discontinuous parameter change. These methods also do not take into account the discontinuity in eigenvalues that occur for continuous parameter and discontinuous parameter changes. In many cases the eigenvalue changes due to discontinuities is virtually all the change that occurs in an eigenvalue that approaches bifurcation [10]. The Voltage Stability Security Assessment and Diagnoses [1]

1. determines the number of discontinuities in any eigenvalue that have already occurred due to generator PV to load PQ bus type changes that are associated with an eigenvalue. The eigenvalue is associated with a coherent bus group (voltage control area). The set of generators that experience $PV - PQ$ bus type changes (reactive reserve basin) for computing a $Q - V$ curve at any bus in that bus group are proven to capture the number of discontinuities in that eigenvalue before bifurcation. The reactive reserves on generators in each voltage control area of a reactive reserve basin measure proximity to each of the remaining discontinuities in the eigenvalue required for bifurcation in the agent composed of the test voltage control area and its reactive reserve basin;

2. can handle discontinuous (equipment outage or large transfer or wheeling transaction changes) or continuous change (load increase, transfer increases, and wheeling increases) where the above methods are restricted to continuous changes;

3. can simultaneously assess proximity to voltage instability for all bifurcation

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modes in a system by assessing percentage of generators in a reactive reserve basin with zero reserves and the reactive reserves remaining on reactive reserve basin voltage control areas that have not yet exhausted reserves;

4. can provide operating constraints or security constraints on reactive reserve basin reserves that prevent voltage instability in each reactive reserve basin in a manner identical to how thermal constraints prevent thermal overload on each branch and voltage constraints prevent bus voltage limit violation at each bus;

5. the reactive reserve basin operating constraints allow optimization that assures that correcting one voltage instability problem will not produce other voltage stability problems in the rest of the system;

6. the reactive reserve basin constraints after an equipment outage and operating change combination allows optimization of transmission capacity that specifically corrects that particular equipment outage and transaction change induced voltage collapse;

3.3 Types of Voltage Instability

Two kinds of voltage instability have been associated with a load flow model [8]:

3.3.1 Loss of Control Voltage Instability

Loss of control voltage instability is caused by exhaustion of reactive supply with resultant loss of voltage control on a particular set of generators, SVC's, or synchronous condensers. The loss of control voltage not only cuts off the reactive supply to a region requiring reactive power supply, but also increases the network reactive losses that choke the network and blocks reactive power supply from reaching that region

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needing reactive power. Loss of control voltage instability occurs in the transmission and sub transmission system due to equipment outages and operating changes combination, such as

- line, transformer, and generator outages
- generator outage with a particular real power generation pickup pattern
- increase in load and generation
- change in wheeling, transfer, and interchange transactions

3.3.2 Clogging Voltage Instability

Clogging voltage instability occurs due to reactive power series I^2X losses, tap changers reaching tap limits, switchable capacitor reaching susceptance limits, and shunt capacitive withdrawal due to decreasing voltage. These network reactive losses can completely block the reactive power flow from reaching the region needing the reactive power supply without even exhausting any reactive reserve and loss of voltage control on generators, SVC's, and synchronous condensers. This effect can occur in distribution, subtransmission, and even in transmission system. This effect occur due to increased wheeling, transfer, and interchange transaction changes or loading and generation pattern change

3.4 Knowledge Development

There are off-line and on-line aspects of the Voltage Stability Security Assessment. The off-line task is knowledge development via learning through applying stress tests. The knowledge gained from the off-task is then used on the on-line task to assess severity and diagnose the voltage instability problem. The knowledge development aspects are to identify the following [8]:

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- Parameters that make a particular region and subregion vulnerable to voltage collapse.
- The structural cause of voltage collapse.
- A proximity measure for identifying how close the region and subregion is to voltage collapse.

The On-Line aspects of Voltage Stability Security Assessment are; (a) to identify and rank the most insecure region and subregion, (b) to find the equipment outages that cause voltage collapse in any region, (c) and finally to rank the equipment outage that brings the region and subregion closer to face voltage collapse [8].

The **first step** in the knowledge development aspect of VSSAD is the stress test. In this stress test we acquire knowledge about each agent or subsystem that can experience voltage instability and in each agent the structural cause of voltage collapse in that agent. The stress test will explain why any equipment outage or operating change will cause voltage collapse to occur at any bus or group of buses. Since loss of control voltage and clogging voltage instabilities are both due to shortage of the reactive power supply to a bus or group of buses in the region or subregion, the stress test must determine why and when voltage collapse occurs due to shortage of reactive power supply. Thus, a $Q - V$ curve is used as the stress test for the knowledge development aspect of voltage stability security assessment and diagnosis since it determines the maximum amount of reactive load that can be added to the bus before voltage instability occurs and the load flow no longer have a solution. A $P - V$ curve, although quite useful in assessing maximum transfer, wheeling, and interchange before voltage instability does not relate to shortage of reactive power supply. Another reason why $P - V$ curve is not as effective as $Q - V$ curve is that $P - V$ curve does not effectively pinpoint the region and subregion where reactive power supply shortage occur in the system for generator outages or line outages. This

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information is easily identified using $Q-V$ curve. A final reason for not using $P-V$ curve is that the minimum singular value of the reactive power Jacobian approximates the changes in the minimum singular value of the full load flow Jacobian [8].

The **second step** of the knowledge development aspects of voltage stability security assessment is to acquire knowledge about each agent or subsystem composed of the test voltage control area and their reactive reserve basin. Computing $Q-V$ curves at every bus in a region and determining the set of generators, that exhausted their reactive reserves (the reactive reserve basin) in the process of reaching the $Q-V$ curve minima at each bus, is needed to identify the agents. The agent is a coherent bus group where all the $Q-V$ curve minima are identical and the reactive reserve basin for every bus in that coherent group is identical. Voltage control areas are the coherent bus groups that have the same $Q-V$ curve minima and the same reactive reserve basin. The algorithm [83, 84, 85] for selecting the size of each non overlapping coherent bus group so all the buses in each group have the same voltage collapse requires the connection between buses in that group have very low impedance. The most important attribute of voltage control areas and their reactive reserve basins is that they don't change when severe contingencies and operating changes occur that cause voltage instability. Another important fact is that more than one voltage control area can have the same reactive reserve basin.

Exhausting all of the reactive reserve in a reactive reserve basin in an agent and thus losing voltage control at all these generators will cause voltage collapse or near collapse in every agent (voltage control area and associated reactive reserve basin). The reactive reserve basin provides the reactive supply needed to prevent every agent with that reactive reserve basin from experiencing voltage collapse. The subset of agents with the same reactive reserve basin is called a voltage collapse region. The exhaustion of all the supply in the reactive reserve basin causes voltage instability in the associated voltage collapse region. Reactive reserve basins and their agents that

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contain them can be classified as global, local, or locally most vulnerable. Global reactive reserve basins are associated with test voltage control areas of the EHV transmission grid encircling different load centers. This global reactive reserve basins generally overlap but usually belong to electrically and geographically distinct region of the transmission system. A global reactive reserve basin can contain one or more nested sets of smaller reactive reserve basins. These are called local reactive reserve basins and contain fewer generators than global reactive reserve basins and their test voltage control areas are either electrically or geographically more remote from generators than the voltage control areas associated with global reactive reserve basins. One or more of these nested sets of progressively smaller local reactive reserve basins can not only cause voltage collapse in the associated test voltage control area or it's agent, but also can cause voltage collapse in test voltage control areas of agents associated with larger reactive reserve basins in which it's local reactive reserve basin is nested. Such local reactive reserve basins are called locally most vulnerable or critical reactive reserves basins and are more often electrically remote from the larger of the nested set of reactive reserve basins it belongs to and in which its reactive supply exhaustion causes reactive reserve exhaustion in all of the larger reactive reserve basins it belongs to. The locally most vulnerable reactive reserve basin usually exhausts supply at minima of the $Q - V$ curve computed in the voltage collapse region of the larger reactive reserve basins in the nested set [8]

The **final step** of the knowledge development aspects of VSSAD is to select a proximity measure for voltage collapse in voltage collapse region and subregion. There are two measures of proximity to voltage collapse. The most obvious measure is the percentage of reactive reserve available after contingency has occurred in the reactive reserve basin compared to that of the base case, which often is the peak load case with no contingency. The other measure of proximity to voltage collapse requires the list of generators in the reactive reserve basin that belongs to voltage collap

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collapse region be grouped by the voltage control area they belong to. This measure is the percentage of a reactive reserve basin voltage control areas that are unexhausted after a contingency.

3.5 Intelligence Development

The knowledge development or the learning activity of finding voltage collapse regions and their associated reactive reserve basins must be completed before applying the on-line contingency selection and ranking aspects of VSSAD. The contingency selection and ranking procedure is an intelligence development task because it ranks the worst contingencies that have a load flow solution for each voltage collapse region as well the most insecure voltage collapse region for each contingency. The outline procedure of the On-Line process of VSSAD is as follows [8]:

1. Rank the worst single line and generator outage contingencies for each voltage collapse region in terms of the smallest percentage of unexhausted reactive reserve of that reactive reserve basin after the contingency;

2. Find and list all of the single line outage and generator outage contingencies that will exhaust more than $P\%$ of the reactive reserve in any reactive reserve basin;

3. Simulate a list of double line outages, double generator outages, and a combination of line and generator outages contingencies from the list of line and generator outages found in step (2);

4. Rank the worst contingencies produced in step (3) for each reactive reserve basin in terms of the the smallest percentage of reactive reserve remaining in the reactive reserve basin;

The contingencies with zero reserves for any voltage collapse region may experience voltage collapse in that voltage collapse region and its reactive reserve basin. If is not possible to say that with zero reserves that the voltage collapse region is experiencing voltage collapse because it may still be obtaining sufficient reactive supply to survive and not experience blackout. With zero reserves in several nested reactive reserve basins, one is virtually certain voltage collapse has occurred. This information can be obtained by observing the ranking of reactive reserve basins for any contingency (step 4). If the percentage of voltage control area with zero reserves is small but not zero for a particular contingency for several nested reactive reserve basins, the system is very near voltage collapse since as exhaustion of the reserves on voltage control areas in a reactive reserve basin occurs, the network reactive losses rise exponentially for each subsequent exhaustion of reserves in yet unexhausted voltage control areas. If is also known that when the reactive reserves in all voltage control areas of a critical reactive reserve basin in a nested set occurs, many if not all larger reactive reserve basins in that nested set also exhaust reserves. This explains why several reactive reserve basins will approach exhaustion and experience exhaustion of reactive reserves simultaneously.

3.6 Diagnosis of Voltage Instability

The use of the physical structural knowledge developed of voltage collapse regions and agents (voltage control areas and their reactive reserve basins) provides a basis for performing diagnostics of the location, cause, and remedial action for each equipment outage and operating change combination that cause voltage instability. The physical structural knowledge developed and the diagnostic capability far exceeds that can be accomplished by; (a) doing trial and error effort to obtain a load flow solution by adjusting operating conditions, load and generation reduction, or adding new reactive sup

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supply sources; (b) finding the last best iteration for a specific equipment outage and operating change combination; or (3) by ignoring the reactive limits on the generators. The diagnosis would suggest whether lack of load flow solution is an algorithmic convergence problem or whether it is voltage instability. Diagnosis can also indicate if voltage voltage stability margin is increased following the control action changes. The diagnostic capability also indicate where, why, and what to do about loss of control voltage instability or clogging voltage instability. Two diagnosis methods has been identified in voltage stability security assessment and diagnosis (VSSAD). One diagnostic method is for loss of voltage control voltage instability, and the other is for clogging voltage instability. The diagnosis for loss of voltage control voltage instability is performed first and if the method fails to obtain the load flow solution, then the diagnosis for clogging voltage instability is applied. There are two cases where the diagnosis will not work; (a) outage of all generators in a reactive reserve basin since additional reactive generation is needed in that reactive reserve basin to obtain a solution; (b) outage of branches that cause isolation of a bus or subsystem. This often requires action that are above and beyond system dispatch of generation and voltage control devices, and require system commitment of additional lines and generators. The diagnosis is thus solely for equipment outages where dispatch of generation or voltage control devices can provide a load flow solution.

3.6.1 Loss of voltage control voltage instability

Loss of control voltage instability occurs because the reactive reserves in a one or more agent's reactive reserve basins are all exhausted due to the contingency. Exhaustion of an agent's reactive reserves and thus loss of voltage control on all generators in its reactive reserve basin produces dramatic increase in network reactive losses as well as terminating reactive supply from these generators. Ignoring reactive limits in all and s

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$$Q_{Gi_{min}} \leq Q_{Gi} \leq Q_{Gi_{max}} \tag{3.12}$$

and solving the load flow would indicate which generators and which reactive reserve basins exceed their reactive limit causing the reactive reserve basin to be negative.

$$RR(P) = \sum_{i \in RRB(P)} (Q_{Gi_{max}} - Q_{Gi}) \tag{3.13}$$

where: $RR(P)$ is the reactive reserve in reactive reserve basin P, and $i \in RRB(P)$ is the set of all the generators in reactive reserve basin P.

The reactive reserve basin with the most negative reserve generally causes the lack of a load flow solution. Adding reactive reserves to that reactive reserve basin by:

- switching in shunt capacitors;
- changing voltage setpoints on generator's exciters;
- adding additional generators (Peakers)

can help the load flow to have a solution. On the other hand if reactive limits are ignored and no load flow solution exists then a lack of load flow solution is due to clogging voltage instability.

3.6.2 Clogging Voltage Instability

If the solution to the load flow does not exist even though that the reactive limit on all of the generators are ignored, then the lack of solution is because of the reactive losses choke off the reactive supply flow to a region or subregion needing reactive supply.

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Methods for obtaining a solution for clogging voltage instability involve (a) trying to reduce the loads and generation (transfer or wheeling transaction reductions or modifications) in agents where collapse occurs until the load flow solves, or (b) adding fictitious reactive power supply (generators) at buses in the agent's test voltage control area until the load flow has a solution. These procedures can take an average of 15 hours per contingency to find a solution. A diagnostic procedure for clogging voltage instability is as follow:

1. for the double contingency that has no load flow solution find the reactive reserve basin where each single contingency exhausts 50% or more of the reserves.

2. the reduction of real and reactive load at all buses in voltage collapse region and reduction of generation on the generators in that reactive reserve basin will generally obtain a load flow solution.

The above procedure works because adding reactive load at buses in the voltage collapse region causes increased reactive losses that together exhausts reactive reserves in the reactive reserve basin, and the contingencies causes increased reactive losses that also exhausts reserves in these same reactive reserve basins. Reducing load should reduce the reactive losses produced by the double contingency that causes clogging voltage instability.

In a deregulated environment voltage collapse problems will become much more common. Deregulation of power industry will start to; (a) bring many additional generating station on to the network, (b) allow shipping of real power along different paths and in different directions than what they were designed for, (c) allow a rapid change in power dispatch due to competition of selling power to different customers as they change generating companies as often as every hour, (d) let power be transferred, wheeled, and interchanged. The absence of the knowledge that there is sufficient reactive reserve in each reactive reserve basin due to the lack of knowledge that additional reactive power supply may be necessary will also contribute to voltage collapse in a deregulated power industry. System failure and black outs due to voltage instability already have been observed in Europe, Japan, Ontario Hydro, New York Power Pool, and lately three blackouts in western USA. The changes (a-d) above brought on by deregulation will only make voltage instability a more common and frequent event.

In this research, the problem of corrective control for voltage collapse problems in a deregulated power system is investigated. The study of the problems is carried out by computing the minimum set of control devices changes and the most effective corrective control changes for each equipment outage and operating changes combination predicted to cause voltage instability problem by Voltage Stability Security Assessment and Diagnosis (VSSAD). The set of control changes would also posture to some extent against the cumulative threats presented by all of the voltage instability causing equipment outage and operating changes. This research is divided into two stages. The first is the development procedure of Voltage Stability Security Assessment and Diagnosis discussed in [8]. The second stage is the development of Secondary and Tertiary control described in [1, 9, 82] using optimal power flow.

A revised form of the Transmission Dispatch and Congestion Management [15] could utilize VSSAD and the secondary and tertiary control, but it's proposed sampling rate is far too slow to even detect occurrence of the voltage instability caused by equipment outage and operating condition change combinations until after voltage collapse has already occurred. Furthermore it's control update rate is far too slow to correct for the voltage instability problem that is developing due to occurrence of a particular equipment outage and operating condition changes combination. Finally, there is no proposed method within the Transmission Dispatch and Congestion Management [15] that could predict all single and multiple contingencies that cause voltage instability and an associated corrective control for each contingency. Selecting a sin

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a single control u_0 as proposed to correct every possible voltage instability, thermal and low voltage problems caused by equipment outage and operating changes as proposed by [15] (1) could have no feasible solution, (2) may be impossible to determine even if such a feasible solution exists, (3) may require large significant and costly transaction changes and (4) may require load shedding as a continuous precaution whenever voltage instability is even remotely possible.

A VSSAD based Transmission Dispatch and Congestion Management requires 5 second sampling and control update rate, a fast state estimator using the fast 5 second sampling rate to detect contingencies quickly, a fast 5 second control rate to implement corrective control computed proposed by a Tertiary Control for the equipment outage or transaction change predicted by VSSAD to cause instability and detected by the state estimator. The corrective control would come from a set of all corrective control computed and stored using the Tertiary Control to be used by the dispatcher for possible later implementation via secondary control when the state estimator detects the occurrence of equipment outage and operating change combinations predicted to produce voltage instability by VSSAD. The corrective control computed by the Tertiary Control is an optimal version of that proposed by the diagnostics of VSSAD for that contingency and operating change condition.

3.7 Numerical Results

The Voltage Stability Security Assessment and Diagnosis is carried out using the following; (a) AVCASP program to compute the voltage collapse region, voltage control area, and reactive reserves basin; (b) CONRES program to perform the single and double contingency analysis; and (c) a PTI load flow to perform the diagnostic analysis in a non-automated fashion.

The test is done on a 162 bus system. This system represent a reduced model of

Iowa, Nebraska, Minnesota, and S. Dakota system and was obtained from a University of Washington data base. This model was the only model where a subset of generator had finite reactive limits and thus could experience loss of control voltage instability. To obtain alpha for identifying voltage collapse region and reactive reserve basin $Q - V$ curves were computed at every bus in the model with the voltage rating above 20 KV. The test value of alpha α obtained from AVCASP, that would make every bus in each voltage control area have the same $Q - V$ curve minima and the same set of generators in their reactive reserves basin, was found to be $\alpha = 0.2224$. The knowledge development task of finding voltage collapse regions, voltage control areas, and reactive reserves basin associated with each voltage collapse region is provided as outputs of AVCASP. The results are shown in Table 1 in the Appendix. The voltage collapse region number is given in column 1, voltage control areas in each voltage collapse region are given in column 2 (bus # and bus name), and column 3 represents the reactive reserves basin associated with each voltage collapse region.

Having knowledge about the coherent bus groups or voltage control areas that experience unique voltage collapse problem will help developing the single and double contingency analysis. The contingency analysis is performed by ranking $N = 5$ worst contingencies for each reactive reserve basin. The contingencies are ordered and presented in term of the largest percentage of the base case reactive reserves exhausted or by each contingency. The contingency ranking for voltage collapse regions# 35 for single contingencies is given in Table 3.1. The voltage control areas that belongs to the voltage collapse region are given at the top left of the table. Each voltage control area is specified by the number and the name of the bus given. Below the voltage control area is the reactive reserve basin. The reactive reserve basin is specified by specifying each of the generators that belong to it in terms of the generator bus number and name as well as their continuous rating reactive capacity in MVAR's, their base case reactive reserves in MVAR's, and the voltage control area number the generator belong to. These voltage control areas are connected by 161 KV lines and the reactive reserve basin at buses 121, 118, 73, and 101 are generating stations that surrounded the voltage collapse region in the 162 system. At the end of reactive reserves basin information, the total base case reactive reserves in the specified voltage collapse region is given. The contingency ranking results for that reactive reserves basin follows the reactive reserves basin information. The contingencies are ordered and presented in term of the largest percentages of the base case reactive reserves exhausted by each contingency. The first column indicates the contingency case number along with description of the contingency showing whether it is a line outage or generator outage. The second column gives the percentage of the reactive reserves of the base case reserves available after the contingency. The following two columns give the generator bus name and its reserves after the contingency. The final column contains the percentage of the reactive reserves in that voltage control area of base case reserves available in that voltage control area after the contingency had occurred. The last column is the most important to indicate how close this voltage collapse region is to loss of control voltage instability caused by that contingency since percentage of voltage control areas with zero reserves is the best proximity measure for assessing the proximity to loss of control voltage instability.

There were 291 single contingencies simulated. These 291 contingencies consist of all single line and generator outage on a 162 bus system. Only 90 double contingencies were identified from combinations of single generator and line outages that exhausted all but 25% of the reserves in some reactive reserve basin based on results similar to Table 3.1. Similar results to Table 3.1 are given in Table 3.2 for the double contingency analysis for the same voltage collapse region and the same reactive reserve basin. The double contingencies consist of double generator outages, double line outages, and a combination of generator outages and line outages. Tables 3.3 and 3.4 shows the single and double contingencies respectively that had the most affect on the largest number wi

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of voltage collapse regions . In both tables, the first column shows the contingency case number, the second column represent the kind of the contingency (line outage or generator outage), and the third column shows the number of voltage collapse regions where the contingency was among the worst five contingencies. Table 3.3 shows that the single contingencies identified as being among the five worst single contingencies in the most reactive reserve basins make up each of the worst double contingencies in Table 3.4. This is expected from studies of large power system models

3.7.1 Loss of Control Voltage Instability

Twenty seven out of the ninety double contingencies simulated did not have a load flow solution. These twenty seven double contingencies were resimulated and eighteen of them solved when the reactive limits on all the generators in the network were ignored. These eighteen double contingencies were associated with loss of control voltage instability. The remaining nine of these twenty seven contingencies were associated with clogging voltage instability. Nine out of eighteen loss of control voltage instability contingencies caused at least one or more voltage collapse regions to have negative reserves in its associated reactive reserves basins. The results are presented in Table 3.5. The first two columns of the table give the contingency case number and the double contingency description, the last column gives the number of voltage collapse regions with negative reserves in its reactive reserves basin. A summary results of loss of control voltage instability for the one voltage collapse region found to be most affected by each contingency in Table 3.5 is given in Table 3.6. The voltage collapse region number is given in column 1. Columns 2,3 represents the voltage control areas, and the reactive reserve basin associated with that voltage collapse region. The base case reactive reserves in the reactive reserves basin is given in column 4, and the last two columns indicates the percentage of the reactive reserves after the contingency and the contingency case number that caused the instability.

The contingency associated with the case number can be found from Table 3.5. The reactive reserve basins in Table 3.6 are nested reactive reserve basin and they form a root of tooth as can be observed by observing the size of the reactive reserve basins and the generators that belong to each as one proceeds down the table. The smallest reactive reserve basins were the most affected reactive reserve basin for the less severe contingencies that requires smaller amounts of additional reactive reserves. Contingencies that require more reactive reserves to be added most severely affected the larger reactive reserve basins in the tooth. The six voltage collapse regions shown in Table 3.6 all had negative reactive reserves in their reactive reserves basins for the nine associated contingencies shown when generator reactive limits are ignored.

A diagnostic study is now performed using the PTI load flow. The result is presented in Table 3.7. The first column shows the generator bus numbers in all of the reactive reserve basin most severely affected by these nine contingencies in Table 3.6. The next nine columns represent each of the nine contingencies by case number and the required additional reactive supply needed by each of the generators and finally the total additional supply required to solve the non converged double contingency. The last two rows of the table represents the most affected voltage collapse region numbers and the generators bus number in the associated reactive reserve basin decided as most affected by that contingency. Note that the generators where reserves were added agree exactly with the generators in the most affected reactive reserve basin except that generator 99 was not in any of the reactive reserve basins. Contingencies are thus shown to sometimes requires reserves outside the agents reactive reserve basin that causes voltage instability and sometimes require adding supply at generators in two reactive reserve basins. The load flow was shown to solve each of the nine contingencies if reactive reserves equal to the value of its negative reserves are added to each generator in the voltage collapse region's reactive reserve basins given in Table 3.7 for each of the above contingencies. Four of the nine diagnosed contingencies were chosen to perform the solvability problem (the corrective control problem) in Chapter 5.

The result shows the worst contingencies that affect the larger reactive reserve basins outage two large generators in these reactive reserve basins. Generators 6, 121 and 6, 131 seems to be the most severe double generator outage contingencies. 121 and 131 are large generators with significant reactive capacity and base case reserve and therefore it makes sense that outage of these generators would have significant affect on loss of control voltage instability. These results suggest that severe contingencies cause increase network reactive losses and or significant reduction in reserves of the affected reactive reserve basin. The results also shows that the double line outage contingencies affected smaller reactive reserve basin and double generator outage contingencies affected the larger reactive reserve basin. Generator outages that affected these large reactive reserve basin were generators within these reactive reserve basins. The results also shows that generator bus number 121 is the most critical bus in the network. This bus needed an additional reactive supply in each one of the contingencies above, except in the case 2 and case 14. In case 2 the generator buses number 6 and 121 were outaged. In case 14 that affected voltage collapse region number 3, generator bus 121 does not belong to its reactive reserves basin.

3.7.2 Clogging Voltage Instability

Nine out of the twenty seven double contingencies did not solve the load flow even when infinite reactive supply were provided to every generator in the network. Some of these nine contingencies, listed in Table 3.8 produced clogging voltage instability. The PTI load flow package is used to study these double contingency cases. Reducing real and reactive power flow on paths with large reactive losses and voltage decline that supply real and reactive power to appropriate voltage collapse region will eventually obtain a load flow solution. The voltage collapse regions, that are most severely impacted by both single contingency components of a double contingency, are voltage collapse regions where all real and reactive load is shed and where an equal amount of active generation is shed. This load and generation shedding is performed one at a time for each of the voltage collapse regions ranked as most severely impacted by the double contingency (based on the results from simulation of its single contingency components). This load and generation shedding is continued until a load flow solution is obtained when reactive limits on all generation are ignored. If reactive power on any generators exceed reactive capability, then reactive capability is added until a solution is obtained when reactive limits are enforced. This procedure was applied to three contingencies in Table 3.8 where the load shedding and generation shedding cured the problem. The amount of load shedding required at various buses and generation shedding required at the generators in various voltage collapse regions is shown in Tables 3.9, 3.10, and 3.11. The voltage collapse regions in the order that load and generation was shed is also shown. In case 8, Table 3.9 shows the load shed equals the generation level on the outaged generators. In other cases, Tables 3.10 and 3.9 shows the total load and generation shed is equal. The load flow solution are obtained in each case after the amount of load and generation is shed. The procedure did not work for case 5 that outaged generators 73 and 76. Generators 73 and 76 are the only two generators in a reactive reserve basin that causes a cascading voltage collapse problem. Reducing generation and load was required in such a large number of voltage collapse regions that the action was so drastic that it was felt that adding an SVC or synchronous condenser to its agent was necessary rather than load and generation shedding. Since Chapter 5 results will obtain corrective controls that eliminate the need to perform load and generation shedding, and since these results in this chapter seeks contingencies where such action might be successful, the results for case 5 were never obtained. For the remaining two cases of Table 3.8 the procedure did not work because these double line outaged caused the network to be split into two networks.

Table 3.1. Single Contingency Ranking for Voltage Collapse Region# 35.

74 LEHIH 3 345 :
55 PLYMH 5 161 :
27 WILMRT3 345 :

Reac. Reser. Basin	CAPACITY	RESERVE	VCA
121 C.BL 3G 24	250.00	99.11	35
118 DPS 57G 14	100.00	40.25	37
73 NEAL12G 20	267.00	181.16	69
101 MTOW 3G 14	38.60	8.26	147
TOTAL BASE RESERVE		328.78	

CONTINGENCY RANKING

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CONTINGENCY	RRB% of BASE	GEN NAME	GEN RES	VCA %
Case:9 L. OUTAGE: 55 149	0.00%			
		C.BL 3G 24	0.00	0.00%
		DPS 57G 14	0.00	0.00%
		NEAL12G 20	0.00	0.00%
		MTOW 3G 14	0.00	0.00%
Case:31 L. OUTAGE: 161 162	0.30%			
		C.BL 3G 24	0.00	0.00%
		DPS 57G 14	0.00	0.00%
		NEAL12G 20	1.00	0.55%
		MTOW 3G 14	0.00	0.00%
Case:39 L. OUTAGE: 68 69	0.33%			
		C.BL 3G 24	0.00	0.00%
		DPS 57G 14	0.00	0.00%
		NEAL12G 20	1.10	0.61%
		MTOW 3G 14	0.00	0.00%
Case:15 L. OUTAGE: 71 85	1.61%			
		C.BL 3G 24	0.00	0.00%
		DPS 57G 14	0.00	0.00%
		NEAL12G 20	5.30	2.93%
		MTOW 3G 14	0.00	0.00%
Case:12 L. OUTAGE: 69 77	2.19%			
		C.BL 3G 24	0.00	0.00%
		DPS 57G 14	0.00	0.00%
		NEAL12G 20	7.20	3.97%
		MTOW 3G 14	0.00	0.00%

Table 3.2. Double Contingency Ranking for Voltage Collapse Region# 35.

