TRANSMISSION CONGESTION MANAGEMENT

BY

Essam Rizg Abdul-Bagi Al-Wafi

A Thesis Presented to the
DEANSHIP OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

In

ELECTRICAL ENGINEERING

June 2010

KING FAHD UNIVERSITY OF PETROLEUM AND MINERALS

DHAHRAN 31261, SAUDI ARABIA

DEANSHIP OF GRADUATE STUDIES

This Thesis, written by Essam R. Alwafi under the supervision of his thesis advisor and approved by his thesis committee, has been presented to and accepted by the Dean of Graduate Studies, in partial fulfillment of the requirement for the degree of MASTER OF SCIENCE In ELECTRICAL ENGINEERING.

THESIS COMMITTEE

Dr. Ibrahim M. El-Amin

Dr. Abu Hamed. M. Abdur-Rahim

M. M. Mansour

Dr. Mohamed M. Mansour

Department Chairman, Dr. Samir H. Abdul-Jauwad

Dean of Graduate Studies, Dr. Salam A. Zummo

13/6/10

Date

اهدي هذه الرسالة

إلى والديَّ – حفظهما الله ورعاهما –

للتنشئة الصالحة والتشجيع المستمر والدعاء لي بالتوفيق ،

إلى زوجتي الغالية:

لصبرها ودعمها المستمر ،

إلى اخواتي و **اخواني** : عبد الرزاق و عبد الهادي و ممدوح

لمساندتهم وتشجيعهم ،

إلى ابنيَّ و **ابنتيَّ** : ركاد و وافي و ريما و ريماس

فرحة اليوم وأمل المستقبل

ACKNOWLEDGEMENT

Praise and glory to Allah the most gracious and merciful, who gave me courage and patience to carry out this work. Peace and blessing of Allah be upon last Prophet Muhammad (Peace Be upon Him).

I would like express my deep appreciation to my thesis advisor Professor Ibrahim M. El Amin, for his guidance, encouragement and constant help throughout this work. Thanks are also due to my thesis committee members Professor Abu Hamed M. Abdur-Rahim and Professor Mohamed S. Mansour, for their cooperation and help.

Acknowledgement is due to the King Fahd University of Petroleum & Minerals for supporting this work.

I also acknowledge my cousins and friends, who supported me throughout this work.

Thanks are due to Saudi Electricity Company, EOA and all its staff members who provided support to complete this work, especially System Operation and Control Manager, Riyadh Al-Omair, for his continues encouragement and support.

Finally, I extend my acknowledgement to my parents, wife, brothers and sisters, sons and daughters who supported me throughout this work.

Contents

Abstract

Name	:	Essam Rizg Abdul-Bagi Al-Wafi
Title	:	Transmission Congestion Management
Major Field	:	Electrical Engineering
Degree	:	Master of Science
Date of Degree	:	January 2010

Under deregulated environment transmission congestion is managed in many different ways. Most utilities create, update their own rules of how the congestion is managed and by what cost. The common output in most cases is temporary congestion relief and higher cost of energy to the end user.

The thesis provides details of how the congestion is managed in different markets and then it presents a permanent transmission congestion relief through transmission expansion and pay back mechanism.

Transmission congestion problem is studied from different aspects, i.e. congestion relief, energy price reduction, congestion costs and cost recovery or pay back period. The proposed method is tested on a modified IEEE 30 bus test system and 11 bus 380 kV real system. The result shows that congestion costs might be utilized to eliminate the congestion permanently in 2 months in the IEEE case and 9 months in the real system. This thesis presents an effective fast solution for transmission congestion that can be applied in today's electricity markets.

MASTER OF SCIENCE DEGREE
KING FAHD UNIVERSITY OF PETROLEUM & MINERALS
DHAHRAN, SAUDI ARABIA
June 2010

خلاصة الرسالة

الاسم : عصام رزق عبد الباقي الوافي

عنوان الرسالة : إدارة اختناقات الشبكات الكهربائية

التخصص : هندسة كهربائية

تاريخ التخرج : صفر 1431 هـ

الدرجة : ماجستير في الهندسة الكهربائية

تختلف طرق التعامل مع الاختناقات الكهربائية في ظل أسواق الطاقة المختلفة ، معظم أسواق الطاقة طورت طريقة للتعامل مع الاختناقات الكهربائية وكيفية فوترتها ، وان كانت النتيجة المشتركة في معظم الحالات حل مؤقت و ارتفاع سعر الطاقة الكهربائية للمستهلك.

يتلخص هذا البحث في استعراض الطرق المستخدمة عالميا لإدارة الاختناقات الكهربائية وطرق فوترتها ومن ثم اقتراح طريقة للتخلص من هذه الاختناقات عن طريق الحل الأمثل والأوفر والدائم وذلك بالتوسع في خطوط نقل الطاقة و دفع تكاليف بنائها من تجميع تكلفة الاختناقات الأصلية. يتم اختيار التوسع بمقارنة تكلفة الاختناقات والتوفير في سعر الطاقة والمدة اللازمة لتغطية التكاليف لبناء كل من خطوط الطاقة المختارة. يتم اختبار هذه الطريقة على IEEE 30 bus test system وأيضا على 11 bus 380 kV real system.

أظهرت النتائج أن تكلفة الاختناقات خلال (شهرين للحالة الأولى و 9 شهور للحالة الثانية) يمكن استخدامها لحل أصل المشكلة وبصورة دائمة. هذا البحث يقدم طريقة فعالة وسريعة لمعالجة اختناقات الشبكات الكهربائية كما يمكن تطبيقها في أسواق الطاقة العالمية.

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CHAPTER 1

INTRODUCTION

Since the 1990's many electric utilities changed their way of doing business, shifting from vertically integrated companies to deregulated companies. After this transformation of structure, new challenges are faced and seen in both day-to-day operations and in long term generation/transmission expansion planning. Transmission access for the generating companies and the likely occurrence of transmission congestion are among the operational problems. This thesis is devoted to the subject of transmission congestion.

Congestion occurs when actual or scheduled flows of electricity on a transmission equipment exceeds a defined levels, either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term transmission constraint may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability. The imposition of transmission constraints will affect the economics of the power network and the cost of electric energy. The cost of energy in open markets usually determined through the following process:-

First, Load of the system is forecasted; Second, Generating Companies offers their willing to sell prices to the market; Third, The market coordinator will select the least cost generators to be used. At this stage the preliminary price of energy is known. This is called Market Clearing Price (MCP) or Market Dispatch (MD) stage.

After wards the Independent System Operator (ISO) runs load flow with all limitations and defined constraints to see the visibility of the resulted set of the selected generators. If no congestion occurs then the following will be added to market clearing price: Losses; ancillary services; transmission usage tariffs and others taxes. But if congestion appears, adjustments of the market dispatch will take place till it satisfies the system constraints, like overloading, over and under voltages, stability violation and security violations. Adjustments may include reducing selected generators, increasing others, running an expensive generator which was not selected in MD stage, shutting down cheap one…etc. After satisfying all system constraints, the price of energy will be recalculated again to include the new set of generators plus additional charges.

In an open electricity markets, congestion is treated in many ways:

1. Load Shifting; 2.Turn off/on Generators; 3. Contracts curtailment…etc. Extra charges added to energy price, are the result of such actions. Congestion usually occurs when less investment is pushed into the need of the growing load. Expansion of the electric networks in open markets might be supplied by governments or paid back as a charge of the transmission usage, or combination of both.

There are many Congestion Management (CM) schemes used around the world. These CM schemes can be represented by five schemes, i.e. England and Wales, Pennsylvania-Jersey-Maryland (PJM), Norway, Sweden and California [1]

1.1 England and Wales Market

1.1.1 Market Mechanism:

This market is an extreme case because only one zone exists. No constraints are considered in Market Dispatch (MD) stage. In this stage the zonal price, System Marginal Price (SMP), is determined from generators offers. In the Congestion Redispatch (CR) stage, all constrains are considered and every bus in the system become a zone. Generators are commanded to adjust their generation by the Independent Grid Operator (IGO) and receive compensation for doing so. Loads are considered to be fixed and do not participate in both stages.

