Harnessing Flexibility of the Transmission Grid to Enhance Reliability of the Power System

by

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ABSTRACT

The standard optimal power flow (OPF) problem is an economic dispatch (ED) problem combined with transmission constraints, which are based on a static topology. However, topology control (TC) has been proposed in the past as a corrective mechanism to relieve overloads and voltage violations. Even though the benefits of TC are presented by several research works in the past, the computational complexity associated with TC has been a major deterrent to its implementation. The proposed work develops heuristics for TC and investigates its potential to improve the computational time for TC for various applications. The objective is to develop computationally light methods to harness the flexibility of the grid to derive maximum benefits to the system in terms of reliability. One of the goals of this research is to develop a tool that will be capable of providing TC actions in a minimal time-frame, which can be readily adopted by the industry for real-time corrective applications.

A DC based heuristic, i.e., a greedy algorithm, is developed and applied to improve the computational time for the TC problem while still maintaining the ability to find quality solutions. In the greedy algorithm, an expression is derived, which indicates the impact on the objective for a marginal change in the state of a transmission line. This expression is used to generate a priority list with potential candidate lines for switching, which may provide huge improvements to the system. The advantage of this method is that it is a fast heuristic as compared to using mixed integer programming (MIP) approach.

Alternatively, AC based heuristics are developed for TC problem and tested on actual data from PJM, ERCOT and TVA. AC based *N-1* contingency analysis is performed to identify the contingencies that cause network violations. Simple proximity based heuristics are developed and the fast decoupled power flow is solved iteratively to identify the top five TC actions, which provide reduction in violations. Time domain simulations are performed to ensure that the TC actions do not cause system instability. Simulation results show significant reductions in violations in the system by the application of the TC heuristics.

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TABLE OF CONTENTS

CHAPTER Page

CHAPTER Page

CHAPTER Page

LIST OF TABLES

LIST OF FIGURES

Figure Page

NOMENCLATURE

SETS AND INDICES

G	Set of all generators
$g(n)$	Group of generators connected to node *n*
$G-2$	Generation double contingencies
GAN	Greedy algorithm with search limit of 'N' through the priority list for beneficial switching action
GA	Greedy algorithm results without imposing any search limit for finding beneficial switching solution
GR	Results with only generation re-dispatch without TC
k	Set of all transmission elements, line or transformer
$\overline{K}$	Set of transmission elements that are out of service
$\widehat{K}$	Set of transmission elements that are in service
MIP	Results for optimal topology control (global optimal solution)
N	Set of nodes
N-1	Single element contingency (line, generator or transformer)
N-1-1	Single element outage followed by system adjustments followed by loss of another single element
N-2	Double element contingency
N-3	Triple element contingency
N-m	Simultaneous contingency of multiple elements
T-2	Transmission line double contingencies
$\delta^{-}(n)$	All transmission elements connected to *n* as the 'from' node

$\delta^+(n)$ All transmission elements connected to *n* as the 'to' node

PARAMETERS

b_k Electrical susceptance of transmission element k

C_g Operating cost for generator g

d_n^{max} Actual demand at node *n*

NL_g No-load cost for generator g

P_g^{min} Minimum real power supplied by generator g

P_g^{max} Maximum real power supplied by generator g

P_k^{max} Maximum real power flow in transmission element *k*

R_g^+ 10 minute ramp-up rate for generator g

R_g^- 10 minute ramp-down rate for generator g

R_g^{SU} Startup ramp rate for generator g

R_g^{SD} Shut-down ramp rate for generator g

$R^{SP\ req}$ Spinning reserve requirement

SU_g Startup cost for generator g

SD_g Shutdown cost for generator g

Z_k^* Parameter representing the state of a transmission element *k*

VARIABLES

d_n Real power load served at node *n*

d_{nt} Real power load served at node *n* at time t

P_{gt} Real power supplied by generator g at time t

P_{kt} Real power flow in transmission line k at time t

$P_{g,t}^{SP\ res}$ Spinning reserve available with generator g at time t

$P_{g,t}^{NSP\ res}$ Non-spinning reserve available with generator g at time t

P_g Real power supplied by generator g

P_k Real power flow in transmission element k

u_{gt} Unit commitment variable

v_{gt} Startup variable

w_{gt} Shutdown variable

Z_k Binary variable representing the state of a transmission element k; 0 for the line out of service; 1 for the line in service

θ_n Bus voltage angle at node n

1. INTRODUCTION

The advancements in the electric power industry have created a need to rethink the way the transmission assets are handled. With increased penetration of renewable resources in the grid, there is a pressing need to achieve more controllability and flexibility from the grid. Traditionally the transmission system is considered as static, and is operated predominantly with a fixed topology except during forced outages or abnormal conditions. However, topology control (TC) has been proposed in the past as a corrective mechanism to relieve overloads and voltage violations (Bakirtzis *et al.* 1987; Granelli *et al.* 2006; Mazi *et al.* 1986; Shao *et al.* 2005; Shao *et al.* 2006). TC has also been proposed as a tool to mitigate line losses and achieve cost reductions (Bacher *et al.* 1988; Fliscounakis *et al.* 2007; Schnyder *et al.* 1990). The concept of TC is evolving over time and is now currently being used as part of special protection schemes, e.g., PJM uses corrective TC as a special protection scheme (PJM 2012). TC is also being employed while executing planned outages to make the transition smooth and for taking post contingency corrective actions (MISO, 2013). However, today TC is done on an ad-hoc basis primarily relying on the historical data and the operators' prior knowledge. Although it has been shown that co-optimization of transmission assets with generation dispatch could potentially provide huge cost benefits to the system (Hedman *et al.* 2010), it is not done currently due to lack of proper tools (Hedman, 2013). While previous work has brought out the ability of TC to provide economic savings, TC has been primarily limited to corrective based applications, which includes improving voltage profiles and transfer capability (California ISO 2010; ISO-NE 2010). It is often assumed that TC would degrade the reliability of the system;

however, (Hedman *et al.* 2009) demonstrated that cost savings can be achieved even while satisfying *N-1* reliability and (Korad *et al.* 2013) demonstrated that TC can help operators satisfy a robust *N-1* standard (demand is uncertain and is modeled by an uncertainty set via robust optimization). While past research (Fisher *et al.* 2008; Hedman *et al.* Feb. 2011; Hedman *et al.* Jul. 2011) has brought out the advantages of TC, the computational complexity has been a major deterrent to its application in real-time. Recent work (Ruiz *et al.* Oct. 2012) has explored formulating the transmission TC problem based on using generalized line outage distribution factors, (Guler *et al.* 2007); most transmission topology control models incorporate the susceptance – bus angle difference (B-θ) framework to model the optimal power flow whereas the work of (Ruiz *et al.* Oct. 2012) formulates a mixed integer program with generalized line outage distribution factors. Previous research indicates that sensitivity studies can be used to reduce the computational time for the TC problem (Foster *et al.* 2011; Fuller *et al.* 2012; Ruiz *et al.* 2011; Ruiz *et al.* Aug. 2012). A line ranking system based on a direct current optimal power flow (DCOPF) formulation is presented in (Fuller *et al.* 2012) and the method is compared against the global optimal solution to evaluate the performance of the heuristics.

The benefits of transmission modelling can be extended to various applications such as outage coordination, transmission expansion planning, seasonal transmission topology control, *N-1-1* reliability assessment, day-ahead operational planning, and real-time operations. There is a great opportunity for efficiency improvement through TC and other power control technologies such as Flexible AC Transmission System (FACTS) devices (Ardakani *et al.* 2015 a, Ardakani *et al.* 2015 b, Ardakani *et al.* 2015 c). The total congestion costs in PJM Interconnection (PJM) system in 2013 increased by $147.9

million, which amounts to a 28% increase compared to 2012 level of $529 million (*PJM*, 2013). Since, TC relieves congestion and enables better deliverability of reserves, application of TC can also help increase the amount of renewable penetration. TC can sometimes even avoid the need to commit an expensive generator in order to meet the demand at a specific location and, thus, reduce costs. TC can also help the system to achieve *N-1-1* reliability since switching provides a possibility of achieving better reliability when added redundancy negatively impacts the transfer capability on corridors of transmission (Hedman, 2013). TC can also be used to improve load shed recovery (Escobedo *et al.* 2014). One of the greatest advantages of using TC is that it helps leverage the flexibility in the operations and planning procedures without the need for any additional investment on infrastructure requirement as circuit breakers are already installed in the system.

Even though TC has enormous potential to provide benefits, there are a few bottlenecks to its implementation. Optimal transmission switching is a very computationally challenging problem to solve with its conventional MIP based modeling approach. Moreover, the current relay settings and coordination is not done for switching under normal operating conditions (Aquiles-Perez, 2013). If switching is done more frequently during base case operations, more frequent updates (recalculations) may be needed for the relay settings. A slight change in the relay settings in one area may affect the protection coordination in adjacent areas. Another concern with the implementation of TC is that the present market structure is not designed to accommodate TC actions during normal operating conditions. Reformulation of market rules might be required to accommodate transmission switching. For instance, the FTR allocations are currently done on longer horizons and the TC decisions made at day-ahead timeframe may affect the FTR payments and can even lead to revenue inadequacy. (Hedman *et al.* Jan.2011), examines how transmission switching affects revenue adequacy of FTR's.

The primary focus of this research is to develop and test new algorithms to facilitate TC in the real-time framework. The computational complexity is one of the key factors inhibiting the application of TC in real-time. In this research, a heuristic for TC based on a greedy algorithm is developed, which could provide quality solutions within a reasonable timeframe. In the greedy algorithm, an expression is derived, which indicates the impact on the objective for a marginal change in the state of a transmission line. This expression is used to generate a priority list with potential candidate lines for switching (both in and out of service), which may provide huge improvements to the system. This method does not solve a mixed integer program (MIP); rather, it is based on the solution of a linear program, the DCOPF problem. With this method, multiple solutions are generated at every stage. If one switching action fails to provide improvement, the next candidate line from the priority list is checked for improvement. The advantage of this method is that it is a fast heuristic, which solves linear programs iteratively to find the beneficial TC actions as compared to solving a mixed integer linear program (MILP) to find a switching solution. The algorithm is tested against the traditional MIP techniques to evaluate the quality of the solutions and the speed up factors that could be achieved with the heuristic. Tests are carried out on the IEEE 73 bus test system and the IEEE 118 bus test system for initial small scale testing and the FERC-PJM test case is used to evaluate the scalability of the algorithm for large scale systems. Parallelization of the heuristic is accomplished with the help of the Lawrence Livermore National Laboratory (LLNL) high performance computing facilities and the performance of the algorithm is analyzed. An application of the greedy algorithm is also proposed, which integrates the TC solutions obtained from the robust optimization framework developed in (Korad *et al.* 2013) with the TC solutions obtained from the linearized sensitivity study performed in real-time based on the current system operating states. Such an approach would combine the benefits of obtaining a robust TC solution offline (which is valid for a predefined uncertainty set) as well as the fast heuristic that could be simulated in real-time thereby effectively increasing the choice for TC in real-time.

While the greedy algorithm works well under the DC framework, the electrical system in practice works on an AC setting and if the switching actions have to be implemented in actual system, the solutions need to be AC feasible and stable. Reference (Soroush *et al.* 2013) compares two different greedy algorithm heuristics, one based on the DCOPF formulation and the other based on the ACOPF formulation for the application of TC and estimates the cost savings that could be achieved with the switching actions. It is found that the DCOPF based heuristics perform very poorly compared to the ACOPF based heuristic and thereby points out the need for developing ACOPF based heuristics for TC, which could provide reliable switching solutions. Reference (Ardakani *et al.* 2014) studies both the DCOPF and ACOPF based greedy algorithm heuristics on a large-scale Polish system and concludes that the greedy algorithm does not perform well for large scale systems in AC setting.

Hence, in this research, an alternative AC based heuristic has been developed to identify a subset of candidate lines for TC, which is simple to implement and could provide reliable beneficial switching solutions within reasonable timeframe. Dynamic studies are performed on the obtained switching solutions to ensure that the switching solutions are stable. The developed heuristic is incorporated into a real-time contingency analysis (RTCA) package, such that TC is used as a corrective mechanism to mitigate thermal flow and voltage violations that arise as a result of a contingency. The RTCA package is tested on the energy management system (EMS) data provided by the ERCOT and the PJM interconnection. The algorithm is also tested on the TVA system. It is found that the algorithms are fast and can easily handle large systems such as the PJM interconnection and solve within reasonable timeframe. Since, AC power flow is directly used in the implementation of the heuristic, there are no concerns about the performance of the heuristic for large systems on AC framework. Moreover, dynamic stability studies are conducted with standard software such as PSS/E to ensure the stability of the proposed TC solutions.

A detailed literature review is provided in Chapter 2. A thorough review of previous research conducted in transmission switching is presented highlighting the need and motivation for this research.

The TC problem is an extension of the optimal power flow (OPF) problem and, hence, a background on OPF is provided in Chapter 3. Since a part of this research is based on the direct current optimal power flow (DCOPF), a detailed derivation of the AC power flow equations is presented, which is followed by the derivation of the DCOPF with the application of suitable assumptions. As the unit commitment forms the basis of the OPF problems, the mathematical modeling of the unit commitment is also presented. The various reliability standards imposed on the system to ensure secure operation of the grid is discussed along with the contingency analysis procedures practiced by different ISO's.

Mathematical modeling forms the core of the OPF problem and the OPF could also be treated as a special form of the network flow problem. Chapter 4 provides a basic introduction to the optimization concepts. Specifically, it deals with the concepts of strong and weak duality, complementary slackness, linear programming, and mixed integer linear programming. The derivation of the heuristic (greedy algorithm) for TC is derived based on the Karush-Kuhn-Tucker (KKT) conditions. Hence, a detailed explanation of the KKT conditions is provided in Chapter 4.

Chapter 5 presents a detailed derivation of the heuristic based on a greedy algorithm. This chapter includes the explanation of the procedure taken for transmission switching by highlighting the insight behind the selection of the approach. It also presents the detailed modelling and the analysis of the proposed heuristic. The results include small scale testing, large scale testing, and an application of high performance computing.

Chapter 6 presents the methodology and the application of TC on an AC framework. Tests are carried out on the TVA, ERCOT and the PJM system to estimate the benefits that could be obtained through topology control on real large scale systems. This chapter also presents the main contributions of this research.

Chapter 7 presents the conclusions and the scope for future work. While Chapter 6 proves the potential of the approach with the various tests conducted and the promising results, Chapter 7 explores further applications and possible enhancements to broaden the scope of this research.

2. LITERATURE REVIEW

2.1 Introduction

One of the main objectives of this research is to develop methods to perform TC actions that could potentially enhance the control and flexibility of the grid. The focus is particularly on developing fast heuristics for transmission switching, which could provide good quality solutions within a reasonable timeframe suitable for real-time applications. Prior research has identified the effectiveness of employing TC for various applications. This chapter provides an overview of past research related to TC and the motivation to pursue further research in this field. A discussion on the current industrial practices where TC is applied is also provided.

2.2 National Directives

Energy has become one of the critical needs in today's world. There is a growing concern over the environmental impacts of producing energy through the use of fossil fuels. This has initiated enormous interests in investigating methodologies to improve the energy efficiency and to develop and commercialize renewable energy technologies. There have been several regulatory laws enacted by the government such as the Energy Policy Act of 2005, the Energy Independence and Security Act (EISA) of 2007, The Energy Improvement and Extension Act of 2008, and the American Reinvestment and Recovery Act of 2009 (Congressional Research Service 2013). Most of these acts were targeted to provide incentives for improving energy efficiency, developing renewable energy technologies, and for energy conservation. More recently, the renewable sources, such as solar and wind, have gained huge attention and sizable investments have been made for their development and commercialization. There have been several programs initiated by the government in the past, as early as 1970's, to motivate research and development in the field of energy, which continues even today.

There is also a growing interest in the development of smart grid technologies. For instance, "approximately $4 billion was used to implement smart grid programs authorized by EISA to accelerate the deployment of smart grid technologies across the transmission and distributions" (Congressional Research Service 2013). Electricity Deliverability and Energy Reliability, Research, Development and Analysis Grant Program administered by the Office of Electricity Deliverability and Energy Reliability (OE), "aims to develop cost effective technology that enhances the reliability, efficiency and the resiliency of the grid" (Congressional Research Service 2013). The Department of Energy through the Advanced Research Projects Energy Financial Assistance Program (ARPA-E) has allocated $276.7 million to finance sophisticated R&D projects to accelerate transmission technology advances in 2013 (Congressional Research Service 2013).

This project is in line with the national directives to develop cost effective technologies to improve the reliability, efficiency, and resiliency of the grid. This project has been funded by ARPA-E and the work is done based on an extensive collaboration with the industry. Topology control (TC) is a cost effective approach as it could enhance the grid flexibility by employing the circuit breakers to make or break the circuit without the need for much additional investments. This also supports the integration of more renewables in the grid as TC enhances deliverability of reserves by managing network congestion, which is essential for handling intermittent resources in the grid.

2.3 Topology Control as a Corrective Mechanism

Several research works in the past have explored the potential of topology control for corrective applications such as to mitigate line overloading and voltage violations. Most of the work does not consider generation re-dispatch along with transmission switching. Usually, a slack bus is assumed to provide the excess generation that is required, and hence, these approaches do not replicate the actual behavior of the system where the generators with available ramping capability respond to contingencies.

In (Mazi *et al.* 1986), corrective switching is presented as a methodology to relieve line overloads by selecting a subset of lines as candidates for switching for a particular system operating state based on the power transfer distribution factors (PTDF). A heuristic for transmission switching is presented, where only the lines from a subset are taken out of service to check for beneficial solutions. The drawback of this method is that it does not consider generation re-dispatch along with transmission switching and it also does not consider switching in lines that were out of service during the overload. (Bakirtzis *et al.* 1987) examines the benefits of transmission switching by employing a continuous formulation and also uses discrete control variables such as capacitor banks. An overview of transmission switching methods and search techniques that can be used to correct a disturbed state after the appearance of a fault is discussed in (Glavitsh *et al.* 1993). A fast corrective switching algorithm is presented to provide an optimal *N-1* secure system state in (Schnyder *et al.* 1990), which simultaneously considers generation re-dispatch and control over the transmission assets.

(Shao *et al.* 2005) develops a new solution technique to use transmission switching as a corrective mechanism to relieve line overloads and voltage violations. This paper proposes a sparse inverse technique combined with a fast decoupled power flow to reduce the number of iterations and increase solution speed. This research is followed by (Shao *et al.* 2006), which uses a binary integer programming approach to solve the same problem.

2.4 Applications of Topology Control for Economics

In (Fisher *et al.* 2008), a mixed integer linear program (MILP) formulation is presented for optimizing the generation dispatch with the network topology and huge cost savings are demonstrated by this application. Contrary to the traditional belief that transmission switching would degrade the reliability of the system, (Hedman *et al.* 2009) demonstrated that it is possible to achieve cost reductions by implementing TC while satisfying an *N-1* reliability standard however, this work only tests for *N-1* reliability with a steady-state linearized AC. It uses a mixed integer programming formulation as the status of the transmission elements are represented by binary variables. A generalized approach for co-optimization of generation unit commitment with transmission switching is presented in (Hedman *et al.* 2010). It demonstrates that the optimal unit commitment schedule changes with changes in network topology, and hence, it is possible to achieve cost savings by simultaneously optimizing the generation re-dispatch with the transmission topology. However, since transmission switching is optimized with unit commitment, the computational complexity is high and is not practical for real-time implementation. (Hedman *et al.* Feb. 2011) builds on the advantages of co-optimizing topology with unit commitment and introduces the concept of constraint relaxations to further improve the social welfare. (Hedman *et al.* Jul. 2011) provides a thorough literature review of the findings and practices of topology control emphasizing the huge potential of TC and reiterates the importance of pursuing further research to develop the technology.

2.5 Topology Control as a Tool to Minimize Losses

Topology control is proposed as a mechanism to reduce losses in the system by (Bacher *et al.* 1988). The nodal voltages, currents, and losses are expressed as a linear function of injected currents, which depends on the network configuration. This work demonstrates, in an AC setting, that network losses could be reduced by performing transmission switching. (Fliscounakis *et al.* 2007) presents a formulation to perform network topology changes to reduce the active power flows that are responsible for resistive losses. A piecewise linear formulation is presented to establish a relationship between active losses and real flows for each branch. An optimal topology is found by solving a mixed integer programming problem to minimize losses in the system. However, this approach does not consider the impact of the topology on the generation and, hence, it does not optimize the total cost nor does it directly enhance the reliability of the system.

2.6 Topology Control for Congestion Management

In (Granelli *et al.* 2006), optimal transmission switching is proposed as a tool to alleviate congestion in the system. It solves a mixed integer programming problem by using a deterministic branch and bound algorithm and a genetic algorithm. *N-1* reliability is enforced through the application of TC through a multi objective optimization framework.

2.7 Topology Control as a Tool to Accommodate More Renewables in the System

A line capacity expansion planning problem with transmission switching is investigated considering future uncertainty in demand and wind generation capacity. A two stage stochastic problem is formulated and solved. Results show that transmission switching helps reduce curtailment of wind power and affects the optimal line capacity expansion planning (Villumsen *et al.* 2013).

2.8 Practical Applications of Topology Control in Power System Operations

Although the transmission assets are traditionally considered to be static, there are several instances where transmission switching is employed for corrective applications by the industry today. Few of the TC operations mentioned in the PJM transmission operations manual are described below.

1. "Loadings on the Sunnyside-Warner-Torrey 138 kV for the loss of the S. Canton-Torrey 138 kV can be controlled by opening the S.E. Canton-Sunnyside 138 kV line at Sunnyside via supervisory control. Contingency loadings need to be watched on the SE Canton-Canton Central 138 kV and S. Canton-Torrey 138 kV circuits when this procedure is implemented." (*PJM*, 2012).
2. The opening of the 138 kV tie line 'L28201' from Zion to Lakeview (ATC) is provided as an option to prevent the system from exceeding its emergency rating if either of the following line outage takes place.
    - Zion Station 22 to Pleasant Prairie (ATC) 345 kV Red (L2221)
    - Zion Station 22 to Arcadian (ATC) 345 kV Blue (L2222)

Another application of transmission switching as mentioned by the California ISO in response to an event that caused substantial congestion in the network is,

> "These constraints resulted from outages in the higher voltage transmission system running north-to-south through the Sacramento Valley; the ISO had multiple days around this time when this 115 kV transmission system had significant congestion costs due to the north-to-south flows, until the ISO was able to later identify a remedy of transmission circuit switching to relieve this congestion." (California ISO, 2010)

The majority of the corrective TC actions are currently done on an ad-hoc basis primarily relying on the operators past knowledge. There is a lack of systematic tools that could provide optimal TC actions in a real-time framework. One of the objectives of this research is to develop a systematic tool that could provide TC actions suitable to be applied in real-time.

2.9 Fast Heuristics for Topology Control

The recent work (Ruiz *et al.* Oct. 2012) has explored formulating the transmission topology control problem based on using generalized line outage distribution factors, see (Guler *et al.* 2007). Most transmission topology control models incorporate the Susceptance – bus angle difference (B-θ) framework to model the optimal power flow whereas the work of (Ruiz *et al.* Oct. 2012) formulates a mixed integer program with the generalized line outage distribution factors, where TC actions are emulated through the use of flow cancelling transactions. Previous research indicates that sensitivity studies can be used to reduce the computational time for the TC problem. In (Barrows *et al.* 2012), a prescreening procedure is proposed based on the line outage distribution factors to reduce the number of candidate lines considered for switching. This makes the transmission switching problem tractable for huge test systems and reduces the computational burden. (Foster *et al.* 2011) proposes advancements to tractable TC techniques by introducing relaxations to the MIP formulation for corrective scenarios and by using sensitivity studies. Two different TC policies are analyzed: namely the Lagrange relaxation policy, which solves a relaxed version of the MIP DCOPF with TC, and the complete price difference policy which uses the sensitivity information obtained by solving a DCOPF. Reference (Ruiz *et al.* 2011) develops a heuristic to perform TC actions based on an individual line profit criteria based on congestion rents, which disconnects the single most unprofitable line. The work in (Ruiz *et al.* Aug. 2012) builds further on the previous work by developing and testing four TC policies based on sensitivity analysis and demonstrates cost savings to the system by the application of the TC solutions. Exploiting symmetry in transmission lines and its impact on computational time for TC is discussed in (Ostrowski *et al.* 2012). A prescreening method is described in (Liu *et al.* 2012) to select a subset of switchable lines to reduce the computational complexity. A line ranking system based on a direct current optimal power flow (DCOPF) formulation is presented in (Fuller *et al.* 2012) and the method is compared against the global optimal solution to evaluate the performance of the heuristic.

Several techniques have been proposed to reduce the computational complexity associated with the TC problem. The heuristics are demonstrated to provide substantial improvements in cost. However, most of the heuristics are tested on relatively small test cases and the application of TC is not extended beyond satisfying the *N-1* reliability standards. The research proposed in this work develops fast heuristics, which will be capable of managing *N-1* and *N-m* events. The potential of TC to mitigate simultaneous contingency events is evaluated. A TC tool is developed for emergency applications, which could provide switching solutions within reasonable timeframes and suitable to be applied in real-time. Moreover, heuristics are developed and tested on realistic systems such as PJM, ERCOT and TVA on an AC framework and a time domain simulation is also performed to check if the switching actions are stable.