74 LEHIH 3 345 :
55 PLYMH 5 161 :
27 WILMRT3 345 :

Reac. Reser. Basin	CAPACITY	RESERVE	VCA
121 C.BL 3G 24	250.00	99.11	35
118 DPS 57G 14	100.00	40.25	37
73 NEAL12G 20	267.00	181.16	69
101 MTOW 3G 14	38.60	8.26	147
TOTAL BASE RESERVE		328.78	

CONTINGENCY RANKING

CONTINGENCY	RRB% of BASE	GEN NAME	GEN RES	VCA %
Case:4 G. OUTAGE: 6	-57.85%			
G. OUTAGE: 131		C.BL 3G 24	-127.3	-128.44%
		DPS 57G 14	-38.4	-95.40%
		NEAL12G 20	14.5	8.00%
		MTOW 3G 14	-39.0	20.50%
Case:27 L. OUTAGE: 68 69	-39.78%			
L. OUTAGE: 69 77		C.BL 3G 24	-19.3	-19.47%
		DPS 57G 14	-32.3	-80.25%
		NEAL12G 20	-44.0	-24.29%
		MTOW 3G 14	-35.2	26.91%
Case:10 L. OUTAGE: 55 149	-39.69%			
L. OUTAGE: 71 85		C.BL 3G 24	-39.8	-40.16%
		DPS 57G 14	-53.9	-133.91%
		NEAL12G 20	-10.1	-5.58%
		MTOW 3G 14	-26.7	20.46%
Case:16 L. OUTAGE: 71 85	-33.58%			
L. OUTAGE: 161 162		C.BL 3G 24	-36.5	-36.83%
		DPS 57G 14	-51.7	-128.45%
		NEAL12G 20	3.6	1.99%
		MTOW 3G 14	-25.8	23.37%
Case:13 L. OUTAGE: 55 149	-32.27%			
L. OUTAGE: 68 69		C.BL 3G 24	-24.8	-25.02%
		DPS 57G 14	-34.5	-85.71%
		NEAL12G 20	-27.5	-15.18%
		MTOW 3G 14	-19.3	18.19%

Table 3.3. Single Outage that had the most affect on Voltage Collapse Region.

Cont. Case	Single Contingency					# of VCR
9	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	48
10	Line Outage:	55	PLYMH 5 161	162	LEEDS 5 161	43
12	Line Outage:	69	HOPET 5 161	77	WRIGT 5 161	10
15	Line Outage:	71	MONOA 5 161	85	CARRLL5 161	48
31	Line Outage:	161	KELOG 5 161	162	LEEDS 5 161	48
39	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	43
2	Gen. Outage:	73	NEAL12G 20			1

Table 3.4. Double Outage that had the most affect on Voltage Collapse Region.

Cont. Case	Double Contingency					# of VCR
8	Gen. Outage:	6	6R1G 22			19
	Gen. Outage:	73	NEAL12G 20			
14	Gen. Outage:	73	NEAL12G 20			3
	Gen. Outage:	130	FT.CL1G 22			
15	Gen. Outage:	73	NEAL12G 20			2
	Gen. Outage:	121	C.BL 3G 24			
18	Gen. Outage:	73	NEAL12G 20			1
	Gen. Outage:	99	PRARK4G 18			
21	Gen. Outage:	130	FT.CL1G 22			1
	Gen. Outage:	131	NEBCY1G 18			
24	Gen. Outage:	121	C.BL 1G 24			31
	Gen. Outage:	131	NEBCY1G 18			
57	Gen. Outage:	76	NEAL34G 24			6
	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	
59	Gen. Outage:	76	NEAL34G 24			3
	Line Outage:	161	KELOG 5 161	162	LEEDS 5 161	
61	Gen. Outage:	76	NEAL34G 24			3
	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	
71	Gen. Outage:	99	PRARK4G 18			47
	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	
72	Gen. Outage:	99	PRARK4G 18			38
	Line Outage:	71	MONOA 5 161	85	CARRLL5 161	
73	Gen. Outage:	99	PRARK4G 18			32
	Line Outage:	161	KELOG 5 161	162	LEEDS 5 161	
75	Gen. Outage:	99	PRARK4G 18			4
	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	
95	Line Outage:	55	PLYMH 5 161	162	LEEDS 5 161	40
	Line Outage:	85	CARRLL5 161	86	GR JT 5 161	
97	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	6
	Line Outage:	85	CARRLL5 161	86	GR JT 5 161	

Table 3.5. Double Outage with negative reserves when the gen. limits are ignored.

Cont. Case	Double Contingency with Ignoring Reactive Limits					# of VCR
1	Gen. Outage:	6	6R1G 22			9
	Gen. Outage:	130	FT.CL1G 22			
2	Gen. Outage:	6	6R1G 22			29
	Gen. Outage:	121	C.BL 3G 24			
4	Gen. Outage:	6	6R1G 22			38
	Gen. Outage:	131	NEBCY1G 18			
10	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	26
	Line Outage:	71	MONOA 5 161	85	CARRLL5 161	
13	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	13
	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	
14	Line Outage:	55	PLYMH 5 161	149	RAUN 5 161	1
	Line Outage:	69	HOPET 5 161	77	WRIGT 5 161	
16	Line Outage:	71	MONOA 5 161	85	CARRLL5 161	13
	Line Outage:	161	KELOG 5 161	162	LEEDS 5 161	
22	Line Outage:	161	KELOG 5 161	162	LEEDS 5 161	2
	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	
27	Line Outage:	68	HOPE 5 161	69	HOPET 5 161	28
	Line Outage:	69	HOPET 5 161	77	WRIGT 5 161	

Table 3.6. Voltage Stability Assessment Results for Voltage Collapse Regions that are Vulnerable to Loss of Control Voltage Instability

VCR #	Voltage Control Area		Reactive Reserve Basin		B. Case Reserves	RR of B. Case	Cont. Case
3	125	PALM710 345	73	NEAL12G 20	181.16	-6.18%	14
	156	E SIDE8 69					
5	161	KELOG 5 161	73	NEAL12G 20	280.27	-13.74%	22
	45	TRIBJI5 161	121	C.BL 3G 24			
	23	HRN K 5 161					
35	74	LEHIH 3 345	73	NEAL12G 20	328.78	-39.78%	27
	55	PLYMH 5 161	101	MTOW 3G 14			
	27	WILMRT3 345	118	DPS 57G 14		-32.27%	13
			121	C.BL 3G 24			
34	77	WRIGT 5 161	73	NEAL12G 20	493.41	-25.03%	10
	39	HAZLON3 345	101	MTOW 3G 14			
	37	ADAM 3 345	118	DPS 57G 14		-20.25%	16
			121	C.BL 3G 24			
			130	FT.CL1G 22			
22	119	SYCAOR3 345	6	6R1G 22	712.60	-21.37%	2
	106	MONRE 5 161	73	NEAL12G 20			
	52	D.MON 5 161	101	MTOW 3G 14			
	4	BOONIL3 345	118	DPS 57G 14		-11.65%	1
	86	GR JT 5 161	121	C.BL 3G 24			
			130	FT.CL1G 22			
23	110	CBLUFS5 161	6	6R1G 22	900.29	-26.88%	4
			73	NEAL12G 20			
			114	C.BL12G 14			
			121	C.BL 3G 24			
			130	FT.CL1G 22			
			131	NEBcy1G 18			

Table 3.7. Additional Reactive Supply Needed to Cure Loss of Control Voltage Instability.

Gen.	Double Contingrncy Case #								
B.#	14	22	13	27	16	10	1	2	4
73	11.20	15.90	27.50	44.00		10.10			
121		22.60	24.80	19.30	36.50	39.80	53.00		127.30
101			19.30	35.20	25.80	26.70	39.10	43.20	39.00
118			34.50	23.30	51.70	53.90	22.90	43.10	38.40
114					40.40	41.30	42.60	73.60	59.70
99							20.30	23.40	15.80
130								77.10	69.50
Tot.	11.20	38.50	106.10	130.80	154.40	171.80	177.90	260.40	349.70
VCR	3	5	35	35	34	34	22	22	23
RRB	73	73	73	73	73	73	73	73	73
		121	121	121	121	121	121	121*	121
			101	101	101	101	101	101	114
			118	118	118	118	118	118	131*
					130	130	130*	130	130
							6*	6*	6*

*** means the generator bus # is part of the double contingency.**

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Table 3.8. Unsolved Double Contingency Cases.

conting.	Double Contingency							
Case: 5	Gen. Outage:	73	NEAL12G	20				
	Gen. Outage:	76	NEAL34G	24				
Case: 8	Gen. Outage:	76	NEAL34G	24				
	Gen. Outage:	131	NEBCY1G	18				
Case: 11	Line Outage:	55	PLYMH 5	161	149	RAUN 5	161	
	Line Outage:	161	KELOG 5	161	162	LEEDS 5	161	
Case: 12	Line Outage:	55	PLYMH 5	161	149	RAUN 5	161	
	Line Outage:	55	PLYMH 5	161	162	LEEDS 5	161	
Case: 20	Line Outage:	71	MONOA 5	161	85	CARRLL5	161	
	Line Outage:	85	CARRLL5	161	86	GR JT 5	161	
Case: 21	Line Outage:	161	KELOG 5	161	162	LEEDS 5	161	
	Line Outage:	55	PLYMH 5	161	162	LEEDS 5	161	

Table 3.9. Load Shed for Case# 8.

Case: 8	Gen. Outage: 76 NEAL34G 24	
	Gen. Outage: 131 NEBCY1G 18	
Load Bus#	Bus Name	Load Reduction
20	HINTON8 69	-40.90
40	BLKHK 5 161	-52.88
87	GUTHIE7 115	-16.91
103	DAVNRT5 161	-322.00
111	AVOC 5 161	-65.41
113	S1211 5 161	-32.70
139	S706 8 69	-10.10
142	CLRNDA8 69	-27.09
157	PLYMTH8 69	-32.00
160	SC WST8 69	-14.40
30	HAYWD 5 161	-190.20
38	DUNDE 5 161	-14.76
46	DENIN 5 161	-65.31
59	EAGL 4 230	-104.43
91	CDRPS 5 161	-51.25
94	HILL 5 161	-162.00
105	DUNDE 7 115	-24.84
Total	=	-1227.18

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Table 3.10. Load and Generation Shedding for Case# 11.

Case: 11	Line Outage: 55 PLYMH 5 161		149 RAUN 5 161
	Line Outage: 161 KELOG 5 161		162 LEEDS 5 161
Load Bus#	Bus Name		Load Reduction
27	WILMRT3	345	-324.00
151	INTRCG5	161	-24.00
80	POMEOY5	161	-15.76
161	KELOG 5	161	-42.00
45	TRIBJI5	161	-20.00
162	LEEDS 5	161	-30.00
54	WISDM 5	161	-94.04
57	SAC 5	161	-48.48
56	OSGOD 5	161	-25.29
29	WINBGO5	161	-28.31
28	FOX k5	161	-38.47
18	ADAM 5	161	-40.40
15	FTRAD 4	230	-160.00
Total	=		-890.75
Gen. Bus#	Bus Name		Gen. Reduction
73	NEAL12G	20	-235.59
76	NEAL34G	24	-133.98
101	MTOW 3G	14	-81.00
118	DPS 57G	14	-81.00
121	C.BL 3G	24	-235.59
130	FT.CL1G	22	-123.59
Total	=		-890.75

Table 3.11. Load and Generation Shedding for Case# 12.

Case: 12	Line Outage: 55 PLYMH 5 161	149 RAUN 5 161
	Line Outage: 55 PLYMH 5 161	162 LEEDS 5 161
Load Bus#	Bus Name	Load Reduction
27	WILMRT3 345	-324.00
151	INTRCG5 161	-24.00
80	POMEOY5 161	-15.76
162	LEEDS 5 161	-30.00
54	WISDM 5 161	-94.04
57	SAC 5 161	-48.48
56	OSGOD 5 161	-25.29
29	WINBGO5 161	-28.31
28	FOX k5 161	-38.47
18	ADAM 5 161	-40.40
15	FTRAD 4 230	-160.00
Total	=	-828.75
Gen. Bus#	Bus Name	Gen. Reduction
73	NEAL12G 20	-204.59
76	NEAL34G 24	-133.98
101	MTOW 3G 14	-81.00
118	DPS 57G 14	-81.00
121	C.BL 3G 24	-204.59
130	FT.CL1G 22	-123.59
Total	=	-828.75

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CHAPTER 4

Optimization Applications in Dispatch of Power System

4.1 Introduction

This chapter reviews the active power dispatch and reactive power dispatch problems, that are the most common optimal power dispatch problems used in operating power systems. The need for including reactive reserve basin constraints on each reactive reserve basin as a means of preventing loss of control voltage instability is discussed. Security constrained dispatch and the tradeoffs between preventive and corrective control formulations is then addressed for thermal and voltage problems and then voltage stability problems. A corrective control is formulated and developed as an alternative to the preventive control currently proposed for the Open Access System Dispatch. The special state estimation, secondary control, and optimization algorithm requirements for implementing the corrective control are discussed. The results obtained from performing corrective control for specific contingencies where VSSAD has provided corrective action are discussed in Chapter 5.

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4.2 Active Power Dispatch

The classical approach to the economic operation of power system is called economic dispatch or active power dispatch. Total production cost is minimized by varying the output of the generators. Normally in active power dispatch problem, the real power generation cost is approximated by a quadratic polynomial, representing the fuel cost for producing power level P_{g_i} on generator i [12]

$$f_i(P_{g_i}) = a_i + b_i P_{g_i} + c_i P_{g_i}^2 \tag{4.1}$$

where P_{g_i} *is the* MW *(per unit) output of the generator* i *and* a_i, b_i, c_i *are constant coefficients.*

The line limits and equipment unit limits are typically used as constraints which include power balance equations, real power generation limits, and thermal limits on branches. The active power dispatch problem formulation is given as follows [13].

$$\left.\begin{array}{ll} Minimize & f(P_g) = \sum_{i=1}^{N_g}(a_i + b_i P_{gi} + c_i P_{gi}^2) \\ Subjet\ to: & f_{i,k}(\theta) - P_{gi} - P_{di} = 0;\ i = 1, ..., N_b \\ & P_{gi_{min}} \leq P_{gi} \leq P_{gi_{max}};\ i \in N_g \\ & I_{ij_{min}} \leq I_{ij} \leq I_{ij_{max}};\ i,j \in N_b \end{array}\right\} \tag{4.2}$$

where:

a, b, and c are system dependent parameters which affect the cost of real power generation; and

P_{gi} *is the real power generation at bus* i

P_{di} *is the real power demand at bus* i

I_{ij} *is the flow of current in branch* ij

$P_{gi_{min}}/P_{gi_{max}}$ *is the minimum/maximum real power for generator* i

$I_{ij_{min}}/I_{ij_{max}}$ *is the minimum/maximum limit on flow of current on the branches* *connecting*

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θ_i *is the phase angle of the voltage at bus* i

N_g *is the number of generators in the system*

N_b *is the number of buses in the system*

Active power dispatch minimizes the fuel cost by determining the generation schedule that minimizes the operating cost and does not violate any of operating constraints of the system.

The optimal active power dispatch as formulated above does not include reactive power balance equation or bus voltage limit violation constraints even though the earliest literature on optimal power flow included such constraints. Subsequent research found that decoupling active power dispatch allowed use of linear programming since the performance index used is quadratic or piecewise linear and linearized network equations could be used. The optimal active power dispatch is implemented on many utilities to dispatch generation by minimizing fuel costs while guaranteeing the dispatch does not violate thermal overload limits. The optimal active power dispatch is also known as Security Constrained Economic Dispatch (SCED) or the Transmission Constrained Economic Dispatch (TCED). SCED is proposed as a component of the Open Access System Dispatch as discussed in Section 4.6. The fuel cost performance index will be replaced by one that is price based in the SCED used in Open Access System Dispatch. The formulation should account for transmission losses, and would provide secure and efficient participation factors for the automatic generation control in an Open Access System Dispatch.

A similar optimal active dispatch would also be developed as part of the power market administration function of an independent system operator [15]. This function entails developing a schedule for all loads and energy supplies for an entire scheduling period based on results of an energy auction. The optimal active dispatch has a quite different per

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different performance index than what is given in 4.2 because it models the consumer surplus in the energy auction market and possibly the spinning reserve market as well as the cost of transmission losses and spinning reserve[16]. This optimal active dispatch problem is an auction resolution optimization that is solved separately from Security Constrained Optimization in a Open Access System Dispatch and the results set the active generation levels on each generator in the auction as well as resolving which generating company will serve each customer through the auction process.

The active power dispatch can drive a system into voltage collapse. The lack of any reactive reserve basin or transfer constraints to prevent loss of control voltage collapse or clogging voltage collapse implies that voltage collapse is possible on this system. If voltage collapse is possible, then active power dispatch must be modified to include reactive power balance equations, reactive reserve basin constraints for each reactive reserve basin in the system, and transfer or wheeling constraints for each contingency that can produce clogging voltage instability. This problem has been formulated and solved and shows that without reactive reserve basin constraints the active power dispatch on a 162 bus model always drives the system into voltage collapse. Adding reactive reserve basin constraints prevents the optimal power flow from producing a solution that has no load flow solution. These reactive reserve basin constraints continue to prevent the optimal power flow from producing solutions that cause voltage collapse and no solution in a load flow model as reactive reserves are progressively reduced in all reactive reserve basins. The optimal power flow has solution when reactive reserve basin constraints are all at limit because the Hessian of the optimal power flow is of larger dimension than the load flow Jacobian because in part the optimal power flow treats tap changers and shunt capacitor controls as continuous variables and thus does not become singular when the load flow Jacobian, a submatrix, becomes singular.

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4.3 Reactive Power Dispatch

In the deregulated environment power utilities will be interconnected to a larger number of other utilities in order to facilitate transactions between them. The stress on transmission system will increase and the ability to control voltage and reactive power flow will be very crucial. The use of reactive power dispatch will help reduce the circulation of reactive power in the network and also maintain acceptable voltage profiles. This reactive dispatch problem assures generator reactive power supply limits and bus voltage limits are not violated. The reactive dispatch problem usually involves minimizing total real power loss P_l in the transmission network which is represented by[17],

$$Minimize\ P_l = \sum_{ij \in I} G_{ij}(V_i^2 + V_j^2 - 2V_iV_j\cos(\delta_i - \delta_j)) \tag{4.3}$$

where, G_{ij} *is the conductance of the line connected between buses* i *and* j, I *is the set of all branches in the system*

or minimizing reactive power injection costs required to keep the system operating in feasible range. This performance index can be written as[18],

$$Minimize\ \sum_{k=1}^{N_b}(C_{ck}S_{ck} + C_{ik}S_{ik}) \tag{4.4}$$

where, C_{ck}/C_{ik} *are capacitive/inductive injection installation costs at bus* k, S_{ck}/S_{ik} *are the amount of reactive injection of the capacitive/inductive type at bus* k, N_b *is the number of buses in the system.*

The associated equality constraints typically are real and reactive power balance equations. The inequality constraints includes the limits of all of the following; real and reactive power generation, voltage at all bus, thermal limited flow on all branches.

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branches, transformer tap position, and switchable shunt capacitor susceptance. A reactive power dispatch will determine the optimal value of all the control variables such as all generation levels, all under tap changer positions, and all switchable shunt capacitor susceptance levels assuming all imposed constraints limits are met.

The problem described above can be formulated mathematically as a separate problem or both of the problem combined together as described in [18]:

$$\left.\begin{array}{ll}
Minimize & P_l + \sum_{k=1}^{N_b}(C_{ck}S_{ck} + C_{ik}S_{ik}) \\
Subjet\ to: & f_k(V,\theta,T) - P_{gk} - P_{dk} = 0\ ;\ k = 1, ..., N_b \\
 & g_k(V,\theta,T) - Q_{gk} - Q_{dk} - V_k^2(S_{ck} - S_{ik}) = 0\ ;\ k = 1, ..., N_b \\
 & V_{k_{min}} \leq V_k \leq V_{k_{max}},\ k \in N_b \\
 & P_{gk_{min}} \leq P_{gk} \leq P_{gk_{max}},\ k \in N_g \\
 & Q_{gk_{min}} \leq Q_{gk} \leq Q_{gk_{max}},\ k \in N_g \\
 & I_{ij_{min}} \leq I_{ij} \leq I_{ij_{max}};\ i,j \in N_b \\
 & T_{j_{min}} \leq T_j \leq T_{j_{max}} \\
 & 0 \leq S_c \leq S_{c_{max}} \\
 & 0 \leq S_i \leq S_{i_{max}}
\end{array}\right\} \quad (4.5)$$

where:

P_{gk}/Q_{gk} *is the real/reactive power generation at bus* k

P_{dk}/Q_{dk} *is the real/reactive power demand at bus* k

$P_{gk_{min}}/P_{gk_{max}}$ *is the minimum/maximum real power produced by generator* k

$Q_{gk_{min}}/Q_{gk_{max}}$ *is the minimum/maximum reactive power produced by generator* k

$V_{k_{min}}/V_{k_{max}}$ *is the minimum/maximum voltage at bus* k *These set of voltage limits on generator terminal voltage* $k \in N_g$ *can actual specify generator terminal voltage or constrain the control change of these voltage set points*

I_{ij} *is the flow of current on branch connecting buses* i *and* j

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$I_{ij_{min}}/I_{ij_{max}}$ *is the minimum/maximum flow of current in all the branches*

θ_k *is the phase angle of the voltage at bus* k

T_j *is transformer tap ratio for the j-th in-phase controllable transformer*

N_g *is the number of generators in the system*

N_b *is the number of buses in the system*

The optimization tool, that performs optimal reactive dispatch, exists in most of the electric power utility control centers in the *U.S.*, but industry surveys indicate it has not been used even though it helps correct voltage limits violation, thermal overload violation, and can save the utility some money in fuel cost by minimizing active losses P_l, It has not been widely used because:

1. all of the fuel cost savings are returned to customers through fuel adjustment clauses and thus there is no economic incentive for a utility to use it;

2. operators desire to supervise and control adjustments in excitation system voltage set points E_i, capacitor insertions S_c, and tap positions T_i on under load tap changers, and are reluctant to allow an optimization program to carry out these adjustments. The coordination of tap changers, the coordination of capacitor insertions, and the coordination of both tap changers and capacitors together has not been acceptably modeled and included in the above formulation;

3. the state estimator is not reliable or consistently accurate enough to allow it to perform loss minimization and thermal and voltage correction.

With deregulation, the operator of the transmission network would accrue some if not all of the I^2R loss savings. Many utilities that hope to be associated with the ISO are implementing this optimal reactive dispatch. Consumer Energy is the first utility to implement optimal reactive dispatch. A difficulty with optimal reactive dispatch as well as

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as well as optimal active dispatch is that the solution could result in voltage collapse. For utilities with voltage collapse problems, the current optimal active dispatch and the reactive dispatch are useless. Replacing the real power losses by a reactive power loss performance measure

$$Q_l = \sum_{ij \in I} B_{ij} \left(V_i^2 + V_j^2 - 2V_i V_j \cos(\delta_i - \delta_j) \right) + \sum_i |V_i|^2 B_{i_s}; \ \forall \ i \ and \ j \qquad (4.6)$$

was used as a means of maximizing reactive supply on generation, where B_{ij} is the series susceptance of line ij and B_{is} is the shunt susceptance at bus i from load, shunt inductors, tap changing transformer shunts ($B_{i_s} < 0$, or $B_{i_s} > 0$), shunt capacitors ($B_{i_s} < 0$), and line charging of transmission lines ($B_{i_s} < 0$) components at bus i. Although this performance index would appear to improve voltage stability security, it still could steer a system into voltage collapse.

The maximization of reactive reserve is not intelligent enough to add reactive reserve in reactive reserve basins that suffer severe equipment outage and transaction combinations that bring it close to voltage collapse. Maximizing system reactive reserve would also not borrow reactive reserve from reactive reserve basins with significant reactive supply compared to the worst equipment outage and transaction combinations that it must endure. Use of the performance measure (4.6) did not prevent voltage instability and in fact could result in voltage instability.The voltage stability security assessment and diagnosis can assess whether any reactive reserve basin will experience voltage instability and the quantity of additional reactive reserve basin reactive reserve necessary to survive any loss of control voltage instability. The maximum added reactive reserve $\triangle R_k$ needed to prevent voltage instability in that reactive reserve basin over all equipment outages and transaction combinations found to produce loss of control voltage instability in that reactive reserve basin can be obtained from VSSAD diagnostic results. If RR_{k_0} is the reactive reserve in reactive reserve b

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reserve basin k in the base case, the reactive reserve basin constraint for reactive reserve basin k is

$$\sum_{i \in RRB_k} Q_{G_{imax}} - Q_{G_i} > RR_{k_0} + \triangle R_k \tag{4.7}$$

where:

RRB_k is the generators in reactive reserve basin k;

$Q_{G_{imax}}$ is the continuous rating upper reactive limit on generator i;

Q_{G_i} is the reactive generation on generator i;

RR_k is the level of reactive reserve in reactive reserve basin k at base case operating conditions;

$\triangle R_k$ is the amount of reactive added to reactive reserve basin k

Adding $\triangle R_k$ to each reactive reserve basin k would prevent loss of control voltage instability detected by VSSAD [1]. This result is obtained when $RR_k = 0$ and $\triangle R_k = 0.10$ *pu* in each reactive reserve basin. It was not surprising to find that the reactive dispatch problem consistently had no solution when the reactive reserve basin constraints were omitted because the reactive capabilities on generator in all reactive reserve basins should prevent violation of generator limits. The optimal reactive dispatch problem with reactive reserve basin constraints prevents simultaneous exhaustion of reserves on all generators and thus prevent loss of control voltage instability in every agent as reactive capability on every generator is reduced. The optimal power flow and load flow had solutions until the interior point optimization algorithm could no longer find a feasible solution to the reactive dispatch problem. These constraints (4.7) also assure that preventing loss of control voltage instability in one location does not cause loss of control voltage instability in another location.

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4.4 Security Constrained Dispatch

A security constraint places an additional inequality constraint on the operating state x_0 and control u_0 for each equipment outage that violates that inequality constraint. If an equipment outage causes a thermal limit violation on an element, the security constraint on flow on that branch could cause a reduction in flow on that branch via real active generation dispatch change so that when the equipment outage occurs the thermal limit violation does not occurs. If the equipment outage causes a voltage limit violation at a bus, the security constraint on the bus voltage could cause a tap position change on an under load tap changer, a switchable shunt capacitor insertion, or an excitation control set point change that would avoid bus voltage limit violation. If an equipment outage or operating change caused a reactive reserve basin reactive reserve constraint(4.7), a security constraint would add the needed reserves in that reactive reserve basin so that if equipment outage occurs that reactive reserve basin has sufficient reserves to prevent voltage instability.

Preventive security constrained dispatch is frequently carried out by adding inequality constraints to the active power dispatch problem or reactive power dispatch problem known as security constraints. The preventive security constrained dispatch problem consists of finding optimal value of all control variables such as active generation output, generator excitation control system set point, and tap changer tap position of the under load tap changer transformer such that the system operation is optimal for some objective function, and making sure that no constraints violation exists after any disturbance or equipment outage. Preventive security constrained dispatch tries to optimize some performance specification such as fuel cost, loss minimization or VAR injection[20] subject to equality constraints, operating constraints, security constraints and control constraints for a list of possible N contingencies and operating change combinations.

4.4.1 Preventive Control Formulation

Preventive security constrained dispatch produces a preventive control in such a way that the controls are adjusted to satisfy the equality and inequality constraints before any of the contingency and operating change combinations have occurred. A preventive control formulation has the form [21]:

$$\left.\begin{array}{ll} Minimize & F(x_0, u_0) \\ subject\ to & G_0(x_0, u_0) = 0 \\ & H_0(x_0, u_0) \leq 0 \\ & G_i(x_i, u_0) = 0\ ,\ i = 0, 1, 2, ..., N \\ & H_i(x_i, u_0) \leq 0\ ,\ i = 1, 2, ..., N \end{array}\right\} \quad (4.8)$$

where:

$i = 0$ is the base case, and $i > 0$ represents the i^{th} post-contingency configuration.

N is the number of contingencies

$F(x_0, u_0)$ represent the performance index to be minimized.

$G_0(x_0, u_0), G_i(x_i, u_0)$ are the real and reactive load flow equation for the system operating constraints and for the i^{th} post-contingency configuration respectively.

$H_0(x_0, u_0)$ represent the system operating constraints limits on reactive reserve basin reactive reserves, thermal overload, bus voltage, tap setting, capacitor insertion, and bound on Var generations before contingency and $H_i(x_i, u_0)$ represent these same inequalities as security constraints state on x_i and control u_0 for the i^{th} contingency respectively.