1.1.2 Pricing System:

Energy price is set at MD stage according to generators offers. Additional charges, called "uplift", i.e. charges for losses and ancillary services, are passed to the consumers.

"Constraint off" occurs when a generator was on in MD stage and instructed by IGO to be off in CR stage. "Constraint on" occurs when a generator was off in MD stage and instructed to be on in CR stage.

For "constraint off" case, generators will receive "lost profit" as a compensation, and for "constraint on" case, generators will be paid its offer price.

1.2 Pennsylvania-Jersey-Maryland (PJM)

1.2.1 Market Mechanism:

The market mechanism in PJM would be considered as the ultimate case of zonal partitioning, where each node is a zone with its own zonal price and each line is an inter-zonal interface. The conceptual basis of the "price-based" dispatch is an optimization framework in which the nodal prices can be determined as dual variables according to specific constraints. All the calculations are conducted in the MD stage using the state estimator data. CR stage is not needed since all constrains are considered in MD stage.

1.2.2 Pricing System:

The dual variables output for each node of the optimized framework are the buy and sell prices and the difference in each node pair is the transmission usage charges that will paid back to transmission investors.

1.3 Norway

1.3.1 Market Mechanism:

In the MD stage, for each hour, the IGO uses the forecasted operational state of the grid to determine whether a partition of the grid into two zones or more is required. In MD stage the grid-wise, in case of one zone, or each zone clearing price is determined. If the grid is divided into zones the tie-lines limits between zones are considered as constraint in MD stage as well. During CR stage, if needed, the participants are adjusted according to their adjusting bids and offers. In this stage each bus is considered a zone.

1.3.2 Pricing System:

As mentioned the MCP is set at MD stage, any adjustment payment might result from CR stage will be added uniformly. Upward adjustment is paid the most expensive bid/offer price and downward adjustment is charged the cheapest bid/offer price. There are two pricing systems used in Nordic pool[2]:

A. Zonal Pricing and works approximately as follows:

1. Based on the supply and demand schedule bids given by the market participants to the spot market, the market is cleared while ignoring any grid limitations. It results in the system price for energy and the amount of electricity traded.
2. If these exchanges induce flows overloading transmission lines, the nodes of the grid are partitioned into different zones on either side of the bottlenecks.
3. A new pool price is determined in each area from the initial bids of the spot market, taking into account the maximum transfer capacity between the areas.

B. Counter Purchases and works approximately as follows:

1. The first stage remains the same as with zonal pricing.
2. If these exchanges induce flows overloading transmission lines, the network operators check where injections into the grid have to be curtailed or increased, so that the congestion could be relieved.
3. These increases and decreases are implemented through separated markets (the "balancing" market in Sweden and the "regulation" market in Norway for instance). Agents offer adjustment bids on these markets, the sole buyer being the system operator.
4. The system operator selects the less expensive bids for increases and decreases. Thus, some generators may be constrained off and compensated with the equilibrium price of the market for generation reductions, whereas others are constrained on and receive the equilibrium price for generation increases.

1.4 Sweden

In Sweden the same rules, as Norway, apply, with one major difference. In Sweden the IGO considers only one zone in MD stage as in England and Wales market. Actually the Nordic pool covers five control areas, i.e. Norway, Sweden, Finland and Denmark (split into two areas). The pricing system used in Sweden is illustrated under Norway pricing system.

1.5 California

1.5.1 Market Mechanism:

The IGO in California uses a predefined set of zones. The MD stage establishes the hourly market zonal prices for the next day market. In MD stage the transmission constraints are not considered, the prices resulted are simply the solution of the preferred schedules introduced by Scheduling Coordinators in bilateral markets. If the MD solution leads to congestion, then elimination will be achieved using CR with zonal partitioning.

1.5.2 Pricing System:

The CR stage gives the zonal prices and the transmission usage prices as dual variables associated with the interface flow. Participants will be paid and charged according to zonal prices defined in CR stage. Congestion charges are applied using the transmission charges in the inter-zonal interface.

After getting a brief description of the international experience, it appears that most of the congestion management techniques used are based on temporary solution to the congestion of electric networks. Some market set percentage by regulators for transmission expansions and that may vary over different system loading as well.

Since transmission investments are un-attractive and use a lot of assets, investments and pay back usually occur at longer term than generation. Moreover, deregulation discourages the investment of transmission equipment, like what happen in Australia. The government took over the control again of transmission after several years due to absence of transmission expansion. Another reason, congestion gives market power the transmission owner and the ISO. Those are usually revenues collectors. So if market participant makes money out of the congestion, there will be incentive to relief it. Due to all that, when moving towards deregulation, governments should consider the transmission expansions and insure its expansion as a part of secure market future.

Installing new transmission facilities are usually initiated by regulators and not directly from market participants. This is based on network and market status, but is not based on market principles. It is due to complexity of power systems and different markets rules. Allowing investors to have early signals of potential expansion projects varies from one market to another.

Setting up clear procedures for Market Participants (MPs) or non MPs to invest in the congestion relief should depend on ISO rules, which include competitive market and system reliability and that is mainly what initiates the congestion in the first place.

For a transmission expansion the "rate of return" should be defined on the basis of system relief to reflect what a project has provided the system with. In order to formulate the incentives for transmission expansion investors, each system should be seen from ISO point of view, and the incentive formula should depend on some of the following: How much is the reliability improved? How much is the power price reduced? And how many more problems will the expansion cause?

1.6 Thesis Motivations

The introduction has shown, that there is no clear approach in eliminating transmission congestions. There is a need to find a methodology that has the following features:-

1. Congestion relief will attract investors.
2. Transmission system will expand as the system needs.
3. All Market Participants (MPs) will contribute to transmission expansion, similar to generation expansion.
4. Enhancement of system security and improvement to operating conditions.
5. Less probability of black out occurrence.
6. Relief of government expense in this infrastructure.
7. Concept of free markets and open access are applied.

If a system has generation deficit, the solution is to build more power plants. If a substation is over loaded, the solution is to add more transformers, or nearby substation. If a transmission network is congested, why lifting up the price of power without enhancing the transmission network in first place?

1.7 Thesis Objectives

The specific objective of this thesis is as follow:

- Suggest a method for congestion relief by transmission expansion and payment recovery process through congestion costs.
- Test the proposed method on
    1. Modified IEEE 30 bus test system.
    2. 11 bus 380 kV real system.

1.8 Thesis Organization

This thesis contains 6 chapters. It starts with an introduction. Chapter 2 provides a literature survey. Chapter 3 presents the problem formulation. Chapter 4 presents the first study case model and solution. The second study case model and solution is presented in chapter 5. Finally, the conclusion is presented in chapter 6.

CHAPTER 2

LITERATURE SURVEY

Substantial work have been done by different researchers in the field of Congestion Management (CM) [1-15]. A review of five CM schemes is presented in [1]. The schemes were selected to illustrate the various CM approaches in use. The author develops a unified framework for the mathematical representation for both Market Dispatch and re-dispatch problem that ISO must solve in the CM in order to compare the schemes.

An overview of the current cross border CM methods used in Europe is presented in [6]. It includes the current implementation of different CM methods with description of each market features. It specifies how the power is traded across each country borders.