3. OVERVIEW OF ELECTRIC POWER SYSTEMS OPERATIONS

3.1 Overview of Optimal Power Flow (OPF)

3.1.1 Introduction to OPF

The optimal power flow problem, along with strict constraints on reliability, makes it a very complex problem. The objective of the economic dispatch problem is to ensure adequate supply to meet the demand at minimum cost. This essentially considers the MW output of generators as variables. On the other hand, the optimal power flow (OPF) problem includes the constraints on the transmission lines power carrying capacity, the limits on the (real and reactive) power output of the generators, and the node balance constraints. Therefore, solving the OPF ensures that the demand can be satisfied economically guaranteeing that none of the transmission or generation limits are violated. Moreover, an OPF could additionally include constraints, which would enhance the ability of the system to operate securely during contingencies by including reserve requirements (Wood *et al*. 2007). This type of OPF is referred to as the security constrained optimal power flow (SCOPF).

Majority of the electric power grid operates on an AC setting. The Alternating Current Optimal Power Flow (ACOPF) can be used to optimize the power flows and generation dispatch in an AC setting. The expression for the AC power flow is given below (3.1 and 3.2) for reference. The derivation of the expression (3.2) is provided in the next section.

The AC power flow has two components as shown in (3.1), the real power (P) and the reactive power (Q). The bus voltage magnitudes are represented by $V_m, V_n.$ The bus voltage angles are represented by θ_m, θ_n. The additional constraints involved in the ACOPF formulation are the constraints on the magnitude of the bus voltage, the constraints on the bus voltage angle, the node balance constraints, the line flow capacity constraints, and the generator operational constraints, which include the unit commitment variables. These constraints make the problem a non-linear mixed integer programming problem, which is non-convex and, hence, very difficult to solve.

$$S_{mn} = P_{mn} + jQ_{mn} \tag{3.1}$$

$$S_{mn} = [V_m^2 g_{mn}] - V_m V_n [g_{mn} \cos(\theta_m - \theta_n) + b_{mn} sin(\theta_m - \theta_n)]$$
$$+j[-V_m^2 b_{mn} - V_m V_n [g_{mn} sin(\theta_m - \theta_n) - b_{mn} \cos(\theta_m - \theta_n)] \tag{3.2}$$

It is common to use a linear approximation to the ACOPF, the direct current optimal power flow (DCOPF), which eliminates the non-linearity and reduces the computational complexity of the problem. This approximation (DCOPF) will be extensively used in the derivation of the greedy algorithm.

3.1.2 Mathematical Formulation of DCOPF

3.1.2.1 Derivation of the Optimal Power Flow Equation

This section presents the derivation of the AC power flow equations as given in (3.3-3.21) and derives the DCOPF by applying suitable approximations to the ACOPF.

$$Z = r + jx \tag{3.3}$$

$$Y = g + jb \tag{3.4}$$

$$Y = Z^{-1} = \frac{1}{r + j\,x} \tag{3.5}$$

$$Y = \frac{1}{(r+j\,x)} \frac{(r-jx)}{(r-jx)} \tag{3.6}$$

$$Y = \frac{(r-jx)}{r^2+x^2} \tag{3.7}$$

$$Y = \frac{(r)}{r^2+x^2} + \frac{j(-x)}{r^2+x^2} \tag{3.8}$$

Therefore, $g = \frac{(r)}{r^2+x^2}$ $and\ b = \frac{(-x)}{r^2+x^2}$ (3.9)

Consider a transmission line connecting bus m and n. Let S_{mn} be the complex power associated with the network flowing through the branch mn.

$$S_{mn} = P_{mn} + j\,Q_{mn} = V_m\,I_{mn}^* \tag{3.10}$$

$$V_m = V_m \cos\theta_m + j\ V_m \sin\theta_m \tag{3.11}$$

$$I_{mn} = \frac{V_m - V_n}{Z_{mn}} \tag{3.12}$$

$$S_{mn} = V_m \frac{(V_m^* - V_n^*)}{Z_{mn}^*} \tag{3.13}$$

$$S_{mn} = [V_m \cos\theta_m + j\,V_m \sin\theta_m] \left[\!\left[\frac{[V_m \cos\theta_m - j\,V_m \sin\theta_m] - [V_n \cos\theta_n - j\,V_n \sin\theta_n]}{r_{mn} - jx_{mn}}\right]\!\right] \tag{3.14}$$

$$S_{mn} = \frac{[V_m^2 \cos^2\theta_m + V_m^2 \sin^2\theta_m] - V_m V_n [\cos\theta_m + j\ \sin\theta_m]\,[\cos\theta_n - j\ \sin\theta_n]}{r_{mn} - jx_{mn}} \tag{3.15}$$

$$S_{mn} = \frac{[V_m^2] - V_m V_n\,[\cos(\theta_m - \theta_n) + j\ \sin(\theta_m - \theta_n)]}{r_{mn} - jx_{mn}} \tag{3.16}$$

$$S_{mn} = \frac{[(r_{mn} + jx_{mn})V_m^2] - (r_{mn} + jx_{mn})V_m V_n\,[\cos(\theta_m - \theta_n) + j\ \sin(\theta_m - \theta_n)]}{(r_{mn} - jx_{mn})(r_{mn} + jx_{mn})} \tag{3.17}$$

$$S_{mn} = \frac{[r_{mn}V_m^2] - V_m V_n\,[r_{mn} \cos(\theta_m - \theta_n) - x_{mn} \sin(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2}$$

$$+ j \left[\!\left[\frac{[x_{mn}V_m^2] - V_m V_n\,[r_{mn} \sin(\theta_m - \theta_n) + x_{mn} \cos(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2}\right]\!\right] \tag{3.18}$$

$$S_{mn} = \frac{[r_{mn}V_m^2] - V_m V_n\,[r_{mn} \cos(\theta_m - \theta_n) - x_{mn} \sin(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2}$$

$$+ j \left[\!\left[\frac{[x_{mn}V_m^2] - V_m V_n\,[r_{mn} \sin(\theta_m - \theta_n) + x_{mn} \cos(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2}\right]\!\right] \tag{3.19}$$

$$S_{mn} = \frac{[r_{mn}V_m^2]}{r_{mn}^2 + x_{mn}^2} - \frac{V_m V_n [r_{mn} cos(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2} + \frac{V_m V_n [-x_{mn} sin(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2}$$

$$+ j \left[\!\left[\frac{[x_{mn}V_m^2] - V_m V_n [r_{mn} sin(\theta_m - \theta_n) + x_{mn} cos(\theta_m - \theta_n)]}{r_{mn}^2 + x_{mn}^2} \right]\!\right] \quad (3.20)$$

$$S_{mn} = [V_m^2 g_{mn}] - V_m V_n [g_{mn} cos(\theta_m - \theta_n) + b_{mn} sin(\theta_m - \theta_n)]$$

$$+ j [-V_m^2 b_{mn} - V_m V_n [g_{mn} sin(\theta_m - \theta_n) - b_{mn} cos(\theta_m - \theta_n)] \quad (3.21)$$

Hence, (3.21) is same as (3.2), which represents the expression for AC power flow.

3.1.2.2 Assumptions Used in DCOPF

The DCOPF can be derived from the expression (3.21) by applying the following assumptions as listed below. The equations (3.22 – 3.30) represents the modeling of the OPF in a DC framework.

1. $V_m = V_n = 1$pu
2. $(\theta_m - \theta_n)$ is very small ≈ 0

   Therefore, $\sin(\theta_m - \theta_n) \approx (\theta_m - \theta_n)$; $\cos(\theta_m - \theta_n) \approx 1$
3. $Q = 0$, reactive power flow is neglected
4. The lines are considered to be lossless, (i.e.) $r = 0$

$$g = \frac{(r)}{r^2+x^2} = 0; \; b = \frac{(-x)}{r^2+x^2} = \frac{-1}{x}. \quad (3.22)$$

Applying these assumptions to the power flow equations derived above,

$P_{mn} = -[b_{mn}(\theta_m - \theta_n)]$ or $P_{mn} = [b_{mn}(\theta_n - \theta_m)]$.

Let the line connecting nodes m and n be denoted as k, the above equation becomes,

$$P_k = [b_k(\theta_n - \theta_m)], \forall k. \quad (3.23)$$

There is a capacity constraint on the transmission element k, which can be modeled as,

$$P_k^{min} \leq P_k \leq P_k^{max}, \forall k. \tag{3.24}$$

For a transmission element, $P_k^{max} = [-P_k^{min}]$ therefore

$$-P_k^{max} \leq P_k \leq P_k^{max}, \forall k. \tag{3.25}$$

The equations (3.23) and (3.24) eliminate the need for specifying separate constraints for limiting the bus voltage angle variable as (3.26) is obtained by substituting (3.23) in (3.24) as shown below

$$(\theta_n - \theta_m)^{min} \leq (\theta_n - \theta_m) \leq (\theta_n - \theta_m)^{max}, \forall n, m \tag{3.26}$$

Node balance equations,

$$\sum_{\forall \delta^+ (n)} P_k + \sum_{\forall g(n)} P_g - \sum_{\forall \delta^- (n)} P_k = d_n, \forall n \tag{3.27}$$

The generator operational constraints are specified by (3.28 and 3.29) and the objective is specified by (3.30).

- Assuming the generator is always committed and it has zero minimum output

  $$0 \leq P_g \leq P_g^{max} \tag{3.28}$$

- If there is a minimum output for the generator specified by P_g^{min}

  $$P_g^{min} \leq P_g \leq P_g^{max} \tag{3.29}$$

The objective is to minimize the cost, $\sum c_g P_g$ (3.30)

3.1.2.3 Injection Shift Factors and the Power Transfer Distribution Factors

An alternative approach to solve the DCOPF is by using the injection shift factor (ISF) or the power transfer distribution factor (PTDF) to approximate the flows in the branches. In the previous section, the formulation discussed was the “susceptance-bus angle” formulation, which is commonly referred to as the “$(b - \theta)$” formulation. The ISF is a linear approximation of the sensitivity of the active power flow in a branch with respect to the nodal injections, where a reference bus is assumed to ensure real power balance (Ruiz *et al.* Oct. 2012). The ISF ($\varphi_{l\tau}^{n}$) is always defined for a line *l* and node *n* and for a particular topology τ and, hence, it has to be recalculated for a different topology. Note that an injection of Δp at node n corresponds to an injection of $-\Delta p$ at the slack bus respectively. Therefore, the ISF is dependent on the location of the slack bus and, hence, the ISF may change if the location of the slack bus is changed. However, the power transfer distribution factor (PTDF) gives the sensitivity of active power flow in a branch for a power transfer from node *m* to node *n*. Therefore, a PTDF ($\emptyset_{l\tau}^{mn}$) is always defined for a line *l* between nodes *n* and *m* for a particular topology τ . Hence, a relationship could be derived to represent the PTDFs based on the ISFs as shown below in (3.31). When there is a transaction Δp between nodes m and n, considering a lossless DC power flow $\Delta p_m = -\Delta p_n$. Hence, the compensation at the slack bus cancels out and PTDF's become independent of the slack bus (Liu *et al.* 2004).

$$\emptyset_{l\tau}^{mn} = \varphi_{l\tau}^{m} - \varphi_{l\tau}^{n} \tag{3.31}$$

3.2 Unit Commitment

3.2.1 Introduction to Unit Commitment

Unlike other commodities, bulk electric energy cannot be stored economically. Even though there are a few storage techniques available, such as the pumped storage, storage of electricity is still not very efficient and is not cheap. This makes it necessary to produce energy at the same time it is consumed. Moreover, the production of energy must comply with various constraints imposed by Kirchhoff's laws and the physical limits imposed by the design of the generators and turbines. The power generation has to comply with the ramp rate constraints of the generator, minimum uptime and minimum downtime constraints and the required reserve levels. The electric power production must also have the flexibility to sufficiently meet the demand considering its dynamic nature. This makes the problem a complex multi-period mixed integer programming problem.

The unit commitment is usually done one or several days in advance to schedule the units to be committed so that the forecasted demand would be satisfied at least cost. This typically includes the constraints involving the capacity limits of transmission lines, the generation capacity, the minimum up/down time for generators, and the generator ramping capability. This process is to facilitate the slow generators to be available when needed and to ensure that there is enough capacity to serve the load economically in real-time. The generators often have non-zero 'eco-min' levels, which requires them to supply power in a specific range for economic operation.

3.2.2 Mathematical Modeling of Unit Commitment

Unit commitment is the scheduling of the generating units by satisfying several operational constraints in order to meet the demand economically and reliably. A binary variable u_g is generally used to indicate the status of a generator. The objective of the unit commitment problem is to minimize the total cost. There are four different costs that can be associated with the operation of a generator (Hedman 2012). The operating cost, no-load operating cost, startup cost and the shutdown cost. The operating cost is a variable cost incurred for producing power in order to meet the demand. The no-load operating cost is a fixed cost incurred during every period when a unit is operating irrespective of the power output from the generator. To startup a generator, such as a coal fired plant, there are many operations that have to be done before the generator produces the scheduled amount of energy. A few of these operations are steam production, warming up of the steam pipeline, warming up of the turbine plant, synchronization, and loading. The cost incurred in this process is termed as the startup cost. There is also a minimum time associated with these processes, which is termed as the startup delay. Hence, all generators cannot respond immediately to an emergency. This is one of the primary reasons why there are spinning reserve requirements to manage unexpected situations. Similarly, there is also a shutdown cost associated with the shutting down of a generator. These startup and shutdown costs are fixed costs, which are incurred when a system is started up and shutdown respectively. To model the startup and shutdown cost in the objective function, a startup variable, (v_{gt}), and shutdown variable, (w_{gt}), could be defined as binary variables such that they get active during startup and shutdown conditions respectively. The product of startup cost and v_{gt} would capture the startup cost and the product of shutdown cost and w_{gt} would capture the shutdown cost. There is also a minimum up and minimum down time constraint for a generator, which is forced by the auxiliary operations and the mechanical and electrical constraints of the system. Modeling all these constraints need the inclusion of a timeframe in the mathematical formulation, which makes it possible to analyze the process in various instants of time. The mathematical modeling of unit commitment is presented by (3.32 – 3.50).

$$\text{Minimize } \sum_t \sum_g (C_g P_{gt} + NL_g u_{gt} + SU_g v_{gt} + SD_g w_{gt}) \quad (3.32)$$

$$P_g^{min} u_{g,t} \leq P_{g,t} \leq P_g^{max} u_{g,t} , \forall g, t \quad (3.33)$$

$$P_{k,t} \;=\; \left[\, b_k(\theta_{n,t} - \theta_{m,t})\right], \forall k \tag{3.34}$$

$$-P_k^{max} \;\leq P_{k,t} \;\leq\; P_k^{max}, \forall k \tag{3.35}$$

$$\sum\nolimits_{\forall \delta^+ (n)} P_{k,t} \;+\; \sum\nolimits_{\forall g(n)} P_{g,t} \;-\; \sum\nolimits_{\forall \delta^- (n)} P_{k,t} \;=\; d_{n,t}, \forall n \tag{3.36}$$

$$v_{gt} - w_{gt} = u_{gt} - u_{gt-1}, \forall g, t \tag{3.37}$$

$$\sum\nolimits_{s=t-UT_g+1}^{t} v_{gs} \leq u_{gt}, \forall g, t \in \{UT_g, \dots, T\} \tag{3.38}$$

$$\sum\nolimits_{s=t-DT_g+1}^{t} w_{gs} \leq 1 - u_{gt}, \forall g, t \in \{DT_g, \dots, T\} \tag{3.39}$$

$$P_{gt} - \; P_{gt-1} \leq R_g^{+}(u_{gt-1}) + \; R_g^{SU} v_{gt}, \forall g, t \tag{3.40}$$

$$P_{gt-1} - \; P_{gt} \leq R_g^{-}(u_{gt}) + \; R_g^{SD} w_{gt}, \forall g, t \tag{3.41}$$

$$P_{g,t}^{SP\;res} \leq \; u_{gt} P_g^{max} - \; P_{gt}\;, \forall g, t \tag{3.42}$$

$$P_{g,t}^{SP\;res} \leq \; u_{gt} R_g^{+} \tag{3.43}$$

$$\sum P_{g,t}^{SP\;res} \geq R^{SP\;req}, \forall g, t \tag{3.44}$$

$$P_g^{max}(1 - u_{gt}) \geq P_{g,t}^{NSP\;res}, \forall g, t \tag{3.45}$$

$$R_g^{+}(1 - u_{gt}) \geq P_{g,t}^{NSP\;res}, \forall g, t \tag{3.46}$$

$$\sum P_{g,t}^{NSP\;res} \;+\; \sum P_{g,t}^{SP\;res} \geq R^{\;req}, \forall g, t \tag{3.47}$$

$$0 \;\leq\; v_{gt} \leq\; 1, \forall g, t \tag{3.48}$$

$$0 \;\leq\; w_{gt} \leq\; 1, \forall g, t \tag{3.49}$$

$$u_{gt} \in \{0,1\} \tag{3.50}$$

3.3 Power System Reliability Metrics

Reliability is a major concern in the electric power industry. High quality power is expected to be delivered as there are severe penalties if the operator fails to meet expected standards. A breach in reliability may lead to blackouts, which can cause huge loss for society. In order to avoid blackouts, the system must be capable of withstanding contingencies such as the transmission line failure, transformer, or generation failure. North American Electric Reliability Corporation (NERC) requires power systems to withstand the loss of a single bulk electric element, which is referred to as the *N-1* requirement (*NERC TPL-002-0b*). The system must also be able to withstand uncertainties associated with the loads and the generation (especially from the renewable resources). The system operators must be capable of managing these problems and ensure reliable supply of energy. This requires the system operators to maintain the supply and demand balance and maintain all network constraints within limits (transmission thermal limits, voltage and stability limits). General corrective actions adopted by the system operators include generation re-dispatch and transmission switching (line and bus bar switching). The reliability requirement is mainly met through proxy reserve requirement rules. Acquiring reserves, however does not guarantee reliability, hence, the operators must ensure that there is enough deliverability of reserves to respond to contingencies.

3.4 Contingency Analysis

Security and reliability are the most important aspects of a power system. Studying the impacts of the outage of key elements such as transmission assets, and generating units, on the power system is termed as contingency analysis. Contingency analysis is a tool to estimate the reliability of the power system. While performing contingency analysis, the system will be tested for its capability to withstand the outage of one or more elements.

The Real-Time Contingency Analysis (RTCA) package in MISO, simulates more than 11,500 contingency scenarios every four minutes (*MISO - Reliability Assurance*).

RTCA utilizes data from state estimator and the contingency analysis is performed by successively solving AC power flows. Thermal and voltage violations corresponding to different contingencies are, then, determined (*MISO*, 2012) by analyzing the power flow result.

A full AC contingency analysis is performed to identify the critical contingencies in the PJM system (Baranowski *et al.* 2012). Every minute, around 6,000 contingencies are evaluated at PJM (Baranowski *et al.* 2012). Note that even though a list of contingencies are identified by PJM, not all of them are always simulated (*PJM*).

ERCOT uses a two-phase procedure to perform breaker-to-breaker contingency analysis (Thompson *et al.* 2009), which is simulated every five minutes (Garcia *et al.* 2012). In the first phase, the critical contingencies that cause the most severe violations are identified with the help of a screening procedure. In the second phase a full AC contingency analysis is performed on the identified contingencies. ERCOT had approximately 2958 single-branch contingencies, 375 double branch contingencies, and 605 generator contingencies, modeled in its system as of 2012 (Garcia *et al.* 2012).

Moreover, ISO's specify specific requirements for the spinning and non-spinning reserves to ensure that there is enough ramping capability to manage certain events. For instance, the California ISO has specified that the spinning reserve must include 5% of the demand met by hydro, 7% of the demand met by other resources, and either a 100% of the interruptible imports or the single largest contingency whichever is greater (California ISO 2006). In this research, algorithms are developed and are tested when there are *N-1*, *N-2*, and *N-m* contingencies and the performance of TC is analyzed. However, note that, while performing contingency analysis, the system status is checked for reliability at specific time stamps and, hence, contingency analysis by itself, does not guarantee that the system is reliable for any single contingency at any instant of time even though it passes the constructed *N-1* contingency analysis test.

3.5 Power System Stability

3.5.1 Introduction

The electric power system being one of the most complex systems in operation is a highly non-linear system, which is constantly subject to change. The fact that electricity is almost instantly produced and consumed forces the system to operate with constant changes in the load, generation. Moreover, there are several other factors such as weather conditions, miscellaneous attacks, which could lead to contingencies, load shedding etc., thereby causing a wide range of disturbances to the system. It is also not practical to design a system to be stable for all possible scenarios. Hence, a system is always designed to be stable for a set of disturbances around an operating state.

The stability of a system which is subject to a particular disturbance depends on its current operating state and the nature of the disturbance. It is possible that the power system operating at a given set of conditions (operating state) is stable for a particular disturbance, however, the same disturbance may cause the system to collapse when it is operating under a different operating state. Hence, it is also not easy to classify a disturbance as small or large depending on its magnitude alone.

Contingencies generally are associated with large changes to the operating equilibrium point of the system. Since, a significant part of this thesis deals with contingency analysis and corrective TC, stability analysis forms an important part of this work. Moreover, there is an overarching concern that TC may introduce more vulnerability to the system leading to system instability and these issues are addressed through this work. This section provides an overview of power system stability studies.

3.5.2 Critical Clearing Time

The power system is a highly interconnected system with various opposing forces that balance out each other at equilibrium. The inertia of the turbine generators and the inductance of the transmission lines are important factors that contribute to the stability of the system. A transient disturbance to one part of the system (generator or topology) could cause the entire system to oscillate. This is primarily because of the fact that while the electrical power output could change instantaneously, the mechanical power output of the system is relatively slower in its response. Hence, there is an imbalance set up in the electrical and the mechanical torque of the system which causes the rotor to accelerate or decelerate depending upon the nature of the disturbance. The system will eventually come to rest if there is enough damping in the system.

The electrical power output of a synchronous machine is the product of the electrical torque and the angular velocity. Considering a fault occurs close to a generator operating at an initial equilibrium point, the electrical power output of the machine drastically reduces. However, due to the rotating inertia of the machine, there is an imbalance created between the electrical and the mechanical torque, which causes the rotor to accelerate resulting an increase in power angle. Once the fault is cleared, the electrical power is restored to a new operating point in the power angle curve depending upon the operating conditions, which causes the electrical torque to be greater than the mechanical torque causing the rotor to decelerate. The stability of the system is dictated by the amount of retarding torque in the system. The important factor that determines the stability of the system is the fault clearing time. If the fault is cleared soon enough such that the retarding torque is sufficient to make up for the accelerating torque the system will return to stable equilibrium point; else, the machine loses synchronism. The maximum time before which the fault has to be cleared to ensure stability is referred to as the critical clearing time. The ability of synchronous machines of an interconnected system to remain in synchronism after being subjected to a disturbance is referred to as the rotor angle stability (Kundur *et al.* 2004).

3.5.3 Classification of Power System Stability

Power system stability has been defined as, "power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact" (Kundur *et al.* 2004). Power system stability is an important requirement for secure operation of the power system. Power system instability has been reported to cause many major blackouts in the past, which emphasizes the need to focus more on the power system stability studies (Vassel 1965). Even though, transient angle instability has been the focus of the industry concerning system stability, different forms of stability studies have emerged with the evolution of power systems and with increased operation of power systems in highly stressed conditions (Kundur *et al.* 2004). As a result, the voltage stability, frequency stability and the analysis of the different modes of oscillations exhibited by the system are becoming increasingly important. For the purpose of analysis, power system stability is classified into three major categories, which are further broken down to sub categories as shown in Fig 3.1 (Kundur *et al.* 2004, Kundur 1994).