In most cases $G_i(x_i, u_0)$ is never included explicitly in the formulation (4.7) but used to determine Δx_i and the security constraints are then $H_i(x_0 + \Delta x_i, u_0) \leq 0$. This dramatically reduces the dimension of the optimization problem by Nn since

Δx_i are no longer variables and $G_i(x_i, u_0)$ are no longer constraints. The dimension of the optimization problem is then $n+m$ but the number of inequality constraints is so large that obtaining feasible and/or optimal solution may be difficult because there are only m controls u_0 to satisfy all these inequality constraints.

The security constrained optimal reactive dispatch would place a very heavy burden on most optimization solution algorithms. In a stressed system, there can be several branches with thermal limit violations and yet generally they are not independent. Thus correcting only one or possibly a few of the thermal limit violation would correct all of the operating constraint and security constraint thermal limit violations not only for one equipment outage and operating change but for all equipment outage and operating change combinations. Bus voltage limit violations (reactive reserve basin reserve violation) are not independent and correcting only a few of the very large number of the voltage limit violations (reactive reserve basin reserve violations produced for all VSSAD determined equipment outage and operating change combinations) could correct all such violations. Similarly the reduction of flow on boundaries and interfaces of a voltage control area that solve clogging voltage instability for a specific equipment outage and operating change are not independent and thus correcting a few such violation could correct all such clogging related operating and security constraint violations produced for all VSSAD determined clogging voltage instability problems. Every optimization algorithm searches for the subset of inequality constraints that should be binding at the optimal solution and act as binding equality constraints. The convergence of any optimization algorithm depends heavily on optimally searching for and finding the correct set of binding inequality constraints that correct all thermal limit operating and security constraint violations, all voltage limit operating and security constraint violations, all reactive reserve basin operating and security constraint violations, and all clogging operating and security transfer or wheeling constraints. Experience with VSSAD [1] indicates there can be a relatively large number of reactive reserve basins that need reactive reserves for any equipment outage and operating change combination predicted to produce voltage instability. This would require adding security constraints for each reactive reserve basin. The VSSAD process attempts to determine critical reactive reserve basin that contains relatively few generators and is nested in successively large reactive reserve basins. The smaller reactive reactive reserve basins are associated with voltage control areas in the distribution system or in a electrically remote part of the subtransmission system. Exhaustion of all reactive reserve on a critical reactive reserve basin causes large series I^2X losses and shunt capacitive supply withdrawal that exhausts reactive reserve in the successively larger reactive reserve basins causing voltage collapse to spread uncontrollably throughout a system. VSSAD [1] may help the optimization algorithm in finding the optimal binding constraints by recognizing the binding constraint always is on reactive reserve in the critical reactive reserve basin for any equipment outage and operating change combination. Experience with VSSAD suggests that there are only a few critical reactive reserve basins in a system that are critical and they generate cascading voltage collapse for all equipment outage and operating change combinations that produce voltage collapse in a system. This implies adding reserve to a relatively few critical reactive reserve basins in the reactive reserve basin constrained optimal reactive dispatch problem (4.5, 4.7) or adding security constraints for each contingency and operating change on just one or a few critical reactive reserve basins can prevent voltage instability for all equipment outage and operating change combinations found to experience voltage instability on a system. The critical reactive reserve basin for loss of control voltage instability may in some cases also be critical for clogging voltage instability. Placing transfer or wheeling constraints on flow on one or more interfaces or on boundaries of critical voltage control areas or on generation and load in the critical agent for clogging voltage instability may cure most clogging voltage instability problems.

The major difficulty with security constrained optimization problems (security constrained active power dispatch and security constrained reactive power dispatch) is that trying to prevent all possible thermal limit violations, all possible voltage limit violations, and all possible voltage instability problems that can occur on all equipment outage and transfer and wheeling transaction combinations adds so many conflicting constraints on selecting the operating state x_0 and control u_0 that there is no solution (x_0, u_0) to the optimization problem (4.8). Even if there are feasible solutions $(x_0 \in X_0, u_0 \in U_0)$, they are so constrained that the performance measured by the objective function is poor and the optimization algorithm may not be able to converge to it due to inability in finding the set of binding constraints that produce an optimal solution. This inability to find feasible and then find optimal solutions for security constrained dispatch problems was already recognized and caused the corrective control problem (4.9) to be formulated.

4.4.2 Corrective Control Formulation

Adding security constraints on reactive reserve basins for each possible loss of control voltage instability contingency affecting each reactive reserve basin, and adding interface and boundary flow constraints for each clogging voltage instability on each distribution voltage control area just makes the determination of a feasible set or an optimal solution that much more difficult. A corrective control based formulation for optimization with security constraints has been developed for thermal and voltage limit violation that assigns a control change $u_i - u_0$ from operating state (x_0, u_0) for each equipment outage and operating change combination that has thermal or voltage limit violations $H_i(x_i, u_i) > 0$ rather than satisfaction $H_i(x_i, u_i) \leq 0$. This corrective control formulation is reasonable because thermal and voltage limit violation can be endured for up to fifteen minutes, which is sufficient time to detect the violation $H_i(x_i, u_i) > 0$, from a state estimator, compute a control u_i to correct it, and implement a corrective control change within 15 minutes after the equipment outage and operating change is detected to have occurred via a 5 second updated state estimator. The 15 minutes update of the security constrained optimization corrected the thermal or voltage problem before equipment damage can occur. A corrective control for voltage instability is also possible because the sequence of events before a voltage instability develops after an equipment outage and operating change combination takes minimum of 2 - 5 minutes to develop. The sequence of actions after the equipment outage and operating change occurs includes

1. distribution level tap changer and switchable shunt capacitor controls that incur delays of 10 seconds to a minute between each step change in tap position and each switching in of an additional capacitor bank segment. These control changes raise distribution level voltage and load, that fell after the contingency, back to precontingency levels over 2-5 minutes . The first change in tap position or switchable shunt capacitors controls requires far greater delay than every subsequent change;

2. generator continuous field current limit violation due to the equipment outage and operating change combination and the control action of distribution level tap changes and switchable shunt capacitors that increase reactive load to pre-contingency levels. The field current can violate thermal limit for a duration of between 10 seconds and 2 minutes depending on the magnitude of the current limit violation before the maximum excitation limiter reduces field current and reactive power output back to continuous rating limit. The maximum excitation limiter causes the exciter to lose control of voltage because the maximum exciter limiter adjusts the voltage set point of the excitation control system on that generator once the maximum excitation limiter over rides the excitation control after the 10 second to 2 minute delay;

3. the progressive loss of voltage control on generators via maximum excitation limiters that reduce field current and reactive power to continuous rating levels after a delay that can range from 10 to 120 seconds [23] depending on the magnitude of the field current limit violation. The reduction of reactive power on generators due to maximum excitation limiter action and the reduction of voltage and increase in network reactive losses due to voltage reduction can cause or increase magnitude of field current and reactive power limit violation on other generators that ultimately no longer supply reactive and lose control of voltage until voltage collapse occurs.

Loss of control voltage instability requires all three control related difficulties to develop. Clogging only requires action (1) which occurs due to restoration of distribution voltage and load. This sequence of control actions can take a minimum of 2 - 5 minutes to occur. Using a Wide Area Measurement System (WAMS) with a sampling period of five seconds to provide state estimation and detection of the equipment outage and operating change, there is an ample time to implement a precomputed computed corrective control for voltage instability. However, if the sampling period is fifteen minutes or up to an hour as proposed for the Transmission Congestion Management System [15] to be used in Independent System Operator (ISO) control center, there is no opportunity to correct thermal, voltage or voltage collapse problems.

The corrective control problem formulation is now given assuming that corrective control is needed and will be implemented in local security based control centers outside the Independent System Operator as proposed in [1];

$$\left.\begin{array}{ll} Minimize & F(x_0, u_0) \\ subject\ to & G_0(x_0, u_0) = 0 \\ & H_0(x_0, u_0) \leq 0 \\ & G_i(x_i, u_i) = 0, \quad i = 1, 2, ..., N \\ & H_i(x_i, u_i) \leq 0, \quad i = 1, 2, ..., N \\ & \varphi_i(u_i - u_0) \leq \Theta_i, \quad i = 0, 1, 2, ..., N \end{array}\right\} \quad (4.9)$$

where:

$u_0, u_i \in \Re^m$ *are the vector of control variables for the base-case and post-contingency configuration i respectively.*

$x_0, x_i \in \Re^n$ *are the vector of state variables for the base-case and post-contingency configuration i respectively.*

$G_i : \Re^{m+n} \rightarrow \Re^a$ *is the vector function representing equality constraints for the* i^{th} *configuration.*

$H_i : \Re^{m+n} \rightarrow \Re^b$ *is the vector function representing inequality constraints for the* i^{th} *configuration.*

$\varphi_i(\cdot)$ *is the distance metric(the Euclidean norm).*

Θ_i *is the vector of upper bounds reflecting ramp-rate limits*

The dimension of the corrective optimization problem is $(N + 1)(n + m)$ and is nearly the same as the preventive control(4.8) but now has m control to satisfy the inequality constraints for the base case and m controls for each contingency rather than just m controls for satisfying the inequality constraints for the base case and all N contingencies. This corrective control problem is quite difficult to solve due to the large number of equality and inequality constraints and the large dimension $(N + 1)(n + m)$ of the optimization problem. Making $G_i(x_i, u_i)$ and $H_i(x_i, u_i)$ functions of u_i and not u_0 lets this complex optimization problem be decomposed in to N slave optimization problems that each minimize $\| u_i - u_0 \|$ subject to the last three constraints in (4.9) that depend on u_i and x_i and a master problem that optimizes $F(x_0, u_0)$ subject to the first two constraints and last constraint in (4.9) that depend on x_0 and u_0. A Benders decomposition algorithm, described in this section is used in this master-slave set of optimization problems.

4.5 Voltage Collapse Constrained Optimal Reactive Dispatch Problems

A preventive voltage collapse constrained optimal reactive dispatch (referred as problem 1) could be formulated that corrects thermal overloads on any branch and voltage limit violations on any bus, via operating constraints $H_0(x_0, u_0) \leq 0$ and prevents and corrects voltage collapse in any reactive reserve basin. The preventive control for solely loss of control voltage collapse corrects voltage collapse not only for the base case with operating state x_0 but also prevents voltage collapse after each equipment outage and operating change combination with operating state x_i using security constraints $H_i(x_i, u_0) \leq 0$. A revision of the corrective optimal reactive dispatch (4.5) is possible by adding sufficient reactive reserve basin reactive reserve $\triangle R_k$ above base case reactive reserve RR_{k_0} for all the equipment outage and transaction combinations that would cause loss of control voltage instability. This optimization problem does not add equality constraint $G_i(x_i, u_0)$ or inequality constraints $H_i(x_i, u_0)$ but just uses VSSAD information to modify the operating constraints $H_0(x_0, u_0)$ to incorporate the reactive reserve basin constraint(4.7) for each contingency. This control corrects and prevents voltage collapse but also corrects thermal or voltage limit violations for each contingency. The operating constraints would correct for thermal and voltage limit violations as they develop and would avoid equipment damage if the update of this control was sufficiently often (10 - 15 minutes).

A second preventive control problem (4.5) would not only add the reactive reserve constraint via $H_0(x_0, u_0)$ but also inequality constraints $H_i(x_i, u_0)$ for specific contingencies. The inequality constraint in $H_0(x_0, u_0)$ assure there is finite reserves in each reactive reserve basin at solution x_0 that satisfies $G_0(x_0, u_0) = 0$ as well as correcting thermal and voltage limit violations for solution x_0 . The constraints $H_i(x_i, u_0)$ would cause u_0 to change to prevent thermal limit violation, and voltage limit violation, and reactive reserve basin constraint violations after the equipment outage and transaction combination that produced load flow model $G_i(x_i, u_0) = 0$. The combination of equality constraints $G_i(x_i, u_0) = 0$ and $H_i(x_i, u_0) \leq 0$ for each thermal, voltage, or voltage instability insecure equipment outage and transaction would place terrible burden on selecting u_0 and may make the optimization problem infeasible as mentioned earlier. If a feasible solution could be found, the performance would be unacceptable.

Preventive control (referred as problems 1 and 2) has been replaced in terms of a strategy for alleviating thermal and voltage limit violation by a corrective control problem formulation (4.9) that allows control change $u_i - u_0$ from base case control u_0. Selecting u_i for equipment outage and operating change combinations $i = 1, 2, ..., N$ and u_0 for the base case implies there is control change $u_i - u_0$ for each equipment outage and transaction combination to be used to correct reactive reserve basin constraint violation(4.7) and voltage collapse only when that equipment outage and transaction combination occurs. The constraint $H_i(x_i, u_i)$ would include thermal or voltage limit constraints. The control u_0 would posture the system based on the performance index $F(x_0, u_0)$ and constraint $\varphi_i(u_i - u_0)$ in (4.9) and satisfy thermal, voltage and reactive reserve basin constraints on x_0 imposed by $H(x_0, u_0) \leq 0$ satisfying $G_0(x_0, u_0) = 0$. The control change $u_i - u_0$ makes satisfying $G_i(x_i, u_i) = 0$ and $H_i(x_i, u_i) \leq 0$ possible through the tailored reactive reserve basin constraints for one or more reactive reserve basin k^*. The reactive reserve basin k^* would add the reactive reserve $\triangle R_{k^*}(x_i)$ recommended by VSSAD

$$\sum_{i \in RRB_{k^*}} Q_{g_{imax}} - Q_{G_i}(x_i) \leq RR_{k^*_{min}} + \triangle R_{k^*}(x_i) \tag{4.10}$$

for x_i satisfying $G_i(x_i, u_i) = 0$ and $H_i(x_i, u_i)$. All other reactive reserve basin would only have minimal level of reactive reserves

$$\sum_{i \in RRB_k} Q_{G_{imax}} - Q_{G_i}(x_0) \geq RR_{k_{min}} \tag{4.11}$$

The corrective control problem formulation (4.9) can also correct for clogging voltage instability problems for equipment outage and transaction combination determined by VSSAD [1]. The constraints $H_i(x_i, u_i) \leq 0$ associated with load flow model $G_i(x_i, u_i) = 0$ after equipment outage and transaction combination would restrict the flow

$$-V_i V_j |Y_{ij}| \sin(\theta_i - \theta_j - \beta_{ij}) \leq P_{ij_{min}} \tag{4.12}$$

or reduce load

$$\sum P_{Di} \leq P_{i_{min}}(x_i) = 0 \tag{4.13}$$

$$\sum Q_{Di} \leq Q_{i_{min}}(x_i) = 0 \tag{4.14}$$

as suggested by VSSAD [1]. These corrective control problem is demonstrated in Chapter 5, where we discuses the solvability problem.

Perhaps the most significant advantages of corrective control are

1. the reactive resources needed to prevent a loss of control voltage instability for a particular equipment outage and transaction combination that impacts a re-

active reserve basin need not reside on that reactive reserve basin but can be borrowed from other reactive reserve basins, that at the moment when that equipment outage and transaction combination occurs have large reactive supply or reserve surpluses. The small level of $RR_{k_{min}}$ needed for all reactive reserve basins k other than k^* assures voltage collapse does not occur in these reactive reserve basins due to this borrowing on reserves for k^*. How small $RR_{k_{min}}$ can be is a subject for research since it would be quite small if reactive reserve basin $k \neq k^*$ could also borrow reserve it needs also suffers a change that requires reactive reserve in its reactive reserve basin. The probability that reactive reserve basins (a) have totally different generators in their reactive reserve basins and (b) are vulnerable to totally independent set of equipment outages requiring additional reactive reserve experience voltage collapse simultaneously is so small that there is no need to deal with this case in operations. Thus borrowing reserves from reactive reserve basins not in the same nested set is only limited by the significant physical limitation in shipping reactive power over any significant distance. Borrowing reactive reserves from large reactive reserve basins that lie in the same nested set as smaller reactive reserve basins that need reserves is not as limited by physical constraints on shipping reactive power. Such borrowing strategy is problematic because it imposes security difficulties in each reactive reserve basin in the nested set that may all cascade into voltage collapse if one of the reactive reserve basins in the nested set, not necessarily the smallest one exhausts reserves. Borrowing reserves from larger reactive reserve basins for smaller ones in the nested set, will likely consume reactive supply in the larger critical reactive reserve basin thus bringing on the voltage collapse. The ability to quickly change exciter set point, tap position on underload tap changer, switchable shunt capacitors, and active power generation set points in the $2-5$ minutes interval is needed. Such a control structure is discussed in [9] and in section 4.7 and 4.8 along with changes in state estimation; the OASYDIS dispatcher of reserves; and OASYCOM scheduler of reserves needed to implement it;

2. The active and reactive constraints on power flow or load needed to prevent a specific clogging voltage instability for a specific equipment outage and transaction combination need not be imposed on base case operation (x_0, u_0) but is only implemented through constraints $H_i(x_i, u_i) \leq 0$ on operation $G_i(x_i, u_i) = 0$ after the equipment outage and transaction combination occurred. Imposing load reduction or transfer constraints on $H_0(x_0, u_0) \leq 0$ would cause large economic penalties on operational costs for the ISO due to penalty payments for curtailed transactions and curtailed customers load. When the probability of the specific equipment outage and transaction combination is small and the cost of prevention is high, imposing such constraints as (4.12, 4.13, 4.14) in $H_0(x_0, u_0) \leq 0$ is unthinkable. This is especially true on systems there numerous agents are one highly probable contingency away from interruption of load to a small set of distribution level customers due to the possibility of voltage instability. In such cases, it would be impossible to find a feasible (x_0, u_0) that satisfies all constraints in $H_0(x_0, u_0) \leq 0$;

3. the ancillary services required by the control change $(u_i - u_0)$ would only be paid for and thus implemented when it is absolutely required to prevent blackout for a specific transaction and equipment outage predicted by VSSAD to produce a clogging or loss of control voltage instability;

4. the control change $u_i - u_0$ required to prevent clogging may not require load shedding for clogging voltage instability even though VSSAD indicates such change will obtain a load flow solution;

5. the increase in transmission capacity and system reliability (security and adequacy) could be quite large for the cost of implementing an improved control using a Wide Area Measurement System (WAMS). Electricite de France (EDF) claims a 20% transmission capacity enhancement via secondary voltage control that just adds reserves via switching of capacitors and reallocation of reactive reserves in a reactive reserve basin so that no generator in a reactive reserve basin exhausts reactive reserve. The EDF control (a) does not coordinate tap changer, switching of capacitor, generator excitation controls in several reactive reserve basins simultaneously; (b) does not optimally allocate reserves on generators in a stressed reactive reserve basins to maximize security; (c) does not optimally borrow reserves from other reactive reserve basins; (d) does not redispatch active power generation to achieve optimal allocation and borrowing of reactive reserve after a contingency and transaction. Adding capabilities (a-d) could add very large additions to transmission capacity.

The corrective control formulation (4.9) of the optimal reactive dispatch can be solved by a decomposition algorithm. The decomposition methods, discussed in [21] break this corrective control into optimization subproblems that are much more easily solved. The Benders decomposition will be used in this thesis.

4.6 Bender Decomposition

Benders decomposition is a technique usually used for large nonlinear programming to partition the system state and control variables (x, u) by holding some variables fixed while the other are being solved for . The fixed variables are adjusted by the master problem while the other variables are solved by the slave problems. The iteration between the master and the slave problems continue until the optimal solution is obtained. The application of this technique to optimal power flow is discussed in [22].

The master problem can be formulated as follows [21]:

$$\left.\begin{array}{ll} Minimize & F(x_0, u_0) \\ subject\ to & G_0(x_0, u_0) = 0 \\ & H_0(x_0, u_0) \leq 0 \\ & \omega_i(u_0) \leq 0, \quad i = 0, 1, 2, ..., N \end{array}\right\} \tag{4.15}$$

where:

the Benders cut function for the i^{th} *contingency is* $\omega_i = \omega_i^* + \lambda_i^T(u_i^* - u_0^*)$

u_i^* *is the optimal value of the slave problem control variable for the* i^{th} *contingency.*

u_0^* *is the optimal value of the master problem control variable obtained from previous iteration.*

λ_i *is the Lagrangian multipliers associated with the* i^{th} *coupling constraint,* $\| u_0^* - u_i \| - s_i \leq \| \Theta_i \|$

ω_i^* *is the minimum value of the slave objective for the* i^{th} *contingency.*

Suppose now for the slave problem that the penalty associated with the control change $(u_0^* - u_i^*)$ have added to the slave problem for each equipment outage and operating change combination for a given u_0^*. The performance index of the slave problem is to minimize the control changes and therefore, minimize the cost associated with the control changes. The slave problem is given as [21]

$$\left.\begin{array}{ll} Minimize & \omega_i^* = ds_i \\ subject\ to & G_i(x_i, u_i) = 0 \\ & H_i(x_i, u_i) \leq 0 \\ & \| u_0^* - u_i \| - s_i \leq \| \Theta_i \| \\ & s_i \geq 0 \end{array}\right\} \tag{4.16}$$

where d is a positive constant and s_i, u_i, x_i are the variables to be optimized.

The algorithm for this decomposition is

Step 1: we start with an approximation of Bender cut function ω_i for $i = 1, 2, \cdots N$

Step 2: solve the master problem (4.15) and obtain a new x_0^* and u_0^*

Step 3: solve the slave problems (4.16) for u_i^* for $i = 1, 2, \cdots, N$ given u_0^*

Step 4: check if $\omega_i^*(u_0)$ is zero for all $i = 1, 2, \cdots, N$;

if yes, x_0^* and u_0^* are the optimal solution, if not, use the results found in **Step 3** to build a more accurate Bender cut function, and go to **Step 2**

The dimension of the master and each slave problem is $n + m$ which reduces the extremely large dimension of the corrective control problem to manageable levels but at the cost of solving $N + 1$ optimization problems rather than just one. Each of the $N + 1$ optimization problems have a large feasible region compared to the protective control problem(4.8). The master and slave corrective control are easy to solve with excellent performance because feasible region is large and only satisfies inequality constraints for one operating condition whereas the protective control problem has poor control performance may be very costly to implement, and will be difficult if not impossible to compute since it is attempting to meet the control, operating, and the security constraints for N contingencies. The preventive control provides protection against security violations for N simultaneous contingencies that would never be required but are being provided and paid for continually. These difficulties with preventive control have been discussed previously and have led to rejection of preventive control for thermal and voltage problems and adaption of corrective control with just operating and control constraints $H_0(x_0, u_0)$ and a sufficiently fast corrective update rate so that thermal overloads are not left on the system long enough to cause equipment damage. The corrective control for clogging and loss of control develop quickly (2-5 minutes) compared to the duration needed to avoid equipment damage (15 minutes) for thermal violation. A special secondary control will be needed to implement the specific controls developed for each contingency.

4.7 Open Access System Dispatch (OASYDIS)

This section is abstracted from [15]. The application of OASYDIS in a deregulated power system is to ensure the security and efficiency of power system operation. The OASYDIS, shown in figure 4.1 is proposed as the principal dispatch control for correcting and preventing thermal, voltage, voltage collapse, and transient stability problems. In this application the normal power system operation is studied as well as the post contingencies. OASYDIS consists of two major modules:

- Contingency analysis module, which identifies the worst contingencies that makes the system insecure. We can use VSSAD to detect, rank, and diagnose contingencies and operating change cause voltage instability. The advantages of using VSSAD are mentioned in section 3.2 .

- Security Constrained Optimization module (SCO), which responsible for dispatching all of the system resources and control. A modified reactive power dispatch corrective control could be used with a different performance index to implement this module. The Security Constrained Optimization problem is formulated in section 5.3 of this thesis.

The Security Constrained Optimization module can be used to run twice for each hour in a control center. The Security Constrained Optimization module consist of two action runs

- **Run 1:** in this action run the SCO attempts to dispatch only dispatchable system resources and control such as power generations, loads ,transaction, and transmission controls which includes voltage set point on generators, switchable capacitors, and tap position on underload tap changer.

- **Run 2:** this action run is put into effect immediately if control action run 1 fails to make the system operation secure. In this action run the SCO attempts to reduce generations, loads, and wheeling and transfer transaction plus the transmission controls.

The major features of the OASYDIS Security Constrained Optimization module, formulated in detail in section 5.3, are:

1) Objective

The performance index of OASYDIS security constrained optimization module is to minimize the operation cost of the system which includes, (a) payments to energy generation companies (or cost of energy if the generation supply is owned or leased by the ISO); (b) cost of transmission losses, reactive power supply, and voltage control; (c) penalty costs for changing bilateral transaction (wheeling and transfer) schedules by the ISO; (d) cost of operating transmission controls including underload tap changer, capacitors, generator AVR set points and (e) costs for curtailing supplies, P_{G_i}, load, P_{L_i}, and wheeling and transfer transaction reduction.

2) Controls

The control of the OASYDIS includes: (a) all dispatchable energy supplies and loads (P_{G_i}, P_{L_i}), (b) dispatchable supplies and load via bilateral transactions ($P_{wheeling}, P_{transfer}$), (c) transmission control (tap position on underload tap changers, capacitor susceptances, voltage setpoint on generator's $AVRs$) and (d) curtailment of loads and supplies and bilateral transactions ($P_{G_i}, P_{L_i}, P_{wheeling}$ and $P_{transfer}$)

3) Constraints

Constraints $H_0(x_0, u_0)$ and $H_i(x_i, u_i)$ include: (a) static network operating constraints (bus voltage limits on buses, thermal limits and angular difference limits on branches, reactive reserve limits on each reactive reserve basin, and transfer and wheeling limits for each contingency that cause clogging voltage instability or some agent), (b) constraints on individual control variable including limits on generators active power P_{G_i} and reactive power Q_{G_i}, and limits on changes in transmission controls (tap position on underload tap changers, capacitor susceptances, and voltage setpoints on generator $AVRs$).
This module should be able to solve very large size networks with more than 10000 buses with all relevant controls, constraints and contingencies.

The control in [15] shown in Figure 4.1 is not in this form of the OASYDIS, are price sensitive loads and price sensitive bilateral transactions. This dispatch could be added to an extended formulation. Ancillary services such as regulation, load following, network stability, real power loss, energy imbalance could also be handled in a security constrained economic dispatch. It may be possible to combine the Security Constrained Economic Dispatch and the OASYDIS Security Constrained Optimization module but efforts at this would produce such a large complex optimization problem that obtaining solution has been problematical. The auction market or bilateral transaction market and the ancillary services market will not be included in the power system dispatch to be formulated in section 5.3 .

4.7.1 Power System Dispatch Function

Power system dispatch shown in Figure 4.1 attempts to output a secure and reliable operating point for a power system. This power system dispatch function should also insure a least economic cost real time dispatch of all dispatchable system resources and controls. The power system dispatch function generally includes the following steps:

Step 1: A State Estimation and Power Flow application to establish a consistent and accurate picture of the power system operating condition. This application will run every 5-30 seconds storing the system operating condition and making it available for use by all other applications of power system dispatch function;

Step 2: A Transmission Constrained Economic Dispatch (TCED) application that updates the active power generation dispatch in response to load change and operating changes to the system in an economic fashion. TCED application would run frequently to reschedule the generation by adjusting the generators active power output P_{G_i}. Linear programming can be used to implement this application considering penalty for transmission loss and including transmission thermal and voltage constraints. Such a dispatch is corrective and does not require development of a preventive control;

Step 3: An On-Line Open Access System Dispatch (On-Line OASYDIS) application that make the necessary modification to the system dispatch to ensure security and efficiency of the system. The application runs every 15-30 minutes or as needed. The On-Line OASYDIS will find the penalty factors and the binding constraints for the TCED application. This dispatch uses all the dispatchable resources and the controls subject to their limits. It will also reduce the generations, loads, bilateral transactions (wheeling, transfer), add or remove switchable capacitors, change underload tap changer tap positions, and change generator, SVC and synchronous condenser voltage setpoints to ensure security of power system operation;

Step 4: An On-Line Voltage Security Assessment (On-Line VSA) application that make sure all bus voltages are within their limits and the power system operation is voltage stability secure. If insecurity is detected via detection of a VSSAD predicted equipment outage and transaction combination has actually occurred on the system, based on using a filter on the state estimator, a trigger would be sent for implementation of the corrective control computed by the Security Constrained Optimization module for that equipment outage and operating change combination. The On-Line VSA runs frequently (every 5 second or more) or as needed.

Step 5: An On-Line Dynamic Security Assessment (On-Line DSA) application that makes sure the loss of transient stability after any disturbance or contingency will not occur and that the transiently stable operating is secure. If insecurity is detected than On-Line DSA will implement a set of operation constraints and send it to On-Line OASYDIS application. On-Line DSA runs infrequently or if it is needed.

4.8 State Estimation Modeling and Measurement

The knowledge of the voltage control areas and their reactive reserve basins that experience loss of control or clogging voltage instability might require providing state estimation at the lowest subtransmission and higher level distribution network as well as geographically remote regions that contain the locally most vulnerable voltage control areas and reactive reserve basins. The monitoring of these regions is necessary to detect occurrence of equipment outage and operating change combinations that can initiate an uncontrollable spreading voltage collapse. The region monitored might need to be outside the region where the ISO has control responsibility if one or more of the locally most vulnerable reactive reserve basins have their bifurcation subsystems [1, 11] partially or totally outside the region of ISO control responsibility.