Barkeley discusses Transmission Congestion Cost in the US electricity markets, and states the difficulty of comparing CM method in use, i.e. uplift charges, system re-dispatch payments and congestion revenues [8]. Also, it includes a review of published estimated Transmission Congestion Costs in the US electricity markets. The CM working group discusses the physical interruption of transaction and the re-dispatching of generation in the US market as well [4]. The latest Department of Energy (DOE) CM report defines three types of congested areas: Critical Congestion Areas, Congestion Areas of Concern and Conditional Congestion Areas [3]. DOE based its classification on the occurrences of the congestion, No. of hours operating more than 90% of the safe level and the cost of congestion. Detailed of California, Texas and PJM markets are presented along with how the market mechanism of the transmission expansion process is undertaken [7].

In North American Reliability Council (NERC) the Improvement of congestion management processes includes:

• The number and amount of transactions curtailed to solve a reliability constraint is excessive and costly to the market.

• There is limited opportunity or incentive to re-dispatch resources or take other actions to minimize reliability impacts on the market.

• There are limited incentives to the transmission provider to build transmission or otherwise remove transmission constraints.

• Market participants don't have access to timely and accurate information about transmission system constraints and congestion management actions [7].

ERCOT report includes many power markets elements and design. Also, it discusses the economics of Congestion Management and states the measures of efficient and sustainable markets [5].

European Commission has drafted congestion management guidelines, Regulation 1228/2003/EC. The following principles have been agreed on [9]:

- Economic efficiency and promotion of competition,
- Maximizing the amount of capacity available and the use made of it,
- Transparency to network users on a non-discriminatory basis,
- Secure network operation,
- Largely revenue neutral mechanisms from the system operators' point of view.

The different methods used for Congestion Management in Nordic pool are investigated [2]. The authors show that different methods yields different prices and of course different surplus for market participants. They also discuss the "market power" of different market agents as well the revenue collected by ISO. Explanations of the evolution of Nordic power market as well as the ancillary service regulation power market is presented [10]. It highlights the generation expansion and how the market mechanism affected that, i.e. creation of Regulation Power Option Market (RPOM) and additive incentives for wind energy.

Different CM schemes used in Europe are discussed in [9-16] as well as the need of enhancing cross-border links in Europe. Power trade has increased a cross borders with little growth in cross border transmission links, since 2004 up to Dec 2008 only 2 "380 kV" links were added [11].

The definition and analysis of Financial Transmission Rights FTRs, Transmission Congestion Contracts TCCs and Contract for Differences CfDs are discussed in [15-16].

CM and Transmission Expansion relation in California, Texas and PJM are listed in [7]. FTR based transmission expansion are discussed in [13-20]. Congestion based transmission expansion are discussed in [21-24]. A congestion indicator of the form of Lerner is used under LMP based market to indicate the required transmission expansion in the IEEE 24 bus system as study case [17]. A planning objective are to maximizing the reliability and minimizing the congestion cost, the NY system as study case [21]. A planning model is developed under different market driven power flow patterns with decision analysis of minimizing the risk of the selected plan [22]. A new probabilistic approach for transmission expansion subject to different Market Participants MP point of view is presented and the IEEE 30 bus system as study case [23]. The planning objectives is to minimize the investment cost taking into consideration the operational problem and the IEEE 24 bus system as study case [24].

Access Charges, transmission rates, ancillary services and regulator rules in San Diego are presented in [27]. An overview of ERCOT bulk power system and issues that face its markets are listed in[28]. Transmission system expansion, reliability enhancement, transmission pricing and cost recovery in the west are included in[29].

A new methodology to estimate the actual cost of congestion by considering the difference in OPF and security constrained OPF using limited, non-state estimator data are included in[31], Eastern interconnection and TVA systems as study cases. Congestion cost allocation & locational marginal pricing are discussed in [32-33, 45], IEEE 5 bus and RTS as study cases.

The use of static synchronous series compensator to resolve congestion-caused problems and to reduce the differences in power prices is discussed in [34]. The congestion management pricing and the uses of FACTS devices to reduce the congestion are listed in [35-36].

The objective of optimal power dispatch, the fairness in contract curtailment and the ISO-MPs coordination are explored in[37]. Aunified framework for reactive power management in competitive market is presented in[38]. A two-stage hybrid model for congestion management for both real & reactive power transaction is discussed[39], modified IEEE 30 bus test system as study case. A probabilistic approach for optimal and reliable scheduling in electric power market is presented[40].

Price investigation caused by random failures and customer response is discussed in[41], IEEE RTS as study case. Evaluation and Comparison of transmission tariffs methods in power markets are discussed in[42-46].

The economic efficiency of assessing charges on the basis of customer-specific costs is discussed in[43], two allocation methods were developed and studied, i.e. the regulation allocation and the load following allocation methods. Transmission Congestion management using economic load management is presented in [44], IEEE 30 bus test system as study case.

A combination of nodal and area pricing with minimization of total congestion costs is discussed in[47], part of the Nordic system as study case. Decentralized approach to solve the CM problem using multi-agent technology is presented in[48]. Transmission planning considering reliability and congestion cost is presented in[49], using GridView power market simulator and NYCA as study case. A review on the Australian power market and how the congestion is managed is described in[50], the paper highlights key aspects need more attention under current market structure for better market environment.

CHAPTER 3

PROBLEM FORMULATION

3.1 Problem Description

Power systems under deregulated environment are usually operated by Independent System Operators (ISO), and their prime duty is to maintain system security with least possible cost of energy. In many markets, like the US, the trades of power are processed through market operator, so that the ISO is not involved directly with contracts curtailment. In some US states, it is even against the law if they communicate with each other outside the proper formal channels, and that is to reduce both operators market power.

To study and propose a solution to congestion cost in a certain system, it is necessary first to define the ISO procedures, in general: How the ISO look into the system, how he sets the power prices and then how to deal with congestion when it occurs.

The ISO deals with real time system status which does not remove the congestions permanently. Most congestions require investments in equipment installation. The permanent removal of congestion under deregulated environments is not defined clearly.

In this thesis a mechanism for permanent congestion removal is presented. It is a function of the congestion cost itself. The mechanism is based on the addition of a transmission line to the congested path, zone and then calculating pay back time through the difference in congestion and investment costs.

Two study cases will be considered in this thesis. The first case is modified IEEE 30 bus test system. The second case is 11 bus 380 kV real system.

The initial analysis of LMPs is obtained through a MATLAB based program called MATPOWER version 3.2. It is an open code and has powerful routines for solving and optimizing power system equations.

After obtaining the LMP's the congestion costs will be calculated based on the congestion defined for each case.

After obtaining the initial congestion costs, simple contingency analysis will be simulated to form set of transmission lines for congestion removal. Then the LMP's and congestion costs will be calculated again with each possible added line. The last steps will be repeated till all lines are considered. Finally, Pay Back Time will be calculated for each possible added line. Figure 3.1 shows the problem solution process.