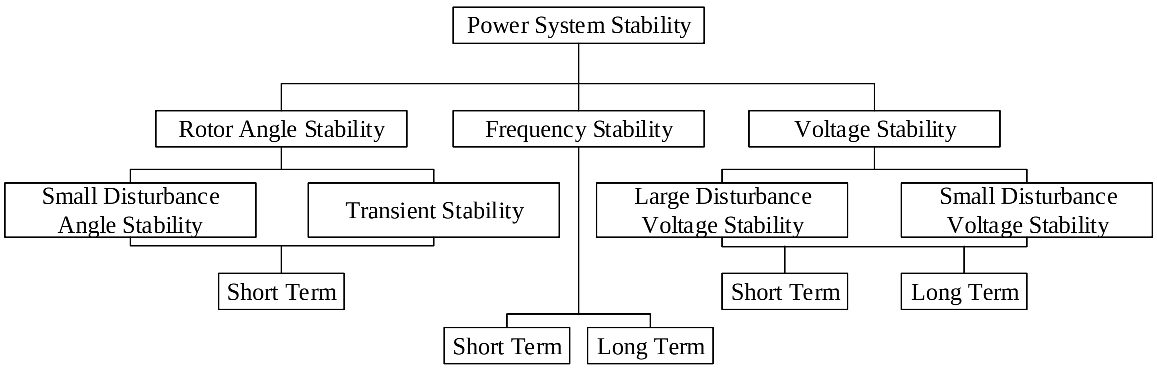


Fig. 3.1: Classification of Power System Stability (Kundur *et al*. 2004, Kundur 1994)

3.5.3.1 Small Signal Stability

The ability of the system to maintain synchronism under the influence of small disturbances is referred to as small signal stability. Usually the disturbance could be a small change in load or generation, which is small enough such that the system could be linearized around its operating point for the purpose of analysis. Following a disturbance, the electrical torque could further be resolved into the synchronizing torque and the damping torque. The component of the torque that is in phase with the rotor angle deviation is referred to as the synchronizing torque. Insufficient synchronizing torque results in non-oscillatory instability. The component of the torque that is in phase with the speed deviation is referred to as the damping torque. Insufficient damping torque leads to oscillatory instability (Kundur *et al*. 2004). The fast acting excitation systems could help with providing the required synchronizing torque; however, the downside of such fast acting excitation system is that it could cause a significant reduction in the damping of the system oscillations thereby contributing to oscillatory instability. These oscillations may be local or global and based on its nature, they are further classified as inter unit oscillations, local mode oscillations and inter area oscillations. If the oscillations involve a set of synchronous machines confined within a power plant or nearby power plants and swing against each other with a frequency of oscillations ranging between 1.5-3 Hertz, they are termed as inter unit oscillations. Local plant mode oscillations generally involve a set of synchronous machines at a power station swinging together against the rest of the power system. Typically, the frequency of local plant mode oscillations are in the range of 0.7 – 2 Hertz. However, if a group of generators in one area swing against a group of generators in another area, it is termed as inter area oscillations. Such oscillations are complex in nature are usually in the frequency range of less than 0.5 Hertz (Basler *et al*. 2008).

3.5.4 Transient Stability

Transient stability is related with large disturbances in the power system for which the system moves from an initial stable operating point to a new operating point and settles down if there is sufficient synchronizing and damping torque. Usually the process involves large deviations in the generator rotor angles and has a non-linear behavior. Hence, for such disturbances, the system could not be linearized around its operating point to analyze the stability of the system. The transient stability of the system is defined as the ability of the system to maintain synchronism when subjected to a severe disturbance and the stability is highly dependent on the operating state of the system and the severity of the disturbance. Instability will usually be in the form of aperiodic angular separation due to insufficient synchronizing torque. Although the initial 3-5s after the disturbance is of interest in studying this phenomenon, for very large systems with dominant inter area swings, the analysis may extend to 10-20 seconds post disturbance (Kundur *et al.* 2004).

3.5.5 Frequency Stability

Any imbalance between the generation and load usually causes variations in the system frequency. The ability of the power system to maintain a steady frequency following a disturbance which causes a significant imbalance between load and generation is referred to as the frequency stability. This essentially requires the ability to restore equilibrium between the load and generation with minimum unintentional loss of load. Sustained frequency oscillations would lead to instability leading to tripping of loads and/or generating units. In large power systems, sometimes the system is split into islands to manage the situation which may lead to cascading failures (Kundur *et al.* 2004). In such cases, the islands must have the capability to reach a new stable operating equilibrium with minimum unintentional loss of load.

3.5.6 Voltage Stability

The ability of the system to maintain steady voltages at all the buses after being subject to a disturbance is referred to as voltage stability. The disturbance might displace the system from its initial operating equilibrium and while the system reaches a new operating equilibrium, instability may occur as a progressive rise or fall of voltage magnitude in specific buses. Voltage instability may lead to a voltage collapse and subsequently there would be load shedding or tripping of transmission elements by the protective devices which may lead to cascading outages. Although the most common cause of voltage instability is the under voltage problem, over voltage instability is also been reported in the literature (Cutsem *et al.* 1997).

4. OVERVIEW OF OPTIMIZATION PROBLEMS

4.1 Introduction to Optimization

An optimization problem is the problem of finding the best solution from a set of feasible solutions. The variables in an optimization problem can be continuous or discrete or a combination of both. An optimization problem with continuous variables is called a continuous optimization problem. If the variables of an optimization problem are discrete, the problem is called a combinatorial optimization problem. It is important to discuss the mathematical framework of optimization problems as the optimal power flow problem, which is discussed in detail in this research can be described as a special form of a network flow problem.

4.2 Linear Programming

A linear programming problem is an optimization problem, which has a linear objective, typically to minimize a linear cost function, subject to linear equality or inequality constraints and has only continuous variables (Bertsimas *et al.* 1997). A general linear programming problem can be expressed as shown in (4.1-4.7). *M1, M2, M3* are index sets for the vectors 'a' and the scalars 'b' respectively. *N1, N2, N3* are the subset of (1…n) indicating sign of the variable x.

Minimize: $c^T x$ (4.1)

s.t.:

$a_i^T x \ \geq b_i, i \in M_1$ (4.2)

$$a_i^T x \leq b_i, i \in M_2 \quad (4.3)$$

$$a_i^T x = b_i, i \in M_3 \quad (4.4)$$

$$x_j \geq 0, j \in N_1 \quad (4.5)$$

$$x_j \leq 0, j \in N_2 \quad (4.6)$$

$$x_j \; free, \;\; j \in N_3 \quad (4.7)$$

A typical example of a linear program in electric power systems would be the DCOPF problem without modeling the constraints for unit commitment and assumes a fixed topology as specified in (4.8 - 4.12).

Minimize: $\sum c_g \, P_g$ (4.8)

s.t.:

$$P_g^{min} \leq P_g \leq P_g^{max}, \forall g \quad (4.9)$$

$$P_k = \; [\, b_k(\theta_n - \theta_m)], \forall k \quad (4.10)$$

$$P_k^{min} \leq P_k \leq P_k^{max}, \forall k \quad (4.11)$$

$$\textstyle\sum_{\forall \delta^+(n)} P_k \; + \; \sum_{\forall g(n)} P_g \; - \; \sum_{\forall \delta^-(n)} P_k \; = \; d_n, \forall n \quad (4.12)$$

4.2.1 Convex Sets

A convex set is one in which a convex combination at any two feasible points must lie within the feasible set. Fig 4.1 illustrates few examples for convex sets.

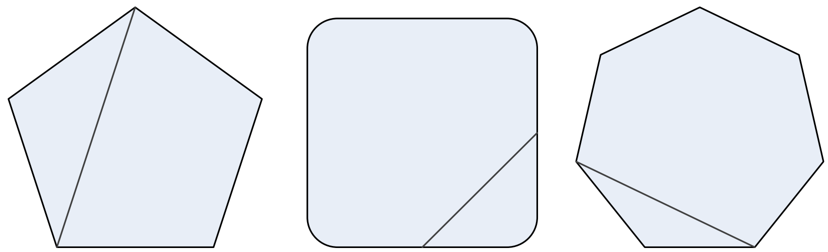


Fig. 4.1: Examples for Convex Set

A non-convex set is one in which a convex combination of any two feasible points need not lie within the feasible set. A few examples of non-convex sets are shown in Fig 4.2.

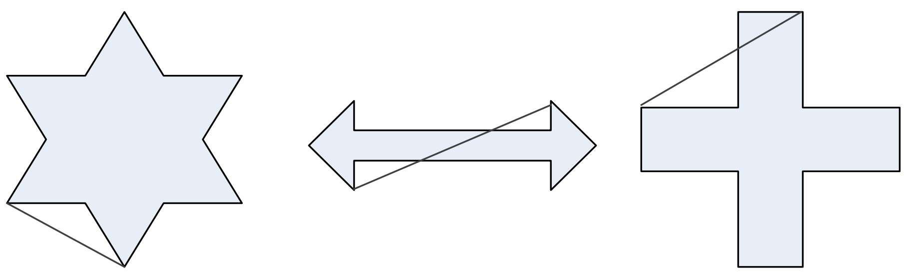


Fig. 4.2: Examples for Non-Convex Set

Operating with convex functions and convex sets makes the problem easier since producing optimality is easier as well as searching for good feasible solutions. When a convex function is minimized over a convex set, then the local minimum becomes the global minimum. This property need not hold true while operating with non-convex sets.

4.2.2 Optimal Solutions

A point X is an extreme point in a convex set S, if the point X cannot be obtained as a convex combination of any other points in S. If a linear program has an optimal solution and it has an extreme point, then there exists at least one extreme point that is the optimal solution to the problem. Generally, optimization algorithms are developed in such a way that if a feasible solution is given, the algorithm searches its neighborhood to find another feasible solution that would further minimize the cost in a minimization problem. If no such solution is available, the algorithm may terminate and give a local optimal solution. One of the widely used algorithms to solve linear programs, the simplex method finds an extreme point and checks whether it is the optimal solution. If that particular extreme point is not the optimal solution, it moves in search of another extreme point in the neighborhood, which corresponds to an improvement in the objective or is at least as good as the previous solution. This iterative process repeats as long as there are no other extreme points in the neighborhood that improves the objective function. This point is the optimal solution to the problem.

4.2.3 Primal and Dual Problems

In optimization problems, there are primal and dual problems. The primal problem is the optimization problem that is meant to be solved whereas the dual problem is some form of relaxation of the primal problem. The relationship between the primal and the dual depends on the class of optimization problem. Linear optimization problems come with nice properties between the primal and dual problems. The following example specified in (4.13-4.24) explains the formulation of a dual problem from a primal problem (Hedman. 2012).

Primal Problem

Minimize: $c^T x$ (4.13)

Such that: $Ax = b$ (p) (4.14)

$x \geq 0$ (4.15)

The relaxation of the above problem would be:

Minimize: $c^T x + p^T(b - Ax)$ (4.16)

Such that: $x \geq 0$ (4.17)

Let $g(p)$ represent the optimal cost for the relaxed problem

$$g(p) = \min_{x \geq 0}\left[c^T x + p^T(b - Ax)\right] \quad (4.18)$$

$g(p)$ forms the lower bound to the original problem which means $g(p) \leq c^T x^*$, $\forall\, p$. For each p, a different lower bound will be obtained. Since $g(p)$ is a lower bound to a minimization problem, the tightest lower bound has to be obtained. Hence it is required to maximize $g(p)$ which forms the dual problem.

Dual Problem

Maximize: $g(p)$ (4.19)

$$g(p) = \max\left[p^T b + \min_{x \geq 0}\left[c^T x - p^T Ax\right]\right] \quad (4.20)$$

$$g(p) = \max[\, p^T b + \min_{x \geq 0}[(c^T - p^T A)x]] \quad (4.21)$$

$$\Rightarrow\; g(p) = \max\left[p^T b + \begin{cases} 0, if : c^T - p^T A \geq 0 \\ -\infty, otherwise \end{cases}\right] \quad (4.22)$$

Hence p^T is chosen such that $p^T A \leq c^T$ otherwise the lower bound would reach -∞.

This gives the dual problem which is:

Maximize: $p^T b$ (4.23)

Subject to: $p^T A \leq c^T(x)$ (4.24)

p is free

4.2.4 Strong and Weak Duality

One of the properties that can be exploited from the duality theory is the property of strong and weak duality. Since, the dual problem is a relaxation to the primal problem, weak duality always holds ($'p^T b \leq c^T x'$ for a minimization problem). However, when a linear program has an optimal solution and so does its dual, the objective values coincide and strong duality holds as there is no duality gap in this case.

4.2.5 Complementary Slackness

The complementary slackness is another property that can be extracted from the duality theory, which states that if x and p are the feasible solutions to the primal and the dual problems respectively then, the vectors x and p are optimal solutions if and only if the (4.25, 4.26) are satisfied:

$$p_i(a_i^T x - b_i) = 0, \forall I \tag{4.25}$$

$$(c_j - p^T A_j)\, x_j = 0, \forall j \tag{4.26}$$

It can be deduced that if there is a constraint that is not binding at the optimal solution, it can be removed without affecting the optimal cost and there is no need to associate a non-zero price with it. However, a dual value of zero does not imply that the constraint is inactive.

The concept of duality and its properties are commonly used in energy markets. For instance, the locational marginal price (LMP) is the dual variable for the node balance constraints, which is used to make settlements to the generating firms. The susceptance price and the flow gate marginal price (the duals of the power balance and the transmission line capacity constraints respectively) along with LMP are used in this research to formulate a heuristic based on sensitivity studies.

4.2.6 Karush-Kuhn-Tucker (KKT) Conditions

The Lagrange relaxation method was briefly explained in the previous sections along with the concepts of duality. An extension of the Lagrange relaxation method could be adopted to ensure the optimality of solutions for both linear and non-linear systems. The necessary and sufficient conditions which are required to check for optimality of the solutions are referred to as the Karush-Kuhn-Tucker (KKT) conditions. The following example (4.27 – 4.36) illustrates the KKT conditions, which will later be used in this research to develop an algorithm for the electric power transmission network topology optimization problem.

For a function $f(x)$, the solution x^* that minimizes $f(x)$ must satisfy the necessary condition that $\nabla f(x^*) = 0$. This point x^* can either be a maximum or minimum or a saddle point. In order to confirm that x^* gives the strict local minimum the sufficient conditions have to be satisfied, which is: $\nabla f(x^*) = 0, \nabla^2 f(x^*)$ must be positive definite.

Minimize: $f(x)$ (4.27)

Subject to: $a_i(x) \geq 0 \quad (\mu), for\ i = 1, 2, ..., I$ (4.28)

$b_j(x) = 0 \quad (\lambda), for\ j = 1, 2, ..., J$ (4.29)

$x = (x1, x2, ..., x_j)$ (4.30)

The necessary conditions to be satisfied to find a strict local minimum as specified by the KKT conditions are given below:

$\nabla f(x) + \sum \mu_i \nabla a_i(x) + \sum \lambda_j \nabla b_j(x) = 0$ (Optimality) (4.31)

$a_i(x) \geq 0, for\ i\ in\ 1,2,\dots I$ (Primal Feasibility) (4.32)

$b_j(x) = 0, for\ j\ in\ 1,2,\dots J$ (Primal Feasibility) (4.33)

$\mu_i a_i(x) = 0, for\ i\ in\ 1,2,\dots I$ (Complementary slackness condition) (4.34)

$\mu_i \geq 0, for\ i\ in\ 1,2,\dots I$ (Dual feasibility) (4.35)

λ_j *is free* (4.36)

A point cannot be optimal if it does not satisfy the KKT conditions. However, the KKT conditions are not sufficient to ensure optimality. If the objective function and the inequality constraints are convex and the equality constraints are linear, then the KKT conditions are sufficient to ensure optimality (*Georgia Tech*, 2004).

4.2.7 Mixed Integer Linear Programming (MIP)

A standard form linear program is one in which the variables take any value as they are continuous in nature. The integer program is one in which the variables can take only integer values. A mixed integer program is one that has a combination of both integer and continuous variables. In general, a linear programming problem can be solved in polynomial time. In other words, a polynomial time algorithm can be used to solve the linear programming problem. However, an integer programming problem or a mixed integer programming problem is an NP hard problem.

Standard form linear program:

Minimize: $c^T x$ (4.37)

Such that: $Ax = b$ (p) (4.38)

$x \geq 0$ (4.39)

Integer program:

Minimize: $c^T x$ (4.40)

Such that: $Ax = b$ (p) (4.41)

$x \geq 0$ (4.42)

x integer (4.43)

Mixed integer program:

Minimize: $c^T x + d^T y$ (4.44)

Such that: $Ax + Ey = b$ (p) (4.45)

$x, y \geq 0$, y integer (4.46)

From the problem it is clear that the feasible set of solution for a MIP is non convex whereas the feasible set of solution for a linear program is convex as shown in Fig 4.3.

There are several methods to solve an integer program in literature. These methods are guaranteed to find an optimal solution, which includes cutting plane algorithms, branch and bound, and branch and cut; however, they might need several iterations to solve. There are also approximation algorithms, which provide sub-optimal solutions. The advantage is that the solution has a bound on the degree of sub-optimality. There are also other heuristics which could provide sub-optimal solutions very fast.

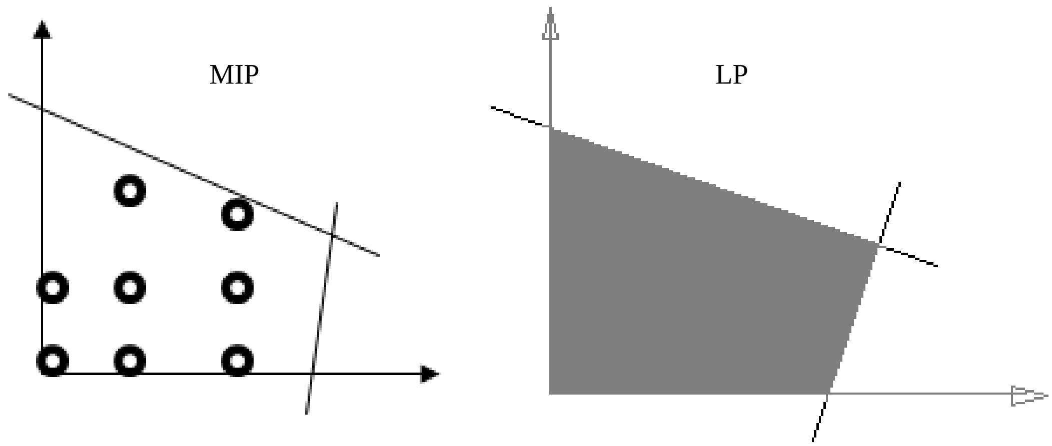


Fig. 4.3: Feasible Sets for a Mixed Integer Linear Program and a Linear Programming Problem

Cutting plane algorithms initially solve a relaxed problem and then apply a cut to the relaxed problem to get a tighter bound. The linear program relaxation is augmented with a new constraint, which represents the cut and is solved to get a new solution. This process is continued until an optimal solution is found or cutting plane algorithms may be used in combination with other techniques, such as branch and bound. The disadvantage of using a cutting plane algorithm to solve for the optimal solution is that it could take an exponential number of cuts. When using cutting plane algorithms in combination with other techniques, it is not always clear what cuts are the best cuts to apply to the problem as well as how many cuts should be applied. However, cutting plane algorithms are very useful as they play a key role in existing state of the art commercial optimization packages today.

A very common approach to solve the mixed integer program is the branch and bound technique. In this technique, the idea is to explore the feasible set of solutions by adopting a divide and conquer technique. This is a technique that, generally, does not require the exploration of the entire feasible set of solutions to find global optimal solution. This algorithm uses a technique to prune the nodes that are found to be infeasible or suboptimal. All the explanations given below are with the assumption that this is a minimization problem.

To solve a MIP, the integrality constraints are initially relaxed from the original problem, i.e., all the integer variables are treated as continuous variables with lower and upper bounds corresponding to integrality constraints. If $X_i \epsilon \{0, 1, 2, 3\}$, then X_i is relaxed to $0 \leq X_i \leq 3$. This creates a linear programming problem. The branch and bound method creates a tree structure of sub-problems as shown in Fig 4.4. In this algorithm, every parent node is the relaxation of the child node. Hence, the parent nodes can never be worse off than any child node. The child nodes have the same constraints as the parent node plus an additional inequality restricting the range of values for the chosen integer variable that was chosen for branching.

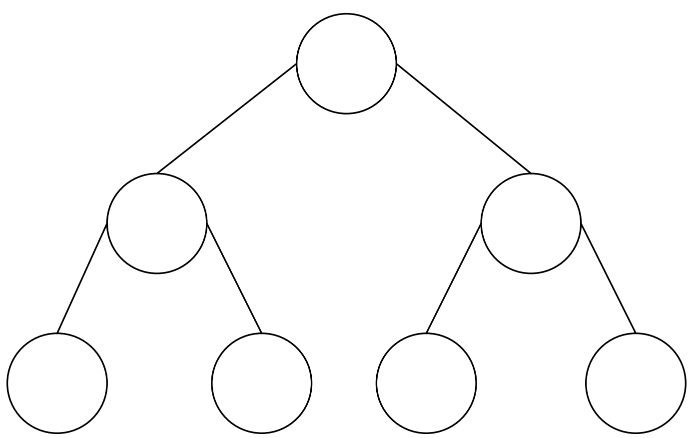


Fig. 4.4: Illustration for Branch and Bound Technique

Algorithm:

1. Relaxation of original MIP - Creates a linear programming problem
2. Solve initial node, if the solution for the initial node is integer feasible, then this is the optimal solution. Stop the process.
3. If the solution is infeasible, then branch on two integer variables, one of them rounded down from its current incumbent solution and the other rounded up from its current incumbent solution. Thus, two child nodes (sub-problems) are created and inequalities are formed for the two child nodes restricting the integer variable to be <= the round down value and >= the round up value.
4. If the solution is feasible,
   - If the optimal solution (from the relaxed problem) is larger than the current best feasible solution, then delete the node (for a minimization problem).
   - If the solution is less than the current best feasible solution and it is integer feasible, then this is the best solution so far.
   - If the optimal solution is less than the current best feasible solution but if it's not integer feasible, then continue branching on this node to find a feasible solution or until all nodes are pruned.
5. Repeat the steps 3 and 4 till optimal solution is obtained

By adopting the pruning technique, it eliminates the need to examine all the possible combinatorial solutions for the problem and saves computational time to get the solution.

A variant of the branch and bound algorithm is the branch and cut method, which augments the relaxed problem with cuts while solving the sub-problems. The cuts added to the sub-problems improve the bounds obtained from the relaxations to the original problem. Addition of cuts can drastically improve the solution speed; however, finding the cuts are, by themselves, a difficult problem.

Another method to solve an integer programming (IP) problem is dynamic programming (DP) approach. This is a sequential approach to solve an IP. In most applications, the backward DP solution approach is used, where the problem is solved by working backwards. The original problem is broken down into sub problems and these sub-problems are solved as a multi stage optimization problem in a sequence. Note that dynamic programming is not guaranteed to find the global optimal solution.

5 FAST HEURISTICS FOR TRANSMISSION SWITCHING – DC FRAMEWORK

5.1 Introduction

Chapter 1 provides the introduction to TC bringing out the need and the benefits of achieving flexibility in the transmission grid. Chapter 2 presents an extensive literature review describing the past research in the field and highlights the lack of systematic tools capable of performing TC in real-time. The primary objective of this research is to develop fast heuristics for transmission switching. Sensitivity based heuristics could be developed to improve the solution time of the TC problem while still maintaining the ability to find quality solutions. One such approach is presented in this section, which builds on the work of (Fuller *et al.* 2012). In (Fuller *et al.* 2012), an expression is derived indicating the impact on the objective for switching a line out of service. This expression is used within this research and another expression is derived indicating the impact on the objective for switching a line into service. Both expressions are used to generate a priority list with potential candidate lines for switching, which may provide huge improvements to the system.

This method does not solve a mixed integer program (MIP); rather, it is based on the solution of a linear program, the DCOPF problem. With this method, multiple solutions are generated at every stage. If one switching action fails to provide improvement, the next candidate line from the priority list is checked for improvement. The heuristic uses a priority list method where the ranking is based on a sensitivity study; linear programs are iteratively solved until a beneficial switching action is determined. Corrective TC strategies for real-time applications are presented, which include *N-1* events, *N-m* events, and an application for mitigating cascading events. The proposed algorithm specifically targets cases that lead to load shedding in the system and provides a quick and efficient method to restore the loads. This algorithm can also be used when a malicious attack or a cascading event causes a blackout. Simulation results on the IEEE 73 bus test system and the IEEE 118 bus test system suggest a significant improvement in the amount of load served to the system with TC, as opposed to without TC, with minimal time and computational efforts.

Rest of this section describes the greedy algorithm heuristic. Section 5.2 provides the generic DCOPF formulation, the MIP formulation for TC, and the derivation of the proposed heuristic. Description of the algorithm is provided along with the tests carried out and the observations showcasing the advantages of the proposed heuristic.

5.2 Mathematical Modeling for the Sensitivity Based TC Heuristic

5.2.1 Derivation of the Greedy Algorithm

5.2.1.1 Generic DCOPF formulation

This section presents the generic DCOPF formulation which will subsequently be used to derive an expression for TC. The formulation presented in (5.1)-(5.12) is similar to the one given in (Hedman *et al.* 2008). The modification is that separate equations are derived for the line flow constraints and the line capacity constraints to account for the lines in service and the lines out of service. Moreover, the objective function is to maximize the demand served, which treats the demand as a variable, instead of the more common objective: to minimize cost based on perfectly inelastic demand. This is done, mainly because, the potential of the greedy algorithm heuristic is going to be evaluated based on its ability to maximize the demand served to the system when the system is subject to contingencies that lead to load shedding.