The state estimator for any ISO is projected to have an update rate of 10-30 minutes and covers the region where the ISO has the Transmission Dispatch and Congestion Management responsibility [15]. Such a sampling rate requires implementation of preventive controls for thermal, voltage, and voltage instability detected by the contingency selection module in the OASYDIS as discussed earlier. A 10-15 minute update period for a state estimator can't detect the equipment outage and operating changes in sufficient time to correct them to avoid thermal damage and insulation damage. This state estimator update period cannot detect the occurrence of the equipment outage and operating changes quickly enough (5-30 seconds) after the initiating events to allow implementation of precomputed controls to correct the voltage instability problem. State estimation is currently provided in a single utility with a 5-10 second update period when required. This type of sampling period is thus proposed for an ISO or auxiliary control center. This sampling and control update period would allow for detection of equipment outage and operating changes that cause thermal and voltage limit violations and update of the corrective tertiary (security constrained optimization) based control to correct the violations before they cause equipment damage. This sampling and control update period would allow implementation of corrective control for voltage instability via the scheduling or dispatch changes as described earlier in this chapter. A state estimator based on the Wide Area Measurement system's 5 second update period would be sufficient to detect the equipment outage and operating change, trigger a precomputed and stored control, and implement the control before the 2-5 minute time frame of development of the classic voltage instability problem. The classic voltage instability is produced through (a) action of distribution level tap changers and switchable shunt capacitors to bring back the voltage and load in the distribution system and (b) a sufficient number of generator field current limit controllers to reduce field current back to continuous rating. This sequence generally requires between 2-5 minutes. The 5 second sampling period is short enough so that each voltage collapse initiating equipment outage and operating change as well as each of the above steps (a,b) in the development of the voltage instability will all occur between samples of the state estimator and thus will be detected. The precomputed corrective control could overcome each of these changes if they were predicted properly and thus the precomputed corrective control could be self checking.

Despite the capabilities of the secondary voltage just described, a state estimator based on Wide Area Measurement system and the secondary voltage control would not have sufficiently fast sampling rate to prevent transient voltage instability that can occur in seconds after the equipment outage. A faster synchronized measurement system and secondary control is required if precomputed control are to be implemented to correct for a transient voltage instability problem. A Wide Area Measurement system measurement system using a 5 second sampling period and a secondary voltage control system with a 2-3 minute response time would not be sufficient to detect via state estimator any VSSAD predicted equipment outage and operating change combination known to produce transient voltage instability in some bifurcation subsystem; trigger the precomputed remedial control; and implement this control. An emergency control, using a very fast measurement system and secondary control, would be needed to correct transient voltage instability. The measurement and control would be part of the primary control system.

4.9 Secondary Voltage Control

A secondary voltage control as proposed by EDF [86] has the objective of producing a strong voltage profile against voltage collapse and assuring that reactive resources are put to better use. Producing a strong voltage profile implies maintaining voltage control in all reactive reserve basin voltage control area. Assuring reactive resources are put to better use could imply making sure that reactive resources are postured or used in a corrective control against voltage stability insecurity. The EDF secondary voltage control [86] achieved these objective by distributing reactive reserves by adjustment of generators excitation voltage set points in each zone so that all generators operate at an equal percentage of their reactive capability. If insufficient reactive reserves are available in a zone, capacitors can be switched in and under load tap changer that pump reactive out of the generators toward the load are blocked or reversed via secondary voltage control. The EDF secondary voltage control has a response time of 3 minutes and thus can sometimes correct a specific developing voltage collapse but certainly can always aid in this correction. In most cases, the EDF secondary voltage control would help prevent voltage collapse for a subsequent equipment outage and operating change.

A far more capable secondary corrective control is proposed as being computed or updated every 10-15 minutes and implemented with a 5 second sampling rate as part of the Open Access System Dispatch (OASYDIS). This secondary control would be aimed at correcting a very specific voltage collapse that is developing because the equipment outage and operating change combination predicted to produce the voltage collapse by the VSSAD has occurred and has been detected via a filter on the Wide Area Measurement system state estimator. The switching of capacitors, under load tap changer position adjustments, and generator excitation voltage set point is determined in an optimal fashion in the Open Access System Dispatch using a set of optimization problems:

1. to eliminate the clogging or loss of control voltage instability on one or more bifurcation subsystems for a specific equipment outage and operating change combination;

2. to prevent loss of control or clogging voltage instability from developing in other reactive reserve basins and their test voltage control areas;

3. to utilize the fewest control change to achieve objective (1) and (2);

4. to minimize ancillary cost for the control changes used;

5. to posture the base case control setting on the entire system to make (1-3) possible for every equipment outage and operating change combination found by VSSAD to produce voltage instability.

The secondary corrective control for each specific equipment outage and operating change combination would be stored, triggered, and implemented once the state estimator with a 5 second sampling period detects the occurrence of that equipment outage through a specific filter that is attempting to detect the occurrence of each one of the equipment outages and operating change combinations predicted to produce voltage instability by VSSAD. This secondary voltage control has available to it stored control changes that correct every developing voltage instability produced by an equipment outage and operating change predicted by VSSAD to produce voltage instability. If a control change cannot be determined for this secondary voltage control using switchable capacitor, under load tap changer tap position, or generator excitation control voltage set points as controls then an emergency secondary voltage control could be used.

An emergency secondary voltage control could also change or curtail transaction and even curtail load and generation if the secondary voltage control could not achieve stability and security. Such an emergency secondary voltage control is far beyond that used in EDF but would be necessary if the stability and security of the system was jeopardized and there was no other method for achieving stability and security for specific equipment outage and operating change combinations.

4.10 Optimization Requirements

The algorithms to be used for solving the Open Access System Dispatch must be selected with care because

1. the power system model is large and nonlinear. The number of network nodes

or buses can be as large as 20000. The voltage and voltage collapse problems occur on stressed system where the nonlinear effects dominate;

2. the number of control constraints, operating constraints, and security constraints can be huge. The algorithm must not only find a feasible solution that satisfies these constraints, but an optimal set of binding constraints that characterize the optimal solution;

3. convergence of the algorithm must be rapid and robust from any starting point;

4. there must be a rapid convergence to finding the set of binding constraints as there is to find the optimal control and state of the power system model;

Nonlinear programming via interior point methods described in Chapter 2, has undergone rapid development over the last fifteen years that allow second order rather than linear convergence to the optimal solution and ability to assure such convergence in selecting the binding constraint set as well as selecting the control and state for the particular optimization based control problem.

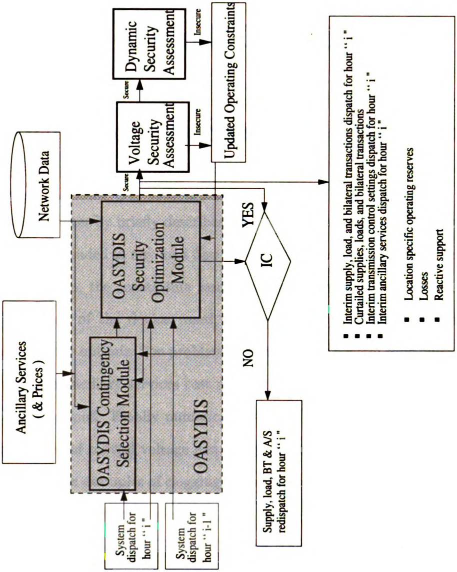

Figure 4.1. Structure, Modules and Interfaces of the OASYDIS Application.

CHAPTER 5

Open Access System Dispatch

We begin this chapter by briefly describing the most important components of power system that are included in any load flow model. The load flow equations are derived for the general case, the constraints associated with the load flow balance and the physical limitation of the devices used in this load flow model are defined. The formulation of three optimization problems: (1) minimum control solvability problem, (2) the minimum ancillary services cost problem (slave problem) and (3) the master problem are developed. Finally numerical results of applying the minimum control solvability for loss of control voltage instability and the minimum control solvability for clogging to three examples of clogging voltage instability are presented. The cases solved are the worst contingencies that were found to produce loss of control and clogging voltage instability in Chapter 3 where VSSAD recommendation obtains a load flow solution. This VSSAD recommendation based solution is the starting point for the minimum control solvability problem that attempts to retain solvability of the solution without the impossible or onerous VSSAD recommendation of increasing generator reactive capability or performing load and generation shedding.

5.1 Load Flow Modeling

Load flow has been found to be exceptional tool for assessing power system solvability and stability analysis. The load flow model consists of (a) a set of buses interconnected together by a transmission system consisting of transformers and transmission lines, and (b) generators and loads connected to the buses of the system. Real and reactive power is injected into the transmission system by generators. The basic load flow problem solves for the voltage at generator buses and both voltage and phase at load buses given the voltage and real power injection (generation) at generator buses and real and reactive load demands at load buses. The load flow problem also determines real and reactive power flow, line current, and transmission losses on transmission lines and transformers. The basic load flow problem involves a large number of nonlinear algebraic equations. In this load flow analysis, a balanced three-phase system operation is assumed. The purpose of a power system is to deliver power to meet customers demand in real time without any violation in voltage at any bus, thermal overload violation on any branch, and to assure that stability of the solution is preserved.

5.1.1 Power System Components

The following are some of the most important components of power system that are included in any load flow model:

- Power generators
- Transformers
- Transmission lines
- Shunt capacitors and inductors

- Loads

the components such as series capacitors,and DC transmission line with associated converter stations may occur in some load flow cases.

Generators

Generators i can usually generate specified amounts of real power P_{G_i} at specified terminal voltage V_i. A generator can also produce positive or negative reactive power Q_{G_i}, depending on the excitation level [12]. The constraints of the power generators for the load flow model, are:

$$\left.\begin{array}{c} P_{Gi_{min}} \leq P_{Gi} \leq P_{Gi_{max}} \\ Q_{Gi_{min}} \leq Q_{Gi} \leq Q_{Gi_{max}} \\ V_{i_{min}} \leq V_i \leq V_{i_{max}} \end{array}\right\} \tag{5.1}$$

In a load flow, the terminal voltage V_i and the real power generation P_{Gi} are specified at a value that satisfy the constraints. Reactive power is proportional to the field current. As reactive power generation Q_{Gi} is increased such that field current exceeds the continuous rating limit and is ultimately reduced after a delay by the maximum excitation limiter, the terminal voltage starts to drops and voltage collapse may begin to develop due to the drop in reactive supply Q_{G_i} from the generator. .

Transformers

The transformer branch can be represented by an equivalent Π model. The derivation of Π equivalent model that applies to fixed and variable tap as well as to under load tap changer. The tap ratio can be a real number or complex number indicating phase shifting characteristics. In this model [12]

$$I_m = t^2 V_m Y_s + t^2 V_m Y_l - t V_k Y_l \tag{5.2}$$

$$I_k = -tV_mY_l + V_kY_l \tag{5.3}$$

this reduces to

$$\begin{bmatrix} I_m \\ I_k \end{bmatrix} = \begin{bmatrix} t^2(Y_s + Y_l) & -tY_l \\ -tY_l & Y_l \end{bmatrix} \begin{bmatrix} V_m \\ V_k \end{bmatrix} \tag{5.4}$$

In most practical cases, Y_s is set to zero. From the above result we can easily show that

$$Y_{mk} = tY_l \tag{5.5}$$

$$Y_{smk} = -t(1-t)Y_l \tag{5.6}$$

$$Y_{skm} = (1-t)Y_l \tag{5.7}$$

Transmission lines

The transmission line for each branch is represented by a resistance R and inductance L. The resistance represents the resistance of the aluminum cable in each line and the inductance represents the effects of the flux linkages set by current in each line. Both R and L depends on the size and the construction of the cable as well as it's length. The transmission lines in the transmission system can be represented by it's equivalent Π model. In this model [12]

$$Y_{mk} = \frac{1}{Z_{mk}} \tag{5.8}$$

$$Z_{mk} = \left(\frac{R + j\omega L}{G + j\omega C}\right)^{1/2} \sinh(\gamma d) \tag{5.9}$$

$$Y_{smk} = \left(\frac{G + j\omega C}{R + j\omega L}\right)^{1/2} \tanh\left(\frac{\gamma d}{2}\right) \tag{5.10}$$

$$\gamma = \equiv [(R + j\omega L)(G + j\omega C)]^{1/2} \tag{5.11}$$

where:

d is the line length in miles

$j = \sqrt{-1}$

$R + j\omega L$ is the series impedance per mile

$G + j\omega C$ is the shunt admittance per mile

The impedance Z_{mk} and the admittance Y_{mk} are defined as follows

$$Z_{mk} = R_{mk} + jX_{mk} \tag{5.12}$$

$$Y_{mk} = G_{mk} + jB_{mk} \tag{5.13}$$

where R_{mk} and X_{mk} are the line series resistance and reactance respectively, G_{mk} and B_{mk} are the line series conductance and susceptance respectively

Y_{smk} corresponds to shunt capacitance in parallel with shunt conductance, and is given by

$$Y_{smk} = G_{smk} + jB_{smk} \tag{5.14}$$

Shunt Capacitors and Inductors

Shunt capacitors and inductors are devices used for voltage and reactive power control in the network system. These devices are turned ON or OFF depending on the current operating condition. Capacitors ($B_C > 0$) need to be turned ON to increase reactive production and hence increase bus voltage. This occurs when voltage tend to decrease to a point less than the acceptable level (typically 0.95 pu) due to high real and reactive demands specially in distribution system (near loads). If real and reactive demand is low on transmission lines near the generators, line charging may be sufficient to over come reactive power losses (I^2X_{mk}) and bus voltages increase. Inductors ($B_I > 0$) may be need to be turned ON to create an effective reactive load and reduce the bus voltages. In the general formulation of the load flow one does not know a priori whether inductors or capacitors banks need to be ON or OFF. This is determined as part of the iterative load flow solution process.

Load

A load is extremely complex and involves many (a) small devices such as appliances, light, and so on, and (b) large components like arc furnaces, large motors, large engines which are considered industrial loads. The demand power or load is produced by generation buses and delivered to these loads through the transmission system, subtransmission system, and finally the distribution system. The power generated goes through several level of step-down transformer before reaching these loads. The affect of distribution level voltage controls, under load tap changers and switchable shunt capacitors, keep steady state level voltage and load equal to precontingency levels. Thus, the loads are modeled as constant power.

5.1.2 Load Flow Equation

A simple two-bus system representation will be analyzed first and then we generalize the load flow equation to an n-bus system [12]. Figure 5.1 shows a simple two-bus system. We have a generator and load at bus 1; at bus 2 we have only load. Bus 1 is connected to bus 2 through a transmission line, whose Π-equivalent model is represented. There is also shunt capacitor bank connected to bus 1. We define the complex per phase injected power S_1 at bus 1 as follows

$$S_1 = S_{G_1} - S_{D_1} \tag{5.15}$$

where S_{G_1} *and* S_{D_1} *are the complex power generated and load consumed at bus 1 respectively.*

The complex power injected at bus 1 can be written in rectangular form,

$$S_1 = P_1 + jQ_1 \tag{5.16}$$

where P_1 *and* Q_1 *are the active and reactive power injected at bus 1 respectively and* $j = \sqrt{-1}$.

The net active and reactive power injected into bus 1 are defined as follows

$$P_1 = P_{G_1} - P_{D_1} \tag{5.17}$$

$$Q_1 = Q_{G_1} - Q_{D_1} \tag{5.18}$$

where P_{G_1} , Q_{G_1} *are the active and reactive power generated at bus 1 respectively, and* P_{D_1} , Q_{D_1} *are the active and reactive power load at bus 1 respectively.*

The complex voltage and current at bus 1 are given as:

$$v_1 = V_1 \, exp\,(j\delta_1) \tag{5.19}$$

$$i_1 = I_1 \, exp\,(j\zeta_1) \tag{5.20}$$

where V_1, I_1 *are the voltage and current magnitude at bus 1 respectively, and* δ_1 *and* ζ_1 *are the phase angle of voltage and current at bus 1 respectively.*

With these above definitions, we can obtain the complex power in term of complex bus voltage and current,

$$S = V_1 I_1^* \tag{5.21}$$

*where * denotes a conjugate value.*

$$\begin{aligned}
I_1 &= V_1\ exp\ (j\delta_1)\,[G_{s12} + j(B_{s1} + B_{s12})] + \\
&\quad (V_1\ exp\ (j\delta_1) - V_2\ exp\ (j\delta_2))\,[G_{12} + jB_{12}]
\end{aligned} \tag{5.22}$$

$$\begin{aligned}
S_1 &= V_1\ exp\ (j\delta_1)\,[V_1\ exp\ (-j\delta_1)\,[G_{s12} - j(B_{s1} + B_{s12})]] + \\
&\quad V_1\ exp\ (j\delta_1)\,[(V_1\ exp\ (-j\delta_1) - V_2\ exp\ (-j\delta_2))\,[G_{12} - jB_{12}]] \\
&= V_1\ exp\ (j\delta_1)\ V_1\ exp\ (-j\delta_1)[G_{s12} - j(B_{s1} + B_{s12})] + \\
&\quad V_1\ exp\ (j\delta_1)\ V_1\ exp\ (-j\delta_1)[G_{12} - jB_{12}] - \\
&\quad V_1\ exp\ (j\delta_1)\ V_2\ exp\ (-j\delta_2)[G_{12} - jB_{12}] \\
&= V_1^2\ [G_{s12} - j(B_{s1} + B_{s12})] + V_1^2\ [G_{12} - jB_{12}] - \\
&\quad V_1 V_2\ exp\ [j(\delta_1 - \delta_2)]\ [G_{12} - jB_{12}] -
\end{aligned}$$

$$\begin{aligned}
S_1 &= V_1^2\ (G_{s12} + G_{12}) - jV_1^2\ (B_{s1} + B_{s12} + B_{12}) - \\
&\quad V_1 V_2\ exp\ [j(\delta_1 - \delta_2)]\ [G_{12} - jB_{12}]
\end{aligned} \tag{5.23}$$

$$\begin{aligned}
S_1 &= V_1^2\ (G_{s12} + G_{12}) - jV_1^2\ (B_{s1} + B_{s12} + B_{12}) - \\
&\quad V_1 V_2\,[(\cos(\delta_1 - \delta_2) + j\sin(\delta_1 - \delta_2))\,(G_{12} - jB_{12})]
\end{aligned} \tag{5.24}$$

$$\begin{aligned}
S_1 &= V_1^2\ (G_{s12} + G_{12}) - V_1 V_2\,[\cos(\delta_1 - \delta_2)G_{12} + \sin(\delta_1 - \delta_2)B_{12}] \\
&\quad -j[V_1^2\,(B_{s1} + B_{s12} + B_{12}) + V_1 V_2[\sin(\delta_1 - \delta_2)G_{12} -
\end{aligned}$$

$$\cos(\delta_1 - \delta_2)B_{12}] \tag{5.25}$$

The real and reactive power balance, obtained by separating the real and imaginary components of (5.25) and they are given as following:

$$\begin{aligned} P_1 &= P_{G_1} - P_{D_1} \\ P_1 &= V_1^2\,(G_{s12} + G_{12}) - V_1 V_2\,[\cos(\delta_1 - \delta_2)G_{12} + \sin(\delta_1 - \delta_2)B_{12}] \end{aligned} \tag{5.26}$$

$$\begin{aligned} Q_1 &= Q_{G_1} - Q_{D_1} \\ Q_1 &= -V_1^2\,(B_{s1} + B_{s12} + B_{12}) - V_1 V_2[\sin(\delta_1 - \delta_2)G_{12} - \\ &\quad \cos(\delta_1 - \delta_2)B_{12}] \end{aligned} \tag{5.27}$$

The above expressions can be easily extended to represent the n-bus system:

$$P_l = V_l^2 G_{ll} - V_l \sum_{m \in k(l)} V_m\,[\cos(\delta_l - \delta_m)G_{lm} + \sin(\delta_l - \delta_m)B_{lm}] \tag{5.28}$$

$$Q_l = -V_l^2 B_{ll} - V_l \sum_{m \in k(l)} V_m\,[\sin(\delta_l - \delta_m)G_{lm} - \cos(\delta_l - \delta_m)B_{lm}] \tag{5.29}$$

where n = *number of buses in the system,* $k(l)$ *is the set of all buses connected to bus* l, *and*

$$G_{ll} = \sum_{m \in k(l)} (G_{slm} + G_{lm}) \tag{5.30}$$

$$B_{ll} = B_{sl} + \sum_{m \in k(l)} (B_{slm} + B_{lm}) \tag{5.31}$$

The branch complex power flow is computed as follows,

$$S_{ml} = V_m I_l^* \tag{5.32}$$

$$\begin{aligned}
&= V_m(V_m - V_l)^*(Y_{ml})^* \\
&= V_m\ exp\ (j\delta_m)[V_m\ exp\ (j\delta_m) - V_l\ exp\ (j\delta_l)](G_{ml} - jB_{ml}) \\
&= V_m\ exp\ (j\delta_m)\ V_m\ exp\ (-j\delta_m)(G_{ml} - jB_{ml}) - \\
&\quad V_m\ exp\ (j\delta_m)\ V_l\ exp\ (-j\delta_l)(G_{ml} - jB_{ml})
\end{aligned}$$

$$\begin{aligned}
S_{ml} &= V_m^2(G_{ml} - jB_{ml}) - V_mV_l[(exp\ (j(\delta_m - \delta_l))(G_{ml} - B_{ml}))] && (5.33) \\
&= V_m^2G_{ml} - jV_m^2B_{ml} - V_mV_l[\cos(\delta_m - \delta_l) + j\sin(\delta_m - \delta l)][G_{ml} - jB_{ml}]
\end{aligned}$$

$$\begin{aligned}
S_{ml} &= V_m^2G_{ml} - V_mV_l[\cos(\delta_m - \delta_l)G_{ml} + \sin(\delta_m - \delta l)B_{ml}] + \\
&\quad j\left(-V_m^2B_{ml} - V_mV_l[\sin(\delta_m - \delta_l)G_{ml} - \cos(\delta_m - \delta l)B_{ml}]\right) && (5.34)
\end{aligned}$$

Once again we can separate (5.34), into real and reactive branch power flow:

$$P_{ml} = V_m^2G_{ml} - V_mV_l[\cos(\delta_m - \delta_l)G_{ml} + \sin(\delta_m - \delta l)B_{ml}] \quad (5.35)$$

$$Q_{ml} = -V_m^2B_{ml} - V_mV_l[\sin(\delta_m - \delta_l)G_{ml} - \cos(\delta_m - \delta l)B_{ml}] \quad (5.36)$$

Now we will represent all of the complex elements derived earlier by rectangular coordinates. The general form of the load flow equations for n-bus system earlier will be represented here by the rectangular form. The complex bus voltage V_i, can be replaced by rectangular form as follows

$$V_i = e_i + jf_i \quad (5.37)$$

where $j = \sqrt{-1}$.

Given the model current injection vector I produced by converting all equivalent models of loads or generations sources into Norton equivalents, equations for n-bus system can be written in the form

$$[I_{bus}] = [Y_{bus}]\,[V_{bus}] \tag{5.38}$$

$$\begin{bmatrix} I_1 \\ I_2 \\ \vdots \\ I_n \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & \cdots & \cdots & Y_{1n} \\ Y_{21} & Y_{22} & \cdots & \cdots & Y_{2n} \\ \vdots & \vdots & & & \vdots \\ Y_{n1} & Y_{n2} & \cdots & \cdots & Y_{nn} \end{bmatrix} \begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_n \end{bmatrix} \tag{5.39}$$

where:

$[Y_{bus}]_{ii}$ = *sum of all admittance connected to bus* i, *(including the admittance of the* Π *equivalent model for the transformer and the shunt capacitors connected to the bus* i *if any)*

$[Y_{bus}]_{ij}$ = - *sum of all admittance connected between bus* i *and bus* j*,(including the admittance of the* Π *equivalent model for the transformer)*

and

$$I_i = \sum_{j=1}^{n}(Y_{ij}V_j) \quad ; \quad i = 1, 2, \cdots, n \tag{5.40}$$

where $Y_{ij} = G_{ij} + jB_{ij}$.

As a result, if the fact that a constant power load model is used we have

$$I_i = \left(\frac{S_i}{V_i}\right)^{*} = \frac{P_i - jQ_i}{e_i - jf_i} \tag{5.41}$$

and thus, the nodal admittance matrix current equation can be written in the power form,

$$P_i - jQ_i = (e_i - jf_i)\sum_{j=1}^{n}(Y_{ij}V_j) \tag{5.42}$$

Substituting (5.37) into (5.42) and after some simplification, we have the real and the reactive power balance equation in rectangular form

$$\begin{aligned} P_i - jQ_i &= e_i\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j) + f_i\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j) \\ &\quad - \left\{ f_i\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j) - e_i\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j) \right\} \end{aligned} \tag{5.43}$$

and as a result we have

$$P_i = e_i\left[\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j)\right] + f_i\left[\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j)\right] \tag{5.44}$$

$$Q_i = f_i\left[\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j)\right] - e_i\left[\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j)\right] \tag{5.45}$$

5.2 Constraints

In normal and secure case with safety margin sense, the system must satisfy a set of algebraic constraints that can be written in the form of equality and inequality constraints as follows:

$$G(x,u) = 0$$

$$H(x,u) \geq 0$$

When the system is insecure or sustains violation, the goal is to come up with a preventive or corrective control to eliminate the violation in the system as soon as possible. Some violation cause equipment damage if they persist. In other cases the system enters the state of instability when some equality or inequality constraints are violated. Both types of constraints are used in this proposed problem.

5.2.1 Equality Constraints

The equality constraints corresponds to an AC power flow model. The equality constraints are ones that must be exactly satisfied to have a feasible solution. The power flow model (5.44) and (5.45) is written here again as follows:

$$P_i = e_i \left[\sum_{j=1}^{n} (G_{ij}e_j - B_{ij}f_j) \right] + f_i \left[\sum_{j=1}^{n} (G_{ij}f_j + B_{ij}e_j) \right] \quad (5.46)$$

$$Q_i = f_i \left[\sum_{j=1}^{n} (G_{ij}e_j - B_{ij}f_j) \right] - e_i \left[\sum_{j=1}^{n} (G_{ij}f_j + B_{ij}e_j) \right] \quad (5.47)$$

where $i = 1, 2, \cdots, n$ *and* n *is the number of buses in the network.*

5.2.2 Inequality Constraints

In this proposal three kinds of inequality constraints are used. They are operating constraints, control constraints, and security constraints. The inequality constraints must satisfy either an upper or lower bound or both on the value of a variable or function for the system to have a feasible solution. Thermal limits, voltage limits, and reactive supply limits expressed as

$$I_{ij_{min}} \leq I_{ij} \leq I_{ij_{max}} \quad (5.48)$$

$$V_{i_{min}} \leq V_i \leq V_{i_{max}};\ i = 1, 2, ..., L \tag{5.49}$$

$$Q_{Gi_{min}} \leq Q_{Gi} \leq Q_{Gi_{max}};\ Gi = 1, 2..., M \tag{5.50}$$

where ij *is the current flow in branch* ij, L *is the number of load buses, and* M *is the number of generation buses in the system.*

These are usually the operating constraints, The control constraints are the tap position limit on under load tap changing transformer limits, the switchable capacitor susceptance limits, and voltage set points on generators

$$A_{t_{min}} \leq A_t \leq A_{t_{max}};\ t = 1, 2, ..., T \tag{5.51}$$

$$C_{sh_{min}} \leq C_{sh} \leq C_{sh_{max}};\ sh = 1, 2, ..., S \tag{5.52}$$

$$V_{Gi_{min}} \leq V_{Gi} \leq V_{Gi_{max}};\ Gi = 1, 2..., M \tag{5.53}$$

where T *is the number of transformers in system,* S *is the number of switchable capacitors,and* M *is the number of generation buses in the system.*

The security constraints are the thermal and voltage limits in the operating constraints plus the changes due to occurrence of contingency. The security constraints can be represented by

$$I_{ij_{min}} \leq I_{ij}^0 + \Delta I_{ij}^p \leq I_{ij_{max}} \tag{5.54}$$

$$V_{i_{min}} \leq V_i^0 + \Delta V_i^p \leq V_{i_{max}} \tag{5.55}$$

where (I_{ij}^0, V_i^0) *and* $(\Delta I_{ij}^p, \Delta V_i^p)$ *are the current and voltage of the base case operating condition and the changes due to contingency p respectively, where* $p = 1, 2, ..., N$ *and* N *is the number of contingencies considered.*

5.3 Open Access System Dispatch Security Constrained Optimization

The Open Access System Dispatch problem is composed of Contingency Selection Module and a Constrained Optimization Module as described in chapter 4. The Contingency Selecting Module finds all combinations of all equipment outage and one or more transfer and wheeling transactions violation of minimum reactive reserve limits on some reactive reserve basin or cause clogging voltage instability for some agent. VSSAD can identify the combinations of an equipment outage with one or more transfer and wheeling transactions that either

1. violate minimum reactive reserve limits on one or more reactive reserve basins. VSSAD will automatically detect the reserve basins with reactive limit violations as well as generators where added reactive supply would cause satisfaction of all violated reactive reserve basin minimum reactive limits. VSSAD would also determine the level of additional reactive reserve or reactive supply capability needed on each of these generators to avoid reactive limit violations;

2. exhaust all reactive reserves on one or more reactive reserve basins, do not have a load flow solution when reactive limits are enforced, but have solution when reactive reserve level increases are added on specific generators, SVCs, or synchronous condensers. VSSAD would also determine the level of additional reactive reserve or reactive supply capability that must be added to each of these generators to obtain a load flow solution;

3. that do not have a load flow solution when reactive limits are enforced or when they are ignored, but have solution when one or more transactions are modified

or curtailed, or load and generation is shed at appropriate buses. VSSAD would determine the transaction to be curtailed and the level of curtailment, the transaction to be eliminated, and the level of load and generation to be shed.