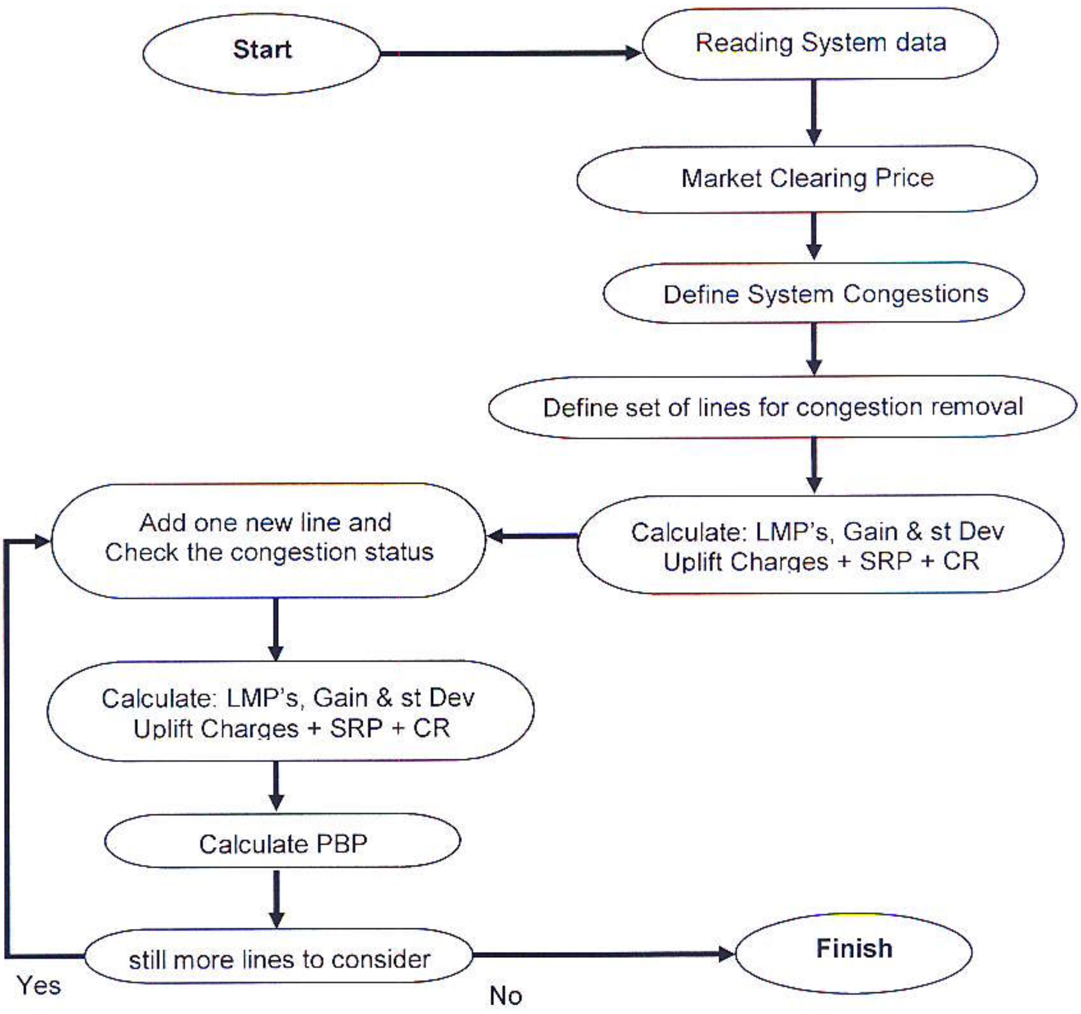

Figure 3.1 Solution Process

3.2 Congestion Costs Calculations

Congestion costs can be obtained by one or more of the following three components:

1. Uplift charges

Congestion costs are equal to the increased dispatch payments by the market to generators that are out of merit order.

2. System Re-dispatch Payments(SRP)

Congestion costs are equal to the difference in dispatch payments by the market to generators in the congested case relative to costs for the un-congested case.

3. Congestion Revenues(CR)

Congestion revenues are the evaluation of transmission of energy across a congested interface. Neglecting losses, these revenues are equal to the product of the energy flow and the price. CR is usually collected by ISO or transmission owners.

The variation in congestion costs calculation depend on the market mechanism and ISO procedures.

In this thesis, based on how the congestion is defined, the congestion costs can be obtained through the addition of all three components.

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3.3 Illustration

Figure 3.2 shows a three bus system. This is used to illustrate the problem of congestion and its effects on energy prices.

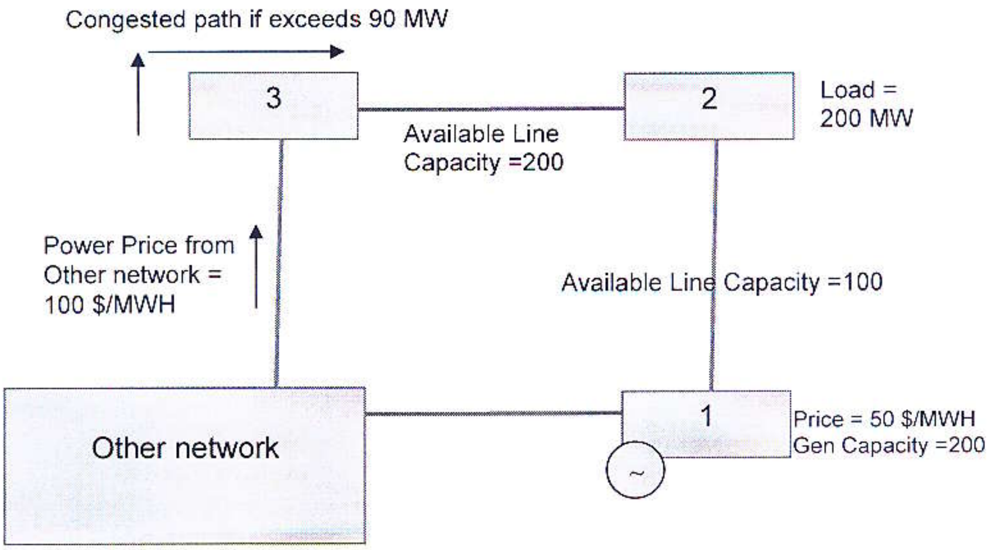


Figure 3.2 simple example

Buses 1, 2 and 3 form a system under study, as in figure 3.2, then:

At Market Dispatch Stage:

The MCP is 50 $ / MWH, and the total energy cost is:

50 $ / MWH X 200 MW = 10,000 $ / hour

At Congestion Re-Dispatch Stage:

In congestion re-dispatch stage the constraint of line 1-2 is considered and power price will be:

At bus 1 : 50 $/MWH

At bus 2: 100 MW @ 50 $ / MWH and 100 MW @ 100 $ / MWH, and becomes:

(100 + 50) / 2 = 75 $/MWH

At bus 3: 100 $/MWH

The total energy cost is:

75 $ / MWH X 200 MW = 15,000 $ / hour

The difference here is 5,000 $ / hour and that can be considered part of uplift charges.

The second charge appears for Generator No1, because it was selected to sell 200 MW of power at Market Dispatch stage but reduced to 100 MW in the congestion re-dispatch stage. Let's assume a 10% lost profit for Gen No1:

So 10% of (100 MW @ 50 $ / MWH) = 500 $ / hour to be paid to Gen No1 as a lost profit, and that can be considered part of System Re-dispatch Payments.

The third charge appears is due to congestion path across Bus No 3. Assuming that if the ISO defines a limit of 90 MW across Bus No. 3. In the congestion re-dispatch stage the flow exceeds 90 MW, and there will be congestion revenues on extra power flow across congested Bus No 3. In this case:

100 MW – 90 MW = 10 MW extra flow,

Then Congestion Revenues equals the extra flow times the interface power price:

10 MW X 100 $ / MWH = 1000 $ / hour.

3.4 Mathematical representation

3.4.1 Market Clearing Price MCP

The MCP used in this thesis is obtained through MATPOWER 3.2 based on an optimal DC load flow solver minimizing the total system generation cost and subject to expanded limits in both generators and transmissions.

3.4.2 Location Marginal Prices

The LMPs used in this thesis is also obtained through MATPOWER based on an optimal market based AC load flow solver minimizing the total system generation cost and subject to generators and transmissions constraints.

3.4.3 Uplift charges

The uplift charges used in this thesis is included in the LMPs calculations, since the LMPs obtained are resulted from OPF but adjusted to network losses and of course, includes the out of merit generators costs.