Maximize: $\sum_{n\in N} d_n$ (5.1)

Subject to:

$-P_g \geq P_g^{max}, g \in G$ (α_g^+) (5.2)

$P_g \geq P_g^{min}, g \in G$ (α_g^-) (5.3)

$P_k \geq -P_k^{max}, k \in \widehat{K}$ (F_k^-) (5.4)

$-P_k \geq -P_k^{max}, k \in \widehat{K}$ (F_k^+) (5.5)

$P_k \geq 0, k \in \overline{K}$ (f_k^-) (5.6)

$-P_k \geq 0, k \in \overline{K}$ (f_k^+) (5.7)

$P_k - [b_k(\theta_n - \theta_m)] = 0, k \in \widehat{K}$ (S_k) (5.8)

$P_k = 0, k \in \overline{K}$ (s_k) (5.9)

$\sum_{k\in\delta^+(n)} P_k + \sum_{g\epsilon g(n)} P_g - \sum_{k\in\delta^-(n)} P_k - d_n = 0, n\epsilon N$ (LMP_n) (5.10)

$-d_n \geq -d_n^{max}, n \in N$ (σ_n^+) (5.11)

$d_n \geq 0, n \in N$ (σ_n^-) (5.12)

Equations (5.2) and (5.3) specify the generator limits. The line capacity limits for the lines in service are specified by (5.4) and (5.5); (5.6) and (5.7) force the flows on the lines, which are out of service, to zero. The DC power flow equations for the lines in service and out of service are represented by (5.8) and (5.9) respectively. The node balance constraints are specified by (5.10) and the limits for the load variables are specified by

(5.11) and (5.12). Even though (5.9) is the same as (5.6) and (5.7), it is included to show the similarity of equations (5.1)-(5.12) with equations (5.13)-(5.22).

5.2.1.2 Algorithm Derivation

The DCOPF formulation for maximizing the demand served via TC is given below. A binary variable z_k is used to represent the state of the transmission element k. This formulation with the inclusion of z_k makes it a MIP, which is NP hard. Both the formulations with and without TC are made equivalent by the addition of constraint (5.22) as shown below. Since both of these formulations are equivalent, the optimal solution to one formulation is also optimal for the other formulation.

Maximize: $\sum_{n \in N} d_n$ (5.13)

Subject to:

$-P_g \geq P_g^{max}, g \in G$ (α_g^+) (5.14)

$P_g \geq P_g^{min}, g \in G$ (α_g^-) (5.15)

$P_k \geq -P_k^{max}(z_k), k \in K$ (F_k^-, f_k^-)(5.16)

$-P_k \geq -P_k^{max}(z_k), k \in K$ (F_k^+, f_k^+)(5.17)

$P_k - [b_k(z_k)(\theta_n - \theta_m)] = 0, k \in K$ (S_k, s_k) (5.18)

$\sum_{k \in \delta^+(n)} P_k + \sum_{g \epsilon g(n)} P_g - \sum_{k \in \delta^-(n)} P_k - d_n = 0, n \epsilon N$ (LMP_n) (5.19)

$-d_n \geq -d_n^{max}, n \in N$ (σ_n^+) (5.20)

$d_n \geq 0, n \in N$ (σ_n^-) (5.21)

$z_k = Z_k^*, k \in K$ $(\gamma_k^{is}, \gamma_k^{os})$ (5.22)

Z_k^* is either 0 or 1, which indicates whether the line is out of service or in service respectively. For a fixed initial topology, the dual variable of (5.22) provides information regarding the change in the objective for a marginal change in the state of the transmission asset. It would be better to work with linear programming for real-time applications as opposed to mixed integer linear program. Hence, by deriving an expression for γ_k^{is} and γ_k^{os}, the sensitivity of all lines in the network can be determined. Based on the value of Z_k^*, the derivative of the Lagrangian with respect to z_k results in different expressions as given below.

If $Z_k^* = 0$,

$$P_k^{max} f_k^- + P_k^{max} f_k^+ - b_k(s_k)(\theta_n - \theta_m) + \gamma_k^{os} = 0. \quad (5.23)$$

$$\gamma_k^{os} = b_k(s_k)(\theta_n - \theta_m) - P_k^{max}(f_k^- + f_k^+). \quad (5.24)$$

If $Z_k^* = 1$,

$$P_k^{max} F_k^- + P_k^{max} F_k^+ - b_k(S_k)(\theta_n - \theta_m) + \gamma_k^{is} = 0. \quad (5.25)$$

$$\gamma_k^{is} = b_k(S_k)(\theta_n - \theta_m) - P_k^{max}(F_k^- + F_k^+). \quad (5.26)$$

When the line is in service,

$$P_k = b_k(\theta_n - \theta_m). \quad (5.27)$$

Equation (5.26) can further be simplified by substituting (5.27) into (5.26) as given below,

$$\gamma_k^{is} = P_k S_k - P_k^{max}(F_k^+ + F_k^-). \quad (5.28)$$

This substitution cannot be done for the lines out of service as P_k becomes zero.

By taking the derivative of the Lagrangian for (5.14)-(5.22) with respect to P_k gives an expression for S_k as shown below, which is the same as the dual constraints inside of (5.1)-(5.12) for P_k.

$$F_k^- + F_k^+ + S_k + LMP_n - LMP_m = 0. \quad (5.29)$$

$$S_k = LMP_m - LMP_n - F_k^- + F_k^+. \tag{5.30}$$

Substituting (5.30) into (5.28) further simplifies the expression,

$$\gamma_k^{is} = P_k(LMP_m - LMP_n - F_k^- + F_k^+) - P_k^{max}(F_k^+ + F_k^-). \tag{5.31}$$

$$\gamma_k^{is} = P_k(LMP_m - LMP_n) + P_k(F_k^+ - F_k^-) - P_k^{max}(F_k^+ + F_k^-). \tag{5.32}$$

$$\gamma_k^{is} = -F_k^-(P_k + P_k^{max}) - F_k^+(-P_k + P_k^{max}) + P_k(LMP_m - LMP_n). \tag{5.33}$$

Applying the property of complementary slackness, gives

$$-F_k^-(P_k + P_k^{max}) = 0. \tag{5.34}$$

$$-F_k^+(-P_k + P_k^{max}) = 0. \tag{5.35}$$

Substituting (5.34) and (5.35) into (5.33), a simplified expression is obtained for γ_k^{is},

$$\gamma_k^{is} = P_k(LMP_m - LMP_n). \tag{5.36}$$

Equations (5.24) and (5.36) give the expressions for γ_k^{os} and γ_k^{is} respectively, which can be used to determine the priority list for the line switching actions by solving the generic DCOPF formulation. It is to be noted that the expressions would still hold irrespective of any change in the objective. Only the interpretation of γ_k^{os} and γ_k^{is} would change for a different objective function and the dual variables would have a different value as a result.

5.3 Algorithm and Implementation

5.3.1 Formulation of the Priority List

This section describes the greedy algorithm procedure followed to find beneficial and feasible switching solutions by iteratively solving linear programming problems. The objective of the greedy algorithm for this particular application is to find a quick solution to minimize the load shedding to the system by employing TC. Here, the problem is broken down to many stages where a single beneficial switching action is implemented at each stage. Equations (5.24) and (5.36) give the possible change in the amount of load served to the system for a marginal change in the state of the transmission element *k*. These equations are used to find a switching solution as it is advantageous to switch the line that provides the maximum improvement to the system. However, the sensitivity study does not guarantee that the switching solutions are beneficial, let alone feasible. Hence, a priority list is formed based on this sensitivity study, e.g., the dual variables, and the algorithm iterates through this list to find a solution that provides an improvement. If the first candidate line did not provide any improvement, the next element in the priority list is checked for improvement. This process is repeated until a beneficial switching is found, a predefined search limit is exhausted, or the priority list itself is exhausted. If none of the candidate lines provide a beneficial switching solution, the problem is solved by fixing the original topology and the generators are re-dispatched with 10 minute ramp rates. If a switching solution provides improvement, then it is checked for AC feasibility and stability and then implemented. This process is repeated as long as there is improvement in the load served.

The description of the process is given in Fig 5.1 and the detailed flowchart for the greedy algorithm is presented in Fig 5.2. Note that, in this section, the results pertain to only testing the proposed solutions against the DCOPF formulation; ensuring AC feasibility and stability of the switching action, is taken into account in the methodology presented in the next section which elaborates on the AC based TC heuristics.

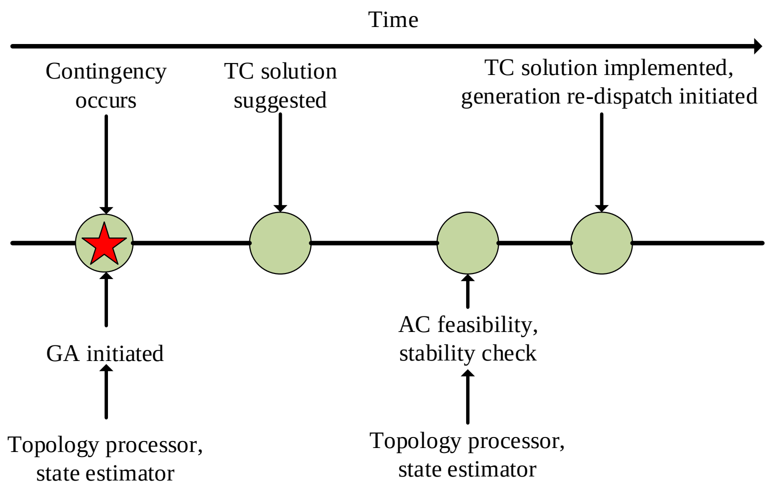


Fig. 5.1: Real-time Corrective Topology Control (TC) Timeline.

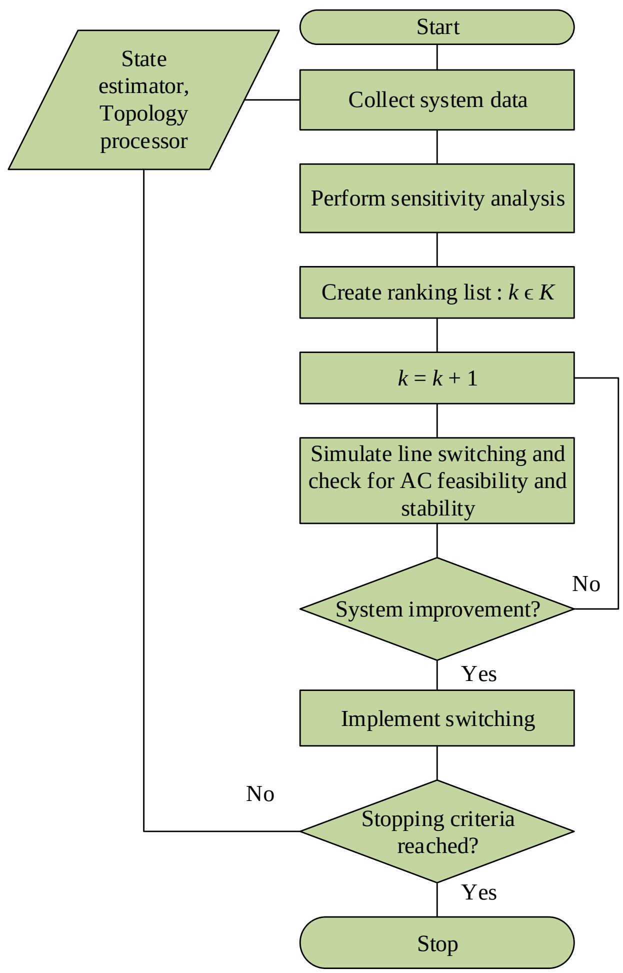


Fig. 5.2: Flowchart for the Greedy Algorithm (GA).

5.3.2 Test System and Machine Specification

The modified IEEE 118 bus test system and the IEEE 73 bus test system are used to analyze the potential of this heuristic to reduce the load shedding in case of different contingencies. The IEEE 118 bus test systems were taken from (University of Washington 2007). Two versions of the IEEE 118 test system are created; one is based on the generator information from (Fisher 2008) and the other is based on the generator information from the Reliability Test System 1996 (RTS96), (University of Washington 2007). The generator information is taken from these two sources since the IEEE 118 test system in (University of Washington 2007) does not provide generator information. Two versions of the RTS 96 (IEEE 73 bus test system) are also created in order to perform a more thorough analysis of the proposed method (University of Washington 2007), with the primary difference being that they have different ramp rates and generation costs, which include the operating costs, startup and shutdown costs, and no-load costs.

The generator operating costs are calculated using the fuel cost given in (Hedman, Feb. 2011). All four test systems (two versions in each test system) are used with two different loading conditions, namely 100% and 103% loading. The IEEE 118v1 test system has 118 buses, 54 generators, and 186 branches. The IEEE 118v2 test system has 118 buses, 19 generators, and 186 branches. The total generation capacity at each bus is the same for both versions of the IEEE 118 bus test systems. However, in the IEEE 118v1 test system, the same generation capacity is distributed among many generators with varying operational costs. The IEEE 73 bus test system is taken from the RTS96 test system (University of Washington 2007). Both the versions of the IEEE 73 bus test system have 73 buses, 96 generators, and 117 branches. However, the generation cost information and the ramp rates are different in both the versions and, hence, they provide different starting point solutions.

All simulations were carried out on a Windows 7 machine, with 48GB RAM, with Intel(R) Xeon(R) CPU with 2 core processors, 3.59GHz each with 64 bit operating system. The algorithm was implemented in Python 2.7 using PYOMO (Python Optimization Modeling Objects – version 3.2.6148). The solver used to solve the DCOPF model was CPLEX 12.4.

5.3.3 Results for *N-1* and *N-2* Events

Initially, to get a feasible, starting point solution, an economic dispatch problem is solved for a particular loading condition with a restriction that all generators must remain switched on and within their minimum and maximum limits. The contingency is applied at this stage and the post-contingency response of the greedy algorithm heuristic is analyzed and compared with other methods, which are described below. Note that while the IEEE 118 bus test system is not *N-1* compliant for the original dispatch solution, this study brings out the capability of the proposed heuristic to provide improvements to the system under such harsh conditions.

The performance of the algorithm is evaluated for all four of the test systems specified above, including both loading conditions (100% and 103%). All *N-1* and *N-2* contingencies were tested; the results are given in Table 5.1 for the *N-1* contingencies and in Table 5.2 and Table 5.3 for the *N-2* contingencies. The contingencies for which the initial 10 minute generation re-dispatch alone is insufficient to prevent load shedding are termed as non-trivial cases. The results for the load shedding incurred to the system are evaluated for two different cases, one with TC and the other without TC.

Table 5.1: Results for *N-1* Contingencies - IEEE 118 Bus Test System

Dataset	118v1		118v2	
Loading	100%	103%	100%	103%
Non trivial cases (%)	3.1	3.1	3.3	3.9
Ave. load shed without switching (MW)	51.3	60.2	104.9	120.3
Ave. load shed with switching (MW)	45	49.6	38.8	45.1
Reduction in load shed with RATC (%)	12.3	17.5	63	62.5
Ave. switching per contingency	0.6	1.4	2.8	3.7
Ave. search depth per iteration	5.2	3.8	3.1	3.2
Ave. time taken with switching (s)	3.08	3.09	3	4.09
Ave. time taken without switching (s)	0.69	0.84	1.04	1.19

Table 5.2: Results for *N-2* Contingencies - IEEE 118 Bus Test System

Dataset	118v1		118v2	
Loading	100%	103%	100%	103%
Non trivial cases (%)	6.3	6.5	7.1	8.2
Ave. load shed without switching (MW)	52.6	60.6	103.1	116.1
Ave. load shed with switching (MW)	45.8	49.7	40.2	44.8
Reduction in load shed with RATC (%)	12.9	18.1	61	61.4
Ave. switching per contingency	0.7	1.4	2.8	3.6
Ave. search depth per iteration	4.5	3.9	2.3	3.3
Ave. time taken with switching (s)	3.51	4.05	4.01	5.41
Ave. time taken without switching (s)	1.19	1.48	2.53	2.91

Table 5.3: Results for *N-2* Contingencies - IEEE 73 Bus Test System

Dataset	73v1		73v2	
Loading	100%	103%	100%	103%
Non trivial cases (%)	2.5	3.6	1.9	3.5
Ave. load shed without switching (MW)	6.2	6.3	6.9	5.3
Ave. load shed with switching (MW)	3.3	2.7	3.9	2.5
Reduction in load shed with RATC (%)	47.1	56.6	42.7	52.3
Ave. switching per contingency	2.4	2.6	1.6	2
Ave. search depth per iteration	1.4	1.4	1.8	1.6
Ave. time taken with switching (s)	1.39	1.54	1.13	1.77
Ave. time taken without switching (s)	1.32	1.42	1.15	1.34

For the RTS96 test systems (IEEE 73v1 and IEEE 73v2), the generation re-dispatch capability is sufficient enough such that there is no load shedding for the *N-1* contingencies, which is why there are no results presented for the *N-1* contingencies for those test systems. However, note that even if there is sufficient re-dispatch capability (from generation alone) without TC this does not mean that there is not a benefit for real-time corrective TC. In such situations, TC can still provide an economic benefit. By implementing real-time corrective TC, it is possible to reduce the cost of re-dispatching the generation. For instance, PJM has established post-contingency corrective TC strategies as special protection schemes (SPS). In the PJM transmission manual, they have documented well known TC strategies where they take a line out of service in order to redirect the power flow when a separate line has been tripped offline, i.e., taken out of service, due to a contingency (PJM 2012); this is to prevent post-contingency line overloads, which would then require generation re-dispatch. For the work presented in this section, the focus is only on *N-m* events that would result in post-contingency load shedding and the results demonstrate that TC can be used to further reduce the amount of load shedding and, at times, save the system from having to shed load when generation re-dispatch alone is insufficient to achieve such a result.

The best possible generation re-dispatch solution is solved iteratively to maximize the demand served to the system considering a fixed network topology and subject to 10 minute generation ramping constraints. The load shed incurred to the system by performing this operation is the load shed without TC.

The application of the greedy algorithm heuristic is to find a single beneficial switching action, to maximize the load served, and implement it iteratively while satisfying 10 minute generator ramping constraints. The load shed incurred to the system by performing this operation is the load shed with TC.

In the greedy algorithm procedure, the limit to search for beneficial switching actions is restricted to six per iteration; in other words, the algorithm checks only the first six proposed switching actions in the generated priority list. This is done to restrict the time the algorithm takes to solve and to reflect the case that, in practice, the algorithm needs to be accurate to produce quality potential actions at the top of the priority list. There is clearly a tradeoff between the solution quality and speed. The more the search limit is increased to search for beneficial switching solutions through the priority list, the better the solution quality will be. It is also true that, beyond a certain limit, the solution quality is unlikely to substantially increase. These observations are very specific to this particular test system and, similarly, a limit of six iterations to check for beneficial candidates for switching might not be the best choice in general. Such a policy can easily be tailored to the corresponding system.

It is observed that both the IEEE 73 bus test systems did not require any switching to prevent load shedding for *N-1* contingencies. Hence, only the results belonging to the IEEE 118 bus test system are analyzed for *N-1* contingencies. However, for *N-2* contingencies, TC provides huge improvements to the IEEE 73 bus test system. It is to be noted that such improvements were obtained with less than 2 iterations through the priority list and, thus, the computational time for the greedy algorithm is very fast. This result is important to emphasize the capability of the heuristic to provide quality solutions at the top of the priority list.

Note that the results for the greedy algorithm heuristic as well as the results for the generation re-dispatch method, which does not incorporate TC, are based on an iterative process and each iteration is modeled by a 10-minute re-dispatch period. Most systems specify operating reserves based on a 10-minute period; since there is load shedding in the examples being analyzed, multiple 10-minute periods are modeled to reflect the process that the operator would take to regain lost load as well as prevent load shedding.

From the results, it is observed that the percentage reduction in load shedding obtained by application of the greedy algorithm heuristic is significant. It is also noted that the results vary drastically depending on the dataset and the loading conditions. For instance, there is a substantial reduction in load shedding in the IEEE 118v2 test system for *N-1* and *N-2* contingencies with the application of the greedy algorithm heuristic. However, in the IEEE 118v1 test system, the reduction in load shedding is comparatively lower as the initial dispatch is different for both the test systems due to the difference in the operating costs. Moreover, the IEEE 118v1 test system has 54 generators that are well distributed in the system, which further reduces the effectiveness of TC in providing improvements by enhancing the deliverability of reserves. It is to be expected that the performance of the greedy algorithm will vary from system to system; however, the results demonstrate that even the lowest improvements are substantial, thereby demonstrating the value of TC in general and the greedy algorithm for fast TC. In general, the time taken by the algorithm to come up with a switching solution for most of the test systems is comparable with the time taken to solve the same problem without TC. This is to be expected for this small-scale test system; further work, which is presented in section 5.3.7 examines the scalability of the algorithm and its computational performance for large-scale systems.

The reliability improvement gained by the system, by the application of the greedy algorithm, can be estimated by analyzing the number of contingencies that are managed without load shedding. This measure is expressed as a percentage improvement in comparison to that achieved without TC in Table 5.4.

Table 5.4: Improvement in Number of Contingencies Managed without Load Shedding

Loading (%)	Dataset	*N-2* contingencies (%)	*N-1* contingencies (%)
100	IEEE 118v1	23.7	28.6
	IEEE 118v2	17.2	16.7
	IEEE 73v1	13.4	-
	IEEE 73v2	50.12	-
103	IEEE 118v1	14	14.3
	IEEE 118v2	15.5	14.3
	IEEE 73v1	5.5	-
	IEEE 73v2	18.6	-

The greedy algorithm results are also compared with an optimal topology control (OTC) method to evaluate the performance of the algorithm with respect to speed and accuracy of results. OTC is a method where the contingency is applied and the problem is solved to maximize the load served to the system without any restriction on the number of switching. However, the generator ramping restrictions are relaxed to allow for a 60 minute ramp rate. In other words, the problem gives the best possible network topology and generation dispatch values to meet the objective. It is obvious that owing to the computational complexity involved, it would require a huge time to solve the problem. On the other hand, the greedy algorithm is a heuristic used to reduce the computational time and, hence, it does not guarantee optimality for the original problem. However, this comparison gives a measure of the accuracy of the solution obtained by the greedy algorithm and its closeness to practical implementation. Table 5.5 presents this comparison for two of the test systems where significant reduction in load shed is observed with switching. The results are based on G-2 contingencies with the IEEE 118v2 test system and T-2 contingencies with the IEEE 73v1 test system.

The solutions from the OTC approach are used to establish the optimality gap for the greedy algorithm, which is presented in Table 5.5. For testing purposes, the MIP gap for OTC was set to 0.01%. It is observed that, the optimality gap is sensitive to the test system and the depth of the priority list for the greedy algorithm. For instance, in the IEEE 118v2 test system with 100% loading, the optimality gap decreases by about 46% if the depth of the priority list is allowed to change from 6 to 11. However, in the IEEE 73v1 test system with 100% loading, the optimality gap reduces by only 10% and remains the same even if the depth of the priority list is increased further. Such results can be used to establish a rule-of-thumb for the desired limitation of the priority list.

For all cases tested, even if the first 11 switching actions from the priority list are considered for switching, the optimality gap is well below 20% and the time taken to solve the greedy algorithm is roughly 21 times faster for the IEEE 118v2 case with 103 percent loading. Also, the number of switching actions required by the heuristic is only 30% of that required by the OTC procedure; this result is important to emphasize the substantial benefits that can be obtained with a fast algorithm that requires minimal switching actions but still obtains the majority of the benefits. At the same time, the greedy algorithm took more time to solve than the OTC method for the IEEE 73v1 test system; this is because the IEEE 73v1 test system is a very simple test system to solve, thereby decreasing the need for the greedy algorithm. In terms of solution time, the performance of the greedy algorithm is expected to substantially improve with larger test systems.

Table 5.5: Performance of the Greedy Algorithm and Optimal Topology Control

	Ave. time (s)	Ave. switching per contingency	Ave. search depth per iteration	Ave. load shed (MW)	Optimality gap (%)
IEEE 118 v2 – 100% loading (G-2)					
MIP	136.2	24.9	-	58.7	-
GR	1.7	-	-	196.5	234.6
GA6	5.3	6.3	2.5	88.9	51.3
GA11	9.	8.5	3.	62.1	5.7
GA16	10.6	9	3.6	61.3	4.4
GA26	15.8	9.8	4.4	60.7	3.4
GA51	22	10.2	5.4	60.6	3.1
GA	36.7	10.3	7.8	60.6	3.1
IEEE 118 v2 – 103% loading (G-2)					
MIP	177.8	24.2	-	58.9	-
GR	1.6	-	-	164.5	179.5
GA6	4.6	5.3	2.6	83	40.9
GA11	8.4	7.3	3.2	64	8.7
GA16	9.8	7.7	3.5	62.9	7.1
GA26	12.1	8	3.8	62.8	6.7
GA51	15.5	8.1	4.7	62.8	6.7
GA	29.4	8.2	7.4	62.8	6.7
IEEE 73 v1 – 100% loading (T-2)					
MIP	0.3	27.3	-	4.7	-
GR	0.8	-	-	11.5	146.2
GA6	1.2	2.6	1.5	6	28.2
GA11	1.0	2.7	1.7	5.6	18.6
GA16	2.1	2.7	1.8	5.6	18.6
GA26	2.2	2.7	2.1	5.6	18.6
GA51	2.6	2.7	2.7	5.6	18.6
GA	3	2.7	4.3	5.6	18.6
IEEE 73 v1 – 103% loading (T-2)					
MIP	0.2	20.4	-	4.2	-
GR	0.9	-	-	11.6	177.1
GA6	1.2	2.7	1.5	5.1	23
GA11	1.5	2.7	1.7	4.7	11.5
GA16	1.7	2.7	1.8	4.7	11.5
GA26	1.8	2.7	2.1	4.7	11.5
GA51	2.4	2.7	2.9	4.7	11.5
GA	3.5	2.7	4.4	4.7	11.5

While the solution time for the greedy algorithm with this IEEE 73v1 test system did not outperform the OTC method, it achieved similar results with roughly 13% of the switching actions proposed by the OTC procedure. It is also to be noted that the average solution time for the IEEE 73v1 test system was below 1 second. It is preferred to investigate the speed up factor provided by the greedy algorithm for large-scale test systems as the computational improvement is expected to be better for large-scale systems due to the combinatorial nature of OTC.