This development of VSSAD capability is a very large contribution because without VSSAD (a) it takes 15 hours engineering and computing time of trial and error by an engineer per equipment outage to obtain a solution when no solution exists, (b) there is no guarantee that the trial and error solution correctly diagnoses the cause, and (c) there is no guarantee the suggested action has the minimal affect on current power system operation. Even though VSSAD provided changes may be diagnostic in determining and verifying the actual cause, it is not clear how the needed reactive reserve can be obtained. It is also not clear (1) what is the minimum set of control actions that are most effective is providing the reactive reserve or reducing network losses in particular agents and (2) what are the control changes that both provide the reactive reserves or reduces the reactive losses and yet require a minimum cost for ancillary services for each equipment outage and transaction change combination identified by VSSAD. Additional reactive reserves are needed in particular agents either because a load flow solution can not be obtained due to loss of control voltage instability without additional reserves on specific generators or because minimum reactive reserve levels on one or more reactive reserve basins are violated after an equipment outage and operating change combination. VSSAD recommends curtailing one or more transactions by cutting real and reactive load in a voltage control area and active generation in its reactive reserve basin generators to reduce the network losses that cause clogging voltage instability for that agent or voltage control area. If is not clear that such a drastic action as curtailing one or more transactions of power marketers and generators is actually necessary to obtain a solution. If transaction curtailment isn't necessary or if other control actions can reduce the transaction curtailments, what are the minimum set of controls, the most effective set of control changes, and the minimum ancillary cost for the set of control actions that will totally or partially eliminate the transaction curtailment.

Two optimization problems are posed; for (a) adding reactive reserves and (b) for minimizing transaction curtailments:

1) Minimum Control Solvability Problem.

A minimum control solvability problem either (a) obtains the reactive reserves on generators in the amounts VSSAD determines are needed to obtain solution of the load flow or so that minimum reactive reserve basin reserve requirements are met or (b) obtains solution of the load flow without curtailment of the set of transactions determined as needed via VSSAD for a solution to exist. The controls include (1) adding switchable shunt capacitors, generators or synchronous condensers close to the generators needing additional reserves (loss of control voltage instability) or the voltage control area needing reactive supply (clogging voltage instability); (2) adjusting AVR voltage set points to reduce reactive power pickup on generators that need reactive reserves (loss of control voltage instability) or to increase reactive generation supply rate out of generators, SVCs, or synchronous condensers outside and sometimes inside voltage control areas needing reactive supply (clogging voltage instability); (3) adjusting tap position on distribution and subtransmission level under load tap changers to reduce distribution level voltage and load (loss of control voltage instability) or to adjust tap position to avoid tap position limits and allow more effective pumping of reactive into the voltage control area needing reactive supply (clogging voltage instability); and (4) reducing active generation out of generators that need reactive reserves (loss of control voltage instability) or redispatch active generation from one or more set of generators to another set of generators to relieve reactive clogging on particular paths to the voltage control area needing reserves.

The objective function for the minimum control solvability problem is to reduce reactive generation and thus provide the additional reactive reserves VSSAD decides are needed (loss of control voltage instability) or to totally eliminate the need to curtail the transactions VSSAD decides are necessary to obtain a load flow solution for a particular equipment outage and operating change combination (clogging voltage instability). The VSSAD recommendations provide a starting feasible solution for the interior point algorithm that is also a load flow solution.

2) Minimum Ancillary Services Cost Problem

The minimum ancillary services cost problem has an objective of minimizing the cost of ancillary services required to correct a clogging or loss of control voltage instability problem while maintaining solvability for a particular VSSAD determined equipment outage and operating change combination. A minimum ancillary cost problem uses the solution of the minimum control solvability problem to achieve as a starting solution that is both feasible and solvable in terms of satisfying reactive reserve basin reactive reserve constraints, thermal constraints and voltage constraints. The objective is to adjust controls (1-4) to minimize ancillary services cost to the ISO. This minimum ancillary services cost can also further attempt to further reduce the number of controls used in the minimum control solvability problem solution.

The minimum control solvability and the minimum ancillary services cost problems are the slave problems in a Benders decomposition. There is a slave problem for each equipment outage and operating change combination that VSSAD determines needs reserves to meet minimum reactive reserve basin requirements, to avoid loss of control voltage instability or that experiences clogging voltage instability. The control determined out of the minimum control solvability and minimum ancillary services cost problem sequence is u_i.

The slave problem is generally just one optimization problem not two as discussed above. One set of objectives is (a) to obtain some control change that obtains a solution and (b) find the minimum control set that will obtain that solution when no solution exists without the control change. These two objective are met by the minimum control solvability problem. An additional objective is to find an even narrower set of controls that are effective in obtaining a load flow (solvability and feasibility) solution and minimize the cost of ancillary services. This third objective is met from the minimum ancillary services cost problem. It was thought that one optimization problem could not achieve all of these objectives, and therefore a sequence of optimization problems is proposed. The minimum control solvability problem is much like the optimizations used to obtain feasible starting solutions for an interior point algorithm. The minimum control solvability is seeking a feasible starting solution for the optimization but also one that has a load flow solution.

The master problem attempts to adjust the control u_0 to posture the system so it is not as vulnerable to the set of equipment outage and operating change combinations via minimizing the ancillary services cost increase and holding it under a certain maximum for each equipment outage and operating change combination identified as causing loss of control or clogging voltage instability in some voltage control area and its reactive reserve basin.

5.3.1 Minimum Control Solvability Problem

The minimum control solvability problem depends on whether clogging or loss of control voltage instability occurs because

- VSSAD recommends adding reactive reserves $Q_{G_i}^{*j}$ to each generator $i \in I_j$ for loss of control voltage instability for the j^{th} equipment outage and operating change combination.

- VSSAD recommends reducing a set of a transfer or wheeling transaction for clogging voltage instability for the j^{th} equipment outage and operating change combination.

The procedure used in VSSAD to determine these precise recommendation is given in chapter 3 and omitted here. The objective of the minimum control solvability problems for any VSSAD recommendation is to completely avoid having to take VSSAD recommended action by adjusting the voltage controls and possibly as a last resort adjusting active power dispatch. The minimum control solvability problem for loss of control voltage instability is now formulated. The minimum control solvability problem for loss of control voltage instability must add reactive generation and generation capacity $Q_{G_i}^{*j}$ to each generator i by modifying $Q_{G_{i_{max}}}^{0}$ and $Q_{G_i}^{0}$.

$$Q_{G_i}^{j} = Q_{G_i}^{0} + Q_{G_i}^{*j} \tag{5.56}$$

$$Q_{G_{i_{max}}}^{j} = Q_{G_{i_{max}}}^{0} + Q_{G_i}^{*j} \tag{5.57}$$

where $Q_{G_i}^{*j}$ is the reactive supply added at generator i in order to obtain a load flow solution for the j^{th} equipment outage and operating changes. $Q_{G_i}^{j}$ is the generation capacity after $Q_{G_i}^{*j}$ is added to the base case. $Q_{G_{i_{max}}}^{0}$ and $Q_{G_{i_{max}}}^{j}$ is the maximum reactive generation in the base case at generator i and the maximum reactive supply at generator i after $Q_{G_i}^{*j}$ is added as VSSAD recommends to obtain a solution for the j^{th} equipment outage and operating change respectively.

If $Q_{G_i}^{0} = Q_{G_{i_{max}}}^{0}$ is the reactive supplied by generator i before reactive supply capability is added to obtain a load flow solution, (5.56) is reactive generation after the equipment outage and operating change j occurred. Use $Q_{G_i}^{j}$ as a starting point for the optimization problem. These modification are needed so that the load flow and optimal power flow has a solution to start the optimization that it would not otherwise have without adding reserves $Q_{G_i}^{*j}$ to generators $i \in I_j$ for equipment outage and operating condition change j. The minimum control solvability problem for loss of control voltage instability will minimize this added reactive generation $Q^{*j}_{G_i}$

$$\sum_{i \in I_j}(Q^j_{G_i} - Q^0_{G_{i_{max}}})^2 = \sum_{i \in I_j}(Q^{*j}_{G_i})^2 \tag{5.58}$$

subject to the reactive reserve basin, thermal,voltage and control constraints that specify three successively large control sets. The constraints are

$$P_{Gi} - P_{Di} = e_i\left[\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j)\right] + f_i\left[\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j)\right] \tag{5.59}$$

$$Q_{Gi} - Q_{Di} = f_i\left[\sum_{j=1}^{n}(G_{ij}e_j - B_{ij}f_j)\right] - e_i\left[\sum_{j=1}^{n}(G_{ij}f_j + B_{ij}e_j)\right] \tag{5.60}$$

$$P_{Gi_{min}} \leq P_{Gi} \leq P_{Gi_{max}} \ ; \ i = 1, 2, ..., M \tag{5.61}$$

$$Q_{Gi_{min}} \leq Q_{Gi} \leq Q_{Gi_{max}} \ ; \ i = 1, 2, ..., M \tag{5.62}$$

$$V^2_{i_{min}} \leq e_i^2 + f_i^2 \leq V^2_{i_{max}} \ ; \ i = 1, 2, ..., n \tag{5.63}$$

$$I^2_{ij_{min}} \leq \ [(e_i - e_j)^2 + (f_i - f_j)^2]^2[G^2_{ij} + B^2_{ij}] \leq I^2_{ij_{max}} \ ; \ ij = 1, 2, ..., Br \tag{5.64}$$

$$A_{t_{min}} \leq A_t \leq A_{t_{max}} \ ; \ t = 1, 2, ..., T \tag{5.65}$$

$$C_{sh_{min}} \leq C_{sh} \leq C_{sh_{max}} \ ; \ sh = 1, 2, ..., S \tag{5.66}$$

$$RR_{r_{min}} \leq \sum_{i_r \in RRB_r} Q^j_{G_{i_{max}}} - Q_{G_i} \ ; \ r = 1, 2, ..., R \tag{5.67}$$

where:

M = *number of generator buses in the network*

n = *number of buses in the network*

Br = *number of branches connected between buses in the network*

T = *number of transformers connected between buses in the network*

S = *number of shunt capacitors in the network*

$RR_{r_{min}}$ *is the minimum reactive reserve in each of the reactive reserve basins*

R = *number of reactive reserve basins(* RRB_r*),and* i_r *is the number of the generators in each reactive reserve basin.*

The minimum control solvability problem is really a series of problems with successively different control sets. There are four control sets proposed:

1. generator AVR set point voltage on generators $i \in I_j$ and generators near $i \in I_j$;

2. switchable shunt capacitors electrically close to generators $i \in I_j$;

3. under load tap changer tap position;

4. active generation at generators P_{G_i} ; $i \in I_j$ and generators near set $i \in I_j$.

The control sets used are 1 and 2, 1-3, and 1-4 where if adding a different control didn't result in a significant improvement in obtaining solution, it was no longer used in a large control set that added control of another set of control devices. There are six very major difference in this optimal power flow problem formulation from the previous literature

1. a set of reactive reserve basin constraints that assure load flow solution when loss of control voltage instability occurs. Since tap changers and capacitors are treated as continuous variables in an optimal power flow, the Hessian of the optimal power flow problem is not singular when the load flow model and the actual power system are experiencing instability. If tap changers and capacitors were treated as discontinuous variables, and the maximum excitation limiter action was more accurately reflected in the optimal power flow, there would never be a solution to the optimal power flow that could not be a solution to the load flow when clogging voltage instability is assumed to be impossible on a particular system. The reactive reserve basin constraints with very modest levels of reactive reserve (10 MVAR or loss) on each helps guarantee that the optimal power flow has no solution when the load flow has no solution due to

loss of control voltage instability. This is true because if all generators on a reactive reserve basin are at reactive limits, no load flow solution may exist and the optimal power flow has no solution due to violation of the reactive reserve basin constraint;

2. when the optimal power flow has a solution since every reactive reserve basin has reactive reserves and thus loss of control voltage instability can not occur on this system, an optimization is possible that attempts to maintain a stable load flow solution while minimizing the VSSAD recommended addition of fictitious generators with fictitious reactive supply capability. This is impossible without reactive reserve basin constraints on all reactive reserve basins from (1) above since one could not be sure that optimal power flow solution would imply a load flow solution and vice versa for system that can only experience loss of control voltage instability. VSSAD recommended action of adding generators at particular buses $i \in I_j$ with starting generation $Q_{G_i}^{*j}$ assures the load flow has a solution and that the optimal power flow with reactive reserve basin constraints has a starting solution;

3. a performance index that is quite different from optimal active and optimal reactive dispatch (total active or reactive network losses). This performance index minimizes a quadratic performance measure

$$\sum_{i \in I_j} (Q_{G_i}^{*j})^2 \tag{5.68}$$

4. $Q_{G_i}^{*j}$, $i \in I_j$ were added fictitious generators in the model after the equipment outage to obtain solution to the load flow and starting point for the optimization model that also has the equipment outage. Fictitious generators were not added into reactive reserve basin constraints that quite possible could have in-

cluded this fictitious reactive generation. Using a modest level of 10MVARs on the reactive reserve basins that could but do not contain these fictitious generators suggests that these reactive reserve basin reserve levels must be maintained as the optimization proceeds using the network model where the contingency has occurred so that load flow solvability in maintained. These reactive reserve constraints maintain these very modest reactive reserves as the fictitious generators reactive generation is reduced to zero and the reserves on these reactive reserve basin generators would have been driven to zero and negative without the reactive capability constraints on each generator and these reactive reserve basin constraints on these reactive reserve basin;

5. the reactive reserve basin constraints on other reactive reserve basins are set at modest level of reserves to prevent loss of control voltage instability and thus voltage collapse on these other reactive reserve basins. These reactive reserve basin constraints allow borrowing of reactive reserve on all reactive reserve basins not needing additional reserves but prevents the solution from exhausting all reactive reserves in any reactive reserve basin causing it to produce a voltage collapse;

6. the use of four different control sets of increasing number of control rather than one that contains all four control sets allows the problem to select a minimum control set;

This set of optimization problems attempts to reduce $Q^0_{G_i}$ rather than add the reactive supply capability $Q^{*j}_{G_i}$ on a set of generators I_j that will obtain a load flow solution. If the performance index is not zero with control set (1), then control set (1) and (2) is used; and if the performance index is still not zero using control sets (1) and (2), then control set (1), (2), and (3) is used since zeroing the performance index assures solvability with reactive limits $Q^0_{G_{imax}}$ enforced. Control set (1), (2), (3), and

(4) is used as a last resort. Control set (1), (2) and (3) has solely ancillary services cost. Control set (4) allows modification or curtailment of transfer and wheeling transactions which is an anathema to power marketer and other generation companies whose business depends on having unfettered and uninterrupted transmission service. These power marketer would receive the cost of the transaction interruption and the profit they would have received if their transaction had been completed, plus some possible penalty which can be a fairly high cost to an ISO. The power marketer may even sue the ISO for damages if the transaction interruptions are frequent. Control set (4) is considered the last choice.

The minimum control solvability problem for loss of control voltage instability attempts to find the minimum set of control changes that provide a solution to the load flow and hopefully allow for stable operation if sufficient reactive reserve margin is achieved for the reactive reserve basins found deficient for a specific equipment outage and operating change combination. The minimum control solvability solution for loss of control voltage instability can also be used to add reactive reserves $Q_{G_i}^{*j}$ to generator $i \in I_j$ to allow (1) reactive reserve basins to remain within minimum reserve requirements $RR_k = 10 \quad MVAR$ after an equipment outage and operating change combination j, (2) allow the load flow to have a solution, (3) avoid loss of control voltage instability, and (4) obtain the reactive reserves from reactive reserve basins that had excess reactive reserves or more likely from capacitors that switch in or tap changers that do not pump reactive power into the distribution and subtransmission system.

Clogging voltage instability occurs when a voltage control area can't obtain needed reactive supply after an equipment outage or operating change occurs because the reactive supply flowing from generators, SVCs, synchronous condensers never reach the voltage control area. The line outage may open an important path for reactive flow to the voltage control area causing clogging voltage instability due to excessive network reactive losses on the other paths to that voltage control area (agent). The operating change may add real and reactive flow on heavily loaded paths or interfaces with rapidly increasing network reactive losses that absorb reactive power that would otherwise flow to and supply reactive needs in the voltage control area (agent for clogging voltage instability).

Minimum control solvability for clogging voltage instability for a particular equipment outage and operating change combination has a different performance index than the minimum control solvability for loss of control voltage instability because VSSAD recommended remedy is different. VSSAD recommends cutting load at buses in voltage control area j and active generation at generators in RRB_j associated with that voltage control area and thus curtail one or more wheeling transactions which would result in a modification of load flow data

$$P_{L_i} = P_{L_i}^0 - \alpha_i P_{wheeling} \quad i \in VCA_j, \quad j = 1, 2, \cdots, J \tag{5.69}$$

$$\sum_{i=1} \alpha_i = 1 \tag{5.70}$$

$$P_{G_i} = P_{G_i}^0 - \beta_i P_{wheeling} \quad i \in RRB_j, \quad j = 1, 2, \cdots, J \tag{5.71}$$

$$\sum_{i=1} \beta_i = 1 \tag{5.72}$$

where $P_{L_i}^0$ *and* P_{L_i} *are the power at load bus* i *before and after the wheeling transaction is curtailed respectively and* $P_{wheeling}$ *is the amount of power wheeling curtailed.* $P_{G_i}^0$ *and* P_{G_i} *are the power at generation bus* i *before and after the wheeling transaction is curtailed respectively.* α_i *and* β_i *are the bus participation factors on the curtailed load and generation, respectively.* VCA_j *and* RRB_j *are the voltage control area and its reactive reserve basin respectively,* j *represents the* j *equipment outage and operating change that produces voltage instability in* VCA_j *and* RRB_j *for* $j = 1, 2, \cdots, J$

The minimum control solvability performance index minimizes

$$\sum_{j=1}^{J}\left[\sum_{i\in VCA_j}(P_{L_i}-P_{L_i}^0)^2+\sum_{i\in RRB_j}(P_{G_i}-P_{G_i}^0)^2\right]=$$

$$\sum_{j=1}^{J}\left(\sum_{i\in VCA_j}\alpha_i^2+\sum_{i\in RRB_j}\beta_i^2\right)P_{wheeling}^2 \tag{5.73}$$

subject to the load flow equation equality constraints (5.59, 5.60) with generation and loads specified by voltage (5.63), thermal (5.64), and reactive reserve basin (5.67)constraints, and control constraint set (5.61, 5.62, 5.65, 5.66) corresponding to set (4), (1), (3) or (2). These constraints are the same as those in the case of loss of control voltage instability (5.59 - 5.67). This performance index for the minimum control solvability for wheeling reduction solved clogging voltage instability should be zero requiring $P_{wheeling}=0$ if a solution to a minimum control solvability exists for a particular control set since without $P_{wheeling}$ being zero there is no load flow solution for the j^{th} equipment outage and operating change combination. Using successively larger control sets (1), (1 and 2), (1, 2, and 3) and (1, 2, 3 and 4) sequentially should obtain a solution.

A second VSSAD recommended action is to curtail one or more transfer transaction

$$P_{G_i} = P_{G_i}^0-\alpha_i P_{transfer} \quad i\in E_j, \quad j=1,2,\cdots,J \tag{5.74}$$

$$\sum_{i\in E_j}\alpha_i = 1 \tag{5.75}$$

$$P_{G_k} = P_{G_k}^0-\beta_k P_{transfer} \quad i\in I_j, \quad j=1,2,\cdots,J \tag{5.76}$$

$$\sum_{k\in I_j}\beta_k = 1 \tag{5.77}$$

where E_j *is the set of exporting generators and* I_j *is the set of importing generators for the transfer of* $P_{transfer}$ *from* E_j *with participation factor* α_i *to* I_j *with participation factor* β_k.

The minimum control solvability performance index that curtails the transfer transactions is

$$\sum_{j=1}^{J}\left[\sum_{i\in E_j}(P_{G_i}-P_{G_i}^0)^2+\sum_{k\in I_j}(P_{G_k}-P_{G_k}^0)^2\right]= \sum_{j=1}^{J}\left(\sum_{i\in E_j}\alpha_i^2+\sum_{k\in I_j}\beta_k^2\right)P_{trensfer}^2 \tag{5.78}$$

subject to the load flow equation constraints, reactive reserve basin, thermal, and voltage inequality constraints and the control constraints corresponding to sets (1), (1 and 2), (1, 2, and 3) and (1, 2, 3 and 4). These constraints are the same as in (5.59 - 5.67). The performance index for the minimum control solvability transfer reduction solved clogging voltage instability should be zero requiring $P_{transfer}=0$ if a solution to the minimum control solvability for clogging voltage instability exists for a particular control set. If $P_{transfer}\neq 0$, VSSAD indicates there would be no load flow solution for equipment outage and operating change combination. Using successively larger control sets, there should be a solution to this minimum control solvability for clogging voltage instability problem.

The minimum control solvability problem for clogging voltage instability has unique attributes (1,5,6) of the minimum control solvability problem for loss of control voltage instability. Attributes (2,3) for the minimum control solvability problem for clogging voltage instability are similar to those for the minimum control solvability problem for loss of control voltage instability except that we have to shed generation and load to obtain a load flow solution in attribute 2 rather than adding fictitious reactive generators so our load flow and optimal power flow have solution when reactive reserve basin constraints are imposed. The performance index, addressed in attribute 3, is again quite different than for optimal active and optimal reactive dispatch but is a quadratic measure of the shed generation and load for wheeling transaction or the curtailed transfer level for a transfer transaction. The solution to the optimal power flow occurs when the level of shed load and generation in a wheeling transaction or the level of the curtailed transfer for a transfer transaction is zero. The performance index require complete elimination of the VSSAD recommended actions while starting the optimization from the VSSAD recommended solution.

Note that there are three minimum control solvability subproblems involving three successively larger control sets (1), (2), and (3) are

(a) *The minimum control solvability for loss of control voltage instability.*

(b) *The minimum control solvability for wheeling reduction solved clogging voltage instability.*

(c) *The minimum control solvability for transfer reduction solved clogging voltage instability.*

5.3.2 Minimum Ancillary Services Cost Problem

The minimum ancillary services cost problem starts with the solvability problem solution appropriate to the VSSAD recommended solution. It attempts to minimize the total system ancillary services cost for the ISO to correct any VSSAD determined voltage instability inducing equipment outage and operating change. The ancillary services cost for tap changers, switchable shunt capacitors, generators, SVCs, or synchronous condenser, and modification of reactive supply generation and change in active generation are

$$a_{t_i} + b_{t_i} \left|T_{ij} - T_{ij}^0\right| + c_{t_i} \left(\left|T_{ij} - T_{ij}^0\right|\right)^2 \tag{5.79}$$

$$a_{c_i} + b_{c_i} C_i + c_{c_i} C_i^2 \tag{5.80}$$

$$a_{q_i} + b_{q_i} Q_{G_i} + c_{q_i} Q_{G_i}^2 \tag{5.81}$$

$$a_{g_i} + b_{g_i} P_{G_i} + c_{g_i} P_{G_i}^2 \tag{5.82}$$

The performance index for control set (3), (2), (1), and (4) in (5.79 - 5.82) is the sum of the cost, $C(u)$, of all services used. The performance index for the minimum ancillary services cost problem should not be a measure of cost, $C(u_i)$, but a measure of incremental cost, $C(u_i - u_0)$, that measures the cost of the change in control from u_0 to u_i. Such a measure can be obtained via Taylor series approximation of $C(u)$ evaluated at u_o . The cost given in (5.79 - 5.82) are speculative since no such function have been derived or justified. It is anticipated that the price of any ancillary service provided rises with consumption levels or rises reciprocally with decrease in reserve levels. Since the quadratic function are analytically easier to handle they are used in formulating the problem. Note that any positive or negative movement of under tap position from normal tap position T_{ij}^0 has a cost for under load tap changers and cost rises quadratically with consumption of C_i, Q_{G_i} and P_{G_i} in (5.80 - 5.82). These costs depend on location and how much demand there is for a particular device based on its effectiveness is resolving difficulties with voltage control and resolving difficulties in completing transactions of different power marketers and supplies. Active power generation cost must include the penalty for generators $i \in E_j \cup I_j$ that is involved transfer transaction reduction or in $i \in I_j$ for wheeling transaction reduction. Generators i, that experience generation change outside of $E_j \cup I_j$ for transfers and I_j for wheeling must be on the spot market or provide energy backup for that ISO or for the generating companies involved in that transaction. The cost of this power would likely be higher than could be arranged via bilateral transactions. The constraints include the load flow equality constraints, thermal, voltage, reactive reserve basin, operating constraints, and the control constraints set (1), (2), (3) or (4) found sufficient to obtain a solution to the solvability problem. The starting point for this minimization is the solution to the solvability problem

The minimum ancillary services cost problem is a second stage of the slave problem that finds a minimum control subset that not only solves a clogging or loss of control voltage instability problem for a particular equipment outage and operating change combination but also minimizes the ancillary services cost and further reduces the number of control changes of voltage control and reactive supply devices. The objective of the slave problem is so broad that breaking up the problem into two appears to be the only way of solving it. Operators at power system control centers will not implement controls that require changes in several control devices to solve a stability problem because the operators (a) believe they can achieve excellent control that corrects security or stability problems with relatively few control changes and believe that any computer determined control should also be able to obtain corrective control with few control changes; (b) they believe several control changes can cause deviations from nominal operation that result in dynamic instability and additional equipment outages that can result in blackout of their system. The minimum control constraint is firmly enforced by the use of control sets (1), (2), (3), and (4) for the solvability problem for each equipment outage and operating change induced instability with no solution. The minimum ancillary services costs problem can be used to further reduce the number of controls used by the solution of the minimum control solvability problem by further restricting the number of controls used in set (1), (2), (3), or (4) selected via the solvability problem. The controls used in the minimum ancillary cost problem would be those found to be most effective in the solvability problem with a secondary requirement of having minimum ancillary service cost (5.79 - 5.82) to correct any voltage instability problem detected by VSSAD.

5.3.3 Master Problem Formulation

The optimal reactive dispatch is the master problem, it is the third level of optimization problem. The price of purchasing power to provide I^2R losses may be the only performance index for selecting u_0 and operating state x_0 in the master problem similar to the reactive dispatch performance index that minimize the I^2R losses (4.3). The performance index for the master problem would be

$$F_1(x_0, u_0) = a + bP_{loss} + cP_{loss}^2 \tag{5.83}$$

where P_{loss} *represent the power losses in the network, and* $a, b,$ *and* c *are constant coefficients.*

The price of ancillary services, $C(u_0)$, to provide control u_0 could be added to this performance measure since one is selecting these controls in this problem. The performance index for the optimal reactive dispatch for a deregulated power system may be of this form

$$\begin{aligned} F_2(x_0, u_0) &= a + bP_{loss} + cP_{loss}^2 + \sum \left\{ a_{t_i} + b_{t_i} \left| T_{ij} - T_{ij}^0 \right| + c_{t_i} \left(\left| T_{ij} - T_{ij}^0 \right| \right)^2 \right\} \\ &+ \sum \left\{ a_{c_i} + b_{c_i} C_i + c_{c_i} C_i^2 \right\} + \sum \left\{ a_{q_i} + b_{q_i} Q_{G_i} + c_{q_i} Q_{G_i}^2 \right\} \\ &+ \sum \left\{ a_{g_i} + b_{g_i} P_{G_i} + c_{g_i} P_{G_i}^2 \right\} = F_1(x_0, u_0) + C(u_i - u_0) \end{aligned} \tag{5.84}$$

where $C(u_i - u_0)$ *is the ancillary cost services for the control changes* $(u_i - u_0)$.

The master problem is stated formally in (4.9). It has equality (5.59- 5.60) and operating and control inequality constraints (5.61- 5.67) on x_0 and u_0, and a normed constraint on the control change $\varphi_i(u_i - u_0) \leq \Theta_i$, where u_i are obtained from each slave problem. This constraint can be either a Euclidean vector norm on control change $u_i - u_0$ or a cost of ancillary services norm of the cost $C(u_i - u_0)$ used as the performance index for the minimum ancillary services problem. The parameter Θ_i is then an upper limit on the cost change in ancillary services cost to solve a particular stability problem.