3.4.4 System Re-dispatch Payments

The SRP are obtained through the following equations:

$$SRP = \sum_{1 \text{ to } n} RP_i \tag{3.1}$$

$$RedGen_i = MDGen_i - CRGen_i \quad , \text{Subject to } RedGen_i > 0 \tag{3.2}$$

$$RP_i = RedGen_i \times LMP_i \times PercentageProfit_i \tag{3.3}$$

where,

n = total number of generators,

i = Congested bus number,

RP_i = Re-dispatch Payment for generator i,

LMP_i = Location Marginal Price at Bus i,

$MDGen_i$ = selected generation output at Market Dispatch stage for generator i,

$CRGen_i$ = selected generation output at Congestion Re-Dispatch stage for generator i,

$RedGen_i$ = reduced generation output at Congestion ReDispatch stage with respect to generation output at MD stage, for generator i,

$PercentageProfit_i$ = percentage lost profit for generator i,

3.4.5 Congestion Revenues CR

The Total Congestion Revenues TCR is obtained through the following equations:

$$TCR = \sum_{1 \text{ to } n} CR_i \tag{3.4}$$

$$ExtraFlowAcross_i = TotalFlowAcross_i - AcceptedISOFlow_i \tag{3.5}$$

$$CR_i = LMP_i \times ExtraFlowAcross_i \tag{3.6}$$

where,

n = total number of congested buses,

i = Congested bus number,

CR_i = Congestion Revenues at Bus i,

LMP_i = Location Marginal Price at Bus i,

$TotalFlowAcross_i$ = Total power flow across bus i,

$AcceptedISOFlow_i$ = Accepted safe power flow across bus i, defined by ISO,

$ExtraFlowAcross_i$ = Extra power flow across bus i

3.4.6 Pay Back Period PBP

The PBP in this thesis is referred to the time needed for a transmission line to cover its cost from the saving in congestion costs. It is obtained through the following equations:

$$PBP_i = ConstCostL_i \ / \ TotalCongCostSav_i \tag{3.7}$$

$$TotalCongCostSav_i = TotalCongCostBase - TotalCongCostL_i \tag{3.8}$$

where,

PBP_i = Pay Back Period (months) for Line i,

$ConstCostL_i$ = Construction Cost ($) of Line i,

$TotalCongCostSav_i$ = Total saving in congestion costs ($) after the addition of Line i,

TotalCongCostBase = Total congestion costs ($) for the base case,

$TotalCongCostL_i$ = Total congestion costs ($) after the addition of line i,

CHAPTER 4

STUDY CASE 1: IEEE MODIFIED 30 BUS TEST SYSTEM

4.1 System Model

The selected system is modified IEEE 30 bus system. Generator limits are set to 300 MW, Loads are increased 3 times and branch limits are set to 75 MW. This is the base case. Figure 4.1 shows the single line diagram for the modified IEEE 30 bus system.

The branch data, bus data, generators data and generators cost coefficients are shown in Appendix A.

In order to obtain the Market Clearing Price, which is simulating the offered power by Generator's companies with no transmission constraints; the following assumptions are made to the base case:

1. Generators Maximum output (MW) = open.
2. Branch limits (MW) = open.
3. DC optimal load flow was used.

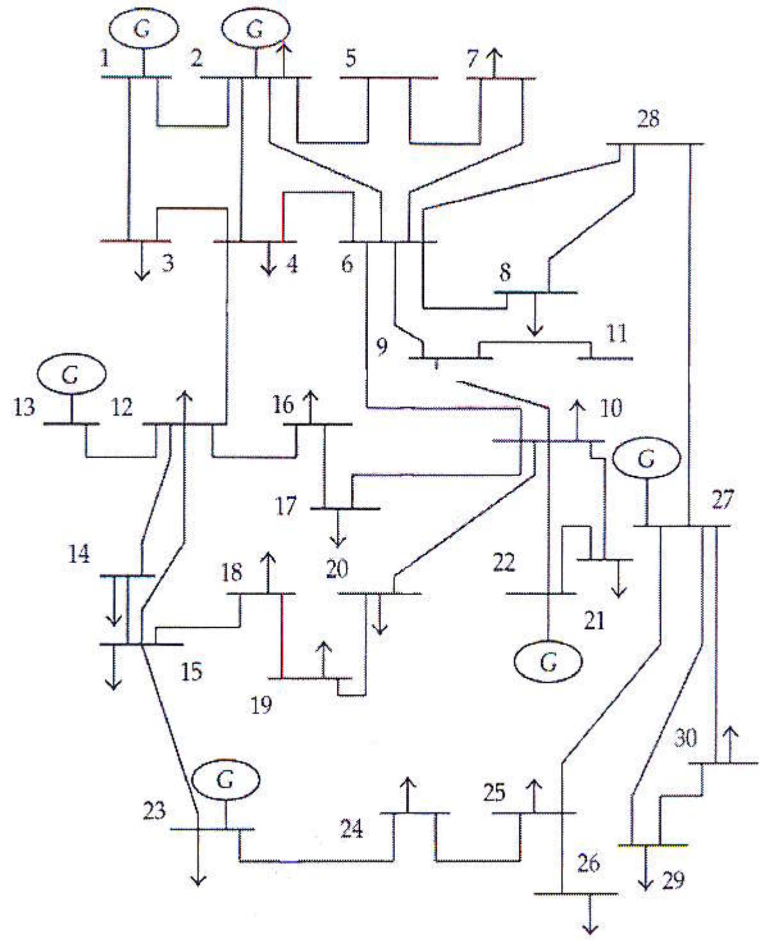


Figure 4.1
Single Line diagram of the IEEE 30 Bus system

4.2 Defining Network Congestions

The latest Department Of Energy (DOE) [3] CM report defines three types of congested areas: Critical Congestion Areas, Congestion Areas of Concern and Conditional Congestion Areas. DOE based its classification on the occurrences of the congestion, No. of hours operating more than 90% of the safe level and the cost of congestion.

Table 4.1. shows the load flow solution for the base case of the IEEE system.

To define the network congestion for this case, only the outage of any line that carries 80% of its capacity is considered. In this case the lines ratings are set to 75 MW and we consider any line that has a flow over 60 MW. Running contingency analysis of one line out at a time, it was found that 4 out of 5 lines will cause other lines to be over loaded. These lines are 2-6 carrying 66 MW, 4-6 carrying 60 MW, 6-8 carrying 75 MW and 21-22 carrying 75 MW as shown in figure 4.2.

The congestion calculations are based on the above assumption.

In this chapter the MCP and LMP's was calculated for the base case. Another circuit is added to the four congested paths, one line at a time. After that the LMP's are recalculated for all the four cases, as shown in table 4.2. The second step is to calculate the LMP's reduction as well as the LMP's average reductions .Step one and two are representing the uplift charges and its variations.

The LMP's standard deviation was calculated to show the power price profile.

The third step is the calculation of Congestion Revenues. The fourth step is the calculation of System Re-dispatch Payments. Then the first 3 steps are repeated after addition of new line, one line at a time. After that the calculation of Pay Back Period is presented.