It is clear that, by increasing the depth of the priority list, the solution quality improves (or stays the same), which must happen. It should be noted that the computational time for the greedy algorithm is directly related to the depth of the priority list under consideration.

5.3.4 Results for *N-m* Events

To get a feasible starting point solution for *N-m* events, an economic dispatch problem is solved for a particular loading condition with a restriction that all generators must remain switched on and within their minimum and maximum limits. The contingency is applied to the system at this stage and the generation output is forced to remain between its previous output from the economic dispatch solution and zero. It is to be noted that the minimum limits for all the generators for this analysis is assumed to be zero. The performance of the greedy algorithm is evaluated by simulating different scenarios for *N-m* events. Two such scenarios are considered and tested on both the versions of the IEEE 73 and IEEE 118 bus test systems. In the first scenario, 5 lines are assumed to have a fault and are out of service. As a result, 15 more lines are tripped out of service and are available to be switched back in service since they do not have a permanent fault (the lines were tripped out of service due to post-contingency overloads). This example is replicated 33 times for the IEEE 118 bus test systems and 14 times for the IEEE 73 bus test systems (with different sets of 5 lines out of service with permanent faults combined with different sets of 15 lines that are tripped offline but do not have a permanent fault). In the second scenario, 3 lines are assumed to have a permanent fault and are out of service. Due to this fault, 12 lines are tripped and are available to be switched back into service since they do not have a permanent fault. Under this scenario, 58 different sets of lines with permanent faults versus lines out of service without permanent faults are tested on the IEEE 118 bus test systems and 35 combinations are tested on the IEEE 73 bus test systems. The greedy algorithm is applied on all of the above mentioned scenarios and its performance is evaluated based on the reduction in load shedding that it provides. The algorithm is also evaluated by varying the available lines for switching. First, the algorithm is tested by allowing any line without a permanent fault to have its status changed (i.e., lines that are in service can be switched out of service and lines that are out of service but do not have a permanent fault can be switched back into service). These results are presented in Tables 5.6-5.9 respectively.

The results pertaining to the *N-m* events demonstrate that the greedy algorithm for TC provides huge improvements to the system as compared to the results obtained by performing generation re-dispatch alone without TC. On average, the heuristic achieved about 80% reduction in load shedding. The important point to be noted here is that such improvements were obtained even with very tight restrictions on the depth of the priority list. For instance, 88.22% and 91.66% improvements were obtained on average for cases with a permanent fault on 3 lines for 100% and 103% loading conditions respectively on the IEEE 118v2 test system. Such improvements were obtained by just checking the first 4 switching actions from the priority list.

The greedy algorithm is also tested when only the lines that were tripped (taken out of service) due to post-contingency overloads (but did not have a permanent fault) are allowed to be switched back into service, i.e., no line in service is allowed to be taken out of service. The results for this case are presented in Table 5.10. For this analysis, both the 100% and 103% loading conditions are considered. In the greedy algorithm procedure, the limit to search for beneficial switching actions is restricted to a depth of four (per iteration) in the priority list.

Table 5.6: Results for *N-m* Events with a Permanent Fault on 5 Lines – IEEE 118 Bus Test System (without switching restrictions)

Dataset	118v1		118v2	
Loading	100%	103%	100%	103%
Ave. load shed without switching (MW)	379	398.6	378.8	400.4
Ave. load shed with switching (MW)	81	89.5	77.6	85
Reduction in load shed with RATC (%)	78.6	77.5	79.5	78.8
Ave. switching per contingency	7.4	7.5	7.2	7.4
Ave. search depth per iteration	1.5	2.1	1.5	1.5
Ave. time taken with switching (s)	4.4	5.3	2.5	3.15
Ave. time taken without switching (s)	0.75	0.73	0.70	0.74

Table 5.7: Results for *N-m* Events with a Permanent Fault on 5 Lines – IEEE 73 Bus Test System (without switching restrictions)

Dataset	73v1		73v2	
Loading	100%	103%	100%	103%
Ave. load shed without switching (MW)	728.5	761.2	721.3	751.1
Ave. load shed with switching (MW)	223.7	199	242.4	200.6
Reduction in load shed with RATC (%)	69.3	73.9	66.4	73.3
Ave. switching per contingency	4.2	5.2	4.5	5.5
Ave. search depth per iteration	1.9	1.8	1.8	1.8
Ave. time taken with switching (s)	3.4	4.5	4.6	3.9
Ave. time taken without switching (s)	0.58	0.68	0.56	0.72

Table 5.8: Results for *N-m* Events with a Permanent Fault on 3 Lines – IEEE 118 Bus Test System (without switching restrictions)

Dataset	118v1		118v2	
Loading	100%	103%	100%	103%
Ave. load shed without switching (MW)	265	281	267.4	410.4
Ave. load shed with switching (MW)	30.1	33	31.5	34.2
Reduction in load shed with RATC (%)	88.7	88.2	88.2	91.7
Ave. switching per contingency	5.5	5.8	5.5	5.5
Ave. search depth per iteration	1.4	1.4	1.4	1.4
Ave. time taken with switching (s)	2.2	2.3	2.2	2.3
Ave. time taken without switching (s)	0.7	0.8	0.6	0.6

Table 5.9: Results for *N-m* Events with a Permanent Fault on 3 Lines – IEEE 73 Bus Test System (without switching restrictions)

Dataset	73v1		73v2	
Loading	100%	103%	100%	103%
Ave. load shed without switching (MW)	633.7	665.6	633.2	665.2
Ave. load shed with switching (MW)	77.5	79.1	81.5	69.6
Reduction in load shed with RATC (%)	87.8	88.1	87.1	89.5
Ave. switching per contingency	4.1	4.3	3.9	4.4
Ave. search depth per iteration	1.6	1.7	1.4	1.5
Ave. time taken with switching (s)	2.4	2.8	2	2.4
Ave. time taken without switching (s)	0.51	0.52	0.51	0.52

Note that Table 5.10 does not display the results for IEEE 118v1 test system and IEEE 73v1 test system. These results are not being displayed since they are almost identical to the results in the previous tables that pertain to the cases where lines that were in service were allowed to be switched out of service. The results in Table 5.10 pertain to the cases where no line that is in service is allowed to be switched out of service.

Table 5.10: Results for *N-m* Events with a Permanent Fault on 3 Lines (with switching restrictions)

Dataset	118v2		73v2	
Loading	100%	103%	100%	103%
Ave. load shed without switching (MW)	267.4	282.3	633.2	665.2
Ave. load shed with switching (MW)	31.6	34.6	93.6	107.3
Reduction in load shed with RATC (%)	88.2	87.8	85.2	83.9
Ave. switching per contingency	5.5	5.5	3.9	4.5
Ave. search depth per iteration	1.4	1.4	1.5	1.5
Ave. time taken with switching (s)	2.2	2.2	1.9	2.6
Ave. time taken without switching (s)	0.64	0.63	0.51	0.52

Upon further analysis, most of the switching actions belonged to the lines that were tripped due to the fault and, hence, restricting the formulation of the priority list only to a small subset of lines (lines that were tripped) did not affect the results in a substantial way. However, this might not be true for a realistic, large-scale system with tighter constraints on the generation and reliability. The results also vary depending upon the initial dispatch solution. Moreover, the similarities between the results for these two test systems (with the restriction and without the restriction) are primarily due to the imposed limit on the depth of the priority list, which is 4.

The greedy algorithm results for the *N-m* events are also compared with the results of the OTC procedure to get a measure of the accuracy of the solutions provided by the heuristic. The results in Table 5.11 pertain to an *N-3* event where there is a permanent fault on one line and two generators are tripped offline. Five additional lines are tripped out of service but do not have a permanent fault. All lines without a permanent fault are allowed to be switched. For this analysis, the greedy algorithm is allowed to check for the first 16 actions in the priority list per iteration to find a beneficial solution. The results are averaged over 63 different events. For testing purposes, the MIP gap for the OTC was set to 0.05%. The algorithm is tested on the IEEE 118 bus test system v2 with 103% loading condition. From the results, it is observed that the greedy algorithm only required 43% of the switching actions required by OTC to provide 2.6 times faster results for an optimality gap of 15.8%.

Table 5.11: Comparison of the Greedy Algorithm Results for *N-m* Event with Optimal Topology Control Method

IEEE 118 v2 – 103% loading			
	MIP	GR	GA16
Ave. time (s)	142.4	2.3	54
Ave. switching per contingency	44.7	-	23.9
Ave. search depth per iteration	-	-	7.08
Ave. load shed (MW)	155.2	384.3	183.4
Optimality gap (%)	-	147.8	15.8

5.3.5 Parallelization of the Greedy Algorithm

In order to analyze the speed up factors that could be achieved by high performance computing, parallelization of the greedy algorithm was performed specifically for corrective based TC applications. The parallelization was carried out for the G-2 events (double generator outage) on the IEEE 118 v2 test system with 103% loading conditions. Table 5.12 represents the comparison of the results obtained with parallel and the sequential implementation of the greedy algorithm for real-time applications. It is to be noted that not all test systems required the application of the greedy algorithm to achieve the speedup factor as some of the test cases could be solved in seconds. Hence, only the cases that had longer solution times are parallelized. The objective of the algorithm for this particular application is to maximize the demand served to the system. The parallel algorithm is checked for its capability to provide quick solutions. The parallelization is done and the solutions are checked by varying the available number of nodes as shown in Table 5.12.

Table 5.12: Parallel versus Sequential Greedy Algorithm: Real-time

	Total # of cores used	Ave. time (s)	Ave. load shed (MW)	Reduction in load shed with switching (%)	Average # of switching actions per contingency
Sequential	1	21.4	48.3	62	6.5
Parallel	31	2.7	45.8	64	4.6
	62	2	45.8	64	4.3
	93	1.5	48	62	3.5
	124	1.4	48.2	62	3.5
	155	1.4	48	62	3.4
	186	1.4	48	62	3.6

From the results, it is observed that substantial improvements in the solution time can be achieved with the parallelization of the greedy algorithm. On average about 87% - 94% reduction in the processing time is achieved with the parallelization. Similar reduction in load shed is achieved with parallelization by employing only 52% - 71% switching actions as of that required by the sequential procedure. The results are encouraging and suggestive of providing significant improvements when applied on large scale systems.

5.3.6 Application of Greedy Algorithm for Real-time Robust TC Solution Evaluation

Three TC methodologies namely the real-time TC, deterministic planning based TC, and robust topology control are presented in (Korad *et al.* 2013). Although, real-time TC methodology is an ideal way to implement TC, it requires fast solution time. The challenge is to come up with an algorithm that scales well for large systems and has the ability to provide quality TC solutions within reasonable timeframe. In case of deterministic planning based TC, the switching actions are determined offline. The biggest advantage of this approach is that the computational complexity is handled offline and hence, the solution speed is not a major concern. However, the major drawback with such an approach is that the TC solutions are not guaranteed to provide improvements if the operator does not have perfect foresight about the system operating state. Application of the TC actions might impact the system negatively even if there is a slight deviation in the estimated operating state of the system. On the other hand, the robust TC methodology proposed in (Korad *et al.* 2013) combines the advantages of the real-time and planning based methodologies. In the proposed method, the TC solutions are determined from the day-ahead algorithm offline, by incorporating uncertainty sets via robust optimization. Hence, the TC solutions are guaranteed to be valid for a predefined uncertainty set, which covers a range of system operating states. The procedure to find robust TC solutions is as described in Fig 5.3. Once the day-ahead unit commitment is solved, a contingency analysis is performed by simulating a set of possible contingencies. The robust TC algorithm will find robust *N-1* TC solutions by considering the contingencies modeled in the contingency analysis routine. These TC solutions will further be tested for AC feasibility and stability. The resulting TC solutions will be evaluated in real-time using the real-time system states.

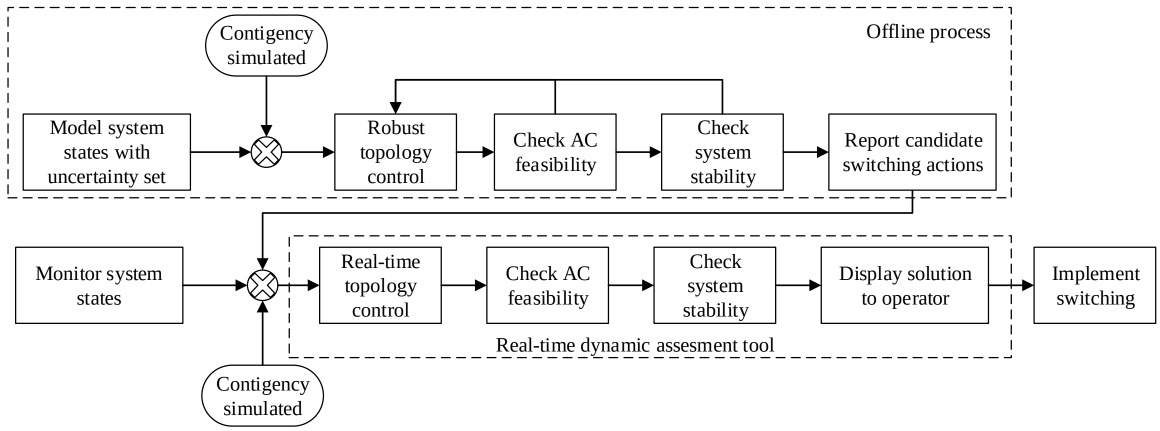


Fig. 5.3: Robust Corrective Topology Control Methodology (Korad *et al.* 2015)

The results from the previous sections highlight the effectiveness of the greedy algorithm heuristic for real-time applications. Multiple TC solutions are obtained to respond to a particular contingency in real-time. The solutions are fast enough to be applied directly in real time; however, the solutions are not guaranteed to be always effective as the TC actions are based on a sensitivity analysis. The TC solutions from the robust methodology is guaranteed to provide benefits for the entire uncertainty set. Hence, it would be advantageous to combine a fast real-time heuristic such as the greedy algorithm and the robust TC methodology in order to improve the solution quality with minimal computational complexity in real-time. Hence, it is proposed that after the robust TC solutions are obtained from the day-ahead stage, the resultant TC solutions could be used to create a rank list for real-time applications followed by the solutions from the greedy algorithm heuristic. Once a particular contingency occurs, the greedy algorithm combined with a real-time security assessment tool could be used to evaluate all the TC actions considering the real-time operating states.

Note that the work presented in this sub-section has been done along with Dr. Akshay Korad, a former graduate student of Dr. Hedman.

5.3.7 Application of Greedy Algorithm on Large Scale System

In the previous section, the results from the greedy algorithm based on the IEEE 118 bus and the IEEE 73 bus test system are presented. From the results it is observed that substantial improvements are achieved with implementation of TC solutions by employing the greedy algorithm. However, for this algorithm to be implementable on realistic systems, the algorithm has to be scalable to larger sized systems. In order to confirm the scalability of the algorithm, the greedy algorithm was implemented on the FERC-PJM test system. The FERC-PJM system comprises of 1384 buses, 18626 lines and 1011 generators.

A security constrained unit commitment (SCUC) is solved for a 24 hour period on the FERC-PJM test case to get an initial solution. In order to reduce the computational complexity, a PTDF structure is used for solving the 24 hour unit commitment problem. All lines and transformers that have a PTDF greater than 0.05 and are at a voltage level greater than 115 KV are modelled into the SCUC formulation. It is observed that, for the FERC-PJM system, it is not possible to meet all the demand without relaxing the line capacity constraints. Hence, the solution from the SCUC is obtained by relaxing the thermal limits of few branches in the system. An *N-1* contingency analysis was subsequently performed for all the single branch contingencies on one of the peak loading hours in the system. Note that while performing the contingency analysis, the capacity of the transmission lines that previously had violations from the SCUC solution are increased by the amount of the flow violation to ensure that there are no violations in the base case. Similar to the analysis done on the previous sections, the contingencies are classified as trivial and non-trivial and all the results pertain only to the non-trivial cases. Table 5.13 presents the single line contingency results from the FERC-PJM test case with and without implementing TC based on the greedy algorithm heuristic. For this particular application, only a single TC solution was implemented and the depth of the candidate list for TC was restricted to 4. In other words, the improvement obtained with TC within the first 10 minutes after the contingency is analyzed.

Table 5.13: FERC-PJM Single Line Contingencies: Results I

Total non-trivial cases (trivial)	201(~18,000)
Ave. load shed without switching (MW)	95.5
Ave. load shed with switching (MW)	19
Reduction in load shed with TC (%)	80.1
Ave. switching per contingency	0.91
Ave. search depth per iteration	2.17
Ave. time taken with switching (s)	77.5
Ave. time taken without switching (s)	26

It is observed that out of the 201 non trivial cases, 105 contingencies result in no load shedding by just switching one line out of service. Table 5.14 elaborates the results further by providing statistics for the 105 cases.

Table 5.14: FERC-PJM Single Line Contingencies: Results II

Cases with load shedding avoided	105
Ave. load shed recovered by implementing single switching for these 105 contingencies (MW)	30
Ave. search depth per iteration	1.9
Ave. time taken with switching (s)	69.9
Ave. time taken without switching (s)	26.9

Although the greedy algorithm scales well under the DC framework, the electrical system in practice works on an AC setting and the switching actions that come out of a DCOPF framework needs to be checked for improvements on an AC setting. Reference (Soroush *et al.* 2013) compares two different greedy algorithm heuristics, one based on the DCOPF formulation and the other based on the ACOPF formulation for the application of TC to estimate the cost savings that could be achieved with the switching actions. It is found that the TC solutions obtained from the DCOPF based heuristics perform very poorly when compared to the TC solutions obtained from an ACOPF based heuristic. Reference (Ardakani *et al.* 2014) studies both the DCOPF and ACOPF based greedy algorithm heuristics on a large-scale Polish system and concludes that the greedy algorithm solutions in general does not perform well for large scale systems on an AC setting. Hence an alternative approach is developed in this research for performing TC in an AC framework as discussed in the following chapter.

6 FAST HEURISTICS FOR TRANSMISSION SWITCHING – AC FRAMEWORK

6.1 Introduction

In Chapter 5, the development and application of a sensitivity based heuristic, a greedy algorithm, was presented along with the detailed formulation and simulation results. All the results were based on a DCOPF framework and the tests were carried out on the IEEE 118 bus test system, IEEE 73 bus test system and the FERC-PJM test system. For TC to be implemented on a real system, the switching actions need to provide benefits in an AC framework. In this chapter, an AC based real-time contingency analysis tool (IncSys) is used to identify the critical contingencies that cause voltage and flow violations in the TVA, ERCOT and the PJM system. Simple heuristics are developed to identify a small subset of candidate lines for switching that could provide improvements to the system and the benefits of TC are evaluated by solving AC power flow. The proposed heuristics are tested on both day-ahead and real-time framework. The results show substantial reduction in violations in the system with TC. Dynamic simulations are also performed on the PJM system to ensure system stability with the proposed TC actions. The heuristics are capable of providing reliable TC solutions within reasonable time frame suitable for real-time applications.

In the next section, details of the actual systems used for the analysis is provided followed by description of the conventional day-ahead scheduling procedure and the real-time process for performing the contingency analysis. The proposed TC actions are integrated into the contingency analysis routine so as to provide a recourse action in response to a contingency. An overview of the results of the contingency analysis and TC heuristics is also given, which highlights the effectiveness of the TC heuristics.

Note that all the work presented in this section, chapter 6, has been done as a part of the project, "Robust Adaptive Topology Control". It's a joint effort made by the graduate students of Dr. Hedman namely, Xingpeng Li, Pranavamoorthy Balasubramanian and Dr. Mostafa Sahraei Ardakani (Post-doctoral researcher).

6.2 Description of Actual System used for Analysis

The data for three days (72 hours) in the month of September 2012 was obtained from TVA. Modifications to the dataset were done to model only the data pertaining to the area within the TVA region. The modified network consists of 1779 buses, 1708 branches, 321 generators, 299 two winding transformers, 98 three winding transformers and 178 switched shunts. The tie line flows which capture the power exchange between TVA and the neighboring areas are also modeled. All the analysis pertaining to the TVA system are done based on this network.

The EMS data obtained from ERCOT and PJM is directly used without any modifications for all the analysis pertaining to the two systems. 167 hours of EMS data, which correspond to a week in the month of July 2013, is provided by PJM. The network consists of around 15200 buses, 14400 branches, 2800 generators, 6200 two winding transformers and 1200 switched shunts. The dynamic files corresponding to the 167 hours of data was also provided by PJM. Three snapshots of the EMS data is provided by ERCOT. The description of the actual system used for the analysis is given in Table 6.1.

Table 6.1: Description of the Actual Systems Used for Analysis

System	Number of hours data	Active Load (GW)	Reactive Load (GVar)	Number of buses	Number of generators	Number of branches
TVA	72	~24	~4	~1.8K	~350	~2,300
ERCOT	3	~56.9	~7.6	~6.4K	~700	~7,800
PJM	167	~139	~22.4	~15.5K	~2,800	~20,500

6.3 Incorporation of TC in the Day-ahead and Real-time Contingency Analysis Procedure

6.3.1 Day-ahead Scheduling Process

A security constrained unit commitment (SCUC) is initially solved by incorporating proxy reserve requirements. The SCUC is usually a deterministic model which is solved in a DCOPF framework. The model assumes a static topology, which may vary for different hours, based on which the generation status and the dispatch levels are determined. Although the reserve requirements are incorporated in the model, a reliable solution is not guaranteed. Moreover, since the unit commitment solution is based on a DCOPF framework, the resulting solution needs to be checked for AC feasibility before implementation. Therefore, a contingency analysis is performed to check for violations. If network violations are observed in the base case or after contingency analysis, the energy schedule is recalculated and the base case power flow is resolved. While it is possible to iteratively calculate the energy schedule until a reliable solution is found, it is often not done owing to limitations on time. The MISO day-ahead scheduling procedure is presented in (Casto A., *MISO*) as shown in Fig 6.1.

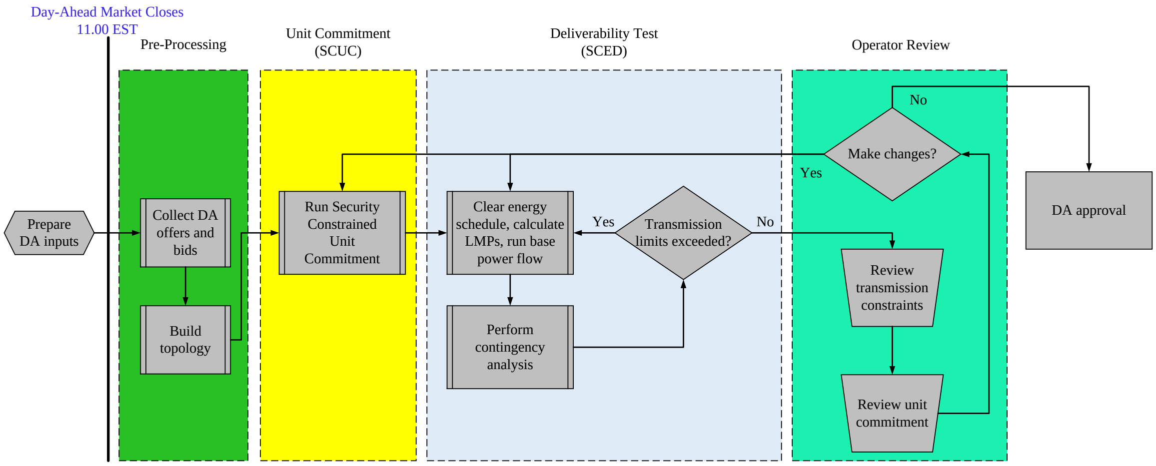


Fig. 6.1: MISO Day-ahead Market Model (Casto A., *MISO*)

6.3.2 Proposed Day-ahead Scheduling with Corrective Topology Control

In the proposed method, TC is included as part of the day-ahead scheduling process. The advantage is that TC may reduce the number of post-contingency violations that the operator needs to correct in order to ensure *N-1* reliability. TC could potentially reduce the number of the SCUC or SCED re-runs or even eliminate the need for costly uneconomic adjustments outside of the market engine (Al-Abdullah *et al.* 2014). By utilizing TC, the operator can quickly alter the power flow through the network during an emergency in order to avoid system violations. The proposed day-ahead scheduling process, with corrective TC, is shown in Fig 6.2. Note that all the analysis done on the TVA system pertain to the TC on a day-ahead framework. In this research, the advantages of including TC as a corrective mechanism in the contingency analysis procedure is analysed. Hence, the violation reduction with TC as opposed to without TC are studied. However, the SCUC/SCED process is not re-run and no out of market corrections are performed on the system once the contingency analysis and TC procedure is implemented.