5.4 Numerical Results

Here we conduct numerical simulation to provide some quantitative performance indices for the developed algorithm. The purpose of so doing is to test the algorithm developed and to find the kind and effectiveness of control change that will obtain solution to the solvability problem. The validity of the proposed method is demonstrated on the 162 bus system for the study of voltage instability problems. Seven cases are chosen from the VSSAD contingency analysis of chapter 3. The first four of these cases in Table 5.1 caused loss of control voltage instability due to equipment outage. The four cases were chosen so that two are double generator outages affecting large reactive reserve basin agents in the same root and two are double line outages affecting small reactive reserve basin agents in that root. The remaining three cases in Table 5.1 caused the system to experience clogging voltage instability. Two are double line outages and one is a double generator outage. Double contingencies that caused network separation or that outaged all generators in an agent were not investigated since VSSAD did not have the ability to recommend system commitment actions such as adding generators or lines. No system dispatch action (1-4) are possible for such contingencies and thus no VSSAD recommendation were made and no minimum control solvability problem could be formulated. For these seven cases where a Minimum

Control Solvability problem is formulated, the objective is not to just obtain a load flow solution where none existed since the VSSAD recommended action would obtain a load flow solution. The objective of the minimum control solvability problem for loss of control voltage instability is to achieve solvability without the impossible or onerous action VSSAD recommends. Adding reactive capacity on particular generators is impossible, but adding capacitors, reducing reactive supply on generators exceeding reactive limits by reducing generator voltage setpoints, reducing the reactive pumped to the distribution network from these generators by reducing tap position on certain under load tap changers, increasing tap position on other tap changers that pull reactive from other generators, and adding shunt capacitors in the distribution network will be proven to provide solvability without the impossible VSSAD recommendation of adding reactive capacity on the generators shown in Table 3.7.

The objective of the minimum control solvability problem for clogging voltage instability is to achieve solvability without load and generation shedding that would be so onerous in a deregulated system that desires competition and the ability to undertake transactions without significant concern for maintaining stability and security, and certainly without the concern that the transaction would be curtailed as the only method of preventing a blackout. The minimum control solvability problem is proven to eliminate the need to perform load and generation shedding by adjusting generators exciter voltage setpoint, adjusting tap changers, adding switchable shunt capacitors, and adjusting the active power dispatch to reduce reactive network flows over critical paths and yet increase the total transfer and wheeling capability so that load and generation shedding is not necessary. It should be noted that thermal and voltage constraints are imposed in both the minimum control solvability problem for loss of control voltage instability and minimum control solvability problem for clogging voltage instability so that the corrective action does not produce voltage or thermal overload problems that must be corrected.

5.4.1 Loss of control voltage instability

The first four cases of Table 5.1 caused the system to experience loss of control voltage instability. The Minimum Control Solvability problem for loss of control voltage instability was applied for each selected unsolvable case. The results of the implementation of the Minimum Control Solvability problem, that minimizes and zeros the fictitious reactive supply capability added at generators shown in Table 3.7, are presented in Tables 5.2, 5.3, 5.4, 5.5 for each of the four cases. At the top of each table, the nature of the contingency is given, below it the value of the primal and dual objectives are given as well as the maximum power mismatch for the primal and dual. The convergence of the optimal power flow occurs when the duality gap between primal and dual performance indices are very small and when the mismatch on the primal dual gradient equation is small. The results in Tables 5.2 - 5.5 establish the algorithm found a solution. The Tables 5.2 - 5.5 are arranged so that the first column gives the bus number of each actual generator, the second column represents the optimal value of the reactive supply at each fictitious and actual generator. The next three columns gives the minimum, maximum, and the initial reactive supply at each actual generator and added to each fictitious generator needing additional reactive supply as suggested by Table 3.7 in chapter 3 respectively. The initial reactive supply is obtained from the load flow solution obtained by using VSSAD recommendation. The last column represent the difference between the initial value and the optimal value. The first ten rows in the Tables 5.2 - 5.5 are the generation at each of the ten generators with finite reactive generation in the 162 bus system. The last rows labeled f_i are the fictitious generators where the initial generation is added as recommended by VSSAD in Table 3.7. The fictitious generators are additional PV buses connected to the actual generators needing reactive supply through reactance of small value in pu. The bus number of the fictitious generators are 163 - 167 in Table 5.2 and are connected respectively to buses 99, 101, 114, 118, and 130 as can be seen in column 1. These values can be checked with Table 3.7 to see that the correct amount of reactive is added to the correct generators based on the VSSAD recommendation for that contingency. The same information is in Tables 5.3 - 5.5 for the other contingencies.

Note that the optimal reactive generation on all fictitious generators is zero and the initial reactive generation on all generators are within finite reactive limits, governed by minimum Q_g and maximum Q_g respectively. Note that in case 1, the generator outage at bus 6 (6R1G 22) and bus 121 (C.BL 3G 24), the critical agent in Table 3.7 contains generators 6, 121, 73, 101, 118, and 130, two of generators in this agent were outaged and caused instability in this agent. VSSAD recommends adding reactive capability at buses 99, 101, 114, 118, and 130 as shown in Table 5.2. The optimal solution provided additional reserve at generators 101, 114, and 125, two of which are where VSSAD adds fictitious generators and adds significant increase in reactive generation at generators 76 and 108, without causing them to get close to reactive limits. The optimal solutions is similar but not identical to VSSAD recommendation for where to add reactive reserves but borrows significant reactive from neighboring reactive reserve basins which are ignored as sources in the VSSAD recommendation.

In case 2, the generator outage at bus 6 (6R1G 22) and bus 131 (NEBCY1G 18), the critical agent shown in Table 3.7 for case 4 contains generators 6, 131, 73, 114, 121, and 130 where the outage of the two generators 6 and 131 caused the collapse in that agent. The VSSAD recommendation in Table 5.3 added fictitious generation at 101, 114, 118, 121, and 130. The optimization add reactive reserve at generators at buses 101, 114, 121, and 125 and increased generation at 73, 76, and 108. This case again showed VSSAD recommendation was not followed exactly but approximately by the optimal solution in terms of increasing the most of the VSSAD recommended generator reserves but also borrowed significant reactive from neighboring reactive reserve basins outside the root shown in Table 3.7. This is an excellent solution since borrowing reactive reserve inside the root would make the root less secure. In case 3, the outage of line 68 (HOPE 5 161) – 69 (HOPET 5 161) and line 69 (HOPET 5 161) – 77 (WRIGT 5 161), the critical agent shown in Table 3.7 case 27 contains generators 73, 101, 118, and 121 and VSSAD recommends adding reactive reserve at buses 73, 76, 101, 118, and 121. The optimization adds reactive reserve at generators at buses 73, 99, 101, 108, 114, 121, 125, and 131 and added significant generation at buses 6 and 76. In case 4, the outage of line 55 (PLYMH 5 161) – 149 (RAUN 5 161) and line 71 (MONOA 5 161) – 85 (CARRLL5 161), the critical agent shown in Table 3.7 case 10 contains generators 73,101, 118,121, and 130 and VSSAD recommends adding reactive reserve at buses 73, 101, 114, 118, and 121. The optimization adds reactive reserve at generators at buses 108, 114, 121, and 125 and reactive significant generation at buses 6 and 76. Note that in each of the four cases, the reactive generation at all generators outside the affected agent increase which is a borrowing reactive supply from other reactive reserve basins outside the root to provide reserves in critical reactive reserve basin that makes possible experiencing the contingency without experiencing voltage instability. Reactive generation on generators in the agent could be anticipated to also increase as reactive generation at fictitious generators are zeroed by the optimization process. The fact that reactive reserves on some but not all generators in the affected agent increase rather than decrease as expected indicates that the optimization is attempting to reduce stress in the agent that will happen if reactive power generation (or real power generation) is decreased out of generators in that agent. The addition of capacitors and reduction of tap positions to reduce the pumping of reactive off the particular agent's generators allows this reduction in reactive generation on some of the affected agents generators. The success of the minimum control solvability problem solution in relieving stress retaining solvability of the load flow and allowing a stable solution to be found is checked by computing a load flow solution from this optimal solution. A load flow solution was obtained in all four cases and had a voltage profile that is far flatter and at higher voltage than in the base case before the double contingency that had no load flow solution occurred.

The Tables 5.6, 5.7, 5.8, 5.9 shows some of the control changes that restore the system solvability. At the top of each table, the nature of the contingency is given, below it in each of these tables a set of control changes are defined and listed. The control change set for voltage setpoint on generators and active power are arranged such that the sequence number is in the first column and the second column represents the bus number. The optimal control value is given in the third column, and the next three columns gives the minimum, maximum, and the initial values of the control. The initial value is that based on the load flow solution obtained based on VSSAD recommendation. The last column represents the difference between the initial value and the optimal value. In the case of transformer tap position changes, the first three columns are the sequence number, the " from " bus number and " to " bus number respectively. The last five columns represent the optimal value, the minimum value, the maximum value, the initial value and the difference between the initial and the optimal values. The set of the switchable shunt capacitors inserted are represented in a way that the sequence number is given in the first column, the second column represents the bus number where the shunt capacitor is inserted. The third column represents the optimal value and the last two columns gives the minimum and maximum values.

For case 1, 5pu or 500 MVAR of capacitive reactive supply was added as shown in Table 5.6 and net reactive generation on the ten generators increased 212.52 Tables 5.2 for a total of 712.52 MVARs. Tables 5.6shows the tap changers did not pump as much reactive to the load buses since the change in tap position for the most part are large and negative. This suggests that the ten generators in the system and the capacitor insertions not only supplied 285 MVARs on the fictitious generators but also supplied the load without as much use of tap changers and achieved incredibly improved voltage profile, as shown in Appendix, Table 2 . The result above shown that the control reduced generation in the agent composed of generators 6, 121, 73, 101, 118, and 130 and thus provides the reserves to relieve stress above and beyond that produced by the contingency. This discussion shows how the reserves were obtained from capacitors, borrowing from other reactive reserve basins and from pulling reactive power off agents generation that was pumped to the distribution system. Allowing reactive power to flow naturally from the capacitors and generators to the distribution system reduces reactive losses in the tap changing transformers and yet maintains a very healthy voltage profile as shown in appendix, Table 2 .

For case 2, the ten generators added a net of 88.74 MVARs, the capacitors add 675 MVARs for a total of 753.74 MVARs, the tap changers tap positions decreased far less than in case 1. This contingency thus used more capacitive supply and less net reactive generation to supply 390 MVARs on the fictitious generators, compared to 212 MVARs for case 1. The fact more fictitious reactive reserve generation was needed suggests a worse contingency and the capacitor insertion increase reflected that fact. The decrease in reactive generation was accompanied by decrease in the reduction of the tap changer pumping action. The results above shows that the control reduces generation in the critical agent composed of generators 6, 131, 73, 114, 121, and 130 by some borrowing reserves from other reactive reserve basins, adding significant shunt capacitive supply and again reducing the reactive pumping to the distribution system via under load tap changers and allowing reactive power to flow naturally from the generators and capacitors to the distribution network buses. The control greatly improves base case voltage profile and prevents and corrects thermal overload problems.

For case 3, a double line outage of HOPE 5 161 to HOPET 5 161 and HOPET 5 161 to WRIGT 5 161, lines, required 700 MVARs of capacitors and a net reduction of 522.54 MVARs on the ten generators for a total of 77.46 MVARs to compensate for a 195 MVARs of fictitious generation. The tap changers had both very large increase in tap positions and very large decrease in tap positions that adjusted direction of reactive flows to prevent the exhaustion of reactive reserves on the generators in the small agent composed of generators at buses 73, 101,118, and 121. The large reduction in total reactive generation outside the agent is apparently possible by the tap changer action, the added capacitors, and the ability of reactive to reach the buses where the is needed from the added capacitors in the distribution network.

For case 4, the double line outage of PLYNMH 5 161 to RAUN 5 161 and MONOA 5 161 to CARRLL5 161, required no addition in capacitor reactive supply but only large increase and decrease of tap positions on a large number of tap changers, reduction of reactive generation of 1076.75 MVARs from the ten generators and the MW change on generators shown in Table 5.5. The tap position changes must have allowed for such a large reduction in generation on the ten generators and supply 225 MVARs on the fictitious generators. This reduction in generation is relieving stress in the affected agents so the fictitious generators are not needed and outside that agent so that the total reactive generation on actual generator can be reduced rather than increased by the 225 MVARs of the fictitious generators. This is extraordinary performance for a control. This is again a very different corrective action for voltage instability on the agent composed of generators 73, 101, 118, 121, and 130. The solution in case 4 is very different than cases 1-3 because no capacitors are added and active power generation dispatch changes are required as seen in Table 5.9. This was obtained because when capacitors were added as part of control set 2 the PTI load flow would not solve after the optimal solution was obtained. Therefore control set 1, 3 and 4 with active power generation changes along with tap position changes and generator voltage set point changes was tried. The solution apparently corrected a clogging voltage instability problem that was being produced with addition of capacitors and that was not being eliminated by reactive reserve basin constraints in the optimal power flow. The solution obtained via power flow changes and tap changer tap position changes so changed the network active and reactive flow that a total reduction of 264.36 MVARs in reactive losses (that was producing clogging voltage instability) that allowed a reduction of 225 MVARs of fictitious generation. An increase of 27.95 MVARs in reactive reserves was possible on the critical agent composed of generators 73, 101, 118, 121, and 130. This added reserves on the critical agent corrected the loss of control voltage instability on that agent by zeroing generation on fictitious generators and then relieving the stress caused by the reactive generation out of agent generators. This solution allowed a load flow solution to be obtained using the minimum control solvability solution.

5.4.2 Clogging Voltage Instability

The last three cases of Table 5.1 caused the system to experience clogging voltage instability. The results of the Minimum Control Solvability for clogging voltage instability problem that minimizes the transaction curtailment are presented in Tables 5.10, 5.11, 5.12. The VSSAD recommended changes, that provide a load flow solution and starting feasible optimization problem solution, are given in Tables 3.9, 3.10, 3.11. The optimization attempts to find a solution using control set 1, control set 2, and control set 3 control changes, but this was not possible.

The formulation of the minimum control solvability problem for clogging was modified slightly to permit ease of implementation using the interior point method algorithm that requires all variables to be positive. This modification also took into account the fact that control set 4, that results in redispatch of active generation, would almost certainly be required to obtain solution to the minimum control solvability problem for clogging voltage instability. The reformulated problem

1. accomplished the VSSAD recommended load and generation shedding shown

in Table 3.9 - 3.11 by adding fictitious generators connected at each load bus through a small reactance. The initial generation P_{f_i} on each fictitious generator connected to each bus in Tables 3.9 - 3.11 was the value of load to be shed at the associated load bus. The minimum control solvability problem results are given in Tables 5.10 - 5.12 for the three clogging voltage instability contingencies given in Tables 5.1. The initial value of P_{f_i}, the fictitious bus number and the load bus it is connected to (given in parenthesis), the optimal value of P_{f_i} and the minimum and maximum P_{f_i} values are also given in these tables. If an optimization solution is obtained, the value of P_{f_i} at each fictitious bus is zero as is obtained for all three contingencies;

2. the performance index used

$$\sum_{i \in F} (P_{f_i})^2 \tag{5.85}$$

where F is a set containing all fictitious generators.

would attempt to zero the fictitious generation at these fictitious generators and thereby eliminate the wheeling curtailment suggested by VSSAD;

3. the value of P_{G_i} at the actual generators in the system are also control variables if control set 4 is used and the summation of P_{G_i} must be increased simultaneous as the summation of P_{f_i} is reduced to zero since the load flow equality constraints must be satisfied in this minimum control solvability problem. The positive initial value of P_{f_i} show the affect of load shedding as noted in (1) above. The initial value of P_{G_i} for the minimum control solvability problem are based on the VSSAD recommendation shown in Tables 3.9 - 3.11 and show the affects of generation shedding. The base P_{G_i} values, given in Tables 5.10 - 5.12, are the values before VSSAD recommended load and generation shedding given in Table 3.9 - 3.11 ;

4. the optimal value of P_{G_i} in Tables 5.10 - 5.12 for the three contingencies reflects the fact that the sum of P_{G_i} increased by approximately the same amount that the sum of P_{f_i} decreased, as the individual P_{f_i} optimal values and the sum of P_{f_i} approach zero. This accomplished the total elimination of the VSSAD recommended wheeling curtailment and the associated load and generation shedding that exists in the initial P_{G_i} and P_{f_i} values at the optimal P_{G_i} and P_{f_i} solution. This optimal solution has a load flow solution that did not exist if the contingency occurs with the base case P_{G_i} solution. Note that optimal P_{G_i} values do not return to precontingency or base case values even though their sum does with the added I^2R loses due to the contingency. The change from base case P_{G_i} value to optimal P_{G_i} values increase the network reactive losses that produced the clogging voltage instability and the lack of a load flow solution. Network reactive losses at the optimal solution is also larger than at the initial or VSSAD based solution as shown in Tables 5.16. This is true because of the optimal control must reduce network reactive losses sufficiently on critical paths to correct the clogging voltage instability by the contingency. However, to add the load and generation recommended to be shed by VSSAD requires significant addition of reactive generation for all these clogging voltage instability. Note that "before" represents the load flow solution produced based on VSSAD recommendation and "after "represents the minimum control solvability solution. The optimal value of P_{G_i} also assures no thermal overload occur on any branch;

5. The optimal values of generator voltage setpoints, tap changer tap position and their changes hopefully help assure the voltage profile meets bus voltage limits and that the network reactive losses that produced the clogging voltage instability are reduced. These control changes are shown in Table 5.13 - 5.15,

and are arranged in the same way as Table 5.12 described above.

It should be noted that contingency cases 5 - 7 in Table 5.1 are shown in Tables 5.10 and 5.13, 5.11 and 5.14, 5.12 and 5.15 respectively. Note that in case 5 shown in Table 5.10, the optimal values of P_{f_i} are not exactly zero but are approximately zero. The optimal values of P_{G_i} sum approximately to 9000 MW where as the sum of base case $P_{G_i^0}$ values equals 9980 MW. This reduction in I^2R losses is unexpected when the double line outage is in optimization model and not in the base case. This agent reflects the large reduction in stress reflected in I^2R losses and reactive losses, that occurs through optimization which makes possible solvability for double contingencies that have no solution in the base case. The value of optimal P_{G_i} at generators 73 (NEAL 12G) and 76 (NEAL 34G) are reduced below the VSSAD recommended initial P_{G_i} values that are reduced from the base P_{G_i} values. This is true because the double line outage eliminates a major subtransmission path out of these generators. The optimal solution thus relieves the stress produced by this double line outage. The power eliminated from the initial P_{G_i} values as shown in the difference column is added to the other generators as can be seen in this column. Generation is restored on generators 121 and 130 to near their base case level and at 131, 118, and 101 at modestly (< 100 MW) above their base case values. The optimal tap position value and changes have both large positive and negative values as shown in Table 5.13. This reflects causes reactive flow changes in the network. The generator voltage setpoint values and changes are also shown. Almost all changes are positive as expected to compensate for the voltage stress of the contingency. The reactive generation change between the optimal and the VSSAD recommended initial value are shown in Table 5.13. The result suggest that despite almost 800 MW of additional load the increase reactive losses in the system were not large.

For case 7, the results are identical to case 5 because it again is a double line outage affecting generators 73 and 76. The results are shown in Table 5.12 and 5.15.

Case 6 results are for a double generator outage. The double generator outage of bus 76 (NEAL 34G) and bus 131 (NEBCY 1G) required shedding of 1227.18 MW of load to compensate for the lost generation of 1227.18 MW of these two generators. The values of load shed at the buses given in Table 3.9 are the initial fictitious generation P_{f_i} added on generators at the fictitious buses connected to the actual load buses as shown in Table 5.11. The generation value after VSSAD are the initial values because VSSAD requires adjustment of the base case generation levels at the actual generator buses shown in Table 5.11. the optimal values of P_{f_i} are zero indicating the VSSAD recommended load and generation shedding has been eliminated in the optimal solution. The optimal value of P_{G_i} on these generator shows the greatest increase on generation occurs at bus 73 (NEAL 12G) and bus 108 (MTOW 3G). The added 1227 MW of generation, eliminates the load shedding and replaces the lost generator's generation. The added generation is less than 100 MW at all other generators in Table 5.11. The optimal tap changer tap position changes and generator voltage setpoint changes in Table 5.14 are chosen to cause voltage to be within bus voltage limits, reactive reserve basin reserves to lie within limits, and to reduce the increase in network reactive losses on critical paths accompanying adding 1227 MW back on the system. The total network reactive losses increase as noted in Table 5.16. The tap position changes show both large positive and negative values and the generator voltage setpoint changes are positive and between 1% and 2% to accomplish these objectives.

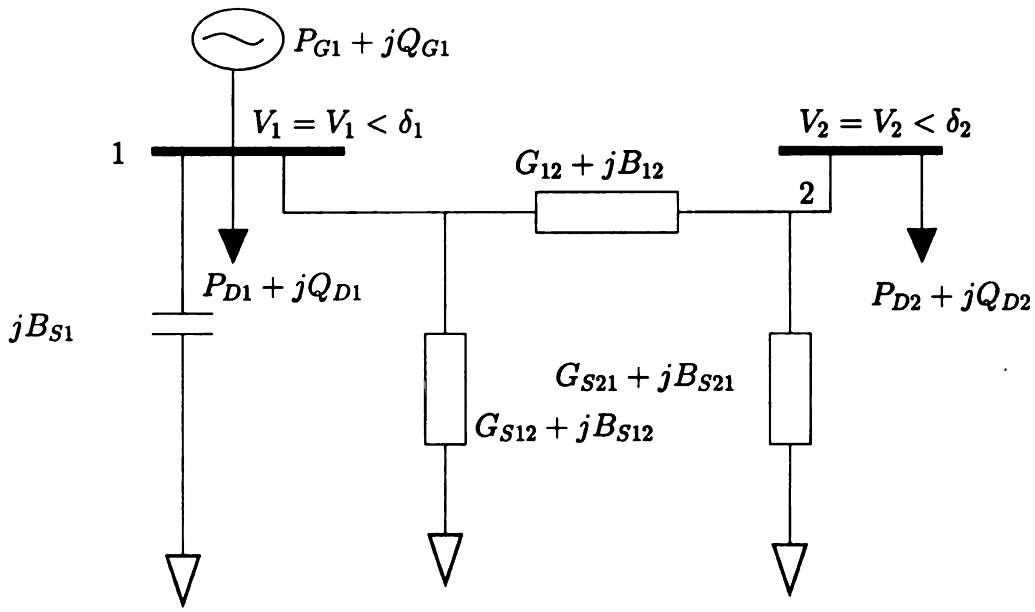

Figure 5.1. Two Bus Model.

Table 5.1. Selected Double Contingency Cases for Solvability problems.

Conting.	Unsolved Double Contingency						
Case: 1	Gen. Outage:	6	6R1G	22			
	Gen. Outage:	121	C.BL 3G	24			
Case: 2	Gen. Outage:	6	6R1G	22			
	Gen. Outage:	131	NEBCY1G	18			
Case: 3	Line Outage:	68	HOPE 5	161	69	HOPET 5	161
	Line Outage:	69	HOPET 5	161	77	WRIGT 5	161
Case: 4	Line Outage:	55	PLYMH 5	161	149	RAUN 5	161
	Line Outage:	71	MONOA 5	161	85	CARRLL5	161
Case: 5	Line Outage:	55	PLYMH 5	161	149	RAUN 5	161
	Line Outage:	161	KELOG 5	161	162	LEEDS 5	161
Case: 6	Gen. Outage:	76	NEAL34G	24			
	Gen. Outage:	131	NEBCY1G	18			
Case: 7	Line Outage:	55	PLYMH 5	161	149	RAUN 5	161
	Line Outage:	55	PLYMH 5	161	162	LEEDS 5	161

Table 5.2. Reactive Generation Supply by Fictitious Generators for Case# 1.

```
Case No. 1  Gen. Outage:    6     6R1G   22
            Gen. Outage:  121   C.BL 3G  24

primal objective            =     .4507062312D-17
dual objective              =    -.2377240562D-04
max. power mismatch         =     .6722707628D-04
max. dual mismatch          =     .9864576821D-06
```

	Bus#	Optimal Q_g	Minimum Q_g	Maximum Q_g	Initial Q_g	Difference
1	73	149.0838	-72.0000	267.0000	85.8400	63.2438
2	76	251.3038	-170.0000	605.0000	136.3100	114.9938
3	99	30.1392	-60.6000	75.6000	5.2100	24.9292
4	101	19.2449	-24.4000	38.6000	30.3400	-11.0951
5	108	448.4322	9999.0000	9999.0000	155.8200	292.6122
6	114	-3.2716	-25.0000	33.0000	22.2900	-25.5616
7	118	66.4634	-44.0000	100.0000	59.7500	6.7134
8	125	-363.2716	1099.0000	9900.0000	-22.9400	-340.3316
9	130	178.5795	-144.0000	288.0000	123.3700	55.2095
10	131	126.5420	-265.0000	320.0000	94.5100	32.0320
f1	163 (99)	.0000	-30.0000	30.0000	25.0000	-25.0000
f2	164 (101)	.0000	-60.0000	60.0000	45.0000	-45.0000
f3	165 (114)	.0000	-80.0000	80.0000	75.0000	-75.0000
f4	166 (118)	.0000	-60.0000	60.0000	45.0000	-45.0000
f5	167 (130)	.0000	-90.0000	90.0000	85.0000	-85.0000

Table 5.3. Reactive Generation Supply by Fictitious Generators for Case# 2.

```
Case No.  2  Gen. Outage:    6      6R1G   22
             Gen. Outage:  131   NEBCY1G   18
```

```
primal objective              =     .2931041047D-16
dual objective                =    -.3543313451D-04
max. power mismatch           =     .1349672117D-04
max. dual mismatch            =     .2565564438D-05
```

	Bus#	Optimal Q_g	Minimum Q_g	Maximum Q_g	Initial Q_g	Difference
1	73	157.3901	-72.0000	267.0000	85.8400	71.5501
2	76	186.1923	-170.0000	605.0000	136.3100	49.8823
3	99	42.4831	-60.6000	75.6000	5.2100	37.2731
4	101	5.9973	-24.4000	38.6000	30.3400	-24.3427
5	108	439.3431	9999.0000	9999.0000	155.8200	283.5231
6	114	14.0119	-25.0000	33.0000	22.2900	-8.2781
7	118	82.3730	-44.0000	100.0000	59.7500	22.6230
8	121	125.9771	-120.0000	250.0000	150.8900	-24.9129
9	125	-348.4704	1099.0000	9900.0000	-22.9400	-325.5304
10	130	130.3286	-144.0000	288.0000	123.3700	6.9586
f1	163 (101)	.0000	-60.0000	60.0000	50.0000	-50.0000
f2	164 (114)	.0000	-80.0000	80.0000	65.0000	-65.0000
f3	165 (118)	.0000	-60.0000	60.0000	45.0000	-45.0000
f4	166 (121)	.0000	-140.0000	140.0000	130.0000	-130.0000
f5	167 (130)	.0000	-90.0000	90.0000	80.0000	-80.0000

Table 5.4. Reactive Generation Supply by Fictitious Generators for Case# 3.

```
Case No. 3   Line Outage:   68   HOPE 5   161        69  HOPET 5  161
             Line Outage:   69  HOPET 5   161        77  WRIGT 5  161

   primal objective              =      .0000000000D+00
   dual objective                =     -.1619183098D-06
   max. power mismatch           =      .1704386895D-03
   max. dual mismatch            =      .4216405042D-07
```

	Bus#	Optimal Q_g	Minimum Q_g	Maximum Q_g	Initial Q_g	Difference
1	6	288.7779	-200.0000	400.0000	180.8100	107.9679
2	73	21.5504	-72.0000	267.0000	85.8400	-64.2896
3	76	420.8147	-170.0000	605.0000	136.3100	284.5047
4	99	-53.7921	-60.6000	75.6000	5.2100	-59.0021
5	101	9.4768	-24.4000	38.6000	30.3400	-20.8632
6	108	94.9468	9999.0000	9999.0000	155.8200	-60.8732
7	114	10.1152	-25.0000	33.0000	22.2900	-12.1748
8	118	86.9789	-44.0000	100.0000	59.7500	27.2289
9	121	97.4573	-120.0000	250.0000	150.8900	-53.4327
10	125	-453.2626	1099.0000	9900.0000	-22.9400	-430.3226
11	130	127.1681	-144.0000	288.0000	123.3700	3.7981
12	131	-150.5728	-265.0000	320.0000	94.5100	-245.0828
f1	163 (73)	.0000	-60.0000	60.0000	50.0000	-50.0000
f2	164 (76)	.0000	-20.0000	20.0000	10.0000	-10.0000
f3	165 (101)	.0000	-60.0000	60.0000	45.0000	-45.0000
f4	166 (118)	.0000	-60.0000	60.0000	45.0000	-45.0000
f5	167 (121)	.0000	-60.0000	60.0000	45.0000	-45.0000

Table 5.5. Reactive Generation Supply by Fictitious Generators for Case# 4.

```
Case No. 4  Line Outage:   55  PLYMH 5  161        149   RAUN 5  161
            Line Outage:   71  MONOA 5  161         85  CARRLL5  161

   primal objective              =     .1858329935D-12
   dual objective                =    -.5247823050D-04
   max. power mismatch           =     .4368341865D-04
   max. dual mismatch            =     .5969542581D-06
```

	Bus#	Optimal Q_g	Minimum Q_g	Maximum Q_g	Initial Q_g	Difference
1	6	305.3386	-200.0000	400.0000	180.8100	124.5286
2	73	117.2346	-72.0000	267.0000	85.8400	31.3946
3	76	236.1612	-170.0000	605.0000	136.3100	99.8512
4	99	42.7035	-60.6000	75.6000	5.2100	37.4935
5	101	38.1811	-24.4000	38.6000	30.3400	7.8411
6	108	-86.3633	9999.0000	9999.0000	155.8200	-242.1833
7	114	-.8450	-25.0000	33.0000	22.2900	-23.1350
8	118	97.4257	-44.0000	100.0000	59.7500	37.6757
9	121	129.8089	-120.0000	250.0000	150.8900	-21.0811
10	125	-406.9398	1099.0000	9900.0000	-22.9400	-383.9998
11	130	131.3392	-144.0000	288.0000	123.3700	7.9692
12	131	153.8545	-265.0000	320.0000	94.5100	59.3445
f1	163 (73)	.0000	-60.0000	60.0000	45.0000	-45.0000
f2	164 (101)	.0000	-40.0000	40.0000	30.0000	-30.0000
f3	165 (114)	.0000	-60.0000	60.0000	45.0000	-45.0000
f4	166 (118)	.0000	-70.0000	70.0000	60.0000	-60.0000
f5	167 (121)	.0000	-60.0000	60.0000	45.0000	-45.0000

Table 5.6. Voltage Set Point, Shunt Cap., and Transformer Tap Control Changes.