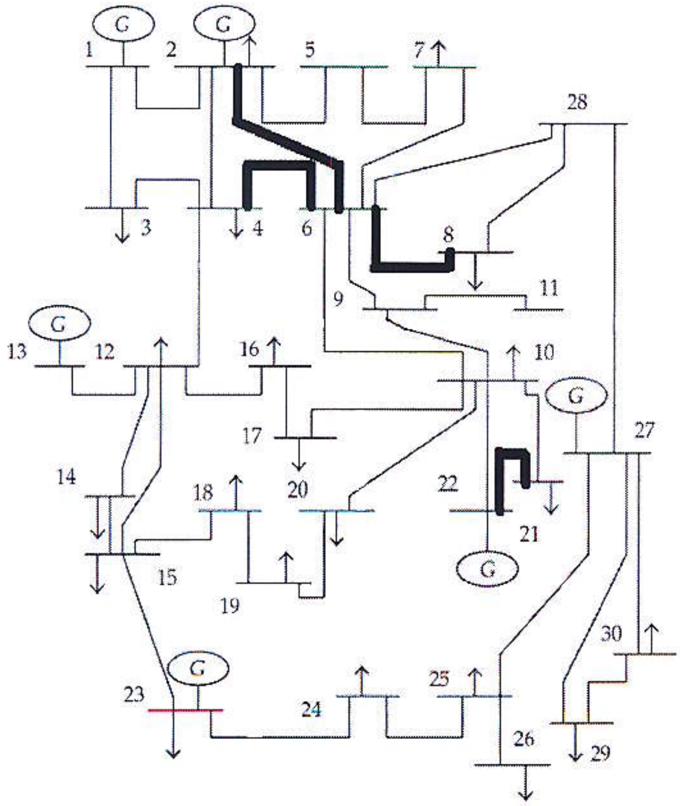


Figure 4.2
Congested paths for IEEE modified 30 bus system (heavy lines)

Table No. 4.1
Branch flows in the base case
IEEE modified 30 bus system

Branch No	From bus	To Bus	From Bus		To Bus		Losses	
			P	Q	P	Q	P	Q
1	1	2	62.78	-21.55	-62.06	20.06	0.716	2.15
2	1	3	57.22	21.94	-55.65	-18.24	1.575	5.98
3	2	4	55.13	27.7	-53.2	-24.52	1.921	5.44
4	3	4	48.45	14.64	-48.21	-13.69	0.238	0.95
5	2	5	43.99	24.53	-42.92	-22.52	1.073	4.29
6	2	6	66.04	36.45	-63.17	-30.08	2.866	8.6
7	4	6	60.45	40.45	-59.95	-38.45	0.501	2
8	5	7	42.92	22.52	-41.81	-20.89	1.107	2.66
9	6	7	26.84	11.5	-26.59	-11.81	0.256	0.68
10	6	8	75	79.46	-73.82	-74.74	1.179	4.72
11	6	9	15.58	-13.4	-15.58	14.28	0	0.88
12	6	10	8.9	-7.66	-8.9	8.42	0	0.76
13	9	11	0	0	0	0	0	0
14	9	10	15.58	-14.28	-15.58	14.73	0	0.46
15	4	12	18.17	-7.04	-18.17	7.97	0	0.93
16	12	13	-60	-37.85	60	44.29	0	6.43
17	12	14	13.26	4.03	-13.05	-3.58	0.21	0.46
18	12	15	16.37	-0.24	-16.2	0.56	0.171	0.32
19	12	16	14.94	3.59	-14.75	-3.16	0.194	0.43
20	14	15	-5.55	-1.22	5.62	1.29	0.068	0.06
21	16	17	4.25	-2.24	-4.23	2.28	0.017	0.04
22	15	18	21.08	5.6	-20.59	-4.62	0.487	0.97
23	18	19	10.99	1.92	-10.91	-1.76	0.074	0.16
24	19	20	-17.59	-8.44	17.7	8.71	0.116	0.27
25	10	20	24.93	12.28	-24.3	-10.81	0.631	1.47
26	10	17	23.03	20.37	-22.77	-19.68	0.257	0.69
27	10	21	-21.13	-36.03	21.6	37.14	0.475	1.11
28	10	22	-19.75	-25.78	20.42	27.21	0.67	1.43
29	21	22	-74.1	-70.74	75	72.54	0.9	1.8
30	15	23	-35.1	-14.94	36.45	17.65	1.356	2.71
31	22	24	2.31	22.49	-1.81	-21.73	0.507	0.76
32	23	24	13.95	9.33	-13.64	-8.7	0.302	0.63
33	24	25	-10.65	10.38	11.02	-9.73	0.373	0.65
34	25	26	10.9	7.5	-10.5	-6.9	0.398	0.6
35	25	27	-21.92	2.22	22.41	-1.3	0.485	0.93
36	28	27	-19.69	-14.68	19.69	17.06	0	2.38
37	27	29	19.29	6.54	-18.49	-5.01	0.799	1.53
38	27	30	22.36	6.86	-20.82	-3.98	1.533	2.87
39	29	30	11.29	2.31	-10.98	-1.72	0.316	0.59
40	8	28	-16.18	-15.26	16.48	14.31	0.299	1
41	6	28	-3.21	-1.38	3.21	0.37	0.002	0.01

4.3 LMPs Calculations

It was found that the addition of either 6-8 or 21-22 lines reduced the price noticeably in bus 8 and 21, respectively, as shown in table 4.2. Noting that both lines were loaded to full rating in the base case as shown in table 4.1.

Table 4.2
LMP's ($ / MWH)
IEEE modified 30 bus system

		LMP's				
Bus No	MCP	Base Case	After adding 2-6 line	After adding 4-6 line	After adding 6-8 line	After adding 21-22 line
1	6.0000	6.8610	6.8370	6.8648	7.9230	5.6000
2	6.0000	7.0000	7.0000	7.0000	8.0782	5.6949
3	6.0000	7.3162	7.2206	7.3335	8.4554	5.8553
4	6.0000	7.4077	7.2951	7.4286	8.5623	5.9034
5	6.0000	7.3088	7.2549	7.2975	8.4497	5.8762
6	6.0000	7.5211	7.3698	7.4901	8.7209	5.9318
7	6.0000	7.6564	7.5320	7.6297	8.8658	6.0791
8	6.0000	14.4848	14.9146	14.5819	**8.7939**	16.7769
9	6.0000	8.0140	7.8441	7.9840	9.2112	6.0477
10	6.0000	8.2612	8.0853	8.2329	9.4573	6.1072
11	6.0000	8.0140	7.8441	7.9840	9.2112	6.0477
12	6.0000	7.4030	7.2964	7.4166	8.3950	6.1411
13	6.0000	7.3902	7.2851	7.4036	8.3825	6.1322
14	6.0000	7.6175	7.5085	7.6298	8.5900	6.4073
15	6.0000	7.4194	7.3146	7.4260	8.3276	6.2929
16	6.0000	7.9170	7.7761	7.9126	9.0158	6.2360
17	6.0000	8.2626	8.0931	8.2405	9.4444	6.2159
18	6.0000	8.0955	7.9546	8.0888	9.1539	6.5205
19	6.0000	8.3922	8.2321	8.3773	9.5274	6.5697
20	6.0000	8.3842	8.2191	8.3657	9.5387	6.4686
21	6.0000	10.1136	9.8461	10.0715	11.8998	**5.9223**
22	6.0000	4.7512	4.7512	4.7512	4.7512	5.8668
23	6.0000	6.4492	6.3858	6.4547	7.0250	6.0241
24	6.0000	5.9458	5.9222	5.9478	6.1562	6.3800
25	6.0000	6.9933	6.9829	6.9934	7.0800	7.1761
26	6.0000	7.3819	7.3764	7.3840	7.4711	7.5630
27	6.0000	7.5000	7.5000	7.5000	7.5000	7.5000
28	6.0000	8.8622	8.8520	8.8629	8.5723	8.2350
29	6.0000	8.1565	8.1703	8.1615	8.1476	8.1118
30	6.0000	8.6621	8.6882	8.6715	8.6453	8.5780

4.4 LMP's Gain Calculation

The LMP's gain is simply the difference in the LMP's for each case with respect to the base case. The base case gain was compared to MCP.

It was found that maximum gain obtained is at bus 8 for base case. The minimum gain obtained is also at bus 8, when line 6-8 is added as shown in table 4.3.