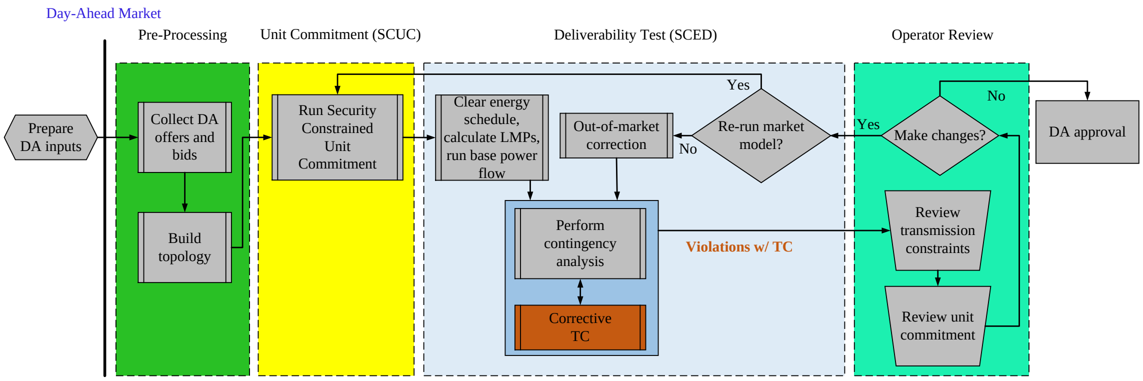


Fig. 6.2: Day-ahead Scheduling with Corrective TC

6.3.3 Conventional and Proposed Real-time Contingency Analysis Procedure

In real-time operations, if a contingency causes a violation in the system, usually the system is re-dispatched to avoid the violation or in some cases, additional units might also be committed based on the severity of the contingency. In the proposed approach, TC solutions are incorporated as a corrective action following a contingency that causes a violation in the system. Other control actions such as generation re-dispatch may also be employed along with TC actions depending on the type of contingency. The amount of violation incurred to the system with and without TC is compared as shown in Fig 6.3 and 6.4 respectively. Note that all the analysis done on the ERCOT and the PJM system are based on the real-time framework.

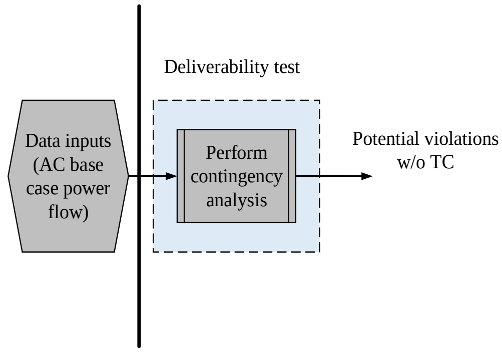


Fig. 6.3: Real-time Contingency Analysis without TC

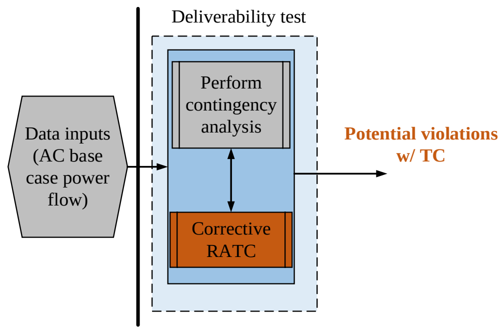


Fig. 6.4: Real-time Contingency Analysis with TC

6.4 Contingency Analysis Methodology

In general, even when a power system operates without any violations in a pre-contingency stage, occurrence of contingencies may cause severe violations in the system. There are numerous ways by which these violations could be handled and this research particularly explores the potential of corrective TC in handling post contingency violations. In this section different heuristics based on an AC setting are used to come up with a rank list for potential TC actions that could completely eliminate or reduce the violations incurred to the system due to a contingency. A complete enumeration of all the possible switching actions is also performed for specific cases so as to estimate the maximum benefits that could be achieved through TC on an actual system based on an AC framework. The results from complete enumeration would provide the upper bound for the benefits that could be obtained with TC on the particular system of interest. The benefits obtained with TC using the different heuristics will be compared with the benefits that could be obtained through complete enumeration procedure to evaluate the quality of the proposed heuristics.

For the purpose of investigation, a subset of contingencies causing violations beyond a certain threshold are identified by performing a complete *N-1* contingency analysis. In this research, 0.005pu is used as the threshold for voltage violation and 5 MVA is used as the threshold for thermal flow violation, both on an aggregate level across the entire system. Note that for the analysis done on the ERCOT and the PJM system, thermal violations on transmission elements connected to buses with voltage levels less than or equal to 70 KV are not monitored. All the different TC heuristics are applied only on this subset of critical contingencies. It is also well known that the system operators do not model all the possible *N-1* contingencies in the contingency analysis routine. However, due to lack of information on the critical contingencies for the different systems, an extensive contingency analysis is performed in this research to identify critical contingencies. Table 6.2 presents the overall statistics for the *N-1* contingency analysis.

In case of transmission contingencies, the pre-contingency output of the generators are retained and the difference in the losses due to rerouting of power flow is assumed to be supplied by the slack bus. In case of generation contingencies, an available capacity based generation participation factor is used for online generators as shown in equations 6.1 and 6.2, where, Δ_{gc} is the participation factor of unit g for contingency c, P_g^0 is the active power output of unit g in the pre-contingency state, $P_g^{\max}$ is the maximum capacity of unit g, P_c is the pre contingency output of the generator that is offline due to contingency c, and P_{gc}^1 is the active power output of unit g in the post-contingency state c. Note that this rule can be easily updated to incorporate ramp rates.

$$\Delta_{gc} = \frac{P_g^{\max} - P_g^0}{\sum_{\forall g, g \neq c} \left(P_g^{\max} - P_g^0\right)} \tag{6.1}$$

$$P_{gc}^1 = P_g^0 + P_c\left(\Delta_{gc}\right) \tag{6.2}$$

Table 6.2: *N-1* Contingency Analysis Results

System	Number of Contingencies Simulated	Number of Contingencies with Violations	Number of Contingencies with Violations beyond Threshold
TVA	126,449 (1756 per hour)	15,540 (216 per hour)	4,272 (59 per hours)
ERCOT	13,044 (4348 per hour)	52 (17 per hour)	40 (13 per hour)
PJM	1,437,749 (8609 per hour)	11,100 (66 per hour)	8,064 (48 per hour)

6.5 Topology Control Heuristics

Three main heuristics are used as part of this research to come up with corrective TC actions which could provide substantial benefits to the system. The heuristics are, the closest branches to contingency element (CBCE), closest branches to violation element (CBVE), data mining approach (DM). The complete enumeration method (CE) was initially performed on the TVA system and it was observed that most of the beneficial switching actions were located either close to the contingency element or the violation element. Based on this observation, two heuristic approaches, CBCE and CBVE, are developed. CBCE searches for the 100 closest branches to the contingency element to find the potential TC solution. CBVE heuristic searches for the 100 closest branches to the violation element to find the potential switching candidate. For transmission contingencies, it is found that the network violations occur on the elements that are very close to the contingency element. Hence, the lists of transmission switching candidates generated by both the CBCE and CBVE approach would be very similar. However, in the case of generator contingencies, generation re-dispatch is applied throughout the entire system, which changes the dispatch of the generators that are even far away from the contingency. The re-dispatch could potentially cause violations in areas far away from the contingency element. In such cases, it is very likely that the CBVE approach provides better TC solutions when compared with the CBCE heuristic.

Note that the closeness of a branch to the contingency element or the violation element is defined based on the network topology. For instance, in case of a branch contingency, the lines closest to the contingency element could be identified as follows. All the lines connected to the 'from' and/or 'to' bus of the contingency element will be the closest lines to the contingency element. Further expanding the graph, the branches connected to the other end of the closest branches identified in the first step will be included in the list of candidate lines for TC. This procedure is repeated to identify 100 closest lines to the contingency element. Similar procedure is used for the CBVE approach as well.

The data mining approach is based on the CE procedure and hence, it is performed only on the TVA system owing to its smaller size. Initially a complete enumeration of all the line switching actions is performed on the TVA data for all the three days. The beneficial actions for each contingency in each hour is identified and combined together. The candidate list for the switching actions for a particular day (test case) will comprise of the beneficial switching actions identified for the other two days (training case).

Different tolerances for identifying beneficial solutions with DM method can result in different candidate list lengths. In this research, three DM methods with different thresholds are studied. They are referred to as DM1, DM2, and DM3, respectively. There is no minimum threshold used in DM1 for identifying the beneficial switching solutions, which makes the list very lengthy for this approach, since even the candidates producing negligible improvements will be considered as potentially beneficial TC solutions. Only the switching actions that provide a violation reduction of more than 5% comprise the candidates for TC in DM2. DM3 has the smallest list length as it includes only those switching actions that provide a violation reduction of more than 10%.

All the heuristics described above identify the top 5 switching candidates that provide maximum reduction in violations to the system. Table 6.3 presents the overall statistics on the reduction in violations obtained by implementing the first best switching action based on the CBVE proximity search algorithm.

Table 6.3: Overall Statistics on Performance of TC

System	Number of Contingencies Fully Eliminated	Number of Contingencies with Partial Viol. Reduction	Number of Contingencies with No Viol Reduction
TVA	427 (6 per hour)	3,535 (49 per hour)	310 (4 per hour)
ERCOT	6 (2 per hour)	27 (9 per hour)	7 (2 per hour)
PJM	2,684 (16 per hour)	4,554 (27 per hour)	826 (5 per hour)

Table 6.4 presents the average violation reduction obtained with the application of TC on the three systems used for analysis. The average thermal flow violation reductions are 40%, 53%, and 59% for the TVA, ERCOT, and PJM systems respectively. Similarly, the voltage violation reductions on average are found to be 36%, 12%, and 20% for the TVA, ERCOT and PJM system respectively. The average violation reduction in percentage is calculated as shown in equation 6.3, where, Δ_{co} denotes the total violations after

contingency c; Δ_{c1} denotes the total violations after implementation of the corrective TC action, and $N_c$corresponds to the total number of critical contingencies investigated.

$$P_{TC} = \frac{1}{N_c}\sum_{1}^{N_c}\frac{\Delta_{c0}-\Delta_{c1}}{\Delta_{c0}} * 100\% \tag{6.3}$$

Table 6.4: Average Violation Reduction with TC

System	Avg. Flow Violation Reduction		Avg. Voltage Violation Reduction	
	w/o PI	w/ PI	w/o PI	w/ PI
TVA	40.0%	40.0%	36.2%	35.6%
ERCOT	53.1%	49.3%	12.3%	12.3%
PJM	59.3%	59.0%	19.5%	19.3%

Although the post-contingency violations may be reduced on an aggregate level by implementing a specific TC action, it is important to analyze the impact of the switching action on individual elements. It is possible that a specific switching action, while reducing the overall violations, creates additional violations that did not exist before implementation of the corrective TC action. TC may also increase the violation on one particular element, while reducing the overall violations. Pareto improvement (PI) is used as a flag to investigate such issues. A switching action makes Pareto improvements if it reduces the total violations without causing any additional violations on any other element of the system. Table 6.4 shows that the violation reductions with and without consideration of Pareto improvement (PI) are not very different. This finding illustrates that the TC actions identified in response to a specific violation almost never induces additional violations in the system. This is an important finding that highlights the quality of the TC solutions obtained from this study.

6.6 Software and Machine Specification

All simulations discussed in this chapter were carried out on a Windows 7 machine, with 16 GB RAM, with Intel(R) Core(TM) i7-3770 CPU, 3.40GHz with 64 bit operating system. The algorithm is built around IncSys' and Power Data's open source decoupled power flow, which is written in Java.

6.7 Application of TC on the TVA System

6.7.1 Performance of TC Heuristics on the TVA System

Table 6.5 presents the results obtained from the different corrective TC heuristics. The results from the complete enumeration (CE) method to find the best switching solution is used as a reference to analyze the effectiveness of the different heuristics. It is observed that the CBVE approach provides 40% reduction in thermal flow violations in comparison with 40.8% reduction achieved with CE. However, the reduction in voltage violation with CBVE method is only 36.2% as opposed to 48.2% that is achieved with CE. It is important to note that the CBVE approach took only 6.8% of the time taken by the CE method to find such quality solutions. It is found that the data mining approach performs better than both the CBVE and CBCE heuristics, which is expected for this small test system. Although all the three data mining methods provide similar reductions in violation, the solution time for DM3 is significantly smaller as it has the shortest candidate list of switching solutions among the three methods. DM3 method provides 26 times faster solutions with almost the same accuracy in comparison to the solutions obtained from CE method. The difference between the three DM methods is the threshold that is used to identify the switching candidates. Since, DM3 uses the largest threshold, it has the least number of switching candidates. Note that the solution time presented in Table 6.5 is for the implementation of the heuristic on a single processor and no parallel processing is involved.

One interesting observation form the results is that the reduction in violations obtained with both CBVE and the CBCE methods are found to be very different for the TVA system. This is primarily because the TVA system has a number of critical generator contingencies, which involves generation re-dispatch from units spreading across the entire system. The generation re-dispatch could potentially create violations in the system at locations which are far away from the initial contingency. Hence, the effect of switching lines in the proximity of a contingency is very different from the effects of switching a line in the proximity of a line that is overloaded.

Table 6.5: Results from Various TC Methods on the TVA System

TC Method	Avg. Solution time (**s**)	Avg. Flow Violation Reduction		Avg. Voltage Violation Reduction	
		w/o PI	w/ PI	w/o PI	w/ PI
CBCE	166.7	15.6%	15.0%	31.8%	30.9%
CBVE	177.8	40.0%	40.0%	36.2%	35.6%
DM1	201.9	40.6%	40.1%	48.1%	47.8%
DM2	106.6	40.5%	40.0%	48.1%	47.7%
DM3	98.3	40.5%	40.0%	48.0%	47.7%
CE	2585.3	40.8%	40.3%	48.2%	47.9%

Table 6.6 presents the solution time for the various TC heuristics implemented on the TVA system along with the time taken to perform contingency analysis. All the statistics on the solution time presented in Table 6.6 are averaged over the 72 hours simulation results. The solution time indicated for TC does not include the time taken to perform the contingency analysis. Note that the solution time for the DM3 method requires only twice the time that is required for performing CA. Moreover, among all the heuristics, the maximum solution time to identify such quality TC solutions is less than 4 minutes

even with sequential processing on a computer with moderate computing capability as described in section 6.6.

Table 6.6: Solution Time for CA and TC Methods on the TVA System

TC Method	average (s)	min (s)	max (s)
CA	45.0	43.4	47.7
CBCE	166.7	16.6	346.4
CBVE	177.8	17.7	373.0
DM1	201.9	17.9	464.2
DM2	106.6	9.9	230.8
DM3	98.3	9.7	207.0
CE	2585.3	208.5	10523.7

Fig 6.5 shows both flow violation reduction and voltage violation reduction associated to the five best CBVE switching actions, without consideration of Pareto improvement. From the figure, it is clear that as the rank of the switching candidate increases, the thermal flow violation reduction drastically falls; however, the variation in voltage violation reduction is not so steep. It should be noted that these results are specific to the TVA system that is used for the analysis and a generalization cannot be made based on these results for other systems. The congestion in the system can drastically alter the effectiveness of the TC technique, which could change depending on the operating state of the system. Other factors such as reserve requirements, type of generators, and the topology of the network also play important roles in performance of corrective TC. Moreover, this analysis is conducted on the data corresponding to 3 days in September 2012. The generation, loading patterns could be very different for a day in the month of January and further investigations have to be done on wide samples of data spreading across different seasons in order to make a generalized conclusion.

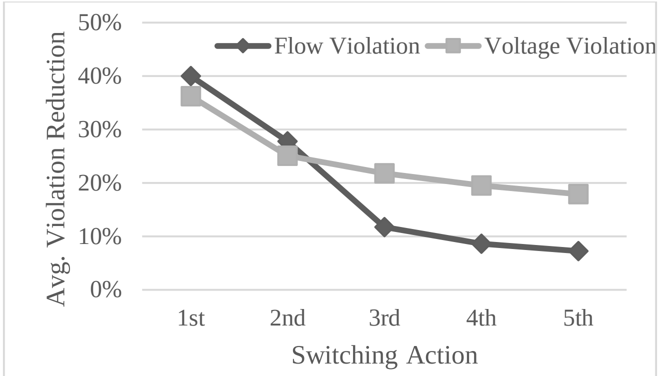


Fig. 6.5: Reduction in Violations Associated with TC Actions on the TVA System

6.7.2 Detailed Example of TC on the TVA System

In this section, a detailed example is presented in Figure. 6.6 to illustrate the effectiveness of TC for relieving post contingency violations. The pre-contingency, contingency, and the post-contingency states with the corrective TC action for a subsection of the TVA system is illustrated with the help of voltage contour plot as shown in Fig 6.6 (Li *et al.* 2014). All buses in the subsection that have an overvoltage problem in the contingency state are the 500 kV buses. All the overvoltage problems are mitigated just by implementing a single corrective switching action. This particular example corresponds to the system operating in a lightly loaded condition. The switching candidate produces reactive power which travels across the rest of the nearby lines in the pre-contingency state. However, as a result of the contingency, the reactive power flow to the rest of the system is inhibited and the excessive reactive power causes over voltage in the affected area. The switching action identifies the source element generating the excessive reactive power and removes it from the system, thereby eliminating the overvoltage problem.

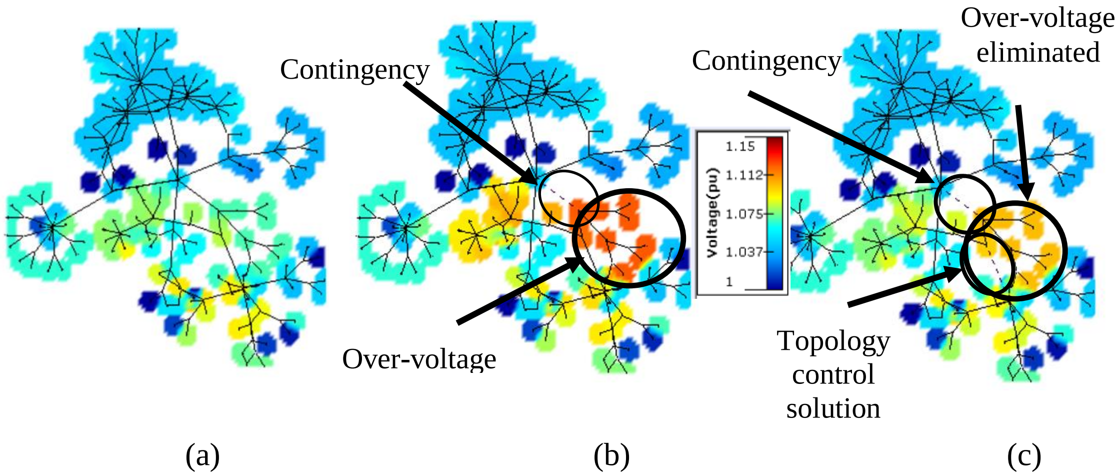


Fig. 6.6: Voltage Levels in (a) Pre-contingency, (b) Contingency, and (c) Post-contingency State for a Sub-section of TVA System (Li *et al*. 2014).

6.8 Application of TC on the ERCOT System

All the analysis on the ERCOT system is done based on the 3 EMS snapshots provided by ERCOT. Similar to the analysis done on the TVA system, a complete *N-1* contingency analysis is performed on the ERCOT system to find the critical contingencies that cause violations beyond the threshold. Since only 3 hours data was available, only the CBVE and CBCE heuristics were used to identify the corrective TC actions on the ERCOT system. A complete enumeration of all the TC actions is also performed to analyze the effectiveness of the TC heuristics. Table 6.7 presents the overall reduction in violations obtained from all the three TC methods and the corresponding solution time. It is found that the CBVE and the CBCE heuristics perform very similar to the complete enumeration procedure as far as the quality of solutions is concerned. However, the heuristics are capable of achieving similar quality solutions 47 times faster in comparison to the CE method, which proves the effectiveness of the approach.

Table 6.7: Results of Various TC Methods on the ERCOT System

TC methods	Avg. Solution time (s)	Avg. flow Violation Reduction		Avg. Voltage Violation Reduction	
		w/o PI	w/ PI	w/o PI	w/ PI
CBCE	245	40.8%	37.7%	12.1%	12.1%
CBVE	244	53.1%	49.3%	12.3%	12.3%
CE	11,505	53.3%	49.3%	14.3%	14.3%

6.8.1 Detailed Example of TC on the ERCOT System

Table 6.8 presents the reduction in violations achieved from implementing the top 5 switching actions as identified by the CBVE heuristic. It is found that the reduction in voltage violations with and without Pareto improvement are the same and the reductions in thermal violation is also very similar. The first best switching action achieves 53.1% reduction in thermal flow violation. Note that even the fifth best switching action achieves 47.2% reduction in violations.

Table 6.8: Results Corresponding to the 5 Best Switching Action on the ERCOT System Based on the CBVE Heuristic

Candidate	Flow Violation Reduction (%)		Voltage Violation Reduction (%)	
	Without PI	With PI	Without PI	With PI
1st Best	53.1%	49.3%	12.3%	12.3%
2nd Best	52.4%	48.9%	8.8%	8.8%
3rd Best	49.2%	46%	5.2%	5.2%
4th Best	48.3%	42.1%	4.2%	4.2%
5th Best	47.2%	41%	2.8%	2.8%

6.9 Application of TC on the PJM System

The PJM system is the largest of the three systems used for the analysis. Hence the computational time to solve the PJM system is very high compared to the TVA and the ERCOT systems. Therefore, all simulations on the PJM system is performed using a parallel processing approach, which uses 6 threads simultaneously to solve. The simulation is performed on the same machine that is used to solve the TVA and ERCOT system, with an exception that they are solved sequentially with only 1 thread at a time.

Similar to the analysis done on the TVA and the ERCOT systems, initially a contingency analysis is performed on the PJM system. The critical contingencies that result in violations beyond a specific threshold (the same threshold used for TVA and ERCOT system) are identified and the TC heuristics are applied to achieve reduction in violations. Similar to the analysis done on the ERCOT system, the two TC heuristics, CBCE and CBVE are used to form a rank list consisting of potential switching candidates for the PJM system. Note that the data mining methods are not performed on the PJM system. This is mainly because the network topology in the PJM system is not consistent between the different hours and more information is required from PJM to match the branch data between the 167 hours. Moreover, owing to the size of the PJM system, performing a complete enumeration to identify the beneficial TC actions is not practical.

Table 6.9 presents the overall benefits in terms of violation reductions obtained from the two TC heuristics on PJM system model. It is found that both the heuristics perform equally well with respect to flow violation reduction, voltage violation reduction, and solution time. Note that the solution time in Table 6.9 does not include the time taken to perform the initial contingency analysis. The solution time presented is the average value for all 167 hours that is tested. Further details on the solution time are presented in Table 6.10, which also indicates the solution time for performing the contingency analysis. Table 6.11 presents the violation reductions obtained from the top 5 TC actions in the rank list based on the CBVE heuristic. Fig 6.7 presents the results in the form of a graph, which represents the percentage reduction in voltage and flow violation without considering the Pareto improvement.