Case No. 1 Gen. Outage: 6 6R1G 22
Gen. Outage: 121 C.BL 3G 24

	Bus	Optimal V_g	Minimum V_g	Maximum V_g	Initial V_g	Difference
1	73	1.01336	.95000	1.05000	1.00000	.01300
2	108	1.02826	.95000	1.05000	1.00000	.02800
3	118	1.01112	.95000	1.05000	1.00000	.01100
4	125	1.04849	.95000	1.05000	1.02000	.02800
5	130	.99811	.95000	1.05000	1.03000	-.03100

	Bus	Optimal S_i	Minimum S_i	Maximum S_i
1	1	.50	.00	1.00
2	5	.50	.00	1.00
3	26	.25	.00	1.00
4	52	.75	.00	1.00
5	70	.25	.00	1.00
6	75	.50	.00	1.00
7	95	.75	.00	1.00
8	96	.50	.00	1.00
9	110	.50	.00	1.00
10	112	.50	.00	1.00

	From Bus	To Bus	Optimal t_{ij}	Minimum t_{ij}	Maximum t_{ij}	Initial t_{ij}	Difference
1	1	6	1.00993	.90000	1.10000	1.05190	-.04197
2	12	2	.99025	.90000	1.10000	1.02520	-.03495
3	18	37	1.03599	.90000	1.13000	1.11930	-.08331
4	60	61	.99013	.90000	1.10000	1.02520	-.03507
5	66	11	.96091	.90000	1.10000	1.00000	-.03909
6	93	42	1.05567	.90000	1.10000	1.02480	.03087
7	95	91	.96902	.90000	1.10000	1.02000	-.05098
8	95	99	.99458	.90000	1.10000	1.02960	-.03502
9	98	93	.98522	.90000	1.10000	1.02520	-.03998
10	110	112	1.03087	.90000	1.10000	1.00000	.03087
11	112	121	1.00597	.90000	1.10000	1.04990	-.04393
12	142	51	1.02225	.90000	1.10000	1.07000	-.04775
13	157	55	1.03651	.90000	1.10000	1.00000	.03651

Table 5.7. Voltage Set Point, and Shunt Cap. Control Changes.

Case No. 2 Gen. Outage: 6 6R1G 22
Gen. Outage: 131 NEBCY1G 18

	Bus	Optimal V_g	Minimum V_g	Maximum V_g	Initial V_g	Difference
1	73	1.01161	.95000	1.05000	1.00000	.01100
2	76	.98556	.95000	1.05000	1.00000	-.01400
3	99	.98973	.95000	1.05000	1.00000	-.01000
4	101	.98444	.95000	1.05000	1.00000	-.01500
5	108	.96213	.95000	1.05000	1.00000	-.03700
6	114	.97757	.95000	1.05000	1.00000	-.02200
7	118	1.02792	.95000	1.05000	1.00000	.02700
8	121	.98792	.95000	1.05000	1.00000	-.01200
9	125	1.04683	.95000	1.05000	1.02000	.02600
10	130	1.00621	.95000	1.05000	1.03000	-.02300

	Bus	Optimal S_i	Minimum S_i	Maximum S_i
1	1	1.00	.00	1.00
2	5	.75	.00	1.00
3	52	1.00	.00	1.00
4	70	.75	.00	1.00
5	75	.50	.00	1.00
6	95	.75	.00	1.00
7	96	.75	.00	1.00
8	110	.75	.00	1.00
9	112	.50	.00	1.00

Table 5.8. Voltage Set Point, Shunt Cap., and Transformer Tap Control Changes.

```
Case No. 3   Line Outage:   68  HOPE 5  161        69  HOPET 5  161
             Line Outage:   69  HOPET 5  161       77  WRIGT 5  161
```

	Bus	Optimal V_g	Minimum V_g	Maximum V_g	Initial V_g	Difference
1	6	1.02665	.95000	1.05000	1.00000	.02600
2	76	1.01808	.95000	1.05000	1.00000	.01800
3	99	.97865	.95000	1.05000	1.00000	-.02100
5	108	1.01670	.95000	1.05000	1.00000	.01600
7	118	1.01919	.95000	1.05000	1.00000	.01900
9	125	1.03406	.95000	1.05000	1.02000	.01400

	Bus	Optimal S_i	Minimum S_i	Maximum S_i
1	1	1.00	.00	1.00
2	5	.75	.00	1.00
3	26	1.00	.00	1.00
4	52	1.00	.00	1.00
5	75	.75	.00	1.00
6	96	1.00	.00	1.00
7	110	.75	.00	1.00
8	112	.75	.00	1.00

	From Bus	To Bus	Optimal t_{ij}	Minimum t_{ij}	Maximum t_{ij}	Initial t_{ij}	Difference
1	12	2	.98037	.90000	1.10000	1.02520	-.04483
3	24	25	1.09988	.90000	1.10000	1.02170	.07818
4	53	11	1.06206	.90000	1.10000	1.00000	.06206
5	60	61	1.08553	.90000	1.10000	1.02520	.06033
6	60	61	1.08749	.90000	1.10000	1.02520	.06229
8	95	91	1.09258	.90000	1.10000	1.02000	.07258
9	95	99	.94656	.90000	1.10000	1.02960	-.08304
10	97	44	1.08048	.90000	1.10000	1.02520	.05528
11	98	93	.90785	.90000	1.10000	1.02520	-.11735
12	104	34	.95335	.90000	1.10000	1.00000	-.04665
13	105	38	1.06065	.90000	1.10000	1.02520	.03545
14	129	132	1.05092	.90000	1.10000	1.00000	.05092
15	142	51	.97726	.90000	1.10000	1.07000	-.09274
16	149	26	1.03573	.90000	1.10000	1.00000	.03573
17	149	26	1.03573	.90000	1.10000	1.00000	.03573

Table 5.9. Active Generation, and Transformer Tap Control Changes.

```
Case No. 4  Line Outage:   55  PLYMH 5  161        149   RAUN 5  161
            Line Outage:   71  MONOA 5  161         85  CARRLL5  161
```

	Bus	Optimal P_g	Min P_g	Max P_g	Init. P_g	Difference
1	73	17.8440	0.0	650.0	600.00	-582.1560
2	76	1298.6490	0.0	1600.0	1555.00	-256.3509
3	99	47.8411	0.0	350.0	300.90	-253.0589
4	108	840.0533	0.0	1400.0	1001.12	-161.0667
5	114	176.8265	0.0	300.0	241.00	-64.1735
6	118	271.9135	0.0	300.0	193.00	78.9135
7	125	2975.2750	0.0	3000.0	2888.00	87.2751
8	131	748.8563	0.0	800.0	675.00	73.8563

	From Bus	To Bus	Optimal t_{ij}	Min t_{ij}	Max t_{ij}	Init. t_{ij}	Difference
1	4	115	.94893	0.90	1.10	1.0000	-.05107
2	12	2	.96137	0.90	1.10	1.0252	-.06383
3	18	37	1.02390	0.90	1.13	1.1193	-.09540
4	20	53	1.05671	0.90	1.10	1.0000	.05671
5	22	39	1.06470	0.90	1.13	1.1081	-.04340
6	24	25	1.05889	0.90	1.10	1.0217	.03719
7	52	118	1.08064	0.90	1.10	1.0429	.03774
8	53	11	.92511	0.90	1.10	1.0000	-.07489
9	60	61	.98270	0.90	1.10	1.0252	-.04250
10	60	61	.98117	0.90	1.10	1.0252	-.04403
11	66	11	.91639	0.90	1.10	1.0000	-.08361
12	79	74	1.06858	0.90	1.10	1.0248	.04378
13	93	42	1.08440	0.90	1.10	1.0248	.05960
14	93	108	.97521	0.90	1.10	1.0503	-.07509
15	95	91	1.08275	0.90	1.10	1.0200	.06275
16	95	99	1.07971	0.90	1.10	1.0296	.05011
17	104	34	1.07700	0.90	1.10	1.0000	.07700
18	110	112	1.06491	0.90	1.10	1.0000	.06491
19	116	119	1.06760	0.90	1.10	1.0248	.04280
20	129	132	1.04060	0.90	1.10	1.0000	.04060
21	133	134	.98843	0.90	1.10	1.0249	-.03647
22	142	51	.97131	0.90	1.10	1.0700	-.09869
24	153	70	.96150	0.90	1.10	1.0000	-.03850
25	153	70	.96150	0.90	1.10	1.0000	-.03850
26	157	55	1.06089	0.90	1.10	1.0000	.06089

Table 5.10. Active Generation Supply by Fictitious Generators for Case# 5.

```
Case No. 5  Line Outage:   55  PLYMH 5  161       149   RAUN 5  161
            Line Outage:  161  KELOG 5  161       162  LEEDS 5  161
```

```
primal objective          =    .3629778538D-05
dual objective            =   -.1145864398D-04
max. power mismatch       =    .1761926754D-04
max. dual mismatch        =    .4434782645D-06
```

	Bus	Optimal P_g	Min P_g	Max P_g	Init. P_g	Difference	Base P_g
1	6	993.5707	0.0	1000.0	930.00	63.5707	930.00
2	73	8.5427	0.0	650.0	364.41	-355.8673	600.00
3	76	1135.0806	0.0	1600.0	1421.02	-285.9390	1555.00
4	99	339.7006	0.0	350.0	300.90	38.8006	300.90
5	101	166.3753	0.0	350.0	41.00	125.3753	122.00
6	108	1394.7930	0.0	1400.0	1001.12	393.6726	1001.12
7	114	291.4761	0.0	300.0	241.00	50.4761	241.00
8	118	295.2564	0.0	300.0	112.00	183.2564	193.00
9	121	791.3781	0.0	800.0	484.41	306.9681	720.00
10	125	2994.2120	0.0	3000.0	2888.00	106.2119	2888.00
11	130	790.4654	0.0	800.0	631.41	159.0554	755.00
12	131	791.9603	0.0	800.0	675.00	116.9603	675.00
f1	163 (27)	.0047	0.0	350.0	324.00	-323.9953	
f2	164 (45)	.0058	0.0	30.0	20.00	-19.9942	
f3	165 (54)	.0049	0.0	100.0	94.04	-94.0351	
f4	166 (80)	.0058	0.0	30.0	15.76	-15.7542	
f5	167 (151)	.0051	0.0	30.0	24.00	-23.9949	
f6	168 (161)	.0048	0.0	50.0	42.00	-41.9952	
f7	169 (162)	.0054	0.0	40.0	30.00	-29.9946	
f8	170 (15)	.0045	0.0	200.0	160.00	-159.9955	
f9	171 (18)	.0054	0.0	50.0	40.40	-40.3946	
f10	172 (28)	.0054	0.0	50.0	38.47	-38.4646	
f11	173 (29)	.0057	0.0	30.0	28.31	-28.3043	
f12	174 (56)	.0057	0.0	30.0	25.29	-25.2843	
f13	175 (57)	.0053	0.0	60.0	48.48	-48.4747	

Table 5.11. Active Generation Supply by Fictitious Generators for Case# 6.

```
   Case No. 6 (17)  Gen. Outage:   76  NEAL34G   24
                    Gen. Outage:  131  NEBCY1G   18

primal objective              =      .3273372182D-05
dual objective                =     -.1301776166D-04
max. power mismatch           =      .8799596186D-04
max. dual mismatch            =      .1441888771D-06
```

	Bus	Optimal P_g	Min P_g	Max P_g	Init. P_g	Difference	Base P_g
1	6	987.0786	0.0	1000.0	930.00	57.0786	930.00
2	73	1037.3590	0.0	1150.0	600.00	437.3589	600.00
3	99	300.7892	0.0	350.0	300.90	-.1108	300.90
4	101	159.4391	0.0	350.0	122.00	37.4391	122.00
5	108	1344.6420	0.0	1400.0	1001.12	343.5216	1001.12
6	114	284.9729	0.0	300.0	241.00	43.9729	241.00
7	118	289.7166	0.0	300.0	193.00	96.7166	193.00
8	121	785.8536	0.0	800.0	720.00	65.8536	720.00
9	125	2983.3930	0.0	3000.0	2888.00	95.3934	2888.00
10	130	784.9462	0.0	800.0	755.000	29.9462	755.00
f1	163 (20)	.0045	0.0	50.0	40.90	-40.8955	
f2	164 (40)	.0044	0.0	60.0	52.88	-52.8756	
f3	165 (87)	.0044	0.0	20.0	16.91	-16.9056	
f4	166 (103)	.0040	0.0	340.0	322.00	-321.9960	
f5	167 (111)	.0044	0.0	70.0	65.41	-65.4056	
f6	168 (113)	.0046	0.0	40.0	32.70	-32.6954	
f7	169 (139)	.0045	0.0	20.0	10.10	-10.0955	
f8	170 (142)	.0045	0.0	30.0	27.09	-27.0855	
f9	171 (157)	.0046	0.0	40.0	32.00	-31.9954	
f10	172 (160)	.0045	0.0	20.0	14.40	-14.3955	
f11	173 (30)	.0041	0.0	200.0	190.20	-190.1959	
f12	174 (38)	.0045	0.0	20.0	14.76	-14.7555	
f13	175 (46)	.0044	0.0	70.0	65.31	-65.3056	
f14	176 (59)	.0042	0.0	120.0	104.43	-104.4258	
f15	177 (91)	.0044	0.0	60.0	51.24	-51.2356	
f16	178 (94)	.0042	0.0	180.0	164.00	-163.9958	
f17	179 (105)	.0045	0.0	30.0	24.84	-24.8355	

Table 5.12. Active Generation Supply by Fictitious Generators for Case# 7.

```
Case No. 7  Line Outage:   55  PLYMH 5  161        149   RAUN 5  161
            Line Outage:   55  PLYMH 5  161        162  LEEDS 5  161

  primal objective           =     .1711047953D-04
  dual objective             =    -.2210446411D-04
  max. power mismatch        =     .3658650046D-04
  max. dual mismatch         =     .1025270371D-06
```

	Bus	Optimal P_{fg}	Min P_{fg}	Max P_{fg}	Init. P_{fg}	Difference	Base P_g
1	6	985.0694	0.0	1000.0	930.00	55.0694	930.00
2	73	23.0953	0.0	650.0	395.41	-372.3147	600.00
3	76	1237.6484	0.0	1600.0	1421.02	-183.3720	1555.00
4	99	308.7199	0.0	350.0	300.90	7.8199	300.90
5	101	162.5759	0.0	350.0	41.00	121.5759	122.00
6	108	1372.4860	0.0	1400.0	1001.12	371.3665	1001.12
7	114	276.8409	0.0	300.0	241.00	35.8409	241.00
8	118	288.8139	0.0	300.0	112.00	176.8139	193.00
9	121	775.6407	0.0	800.0	515.41	260.2307	720.00
10	125	2985.2110	0.0	3000.0	2888.00	97.2107	2888.00
11	130	788.5820	0.0	800.0	631.41	157.1720	755.00
12	131	779.0364	0.0	800.0	675.00	104.0364	675.00
f1	163 (27)	.0108	0.0	350.0	324.00	-323.9892	
f2	164 (54)	.0115	0.0	100.0	94.04	-94.0285	
f3	165 (80)	.0141	0.0	20.0	15.76	-15.7459	
f4	166 (151)	.0122	0.0	30.0	24.00	-23.9878	
f5	167 (162)	.0132	0.0	40.0	30.00	-29.9868	
f6	168 (15)	.0106	0.0	180.0	160.00	-159.9894	
f7	169 (18)	.0127	0.0	50.0	40.40	-40.3873	
f8	170 (28)	.0130	0.0	50.0	38.47	-38.4570	
f9	171 (29)	.0132	0.0	40.0	28.31	-28.2968	
f10	172 (56)	.0130	0.0	40.0	25.29	-25.2770	
f11	173 (57)	.0125	0.0	60.0	48.48	-48.4675	

Table 5.13. Voltage Set Point, Active Generation, and Transformer Tap Control Changes.

```
Case No. 5  Line Outage:   55  PLYMH 5  161        149   RAUN 5  161
            Line Outage:  161  KELOG 5  161        162  LEEDS 5  161
```

	Bus	Optimal V_g	Minimum V_g	Maximum V_g	Initial V_g	Difference
1	6	1.02433	.95000	1.05000	1.00000	.02400
2	73	1.01417	.95000	1.05000	1.00000	.01400
3	76	1.01798	.95000	1.05000	1.00000	.01700
4	101	1.02392	.95000	1.05000	1.00000	.02300
5	108	1.02759	.95000	1.05000	1.00000	.02700
6	118	1.02001	.95000	1.05000	1.00000	.02000
7	125	1.04537	.95000	1.05000	1.02000	.02500
8	130	1.01755	.95000	1.05000	1.03000	-.01200

	From Bus	To Bus	Optimal t_{ij}	Minimum t_{ij}	Maximum t_{ij}	Initial t_{ij}	Difference
1	12	2	.97619	.90000	1.10000	1.02520	-.04901
2	18	37	1.03097	.90000	1.13000	1.11930	-.08833
3	20	53	1.05147	.90000	1.10000	1.00000	.05147
4	24	25	1.09333	.90000	1.10000	1.02170	.07163
5	60	61	.97692	.90000	1.10000	1.02520	-.04828
6	60	61	.97567	.90000	1.10000	1.02520	-.04953
7	93	42	1.07476	.90000	1.10000	1.02480	.04996
8	95	91	1.08180	.90000	1.10000	1.02000	.06180
9	96	101	.99883	.90000	1.10000	1.02960	-.03077
10	104	34	1.04166	.90000	1.10000	1.00000	.04166
11	105	38	.97957	.90000	1.10000	1.02520	-.04563
12	110	112	1.04992	.90000	1.10000	1.00000	.04992
13	116	119	1.05744	.90000	1.10000	1.02480	.03264
14	128	72	1.05406	.90000	1.10000	1.00000	.05406
15	133	134	.99312	.90000	1.10000	1.02490	-.03178
16	142	51	1.00114	.90000	1.10000	1.07000	-.06886
17	153	70	.96299	.90000	1.10000	1.00000	-.03701
18	153	70	.96299	.90000	1.10000	1.00000	-.03701
19	157	55	1.04363	.90000	1.10000	1.00000	.04363

Table 5.14. Voltage Set Point, Active Generation, and Transformer Tap Control Changes.

Case No. 6 (17) Gen. Outage: 76 NEAL34G 24
Gen. Outage: 131 NEBCY1G 18

	Bus	Optimal V_g	Minimum V_g	Maximum V_g	Initial V_g	Difference
1	6	1.02151	.95000	1.05000	1.00000	.02100
2	73	1.03132	.95000	1.05000	1.00000	.03100
3	101	1.01609	.95000	1.05000	1.00000	.01600
4	108	1.02313	.95000	1.05000	1.00000	.02300
5	118	1.02018	.95000	1.05000	1.00000	.02000
6	121	1.01758	.95000	1.05000	1.00000	.01700
7	125	1.04699	.95000	1.05000	1.02000	.02600

	From Bus	To Bus	Optimal t_{ij}	Minimum t_{ij}	Maximum t_{ij}	Initial t_{ij}	Difference
1	12	2	.98631	.90000	1.10000	1.02520	-.03889
2	18	37	1.05058	.90000	1.13000	1.11930	-.06872
3	24	25	1.05581	.90000	1.10000	1.02170	.03411
4	26	76	.98578	.90000	1.10000	1.04000	-.05422
5	60	61	.98751	.90000	1.10000	1.02520	-.03769
6	60	61	.98735	.90000	1.10000	1.02520	-.03785
7	66	11	.95911	.90000	1.10000	1.00000	-.04089
8	93	42	1.05821	.90000	1.10000	1.02480	.03341
9	93	108	1.01035	.90000	1.10000	1.05030	-.03995
10	95	91	1.05219	.90000	1.10000	1.02000	.03219
11	96	101	1.00511	.90000	1.10000	1.02960	-.02449
12	104	34	1.04647	.90000	1.10000	1.00000	.04647
13	110	112	1.03927	.90000	1.10000	1.00000	.03927
14	110	114	1.00765	.90000	1.10000	1.03980	-.03215
15	112	121	1.01622	.90000	1.10000	1.04990	-.03368
16	116	119	1.06023	.90000	1.10000	1.02480	.03543
17	142	51	1.02983	.90000	1.10000	1.07000	-.04017
18	149	26	1.06857	.90000	1.10000	1.00000	.06857
19	149	26	1.06857	.90000	1.10000	1.00000	.06857
20	157	55	1.03504	.90000	1.10000	1.00000	.03504

Table 5.15. Active Generation and Transformer Tap Control Changes.

Case No. 7 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161
Line Outage: 55 PLYMH 5 161 162 LEEDS 5 161

	From Bus	To Bus	Optimal t_{ij}	Minimum t_{ij}	Maximum t_{ij}	Initial t_{ij}	Difference
1	12	2	.97610	.90000	1.10000	1.02520	-.04910
2	18	37	1.02339	.90000	1.13000	1.11930	-.09591
3	20	53	1.04819	.90000	1.10000	1.00000	.04819
4	24	25	1.08474	.90000	1.10000	1.02170	.06304
5	60	61	.97207	.90000	1.10000	1.02520	-.05313
6	60	61	.96579	.90000	1.10000	1.02520	-.05941
7	79	74	1.05582	.90000	1.10000	1.02480	.03102
8	93	42	1.07478	.90000	1.10000	1.02480	.04998
9	93	108	1.01891	.90000	1.10000	1.05030	-.03139
10	95	91	1.06705	.90000	1.10000	1.02000	.04705
11	104	34	1.04985	.90000	1.10000	1.00000	.04985
12	110	112	1.04997	.90000	1.10000	1.00000	.04997
13	116	119	1.06198	.90000	1.10000	1.02480	.03718
14	133	134	.99454	.90000	1.10000	1.02490	-.03036
15	142	51	1.01384	.90000	1.10000	1.07000	-.05616
16	157	55	1.04772	.90000	1.10000	1.00000	.04772

Table 5.16. Reactive Generation Before and After Optimization.

Gen. Bus #	Name	Case# 5 Before	Case# 5 After	Case# 6 Before	Case# 6 After	Case# 7 Before	Case# 7 After
6	6R1G 22	348.01	400.00	195.58	363.54	347.78	344.13
73	NEAL12G 20	153.93	147.56	46.37	267.00	159.79	153.50
76	NEAL34G 24	402.01	369.14	**	**	403.05	253.74
99	PRARK4G 18	50.62	49.55	0.40	37.64	50.28	46.52
101	MTOW 3G 14	38.60	38.60	21.49	38.60	38.60	38.60
108	AROL 1G 22	195.54	432.63	76.94	318.65	194.01	360.50
114	C.BL12G 14	33.00	14.50	32.84	29.67	33.00	11.59
118	DPS 57G 14	100.00	100.00	30.38	97.31	100.00	95.88
121	C.BL 3G 24	236.75	204.72	143.89	247.08	239.54	200.72
125	PALM710 345	-414.82	-357.05	-669.83	-378.88	-415.99	-364.27
130	FT.CL1G 22	235.08	232.08	144.96	250.63	233.87	223.72
131	NEBCY1G 18	212.67	210.31	**	**	212.22	165.50

** means the generator is part of the double contingency.

CHAPTER 6

Conclusion and Future Work

6.1 Summary of the Work Completed

A summary of work completed in this thesis is given below:

1. **Background overview:** An overview of the application of optimization to dispatch of power systems has been presented in this thesis. Difficulties associated with each one of the dispatch problems has been identified. Formulation of preventive and corrective control dispatch problem has been derived and formulated incorporating reactive reserve basin constraints, incorporated as a means of preventing or correcting loss of control voltage instability.

2. **Voltage stability:** Voltage stability problems in a deregulated environment has been outlined and studied. Two kinds of voltage instability, loss of control and clogging voltage instability, were described. A method of acquiring knowledge about voltage control area and their reactive reserve basins was described. Voltage Stability Security Assessment and Diagnosis was developed to use this knowledge to identify (a) the region and subregion where voltage collapse occur for any contingency and (b) the set of all equipment outage and operating

change combinations that cause voltage collapse in that region and subregion. Voltage instability diagnosis is performed to determine the voltage collapse regions that are closest to voltage collapse or are experiencing voltage collapse for each contingency and operating change as well as when, why, and what can be done to cure developing voltage instability problem.

3. **Interior Point Method:** A brief overview of the algorithms and techniques used to solve linear and nonlinear optimization problems have been given. Derivation and formulation of nonlinear interior point methods have been reviewed and its application to the optimal power flow problem has been discussed. A primal dual logarithmic barrier interior point algorithm was discussed. A predictor corrector version was discussed and is the algorithm used in this thesis. Successfully modifying the formulation and Fortran code for this predictor corrector interior point algorithm based optimal power flow to (a) incorporate the reactive reserve basins constraints and (b) modify the objective function to solve the minimum control solvability problems was accomplished.

4. **Corrective control:** Open Access System Dispatch Security Constrained Optimization was proposed to compute a corrective control for each specific mode of voltage instability predicted to occur by VSSAD. The control is applied when the voltage instability is developing because the equipment outage and operating change combination that is predicted to produce it has been detected as having occurred via the state estimator. The Open Access System Dispatch Security Constrained Optimization is formulated to obtain a minimum set of control changes to achieve corrective control for any particular equipment outage and operating change, and also to posture the operating state and control setting on the whole system to help prevent voltage instability. These minimum set of control would be stored, triggered and implemented once the state estimator

detects the occurrence of equipment outage and operating change predicted to produce voltage instability by VSSAD. A set of optimization problems was formulated and developed in this thesis, A Minimum Control Solvability Problem, a Minimum Ancillary Services Cost Problem, and a Optimal Reactive Dispatch as the Master Problem. These set of optimization problems will meet the requirement set forth for the Security Constrained Optimization Module proposed in [15]. The Minimum Control Solvability Problem either (a) obtains the reactive reserves VSSAD determines are needed in one or more agents reactive reserve basins to obtain solution of the load flow when loss of control voltage instability occurs or (b) obtains solution of the load flow without curtailment of the set of transaction determined via VSSAD as needed for a solution to exist when clogging voltage instability occurs. VSSAD provides starting feasible load flow solvable starting points for the Minimum Control Solvability Problem. Two objective functions for a Minimum Control Solvability Problem are formulated; one for loss of control voltage instability and the other for clogging voltage instability. The optimization of these objective functions is subject to the reactive reserve basin, thermal, voltage, and control constraints that specify four different control sets. Numerical evaluation of the optimal corrective control for several cases for both types of voltage instability has been carried out. The developed minimum control solvability based solution have been tested in a load flow for each of these cases. The numerical results have been documented. A Minimum Ancillary Services Cost Problem, that further minimizes the number of control changes and the ancillary services cost for providing the corrective control is formulated. The Minimum Control Solvability Problem is effectively an optimization that provides a feasible solvable starting solution to the Minimum Ancillary Services Cost Problem. The Minimum Ancillary Services Cost problem has the objective of minimizing the cost of ancillary services required to correct a clogging or loss of control voltage instability problem while maintaining solvability for a particular VSSAD determined equipment outage and operating change combination. A Master Problem is also formulated to optimize the current operation of the system so that no thermal or voltage limit violations occur and so that the system is postured to implement the corrective controls computed by the Minimum Ancillary Services Cost Problem. The Master Problem is similar to the reactive dispatch problem that minimize I^2R losses. The price of ancillary services to provide control change could be added to the objective function of this problem. The Minimum Ancillary Services Cost Problem and the Master Problem have been formulated but not tested.