Table 4.3
LMP's Gain ($ / MWH)
IEEE modified 30 bus system

Bus No	Base Case	After adding 2-6 line	After adding 4-6 line	After adding 6-8 line	After adding 21-22 line
1	-0.861	0.024	-0.0038	-1.062	1.261
2	-1	0	0	-1.0782	1.3051
3	-1.3162	0.0956	-0.0173	-1.1392	1.4609
4	-1.4077	0.1126	-0.0209	-1.1546	1.5043
5	-1.3088	0.0539	0.0113	-1.1409	1.4326
6	-1.5211	0.1513	0.031	-1.1998	1.5893
7	-1.6564	0.1244	0.0267	-1.2094	1.5773
8	-8.4848	-0.4298	-0.0971	5.6909	-2.2921
9	-2.014	0.1699	0.03	-1.1972	1.9663
10	-2.2612	0.1759	0.0283	-1.1961	2.154
11	-2.014	0.1699	0.03	-1.1972	1.9663
12	-1.403	0.1066	-0.0136	-0.992	1.2619
13	-1.3902	0.1051	-0.0134	-0.9923	1.258
14	-1.6175	0.109	-0.0123	-0.9725	1.2102
15	-1.4194	0.1048	-0.0066	-0.9082	1.1265
16	-1.917	0.1409	0.0044	-1.0988	1.681
17	-2.2626	0.1695	0.0221	-1.1818	2.0467
18	-2.0955	0.1409	0.0067	-1.0584	1.575
19	-2.3922	0.1601	0.0149	-1.1352	1.8225
20	-2.3842	0.1651	0.0185	-1.1545	1.9156
21	-4.1136	0.2675	0.0421	-1.7862	4.1913
22	1.2488	0	0	0	-1.1156
23	-0.4492	0.0634	-0.0055	-0.5758	0.4251
24	0.0542	0.0236	-0.002	-0.2104	-0.4342
25	-0.9933	0.0104	-0.0001	-0.0867	-0.1828
26	-1.3819	0.0055	-0.0021	-0.0892	-0.1811
27	-1.5	0	0	0	0
28	-2.8622	0.0102	-0.0007	0.2899	0.6272
29	-2.1565	-0.0138	-0.005	0.0089	0.0447
30	-2.6621	-0.0261	-0.0094	0.0168	0.0841

4.5 LMP's Average Price Reduction

It was found that LMP's average reduction as minimum of -1.0427 $/hour and a maximum of 1.8514 $/hour when, line 21-22 and in the base case, respectively. That is among the considered cases as shown in tables 4.4 and 4.5. Beside the base case, there is an increase of 7.56% after adding 6-8 line, and a decrease of 13.28% after adding 21-22 line.

Table 4.4 LMP's Averages ($ / hour) IEEE modified 30 bus system	
Base Case	7.8514
After adding 2-6 line	7.7784
After adding 4-6 line	7.8495
After adding 6-8 line	8.4451
After adding 21-22 line	6.8087

Table 4.5 Average Price Reduction ($ / hour) as compared to base case IEEE modified 30 bus system	
Base Case	1.8514
After adding 2-6 line	-0.073
After adding 4-6 line	-0.0019
After adding 6-8 line	0.5937
After adding 21-22 line	-1.0427

4.6 LMP Standard Deviation

The standard deviation is used in this thesis to show how close the prices in different buses to each other. As the standard deviation gets smaller as the price profile becomes narrower. Also, the smaller standard deviation shows less congested network as well as more competitive market. It was found a minimum standard deviation of 1.2306 produced when 6-8 line is added as shown in table 4.6.

Table 4.6 LMP Standard Deviation IEEE modified 30 bus system	
Base Case	1.5702
After adding 2-6 line	1.6262
After adding 4-6 line	1.5808
After adding 6-8 line	1.2306
After adding 21-22 line	2.0376

4.7 Uplift charges Calculations

The uplift charges are equal to the increased dispatch payments by the market to generators that are out of merit order plus system losses. For this case, it can be obtained through the difference in prices between the MCP and LMPs, in other words, it can be derived from difference in the total system cost as shown in table 4.7.

Table 4.7
Uplift Charges ($ / hour)
IEEE modified 30 bus system

Case No.	Added Line		Total system Cost	Base Case	Gain
	from	To		Total system Cost	
1	2	6	3,894	**3,923**	29
2	4	6	3,921		2
3	6	8	4,319		-396
4	21	22	3,535		388

4.8 Congestion Revenues Calculations

The CR equals the extra flow across the congested path times that bus power price. Obviously, when the congestion is reduced the CR reduced as well. It was found that CR in all considered cases is smaller than the base case value. The minimum obtained CR is when 21-22 line is added as shown in table 4.8.

Table 4.8 Congestion Revenues ($ / hour) IEEE modified 30 bus system	
Base Case	229.698
After adding 2-6 line	181.815
After adding 4-6 line	200.559
After adding 6-8 line	195.810
After adding 21-22 line	138.972

4.9 System Re-dispatch Payments(SRP) Calculations

The SRP obtained in each case are very close to the SRP in the base case. Although the SRP figures are quite high but when the difference with respect to base case is considered it becomes very small, except when 21-22 line is added as shown in table 4.9. The difference is considered here to measure the saving in each of the added lines.

Table 4.9 System Re-dispatch Payments ($ / hour) IEEE modified 30 bus system	
Base Case	103.519
After adding 2-6 line	105.598
After adding 4-6 line	104.238
After adding 6-8 line	115.345
After adding 21-22 line	154.286

4.10 Total Congestions Cost

The total congestion cost gained by each case can be derived by calculating difference in:

- Uplift charges: total price reduction per hour, with respect to base case.
- SRP : total price reduction per hour, with respect to Market dispatch case.
- CR : total price reduction per hour, with respect to base case.

All the above calculations duration is one hour. Summary of all considered lines congestion costs is shown in table 4.10. Total Saving in Congestion Costs is shown in table 4.11.

Table No. **4.10**
Summary of SRP & CR ($ / hour)
IEEE modified 30 bus system

Case No.	After Adding	SRP	CR	Base Case SRP	Base Case CR
1	2-6 line	105.60	181.82	**103.52**	**229.70**
2	4-6 line	104.24	200.56		
3	6-8 line	115.35	195.81		
4	21-22 line	154.29	138.97		

Table No. **4.11**
Total Saving in Congestion Costs $ / hour
IEEE modified 30 bus system

Total Saving in Congestion Costs $ / hour

Case	Uplift Charges	CR	SRP	total saving
After adding 2-6 line	29	47.88	2.08	79
After adding 4-6 line	2	29.14	0.72	32
After adding 6-8 line	**-396**	33.89	11.83	**-350**
After adding 21-22 line	388	90.73	50.77	530

4.11 Added lines parameters and construction cost

The same line parameters used for each added second circuits. The added lines construction cost are assumed to be 266,666 \$ per kilometer for the 132 kV lines and 160,000 \$ per kilometer for the 33 kV lines. In order to obtain line lengths typical impedances were used. For 132 kV lines typical impedance of 0.0001825 + j0.0019192 and for 33 kV cable a typical impedance of 0.00292876 + j0.006005 were used.

Table 4.12 shows the construction cost for each added line.

Table No. **4.12**
Used Lines parameters and Construction Cost (k $)
IEEE modified 30 bus system

Case No.	from	to	length km	Line Parameters	Construction Cost (k $)
1	2	6	98	As existing 2-6	26,133
2	4	6	21	As existing 4-6	5,600
3	6	8	21	As existing 6-8	5,600
4	21	22	3	As existing 21-22	480

4.12 Pay Back Period PBP

The PBP for any line here is defined as the time needed to collect enough congestion cost saving equals to its construction cost, that can be derived by dividing the construction cost on the total saving as shown in table 4.13. It was found that the PBP is as low as 2 months only when adding line 21-22.

Table No. 4.13
Pay Back Period PBP (months)
IEEE modified 30 bus system

Pay Back Period PBP

Case	Construction cost k$	Total saving k$ / month	PBP (months)
After adding 2-6	26,133	57	459
After adding 4-6	5,600	23	243
After adding 6-8	5,600	-252	Never
After adding 21-22	480	382	2

CHAPTER 5

STUDY CASE 2: 11 BUS 380 KV REAL SYSTEM

5.1 System Model

The selected system is real 380 kv system reduced to 11 buses. The reduced system has 6 power plants with total capacity of 15,500 MW, total Load of 13,600 MW and 22 "380 kv" transmission lines, as shown in figure 5.1.