Table 6.9: Results of Various TC Methods on PJM System

TC methods	Avg. Solution time (s)	Avg. flow Violation Reduction		Avg. Voltage Violation Reduction	
		w/o PI	w/ PI	w/o PI	w/ PI
CBCE	1592.6	61.6%	60.2%	19.1%	18.8%
CBVE	1611.8	59.3%	59.0%	19.5%	19.3%

Table 6.10: Solution Time of Contingency Analysis and Various Transmission Switching Methods on PJM

	average (s)	min (s)	max (s)
CA	2617.3	2186.5	3100.1
CBCE	1592.6	236.9	3499.4
CBVE	1611.8	241.9	3441.1

Table 6.11: Results of the 5 Best Switching Actions on the PJM System

Candidate	Avg. flow Violation Reduction		Avg. Voltage Violation Reduction	
	w/o PI	w/ PI	w/o PI	w/ PI
1st Best	59.3%	59.0%	19.5%	19.3%
2nd Best	57.7%	57.3%	14.6%	14.4%
3rd Best	52.6%	51.9%	11.5%	11.2%
4th Best	49.0%	48.7%	7.8%	7.7%
5th Best	46.3%	45.5%	6.4%	6.1%

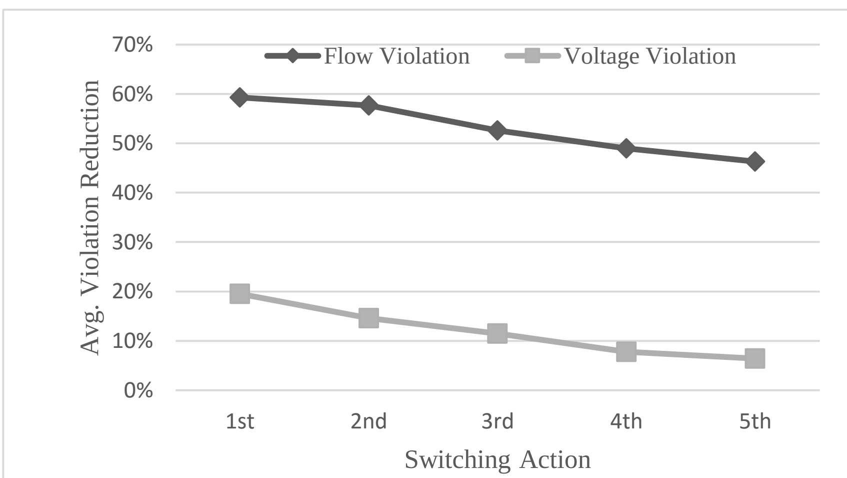


Fig. 6.7: Reduction in Violations Associated with TC Actions on the PJM System Using the CBVE Heuristic

In order to estimate the quality of solutions obtained from the two TC heuristics applied on the PJM system, the complete enumeration of possible switching actions could be performed. The solution from the complete enumeration could be used as an upper bound to evaluate the performance of the TC heuristics. However, owing to the size of the PJM system, it is not practical to perform complete enumeration on the entire system for all the 167 hours as the computational time will be enormous. Therefore, 6 hours data on a particular day is chosen and a complete enumeration of possible switching actions is performed on it. The hours 1, 5, 9, 13, 17, and 21, which represent sample data for peak hour, off-peak hour, and shoulder hour are chosen for this analysis.

Table 6.12 presents the violation reductions and the corresponding computational time for the complete enumeration method as well as the CBCE and CBVE heuristics. The results pertain only to the 6 hours data on which the analysis is done. It is found that both the heuristic methods provide reduction in violations very close to what is obtained from the complete enumeration procedure. This finding is very important which emphasizes the quality of the TC solutions which almost leaves no room for improvement in terms of solution quality. The significant advantage of the heuristics is that the solution time to achieve such good quality TC actions is more than 100 times faster in comparison with the complete enumeration method. These results prove the effectiveness of the heuristics to provide quality solutions within short timeframe.

Table 6.12: Comparison of Various TC Methods on PJM System for Selected Hours

TC methods	Avg. Solution time (s)	Avg. flow Violation Reduction		Avg. Voltage Violation Reduction	
		w/o PI	w/ PI	w/o PI	w/ PI
CBCE	872.3	62.1%	61.0%	19.4%	19.4%
CBVE	874.8	59.4%	59.4%	19.4%	19.4%
CE	96921.5	62.5%	62.5%	21.0%	20.4%

6.9.1 Detailed Example of TC on the PJM System

The effectiveness of the TC solutions on the PJM system could be further illustrated with the help of a detailed example. For instance, it is found that a particular contingency simulated on the PJM system resulted in a worst case flow violation scenario over the entire week's data. Note that the contingency resulted in the overload of only a single line in the system. Five switching actions were identified with the TC heuristic. The best switching action provided a 100% reduction in violation, while the fifth best TC action provided 18% reduction in violation. Note that all the five switching actions provide Pareto improvement. The percentage reduction in violations obtained corresponding to the top 5 switching actions for this particular contingency case is presented in Fig 6.8.

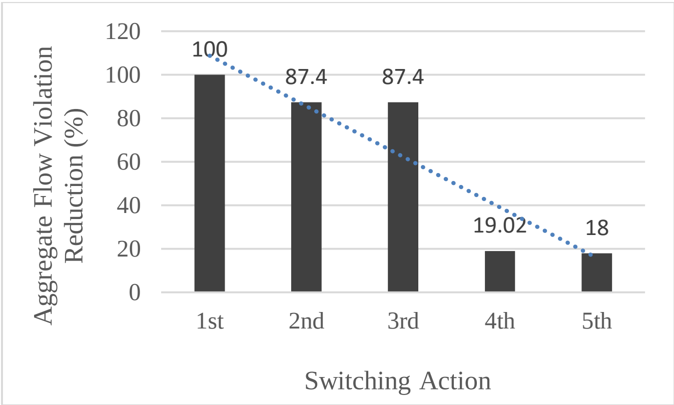
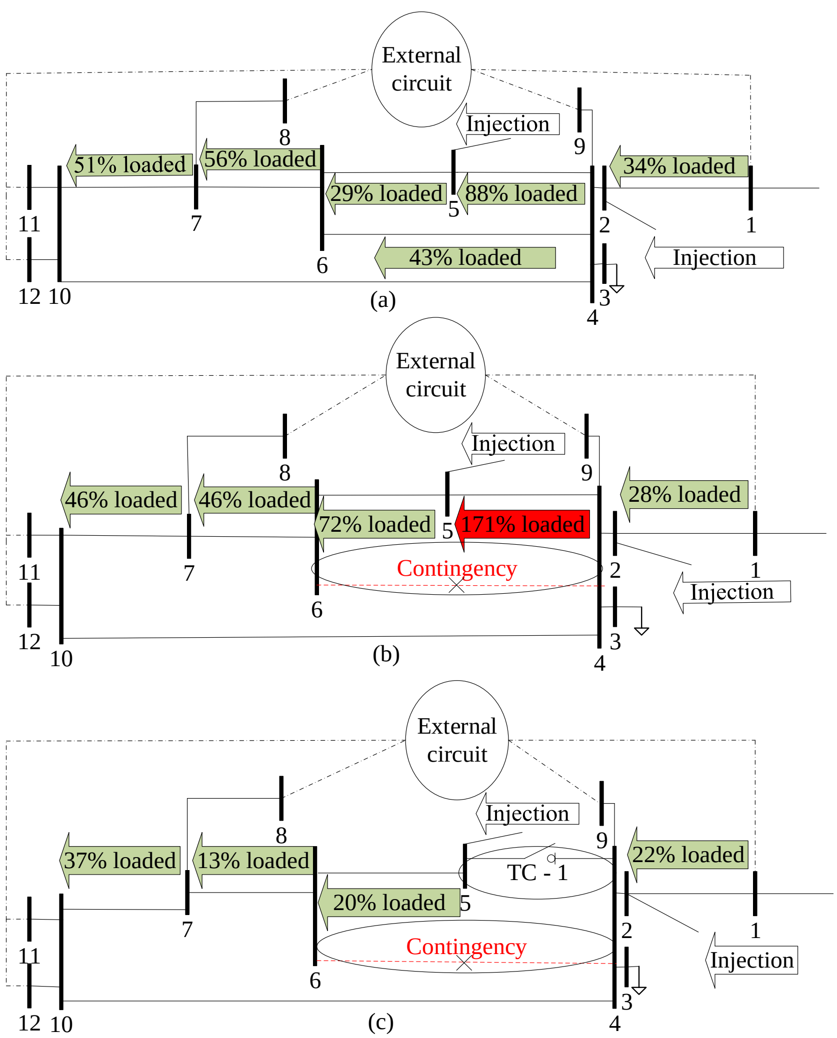


Fig. 6.8: Reduction in Worst Case Flow Violation Corresponding to Top 5 TC Actions on the PJM System

Fig 6.9 presents an artificially created example that conceptually shows the case discussed in Fig 6.8. There is power flow from bus 1 towards buses 6, 7, 10 and the rest of the system as seen in Fig 6.9 (a). A contingency on line connecting buses 4 and 6 creates a flow violation on the parallel path connecting buses 4 and 5 as shown in Fig 6.9 (b). The top 5 switching actions identified by the CTS tool and the corresponding flow violation reductions on the overloaded line are presented in Fig 6.9 (c), (d), (e), (f), and (g), respectively. Note that the percentage loading on the lines presented in Fig 6.9(a) is based on the normal rating, ‘RATE A’ and the percentage loading in the rest of the post contingency cases are presented with respect to the emergency rating, ‘RATE C’.



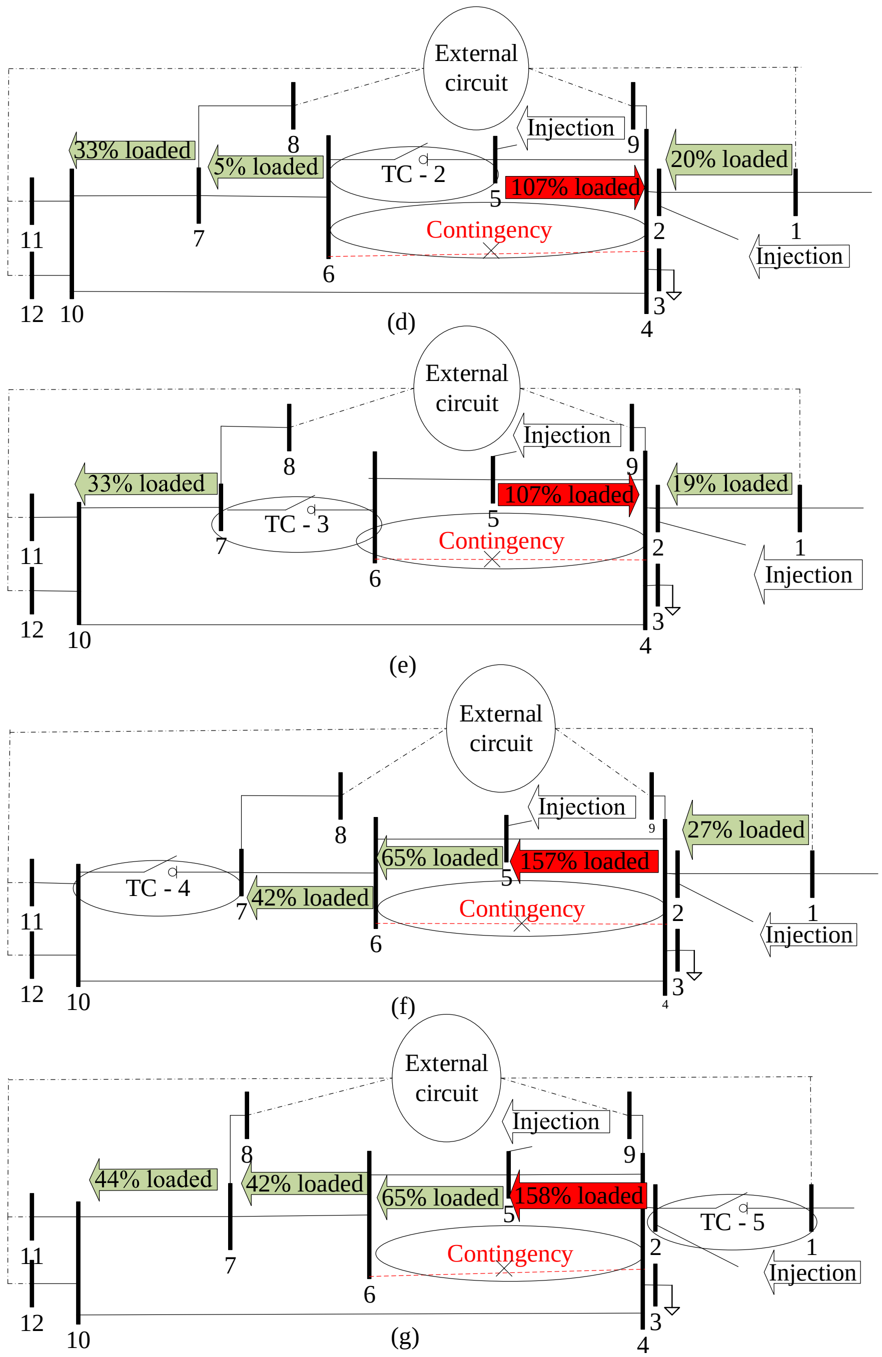


Fig. 6.9: An Artificially Created Example that Conceptually Represents a PJM Case with Flow Violations. The Performance of the Top Five TC Actions on the PJM System is Shown: (a) Pre-contingency case, (b) Post-contingency case, (c) Post Switching – Candidate 1, (d) Post Switching – Candidate 2, (e) Post Switching – Candidate 3, (f) Post Switching – Candidate 4, (g) Post Switching – Candidate 5.

In another instance, it is found that a particular contingency resulted in an aggregate voltage violation of 0.4 pu which was spread across 17 buses in the system. It is found that all the top five switching actions that were identified by the TC heuristics eliminated the violations by 100%. Since there is a restriction on the amount of information that could be shared publicly, the detailed contour plots could not be provided for the PJM system in this report.

6.9.2 Stability Analysis on the PJM System

This section provides the details of the stability analysis done on the corrective TC solutions identified for the PJM system. The dynamic data was provided for all the 167 hours by PJM, which contain information about the different machine models in the system. Specifically, the models are provided for the generator, exciter, turbine governor, and power system stabilizer. Time domain simulation is performed with the help of PSS/E to analyze the effect of the proposed TC actions on the system stability. This section discusses the methodology, the results and conclusions derived from the stability studies which were conducted on selected hours with different loading profiles and different number of critical contingencies.

6.9.2.1 Modifications to the Dynamic Data

This section provides details about the modifications done to the dynamic data provided by PJM. Even though the dynamic file was provided for all the 167 hours, the dynamic files contain a set of machines modeled with user defined models which could not be read by PSS/E. Hence the output of the generators with user defined models are netted with load in order to get rid of the model errors in PSS/E. However, it is observed that most of the units designated by the user defined models are the smaller units and they provide only a small fraction of the total power for the overall system. The number of user defined models change for different hours, the statistics on the number of generators with user defined models for different hours is presented in Table 6.13. It was also found that for a set of generators, the generation output was more than the MVA base values provided in the .raw files. So the MVA base was changed to 1.1 times the MVA generation for all the generators whose MVA base was less than the MVA generation in the given data. Table 6.14 provides the details of the changes made for different hours tested.

Table 6.13: Information on Generators with User Defined Models

Data	Number of generators netted with load within PJM area (%)	Real power output from the netted generators within PJM area (%)
Hour 7	23.75	1.58
Hour 71	17.26	1.67
Hour 109	14.68	3.77
Hour 113	13.69	5.2
Hour 166	17.77	4.06

Table 6.14: Information Regarding MVA Base Change on the PJM System

Data	Number of generators with MVA base changed within PJM area (%)	Increase in MVA base for generators within PJM area (%)
Hour 7	17.44	7.53
Hour 71	35.23	9.68
Hour 109	20.93	8.65
Hour 113	23.28	8.96
Hour 166	19.37	8.31

There were also some initialization issues present in the dynamic files. Some parameter values in the turbine governor were misplaced, for instance, the turbine governor time constants for HP and LP units for the CRCMGV model were misplaced. In lightly loaded hours, the gain on the power system stabilizers had to be reduced to avoid unnecessary oscillations in the base case. Minor changes were made to correct these issues to get a valid base case stable solution from the time-domain simulation.

6.9.2.2 Dynamic Simulation Methodology

A time domain simulation was performed on all the *N-1* contingencies on the selected hours to check the stability of the switching solutions. It is very essential to check the stability of TC actions as unstable switching solutions would weaken the system rather than reducing the violations and bringing back the system to normal operating condition. Two different methodologies are followed to perform the time domain simulation for the branch contingencies and the generator contingencies. In case of the branch contingencies, generator re-dispatch is not performed, however, a generator re-dispatch based on the available capacity is performed following a generator contingency. While simulating branch contingencies, the base case power flow is run for the initial 2 seconds after which a branch contingency is simulated. At 20 seconds the topology control action is implemented and the simulation is terminated at 40 seconds. The time domain simulation is run for a total of 60 seconds in case of generator contingencies. The base case is run for the initial 2 seconds without any disturbance to the system. The generation contingency is simulated at 2 seconds and the generation re-dispatch associated with the particular contingency is implemented at 20 seconds followed by the switching action, which is implemented at 40 seconds and the simulation is terminated at 60 seconds.

The rotor angle, frequency and voltage stability are checked for all the topology control actions. The relative rotor angles of all the machines are monitored throughout the duration of simulation to ensure that no single machine or group of machines swing away from the rest of the system and loose synchronism. If there is a relative rotor angle separation of any machine from the rest of the system such that it loses synchronism, the TC action is concluded to be non-stable. The frequency of all the buses in the area of disturbance is monitored and it is checked if the frequency stays within the limits of 59.5 Hz < f < 60.5 Hz. For any bus in the system, if the frequency exceeds beyond the specified threshold, the switching action is considered to be insecure. Similarly, a voltage threshold of 0.9 p.u. < V < 1.1 p.u. (NERC, *Standard PRC-024-1*) is used to ensure that the switching action does not cause a voltage instability.

Note that the objective of performing stability studies in this work is to check if the switching solution is stable, provided the system remains stable after the contingency. Hence the emphasis of this study is more on the stability of TC action by itself and not much on the dynamics of the contingency. Hence, the branch and the generation contingencies are simulated just by tripping the respective branch and the generator from the system. This is done to observe the response of the system for a disturbance and its ability to remain stable before checking the stability of the proposed TC action.

6.9.2.3 Results on the Stability Analysis – Stable Switching Actions

This section presents the results from the stability analysis performed on the PJM system. The stability studies are conducted on specific hours of the system spreading across the entire week of PJM data. The specific hours for testing the stability of the TC actions were chosen based on different loading conditions and the number of critical contingencies present for that particular hour. Samples of peak, off peak and shoulder hours are chosen along with hour that have maximum number of critical branch contingencies and the hour that have maximum number of critical generator contingencies. Overall the stability analysis is performed on 5 hours of data with completely different system operating states.

A time domain simulation is performed on all the contingencies that have network violations on the selected hours. Totally, 284 contingencies with the corresponding best TC actions are analyzed. Overall, only 2 (0.7%) of the cases that were tested failed the transient stability analysis. Fig 6.10 presents the time domain simulation response for a branch contingency with TS to relieve voltage violations in the system. Note that this particular contingency resulted in voltage violations on 17 buses in the system with an aggregate violation of 0.4 pu. The TS action completely eliminates those voltage violations. Fig 6.11 represents the time domain simulation for a generator contingency with generation re-dispatch and TC to relieve thermal flow violations.

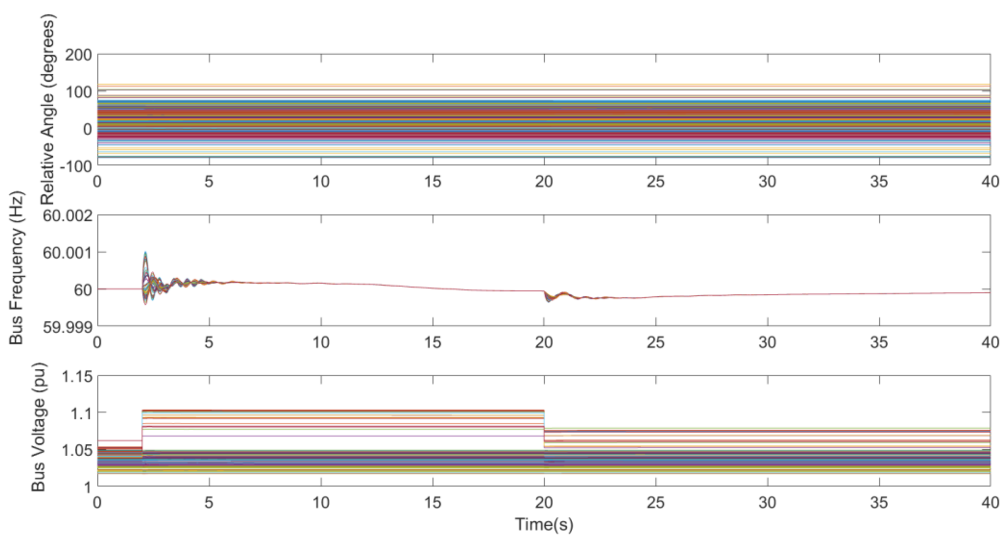


Fig. 6.10: Time Domain Simulation for a Transmission Contingency with TC Action on a Lightly Loaded Hour on the PJM System

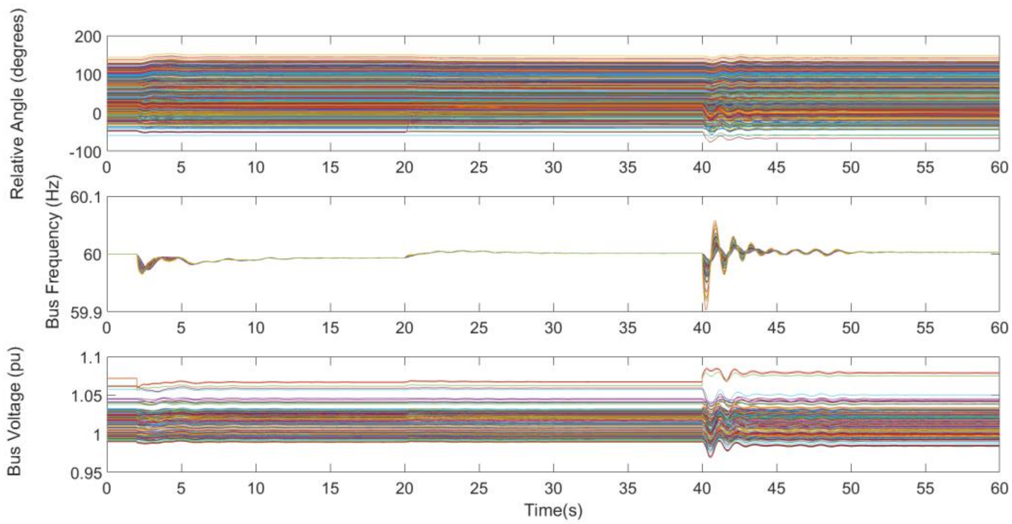


Fig. 6.11: Time Domain Simulation for a Generator Contingency with Generation Re-dispatch and TC

Regarding voltage stability, even though the system is transiently stable, there are few cases where, the voltage level at various buses are less than 0.9pu and there are a few more cases that have voltage levels more than 1.1pu. Note that this voltage deviation happens immediately after contingency and does not recover back fully even after the TC action, which may not be acceptable. Overall, 9.5% of the cases tested fall under this category. Transformer tap adjustments, switchable shunts may help in this regards, however such issues are not studied in this research. The operators use these tools, and others, to handle many of these voltage issues. Moreover, TC actions do not push the voltage levels to go beyond the limits; it is rather the contingency itself that creates voltage problems. Therefore these cases should not be counted towards unstable corrective TC actions.

Overall, more than 99% of the top switching candidates tested provide a stable solution as expected according to the NERC standard. Note that only 0.7% of the cases tested have a transient rotor angle stability issue associated with the switching action. These results are found to be consistent with the actual PJM system response as PJM in reality is reported not to have a serious concern regarding the stability of their system (*PJM,* 2014).

6.9.2.4 Results on the Stability Analysis – Unstable Switching Actions

A detailed analysis of the cases for which the identified TC actions were unstable is presented in this section. From the results, it is found that only 2 switching actions out of 284 cases tested are unstable. It is very important to perform a detailed analysis on these cases to develop further insights on the kind of TC actions that are likely to cause system instability. Such an understanding will be helpful in further filtering out the TC solutions and retain only the candidates that are more likely to provide beneficial solutions that are also dynamically stable.

Since, there is a restriction on the level of details that can be published in this report from the PJM system, an artificially created example is presented in this section which is helpful in describing the events that lead to system instability. Base case, contingency case and post switching case are presented along with detailed explanations on the impacts observed by performing time-domain simulations. Fig. 6.12 presents the base case operating state of a subsection of the PJM system. Buses 1, 2, 8, and 9 represent the generation buses in this subsection. Bus 12 is a load pocket and this subsection is interconnected to the rest of the system through external circuits as shown in Fig. 6.12. The 'green' arrows in the figure indicate the real power flow and the 'orange' arrows indicate the reactive power flow corresponding to the different branches of interest. An important observation in the base case is that, generators B, D, F and H are producing real power output at their maximum capacity. For this particular case, contingency on the branch connecting bus 3 and 4 causes a high voltage violation on bus 3 and there are no thermal flow violations associated with this contingency. The top 5 TC solutions that alleviates the violation, as obtained from the developed heuristics, are tested to analyze the impact of TC on system stability. It is very evident from Fig 6.12 that opening the branch connecting bus 3 and 4 (which is the contingency) removes an important path for the transport of reactive power that is generated from generators A, B, C and D. As a result, although the real power output from these generators remain the same, the reactive power output drops in order to maintain the voltage set points at buses 1 and 2.