5. **Numerical results:** The VSSAD methodology have been tested on a 162 bus system and the results show that small stressed system could experience voltage instability due to equipment outrage and operating change combinations. Several contingencies have been picked for the study of the Minimum Control Solvability Problem. The developed methodologies have been tested for these cases. The numerical results have been documented.

6.2 Conclusions

Deregulation has brought great opportunities for increased efficiency of production and delivery and reduced cost to customers. Deregulation has also brought great challenges to provide the operating reliability and security that customers have come to expect and demand from an electrical power system. One of the challenges in a deregulated power system is voltage collapse. Voltage collapse is one of the biggest concerns in operating and planning electric power system before deregulation occurs. To prevent voltage collapse from occurring, system operators and planners are looking for analytical tools that can enhance their understanding of where the system is actually operating with respect to any instability point (point of collapse). In addition to knowing the load level where the system will experience voltage collapse, it is of particular interest to determine how much reactive power supply is required in each reactive reserve basin and where it should be located (voltage collapse region) so that the power system can be operated at maximum reliability and economy.

A Voltage Stability Security Assessment and Diagnoses (VSSAD) was developed at Michigan State University to identify each region and subregion where voltage collapse occurs and the set of all equipment outage and operating change combinations that cause voltage collapse in that region or subregion. VSSAD was used to simultaneously assess the proximity to voltage instability for all bifurcation modes in a 162 bus system by assessing percentage of generators in a reactive reserve basin with zero reserves and the reactive reserves remaining on reactive reserve basin voltage control areas that have not yet exhausted reserves. The operating constraints or the security constraints on reactive reserve basin was provided by VSSAD that prevent voltage instability in each reactive reserve basin in a manner identical to how thermal and voltage constraints prevents thermal and voltage limit violations. The test and numerical simulation of VSSAD in chapter 3 provided the knowledge about voltage control areas and their associated reactive reserve basins as well as the voltage collapse region This was the most comprehensive test ever done of VSSAD to date. The voltage instability diagnosis was performed by simulating all single and double contingencies. These numerical investigations verify the theoretical assertions and provide the foundation for the formulation of preventive and corrective Open Access System Dispatch proposed in Chapter 4 of this thesis. The test and the numerical results of the investigation of VSSAD has provided guidelines for VSSAD algorithm implementation.

The thesis proposes a corrective control that optimally stretches the security region and transmission capacity in the direction where a specific equipment outage and operating change causes contraction. The preventive control formulation attempts to expand the security region and transmission capacity in almost all directions simultaneously and doesn't focus on solving the reduction in transmission capacity produced by a single contingency and how to correct and expand it to the level needed. On the other hand, the proposed corrective control formulation has the ability to expand the security region and transmission capacity in just the one or possibly two direction where it was reduced by a particular contingency. This adaptive transmission capability correction capability is due to the ability to:

1. posture exactly the correct amount of reactive reserves on generators to prevent exhaustion of all reserves and voltage control on all generators in an agent for a specific equipment outage and operating change combination and cause the instability in sufficient time so that the voltage collapse does not occur;

2. borrow reactive reserves from several neighboring reactive reserve basin to the one needing it as long as the reactive reserve basins have independent voltage instability problems and the short period when the corrective control is needed is guaranteed to be short;

3. avoid the need to modify the bilateral transactions, supplier, and load schedules via optimizing voltage set points on generators, tap position on under load tap changer, and capacitor insertion;

4. avoid producing voltage instability in other agents in an attempt to or correct stability problems in one or more agents;

5. perform the optimization to obtain minimum control changes and minimum ancillary cost corrective controls;

6. dramatically reduce the network I^2R and network reactive losses in a manner that reduces the stress that made obtaining the load flow solution impossible

without added reactive capability or load shedding that is not necessary through optimization.

This thesis also describe an important new application of an optimal power flow, using a VSSAD produced starting point to restore system solvability. The solvability problems minimize added reactive supply (loss of control voltage instability) and minimize load and generation shedding (clogging voltage instability) recommended by VSSAD as a means of obtaining load flow solvability. The Interior Point Method has the flexibility to allow some multiple control changes such as voltage setpoint on the generator buses, tap position transformer tap changes, switchable shunt capacitor insertions, and active power dispatch to be optimized within limits and yet satisfy inequality constraints on each branch current, on each bus voltage, and on each reactive reserve basin's reserves. The solvability problems were formulated as an interior point optimization problem. Fortran programs for performing optimal power flow were modified to handle this new application, and seven examples illustrate the capability of the formulation to retain solvability and eliminate the impossible or onerous VSSAD recommendation for retaining solvability.

The numerical results have shown that the proposed interior point method was very effective in dealing with seven loss of control and clogging voltage instability unsolvable load flow cases of a power system. The VSSAD method was able to identify the agent, the cause, and cure on each of voltage collapse to obtain solvability. The optimization retained solvability and totally eliminated the need of additional reactive supply or to curtail load and generation to restore solvability of the load flow as VSSAD recommended in each of the seven cases.

6.3 Future Work

The research to be conducted in the future concerns implementation of the Minimum Ancillary Cost Problem and the Master Problem. Currently, there is significant ongoing work on modeling the cost of ancillary services needed to solve these problems. The modification of the interior point optimal power flow algorithm to solve these problems must be undertaken. Finally, the solution must be obtained on small example systems to prove the formulation is valid. The practical implementation of a secondary voltage control and tertiary control that performs VSSAD, Minimum Control Solvability Problem and Minimum Ancillary Services Cost Problem for each VSSAD identified contingency, and Master Problem is beyond the scope of academic research. However, the implementation would be a direct result of the research undertaken in the thesis and these extensions.

The coordination of stabilization control of the dynamics and the corrective control is another topic for future research. Should the same controls be used for stabilization and corrective control, and how can coordination be achieved are two subjects for investigation. The impact of corrective control on stabilization and stabilization on corrective control also requires research. This research requires application of dynamical system theory.

The research on assessment and diagnosis of voltage instability requires inclusion of both load and generator dynamics. The research on extending VSSAD and finally preventive and corrective control to dynamical models is just begun but is necessary to assure the results are correct and accurate.

APPENDIX

APPENDIX

Table 1. Voltage Collapse Region, Voltage Control Areas, and Reactive Reserves Basin.

VCR	Voltage Control Area		Reactive Reserve Basin	
#	Bus#	Bus Name	Bus#	Bus Name
1	130	FT.CL1G 22	73	NEAL12G 20
2	10	TWINCH4 230	130	FT.CL1G 22
	64	SIOXLS 345	121	C.BL 3G 24
	63	HANLN 4 230	73	NEAL12G 20
	62	FTTHMP4 230		
	60	SX FLL7 115		
	57	SAC 5 161		
	56	OSGOD 5 161		
	31	RAPIAN5 161		
	29	WINBGO5 161		
	28	FOX K 5 161		
	18	ADAM 5 161		
	15	FTRAD 4 230		
3	125	PALM710 345	73	NEAL12G 20
	156	E SIDE8 69		
4	162	LEEDS 5 161	121	C.BL 3G 24
	76	NEAL34G 24	118	DPS 57G 14
	54	WISDM 5 161	73	NEAL12G 20
	24	LAKFD 5 161		
5	161	KELOG 5 161	121	C.BL 3G 24
	45	TRIBJI5 161	73	NEAL12G 20
	23	HRN K 5 161		

Table 1 (cont'd).

VCR	Voltage Control Area		Reactive Reserve Basin	
#	Bus#	Bus Name	Bus#	Bus Name
6	157	PLYMTH8 69	99	PRARK4G 18
	139	S706 8 69	131	NEBCY1G 18
	111	AVOC 5 161	130	FT.CL1G 22
	58	UTICJC4 230	121	C.BL 3G 24
	20	HINTON8 69	76	NEAL34G 24
	2	MOOR 3 345	73	NEAL12G 20
			6	6R1G 22
7	153	NEAL 8 69	73	NEAL12G 20
	71	MONOA 5 161	76	NEAL34G 24
	155	M SIDE8 69		
8	152	TEKAMA5 161	130	FT.CL1G 22
	82	WATELO5 161	73	NEAL12G 20
	41	WSHBN 5 161		
	22	HAZLON5 161		
	16	ROCHTR5 161		
	21	POSTIL5 161		
9	151	INTRCG5 161	121	C.BL 3G 24
	149	RAUN 5 161	76	NEAL34G 24
	80	POMEOY5 161	73	NEAL12G 20
	17	HARMNY5 161	130	FT.CL1G 22
10	150	NEAL4 5 161	121	C.BL 3G 24
			76	NEAL34G 24
			73	NEAL12G 20

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Voltage Control Area Bus Name	Reactive Reserve Basin Bus#	Reactive Reserve Basin Bus Name
11	148	SYCAOR8 69	130	FT.CL1G 22
	117	ASHAA 5 161	121	C.BL 3G 24
	116	SYCAOR5 161	118	DPS 57G 14
	48	CRESN 5 161	73	NEAL12G 20
	47	ANITTP5 161	6	6R1G 22
12	147	WABASH5 161	130	FT.CL1G 22
	115	BOONIL5 161	121	C.BL 3G 24
			118	DPS 57G 14
			73	NEAL12G 20
			6	6R1G 22
			76	NEAL34G 24
13	144	HSTNGS8 69	130	FT.CL1G 22
	141	HSTNGS5 161	121	C.BL 3G 24
	140	S705 8 69	73	NEAL12G 20
	138	CBLUFS8 69	6	6R1G 22
	135	S702 8 69	131	NEBCY1G 18
	133	S701 8 69		
	132	S1255 5 161		
	129	S3455 3 345		
	72	S1209 5 161		
	14	S1206 5 161		
	5	NEBCY 3 345		
	3	STJO712 161		
14	137	S704 8 69	130	FT.CL1G 22
	136	S703 8 69	121	C.BL 3G 24
	134	S701 5 161	73	NEAL12G 20
	50	MARY 12 161	6	6R1G 22
	49	ANIT 5 161		
	13	GR ILD3 345		
	12	SHELON7 115		
	9	94 3 345		
	8	8ER7 115		
	7	7LN3 345		

Table 1 (cont'd).

VCR	Voltage Control Area		Reactive Reserve Basin	
#	Bus#	Bus Name	Bus#	Bus Name
15	113	S1211 5 161	131	NEBCY1G 18
			130	FT.CL1G 22
			121	C.BL 3G 24
			73	NEAL12G 20
			6	6R1G 22
			76	NEAL34G 24
16	127	LACRSS3 345	121	C.BL 3G 24
	30	HAYWD 5 161	73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
			76	NEAL34G 24
17	126	PR ILD3 345	130	FT.CL1G 22
	69	HOPET 5 161	121	C.BL 3G 24
	11	SX CY 4 230	118	DPS 57G 14
			76	NEAL34G 24
			73	NEAL12G 20
			101	MTOW 3G 14
			6	6R1G 22
18	124	DVNPT 3 345	99	PRARK4G 18
	109	HILL 3 345	73	NEAL12G 20
	102	MQOKTA5 161	6	6R1G 22
	97	CALUS 7 115	130	FT.CL1G 22
	95	PRARCK7 115		
	92	WYOMG 5 161		
	44	CALUS 5 161		
	43	CLINON5 161		
19	123	WAPELO5 161	130	FT.CL1G 22
			73	NEAL12G 20
			6	6R1G 22
			76	NEAL34G 24

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Voltage Control Area Bus Name	Reactive Reserve Basin Bus#	Reactive Reserve Basin Bus Name
20	122	OSKLOS5 161	130	FT.CL1G 22
			73	NEAL12G 20
			6	6R1G 22
21	121	C.BL 3G 24	131	NEBCY1G 18
	145	GWOOD 8 69	130	FT.CL1G 22
			73	NEAL12G 20
			6	6R1G 22
22	119	SYCAOR3 345	130	FT.CL1G 22
	106	MONRE 5 161	121	C.BL 3G 24
	52	D.MON 5 161	118	DPS 57G 14
	4	BOONIL3 345	73	NEAL12G 20
	86	GR JT 5 161	6	6R1G 22
			101	MTOW 3G 14
23	110	CBLUFS5 161	130	FT.CL1G 22
			121	C.BL 3G 24
			114	C.BL12G 14
			73	NEAL12G 20
			6	6R1G 22
			131	NEBCY1G 18
24	107	POWAHK5 161	130	FT.CL1G 22
			118	DPS 57G 14
			73	NEAL12G 20
			6	6R1G 22
25	105	DUNDE 7 115	99	PRARK4G 18
	94	HILL 5 161	130	FT.CL1G 22
	91	CDRPS 5 161	73	NEAL12G 20
	38	DUNDE 5 161	76	NEAL34G 24
			6	6R1G 22

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Voltage Control Area Bus Name	Reactive Reserve Basin Bus#	Reactive Reserve Basin Bus Name
26	104	IA FS 7 115	73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
27	103	DAVNRT5 161	99	PRARK4G 18
	160	SC WST8 69	131	NEBCY1G 18
			130	FT.CL1G 22
			76	NEAL34G 24
			73	NEAL12G 20
			6	6R1G 22
28	98	SIX T 7 115	99	PRARK4G 18
	84	DYSAT 5 161	73	NEAL12G 20
	19	DUBUUE5 161	130	FT.CL1G 22
29	93	ARNOD 5 161	99	PRARK4G 18
			73	NEAL12G 20
30	88	JASPR 8 69	130	FT.CL1G 22
			118	DPS 57G 14
			73	NEAL12G 20
			6	6R1G 22
			101	MTOW 3G 14
			76	NEAL34G 24
31	87	GUTHIE7 115	99	PRARK4G 18
	40	BLKHK 5 161	131	NEBCY1G 18
			130	FT.CL1G 22
			121	C.BL 3G 24
			76	NEAL34G 24
			73	NEAL12G 20
			6	6R1G 22
			101	MTOW 3G 14

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Voltage Control Area Bus Name	Reactive Reserve Basin Bus#	Reactive Reserve Basin Bus Name
32	83	WTR OGT 161	73	NEAL12G 20
	35	FLOY 5 161	130	FT.CL1G 22
	154	KELLOG8 69	76	NEAL34G 24
	159	MCCOOK8 69		
	158	LOGANP8 69		
33	79	LEHIH 5 161	121	C.BL 3G 24
	78	FT.DDG5 161	118	DPS 57G 14
	68	HOPE 5 161	73	NEAL12G 20
	67	BURT 5 161	130	FT.CL1G 22
	66	SX CY 3 345		
	61	SIOXLS4 230		
34	77	WRIGT 5 161	121	C.BL 3G 24
	39	HAZLON3 345	118	DPS 57G 14
	37	ADAM 3 345	73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
35	74	LEHIH 3 345	121	C.BL 3G 24
	55	PLYMH 5 161	118	DPS 57G 14
	27	WILMRT3 345	73	NEAL12G 20
			101	MTOW 3G 14
36	73	NEAL12G 20	121	C.BL 3G 24
			76	NEAL34G 24
			130	FT.CL1G 22
37	65	WTRTWN3 345	130	FT.CL1G 22
	26	RAUN 3 345	121	C.BL 3G 24
			118	DPS 57G 14
			73	NEAL12G 20
			76	NEAL34G 24

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Voltage Control Area Bus Name	Reactive Reserve Basin Bus#	Reactive Reserve Basin Bus Name
38	59	EAGL 4 230	130	FT.CL1G 22
	51	CLRNA 5 161	121	C.BL 3G 24
	46	DENIN 5 161	76	NEAL34G 24
			73	NEAL12G 20
			6	6R1G 22
39	42	ARNOD 3 345	121	C.BL 3G 24
			73	NEAL12G 20
			99	PRARK4G 18
			130	FT.CL1G 22
40	36	GARNR 5 161	121	C.BL 3G 24
	32	LIMECK5 161	73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
41	34	FRANKN5 161	121	C.BL 3G 24
	33	MASNTY5 161	118	DPS 57G 14
			73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
			76	NEAL34G 24
42	25	LAKFD 3 345	121	C.BL 3G 24
			118	DPS 57G 14
			73	NEAL12G 20
			101	MTOW 3G 14
			76	NEAL34G 24
43	6	6R1G 22	131	NEBCY1G 18
			130	FT.CL1G 22
			121	C.BL 3G 24
			73	NEAL12G 20

Table 1 (cont'd).

VCR #	Voltage Control Area Bus#	Bus Name	Reactive Reserve Basin Bus#	Bus Name
44	142	CLRNDA8 69	130	FT.CL1G 22
			73	NEAL12G 20
			6	6R1G 22
			76	NEAL34G 24
			131	NEBCY1G 18
45	100	WELSRG7 115	99	PRARK4G 18
			130	FT.CL1G 22
			73	NEAL12G 20
			101	MTOW 3G 14
			76	NEAL34G 24
			6	6R1G 22
46	96	MTOW 7 115	99	PRARK4G 18
			73	NEAL12G 20
			101	MTOW 3G 14
			130	FT.CL1G 22
			6	6R1G 22
47	89	GR JT 7 115	130	FT.CL1G 22
			73	NEAL12G 20
			101	MTOW 3G 14
			76	NEAL34G 24
			6	6R1G 22
48	85	CARRLL5 161	73	NEAL12G 20
			101	MTOW 3G 14
			76	NEAL34G 24
			130	FT.CL1G 22

Table 2. Voltage Comparison, Before and After Contingency for case# 1.

```
Case No. 1  Gen. Outage:    6     6R1G   22
            Gen. Outage:  121  C.BL 3G   24
```

Bus#	Bus Name	Voltage Befor Contingency	Voltage After Contingency	Difference
1	COOPR 3 345	1.0118	0.9832	0.0286
2	MOOR 3 345	0.9911	0.9760	0.0151
3	STJO712 161	0.9609	0.9537	0.0072
4	BOONIL3 345	0.9768	0.9759	0.0009
5	NEBCY 3 345	1.0196	0.9979	0.0217
6	6R1G 22	1.0000	0.9780	0.0220
7	7LN3 345	0.9882	0.9725	0.0157
8	8ER7 115	1.0028	0.9647	0.0381
9	94 3 345	0.9993	0.9818	0.0175
10	TWINCH4 230	0.9197	0.9639	-0.0442
11	SX CY 4 230	0.9265	0.9756	-0.0491
12	SHELON7 115	1.0055	0.9620	0.0435
13	GR ILD3 345	0.9691	0.9600	0.0091
14	S1206 5 161	1.0049	0.9813	0.0236
15	FTRAD 4 230	0.9343	0.9636	-0.0293
16	ROCHTR5 161	0.9324	0.9302	0.0022
17	HARMNY5 161	0.9301	0.9235	0.0066
18	ADAM 5 161	0.9503	0.9325	0.0178
19	DUBUUE5 161	0.9570	0.9512	0.0058
20	HINTON8 69	0.9100	0.9677	-0.0577
21	POSTIL5 161	0.9477	0.9414	0.0063
22	HAZLON5 161	0.9885	0.9706	0.0179
23	HRN K 5 161	0.9044	0.9423	-0.0379
24	LAKFD 5 161	0.9286	0.9709	-0.0423
25	LAKFD 3 345	0.9277	0.9616	-0.0339
26	RAUN 3 345	1.0078	1.0279	-0.0201
27	WILMRT3 345	0.9220	0.9516	-0.0296
28	FOX K 5 161	0.8949	0.9359	-0.0410
29	WINBGO5 161	0.8898	0.9187	-0.0289
30	HAYWD 5 161	0.8914	0.8900	0.0014
31	RAPIAN5 161	0.9000	0.9296	-0.0296
32	LIMECK5 161	0.9138	0.9080	0.0058
33	MASNTY5 161	0.9143	0.9122	0.0021
34	FRANKN5 161	0.9281	0.9242	0.0039
35	FLOY 5 161	0.9159	0.9034	0.0125
36	GARNR 5 161	0.9108	0.9195	-0.0087
37	ADAM 3 345	0.9223	0.9529	-0.0306

Table 2 (cont'd).

Bus#	Bus Name	Voltage Befor Contingency	Voltage After Contingency	Difference
38	DUNDE 5 161	0.9772	0.9577	0.0195
39	HAZLON3 345	0.9562	0.9617	-0.0055
40	BLKHK 5 161	0.9441	0.9229	0.0212
41	WSHBN 5 161	0.9641	0.9364	0.0277
42	ARNOD 3 345	0.9947	0.9876	0.0071
43	CLINON5 161	1.0001	1.0005	-0.0004
44	CALUS 5 161	0.9991	0.9947	0.0044
45	TRIBJI5 161	0.9136	0.9542	-0.0406
46	DENIN 5 161	0.9289	0.9742	-0.0453
47	ANITTP5 161	0.9326	0.9677	-0.0351
48	CRESN 5 161	0.9520	0.9818	-0.0298
49	ANIT 5 161	0.9306	0.9653	-0.0347
50	MARY 12 161	0.9544	0.9720	-0.0176
51	CLRNA 5 161	0.9469	0.9721	-0.0252
52	D.MON 5 161	0.9769	1.0117	-0.0348
53	SX CY 5 161	0.9259	0.9598	-0.0339
54	WISDM 5 161	0.9065	0.9457	-0.0392
55	PLYMH 5 161	0.9282	0.9621	-0.0339
56	OSGOD 5 161	0.9070	0.9406	-0.0336
57	SAC 5 161	0.9209	0.9592	-0.0383
58	UTICJC4 230	0.9288	0.9695	-0.0407
59	EAGL 4 230	0.9050	0.9539	-0.0489
60	SX FLL7 115	0.9073	0.9195	-0.0122
61	SIOXLS4 230	0.9013	0.9474	-0.0461
62	FTTHMP4 230	0.9477	0.9710	-0.0233
63	HANLN 4 230	0.9065	0.9480	-0.0415
64	SIOXLS 345	0.9382	0.9444	-0.0062
65	WTRTWN3 345	0.9165	0.9369	-0.0204
66	SX CY 3 345	0.9268	0.9251	0.0017
67	BURT 5 161	0.9169	0.9416	-0.0247
68	HOPE 5 161	0.9402	0.9671	-0.0269
69	HOPET 5 161	0.9519	0.9786	-0.0267
70	NEAL 5 161	0.9972	1.0262	-0.0290
71	MONOA 5 161	0.9356	0.9773	-0.0417
72	S1209 5 161	0.9934	0.9758	0.0176
73	NEAL12G 20	1.0000	1.0190	-0.0190
74	LEHIH 3 345	0.9553	0.9708	-0.0155
75	FT.CL 3 345	1.0082	0.9897	0.0185
76	NEAL34G 24	1.0000	1.0241	-0.0241

Table 2 (cont'd).

Bus#	Bus Name	Voltage Befor Contingency	Voltage After Contingency	Difference
77	WRIGT 5 161	0.9401	0.9601	-0.0200
78	FT.DDG5 161	0.9574	0.9871	-0.0297
79	LEHIH 5 161	0.9707	1.0015	-0.0308
80	POMEOY5 161	0.9385	0.9726	-0.0341
81	WATELO8 69	0.9463	0.9178	0.0285
82	WATELO5 161	0.9456	0.9217	0.0239
83	WTR OGT 161	0.9549	0.9285	0.0264
84	DYSAT 5 161	0.9834	0.9454	0.0380
85	CARRLL5 161	0.9075	0.9461	-0.0386
86	GR JT 5 161	0.9138	0.9391	-0.0253
87	GUTHIE7 115	0.9223	0.9535	-0.0312
88	JASPR 8 69	0.9534	0.9686	-0.0152
89	GR JT 7 115	0.9379	0.9784	-0.0405
90	BOON 7 115	0.9132	0.9375	-0.0243
91	CDRPS 5 161	1.0075	0.9964	0.0111
92	WYOMG 5 161	0.9961	0.9869	0.0092
93	ARNOD 5 161	1.0220	1.0078	0.0142
94	HILL 5 161	1.0330	1.0362	-0.0032
95	PRARCK7 115	1.0201	0.9876	0.0325
96	MTOW 7 115	0.9787	0.9633	0.0154
97	CALUS 7 115	1.0170	0.9748	0.0422
98	SIX T 7 115	1.0327	1.0072	0.0255
99	PRARK4G 18	1.0000	1.0025	-0.0025
100	WELSRG7 115	0.9415	0.9548	-0.0133
101	MTOW 3G 14	0.9824	0.9918	-0.0094
102	MQOKTA5 161	0.9960	0.9891	0.0069
103	DAVNRT5 161	1.0093	1.0112	-0.0019
104	IA FS 7 115	0.9279	0.9680	-0.0401
105	DUNDE 7 115	1.0040	0.9462	0.0578
106	MONRE 5 161	0.9611	0.9838	-0.0227
107	POWAHK5 161	0.9665	0.9801	-0.0136
108	AROL 1G 22	1.0000	1.0312	-0.0312
109	HILL 3 345	1.0333	1.0318	0.0015
110	CBLUFS5 161	1.0004	1.0045	-0.0041
111	AVOC 5 161	0.9679	0.9888	-0.0209
112	CBLUFS3 345	1.0057	0.9713	0.0344
113	S1211 5 161	1.0011	0.9882	0.0129
114	C.BL12G 14	0.9691	0.9889	-0.0198
115	BOONIL5 161	0.9739	1.0135	-0.0396

Table 2 (cont'd).

Bus#	Bus Name	Voltage Befor Contingency	Voltage After Contingency	Difference
116	SYCAOR5 161	0.9808	1.0228	-0.0420
117	ASHAA 5 161	0.9700	1.0101	-0.0401
118	DPS 57G 14	0.9840	1.0062	-0.0222
119	SYCAOR3 345	0.9684	0.9684	0.0000
120	S3456 3 345	1.0028	0.9752	0.0276
121	C.BL 3G 24	0.9957	0.9747	0.0210
122	OSKLOS5 161	0.9658	0.9797	-0.0139
123	WAPELO5 161	0.9793	0.9932	-0.0139
124	DVNPT 3 345	1.0075	1.0104	-0.0029
125	PALM710 345	1.0200	1.0475	-0.0275
126	PR ILD3 345	0.9398	0.9679	-0.0281
127	LACRSS3 345	0.9162	0.9397	-0.0235
128	S3459 3 345	1.0019	0.9764	0.0255
129	S3455 3 345	1.0038	0.9779	0.0259
130	FT.CL1G 22	1.0300	1.0045	0.0255
131	NEBCY1G 18	1.0180	0.9984	0.0196
132	S1255 5 161	0.9972	0.9739	0.0233
133	S701 8 69	1.0089	0.9805	0.0284
134	S701 5 161	0.9983	0.9901	0.0082
135	S702 8 69	1.0056	0.9790	0.0266
136	S703 8 69	0.9985	0.9746	0.0239
137	S704 8 69	1.0024	0.9773	0.0251
138	CBLUFS8 69	1.0044	0.9868	0.0176
139	S706 8 69	0.9994	0.9786	0.0208
140	S705 8 69	1.0018	0.9777	0.0241
141	HSTNGS5 161	0.9637	0.9774	-0.0137
142	CLRNDA8 69	0.9772	0.9750	0.0022
143	R.OAK 8 69	0.9592	0.9685	-0.0093
144	HSTNGS8 69	0.9806	0.9948	-0.0142
145	GWOOD 8 69	0.9833	0.9831	0.0002
146	SHENDO8 69	0.9642	0.9707	-0.0065
147	WABASH5 161	0.9661	1.0072	-0.0411
148	SYCAOR8 69	0.9673	0.9833	-0.0160
149	RAUN 5 161	0.9956	1.0248	-0.0292
150	NEAL4 5 161	0.9906	1.0210	-0.0304
151	INTRCG5 161	0.9627	0.9949	-0.0322
152	TEKAMA5 161	0.9954	0.9991	-0.0037
153	NEAL 8 69	0.9820	1.0044	-0.0224
154	KELLOG8 69	0.9181	0.9628	-0.0447

Table 2 (cont'd).

Bus#	Bus Name	Voltage Befor Contingency	Voltage After Contingency	Difference
155	M SIDE8 69	0.9335	0.9723	-0.0388
156	E SIDE8 69	0.9216	0.9667	-0.0451
157	PLYMTH8 69	0.9124	0.9697	-0.0573
158	LOGANP8 69	0.9039	0.9567	-0.0528
159	MCCOOK8 69	0.9073	0.9572	-0.0499
160	SC WST8 69	0.9126	0.9593	-0.0467
161	KELOG 5 161	0.9493	0.9823	-0.0330
162	LEEDS 5 161	0.9404	0.9740	-0.0336

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