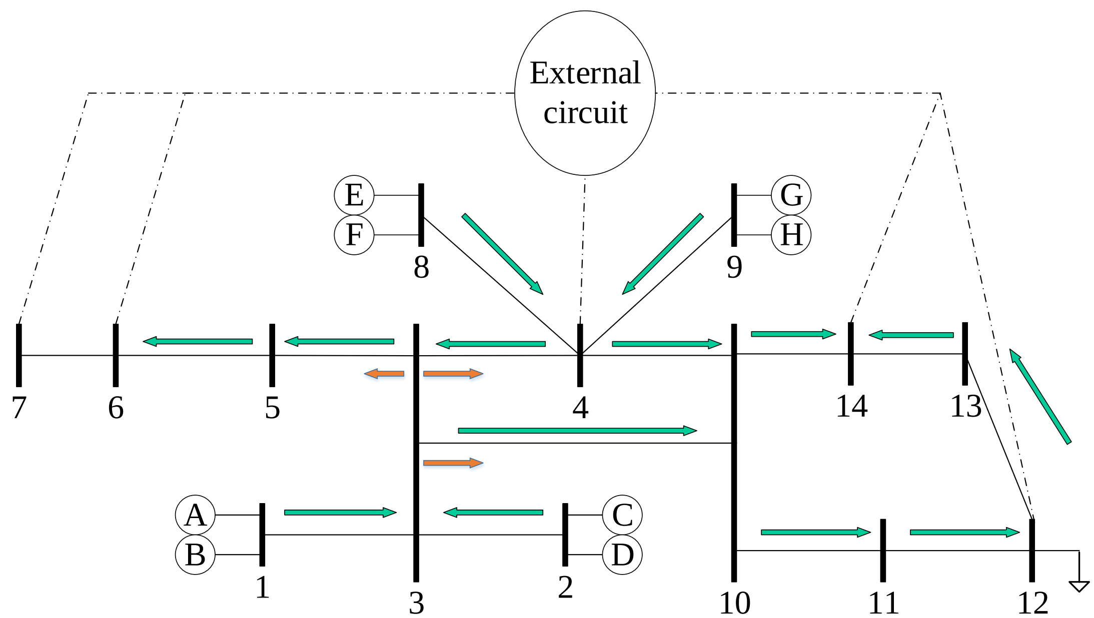


Fig. 6.12: Artificially Created Subsystem of PJM to Illustrate the Mechanism by Which the TC Solution Causes System to Loose Stability (Base Case)

Fig 6.13 presents the reactive power output of the generators based on a time-domain simulation. It is observed that although the system remains stable after the contingency, the reactive power output of the generators are below their minimum limits of 60 Mvar for generators A and B and 25 Mvar for generators C and D respectively. Note that the reactive power is represented in p. u. on system base. However, while simulating a static power flow the magnitude of reactive power drop will be lesser as the generator reactive limits will be obeyed, which will make the reactive power production from the generators to stay at its minimum steady state limit. In the dynamic simulation, the exciter responds in such situations and depending on the exciter settings the unit may trip if the machine reaches the preset under excitation levels.

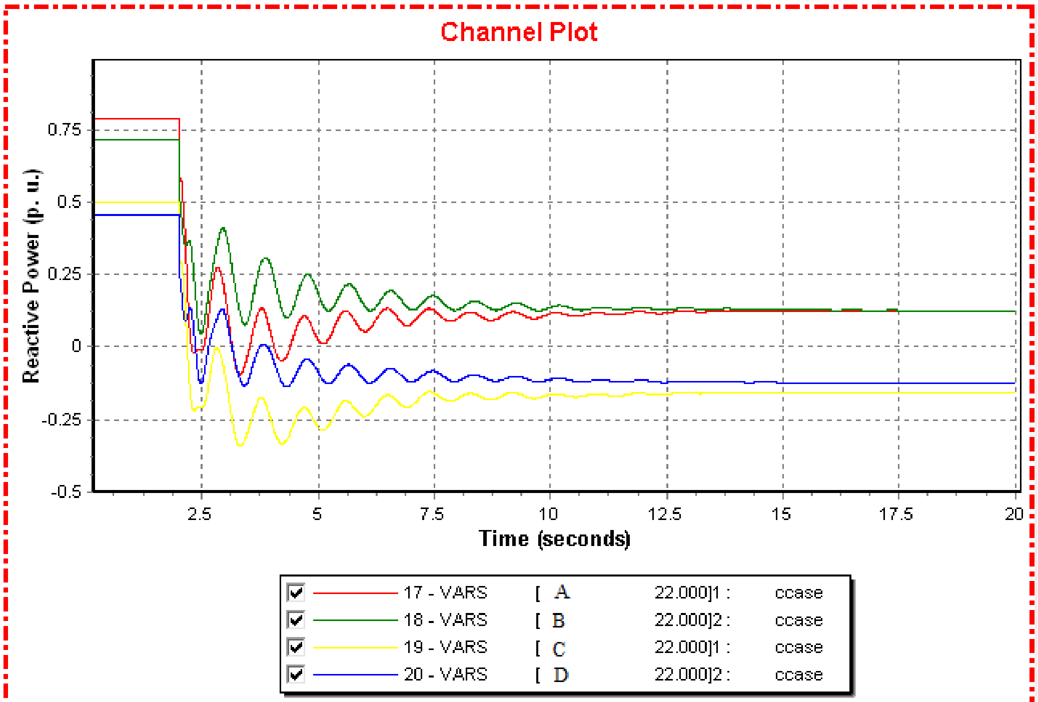


Fig. 6.13: Reactive Power Output from the Machine A, B, C and D (Post Contingency)

Fig. 6.14 presents the contingency case which also indicates the top 5 corrective TC actions that eliminates or reduces the violation corresponding to this contingency. Note that in this example, the contingency line as well as the switching candidate lines are all 500 KV lines. It is found that except for the first candidate switching action, all other TC actions are stable. Upon further analysis, it is found that among the top 5 switching candidates, the first candidate line has the largest reactance and line charging, which is indicative of a very long line. Loss of a long line immediately following the contingency, which is very close to the generators A, B, C and D, causes the generators to loose synchronism as indicated by the relative rotor angle plot presented in Fig 6.15.

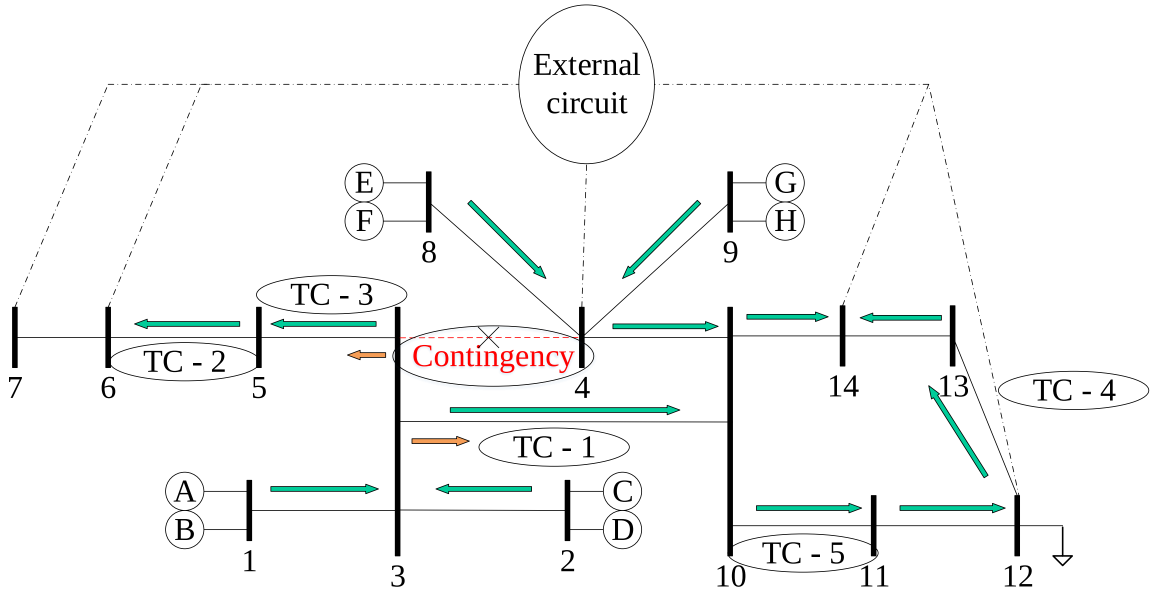


Fig. 6.14: Artificially Created Subsystem of PJM to Illustrate the Mechanism by which the TC Solution Causes System to Loose Stability (Contingency Case)

One way to avoid this issue is to change the operating state of the system even before the contingency happens. For instance, if the real power output of the generators B and D, which are operating at their maximum capacity is reduced by a significant amount, the response of the generators to the contingency are different and the loss of line connecting bus 3 and 10, which is the top switching candidate, does not cause these generators to loose synchronism. At the same time, solving a static power flow after the contingency also changes the operating state of the system as opposed to performing dynamic simulation. If the contingency is simulated and a power flow is solved, the post contingency operating state of the system is changed. If the dynamic simulation is performed by treating the contingency case as the base case, the switching action does not cause instability. The above described method in a way captures the adjustments the operator would do to ensure *N-1-1* stability of the system.

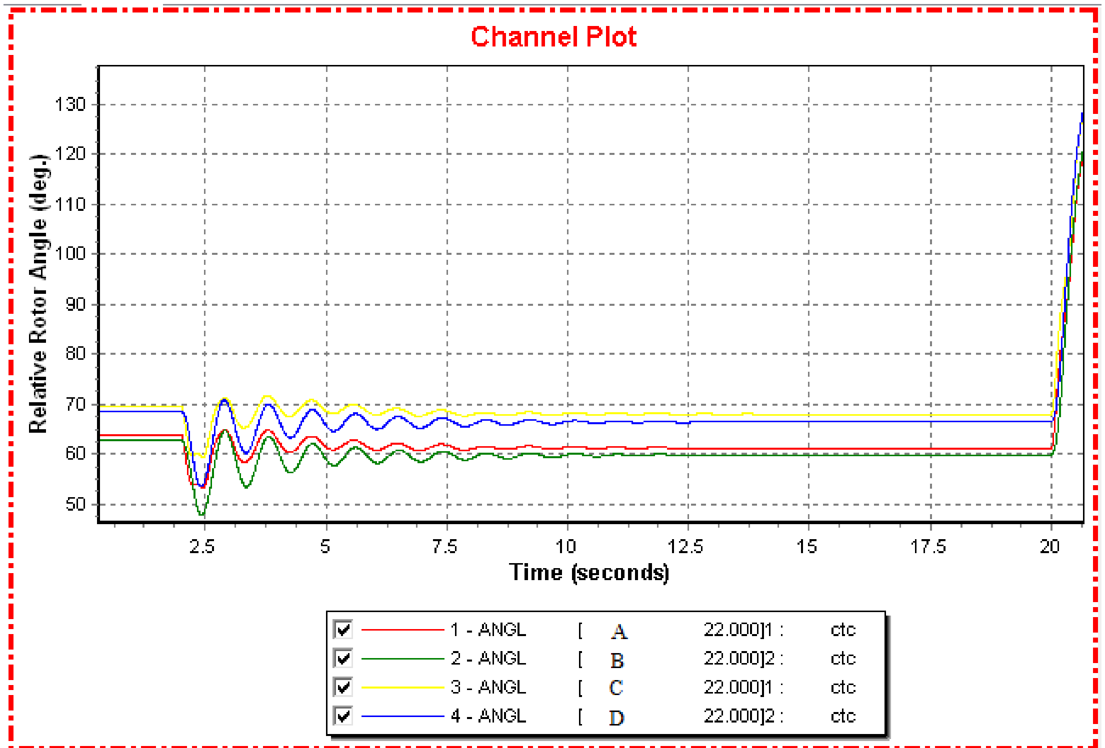


Fig. 6.15: Relative Rotor Angle Plot (Unstable Post Switching Case)

Another case which was found to be unstable was also for the exact same subsection of the system with similar operating states. However, it is very difficult to generalize a conclusion based on the results to indicate whether switching a long line, which is close to a generator will always cause instability. It would be helpful to be vigilant in such cases where the algorithm suggests switching a high reactance line which is very close to a generator that is operating at its limits. The electrical distance will also be a good measure to indicate the impact of the switching action on the generating unit. For instance, in this example it is found that the electrical distance of the units B and D to bus 3 is much lesser in comparison to units F and H. In transient analysis, for a sudden change in load, the generators, in order to maintain the air gap flux within the machine, respond near instantaneously based on the shortest electrical distance to the disturbance (Anderson *et al.* 2003) Hence, at the instant of disturbance, the generators located closer to the disturbance would absorb a larger percentage of the disturbance. The electrical power output of the generators A, B, C and D is presented in Fig 6.16 in comparison with the electrical output of generators E, F, G and H in response to an addition of 500MW load at bus 3 for a small period of time. Table 6.16 presents the change in the electrical power output corresponding to the different machines in response to the disturbance. All values are presented in p.u. on system base.

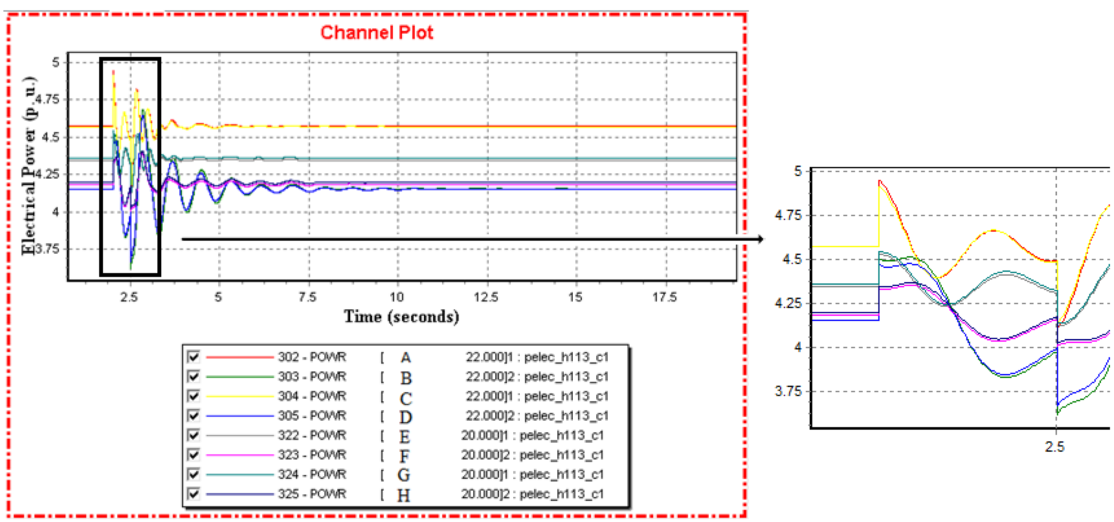


Fig. 6.16: Electrical Power Output for Different Machines Corresponding to a Disturbance in the System

Table 6.15: Change in Electrical Power Output of Machines Corresponding to the Disturbance

Machine	Change in electrical power output (p.u.)
A	0.375076
B	0.351752
C	0.34242
D	0.322093
E	0.183103
F	0.15124
G	0.181943
H	0.150019

6.9.2.5 Analysis of Cases with Static Power Flow Convergence Issues

As mentioned in the earlier chapters, an extensive *N-1* contingency analysis was performed on the PJM system. It is found that few contingency cases (<0.02%) were found to not converge in the static power flow simulations. Upon further analysis, most of the cases that did not converge had convergence issues due to reactive power mismatch in the static power flow simulations. In most cases, the contingency line happens to be an important line that ships reactive power from one part of the system to the other part. Loss of this line causes reactive power mismatch in the system and causes voltage collapse. An example is illustrated with the help of Fig 6.17.

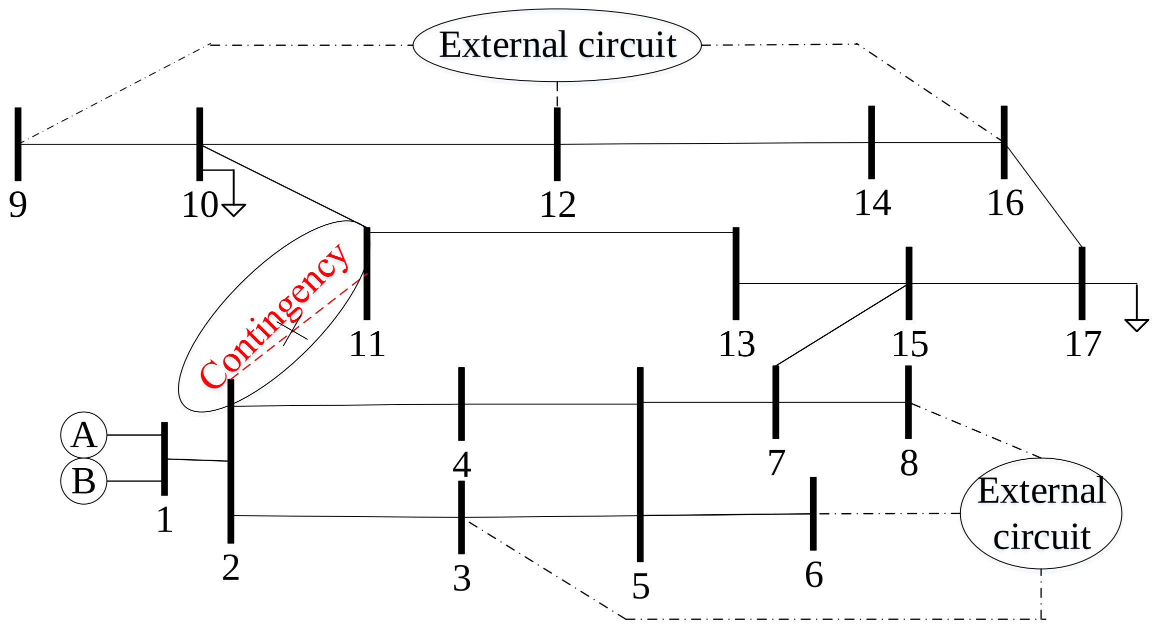


Fig. 6.17: Example Illustrating a Case that has Power Flow Convergence Issues due to Reactive Power Mismatch

Further analysis can be done by performing dynamic simulations on such cases. However, in PSS\E, dynamic simulations performed on the cases that do not converge returns a warning, “network not converged”. Note that not all lines are monitored in actual practice. Moreover, Fig 6.17 represents a sample network connecting PJM and adjacent areas which are not accurately modeled. This is not a major concern as the ISO’s have other ways to handle such issues.

7 CONCLUSIONS AND FUTURE WORK

Currently, there is a national push to create more intelligent and more flexible electric grid. Even though the transmission assets are traditionally treated as static assets, research in the past have investigated the advantages of having a flexible transmission grid. In the past, various beneficial applications for TC have been identified such as to minimize losses, for congestion management, improve grid efficiency, improve renewable integration and cost minimization. However, TC is predominantly being used based on ad-hoc methods in the industry today. One of the major drawbacks to the implementation of TC in real-time is its computational complexity. This research primarily focuses on developing and testing new algorithms to reduce the computational complexity of the TC problem. In this research, several heuristics are developed for TC and tested on both real-time as well as day-ahead framework. A heuristic based on a greedy algorithm is developed based on a DC framework, which can be triggered by an operator in real-time to provide a list of beneficial switching actions to help respond to *N-1*, *N-2*, and *N-m* contingencies. The greedy algorithm has been applied on the IEEE 73 and IEEE 118 bus test systems as well as the FERC-PJM system.

Even though the benefits of TC have been investigated by several researchers in the past, the industry adoption of TC has been very limited due to several reasons as mentioned below:

1. Although many studies have been conducted in the past, which highlights the benefits of TC, majority of the results are not based on tests conducted on actual large scale systems. Hence, a realistic assessment of the actual benefits that could be obtained with TC is very limited.

2. Optimal TC problem is a computationally complex problem to solve. Implementation of TC on huge systems require sophisticated hardware and needs considerable amount of time, which limits its application in real-time.
3. In literature, several heuristics have been developed to address the computational complexity of the TC problem. However, most of the heuristics are either not scalable or they are developed based on a DC framework. The effectiveness of the heuristics on an AC setting for a realistic system is uncertain.
4. There is a concern that the TC actions might cause the system to loose stability. Research in the past have not provided any conclusive findings on the stability of a system with corrective TC application.

In this research, a TC based AC real-time contingency analysis tool has been developed to address all the major bottlenecks to the implementation of TC in real-time framework. The heuristics are implemented on real system data such as the TVA system, ERCOT and the PJM interconnection. The advantage of the heuristics is that all the analysis are done based on an AC framework and hence, the solutions are inherently AC feasible. Moreover, time domain simulations are performed to check the stability of the proposed TC actions to ensure that the TC solutions are stable. Multiple TC solutions are generated for each contingency and hence, the operator is provided with a variety of different choices to take corrective actions. Application of high performance computing is very critical when dealing with realistic systems to reduce the computational time. Hence, the developed algorithm is also parallelized to get a closer approximation of the actual time the algorithm would take to provide solutions if adopted by the industry today. Note that this research has been developed based on an extensive collaboration with industry partners and with continuous feedback from them and hence, the methodologies used in this research are in tune with the current industry practice. The results show significant reduction in violations after implementation of just 1 switching action. Overall it could be concluded that with the promising results presented through this research, TC is ready for industry adoption for real-time corrective applications. Some of the potential areas for future work are listed below.

7.1 Estimate Economic Benefits with TC

All the analysis done on the TC heuristics in this research are based on its capability to enhance the reliability of the grid. However, the work can be extended further to the day-ahead applications, where, the economic savings obtained from the TC actions could be estimated by rerunning the SCUC/SCED with the TC actions.

7.2 Bus Breaker Models

In this research the bus branch model is being used to formulate the TC problem. The bus branch model does not have the information about the substation breaker configuration and, hence, it is not possible to determine how it actually operates during emergencies. In such a case, it is not possible to model the bus contingencies and the breaker failure contingencies from the available data. However, these contingencies could be manually created to replicate the contingencies with certain assumptions.

A bus breaker model could be used to replicate the analysis done in this research, which would potentially provide more clarity to the corrective actions that needs to be taken at a substation level. Substation switching consists of switching a set of breakers to accomplish a particular switching operation. It may typically consist of switching a set of 5-10 breakers per switching scenario and it may include opening and closing operations simultaneously (Wrubel *et al.* 1996). The presented model could be extended to substation switching applications if required in the future.

7.3 Bus–Bar Switching

The TC actions discussed in this research are based on the line (branch) switching actions, which are well known and widely used in many power system applications. However, bus bar splitting could also be used to perform TC actions. A typical bus bar switching model would consist of several additional constraints to be modeled to replicate the bus splitting operations. A detailed procedure for modeling bus bar switching is presented in (Shao *et al.* 2004).

7.4 Ensuring *N-1* Reliability Criterion at the Post Switching Stage

In this research, *N-1* contingency analysis is performed extensively and TC actions are implemented to regain the system to reliable operating state immediately following a contingency. However, further work could be done to ensure that the system is *N-1* reliable following the TC action. Note that while the *N-1* reliability criterion requires the system to regain reliable operation within the initial 10 minutes following the contingency, the operator has 30 minutes to regain *N-1-1* reliability. Hence, corrective TC as developed in this research can be considered as a cheap alternative to other control techniques such as generator re-dispatch to regain reliable operation immediately after the contingency.

Further work could be done to check the system state after the TC actions and what kind of adjustments are required to bring back the system to N-1 reliable operating state.

7.5 Flexible Transmission in Generation and Transmission Expansion Planning

In this research, practical and effective algorithms are developed for corrective application of TC. In most cases, the TC action simply reroutes the power flow across a different transmission path thereby relieving violations. Hence, TC can be viewed as an excellent technique to manage congestion in the system. Considering the increasing demand for electric power, and the rapid rise of renewable energy resources in the grid, more attention will be given to generation and transmission expansion planning process. While solving the problem of reserve allocation and transmission expansion planning to facilitate the transfer of power from remote locations, it would be beneficial to consider the flexibility of the transmission grid. By simply accounting for TC in the planning process, it would even be possible to eliminate the need to construct an expensive line, which would save huge investments by not adding additional redundancy. Similarly, TC could also help better deliverability of reserves from a cheap generator to a different location which may eliminate the need to build an additional generating unit. Since the expansion planning process as such is very complex and requires a lot of assumptions, adding TC to the study makes it a very difficult problem to solve. Further research could be done to develop better heuristics to enable smooth integration of grid flexibility into the expansion planning process.

7.6 Flexible Transmission in Maintenance Scheduling/ Outage Co-ordination

Regular maintenance of the power system components are carried out frequently at different times of the year. A scheduling procedure is followed before any equipment may be taken down for maintenance. Once an equipment is switched out for maintenance, it may take a long time before it can be restored and the time period for maintenance varies depending on the type of equipment. Flexibility in the transmission grid could be considered to optimally determine when a line could be taken out of service. Such an approach could help economic operation of the grid.

7.7 Effect of Topology Control on Relay Coordination

Transmission switching has been proposed in this research as a tool to enhance the reliability of the system. However, it is also important to acknowledge the effects of transmission switching on the relay coordination. The current relay settings and coordination are done to operate without any recalculations for *N-1* contingencies (Aquiles-Perez, 2013). If switching is done more frequently during base case operations, more frequent updates may be needed for the relay coordination settings. A slight change in the relay settings in one area may affect the protection coordination in adjacent areas. For instance, the coordination and relay settings will need to be reevaluated for events like removing a bus and connecting two lines together (Aquiles-Perez, 2013). Further investigations need to be performed to analyze the impact of switching on the relay coordination recalculations for different applications.

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