The branch data, bus data and generators data are shown in Appendix A.

Due to unavailability of exact generators coefficients cost data, the IEEE 30 bus system generator cost data will be used, and then the average cost produced will be compared to the system average production cost, hence the average power price with uplift charges should be in the range of 10 – 30 $ / MWH.

In order to obtain the Market Clearing Price, which is the simulating of the offered power by Generator's companies with no transmission constraints; the following assumptions are made to the base case:

1. Generators Maximum output (MW) = open.
2. Branch limits (MW) = open.
3. DC Optimal load flow was used.

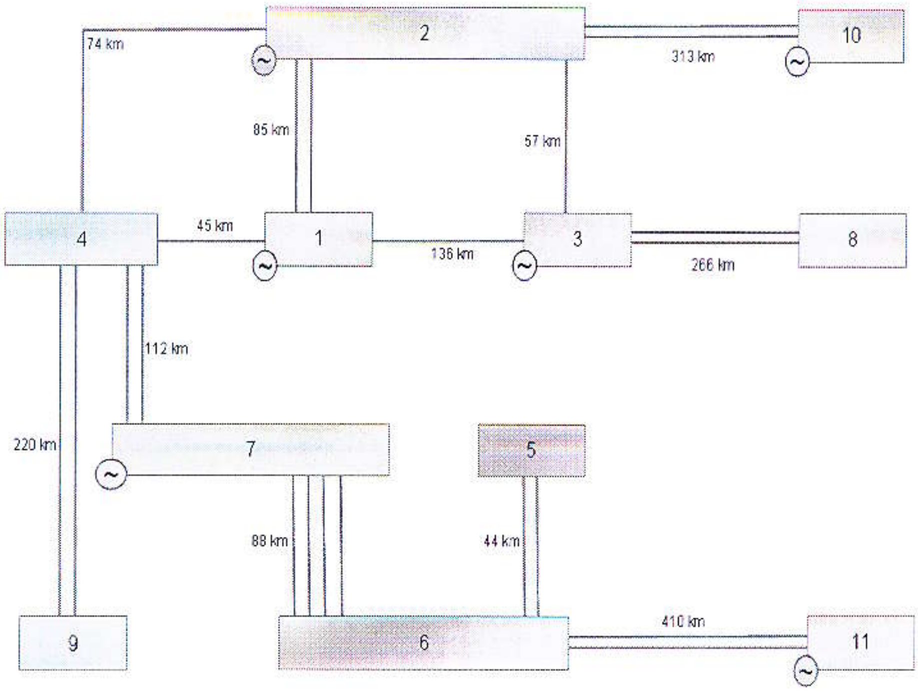


Figure 5.1
Single Line Diagram
11 bus 380 kV real svstem

5.2 Defining Network Congestions

In order to define the congested zones, contingency analysis was run on the 11 bus 380 kV real system, shown in figure 5.1, and that is by considering one line outage at a time. Branch flows in the base case is shown in table 5.1.

All lines outages in base case do not cause other lines to be overloaded except for either 1-4 or 2-4 lines. The outage of 1-4 line will cause 2-4 line to be overloaded and vice versa. Tables 5.2 and 5.3 show the branches flow during these 2 lines outage. From contingency analysis and by varying the loads it was found that if the flow across zone 4 is limited to 630 MW, no line will be over loaded. Based on that we choose zone 4 to be congested zone or bus and congestion calculations are based on that.

In this chapter first the LMP's in MCP, Base case are calculated. Second, are the calculations of LMP's reduction, average reduction, gain and standard deviation. Third, are the calculations of Congestion Revenues and System Re-dispatch Payments.

After that, the Congestions Elimination Mechanism is presented and the set of possible added lines is formed. Also, congestion is tested in each case. Then the first 3 steps are repeated after addition of new line, one line at a time. After that the calculation of Pay Back Period is presented.

Table No. 5.1
Branch flows in the base case
11 bus 380 kV real system

Branch No	From bus	To Bus	From Bus		To Bus		Losses	
			P	Q	P	Q	P	Q
1	1	2	418.03	-8.5	-416.45	37.36	1.586	28.86
2	1	2	418.03	-8.5	-416.45	37.36	1.586	28.86
3	1	3	321.33	-0.76	-319.83	31	1.498	30.25
4	1	4	1442.62	244.39	-1432.91	-37.97	9.709	206.42
5	2	3	230.47	-16.16	-229.99	21.95	0.479	5.79
6	2	4	451.32	121	-449.54	-86.34	1.782	34.66
7	2	10	575.56	0	-570	50.93	5.559	50.93
8	2	10	575.56	0	-570	50.93	5.559	50.93
9	3	8	378.31	109.69	-375	-75	3.307	34.69
10	3	8	378.31	109.69	-375	-75	3.307	34.69
11	4	7	290.63	-98.32	-289.26	120.04	1.37	21.72
12	4	7	290.63	-98.32	-289.26	120.04	1.37	21.72
13	4	9	150.6	10.47	-150	0	0.599	10.47
14	4	9	150.6	10.47	-150	0	0.599	10.47
15	5	6	-75	-25	75.03	25.6	0.027	0.6
16	5	6	-75	-25	75.03	25.6	0.027	0.6
17	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
18	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
19	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
20	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
21	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46
22	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46

Table No. 5.2
Branch flows during the outage of line 1-4
11 bus 380 kV real system

Branch No	From bus	To Bus	From Bus		To Bus		Losses	
			P	Q	P	Q	P	Q
1	1	2	1020.67	30.24	-1011.22	141.88	9.457	172.13
2	1	2	1020.67	30.24	-1011.22	141.88	9.457	172.13
3	1	3	558.66	18.21	-554.13	73.33	4.534	91.53
4	2	3	-44.65	3.81	44.66	-3.59	0.018	0.22
5	2	4	1915.97	513.71	-1883.85	110.86	32.121	624.58
6	2	10	575.56	0	-570	50.93	5.559	50.93
7	2	10	575.56	0	-570	50.93	5.559	50.93
8	3	8	378.31	109.69	-375	-75	3.307	34.69
9	3	8	378.31	109.69	-375	-75	3.307	34.69
10	4	7	291.29	-216.55	-289.26	248.79	2.033	32.24
11	4	7	291.29	-216.55	-289.26	248.79	2.033	32.24
12	4	9	150.64	11.12	-150	0	0.636	11.12
13	4	9	150.64	11.12	-150	0	0.636	11.12
14	5	6	-75	-25	75.03	25.6	0.027	0.6
15	5	6	-75	-25	75.03	25.6	0.027	0.6
16	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
17	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
18	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
19	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
20	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46
21	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46

Table No. 5.3
Branch flows during the outage of line 2-4
11 bus 380 kV real system

Branch No	From bus	To Bus	From Bus		To Bus		Losses	
			P	Q	P	Q	P	Q
1	1	2	228.76	-8.23	-228.28	16.88	0.475	8.65
2	1	2	228.76	-8.23	-228.28	16.88	0.475	8.65
3	1	3	242.55	-3.37	-241.7	20.61	0.854	17.24
4	1	4	1899.94	403.08	-1882.8	-39.37	17.108	363.71
5	2	3	305.45	-20.17	-304.61	30.33	0.841	10.17
6	2	10	575.56	0	-570	50.93	5.559	50.93
7	2	10	575.56	0	-570	50.93	5.559	50.93
8	3	8	378.31	109.69	-375	-75	3.307	34.69
9	3	8	378.31	109.69	-375	-75	3.307	34.69
10	4	7	290.81	-141	-289.26	165.62	1.552	24.61
11	4	7	290.81	-141	-289.26	165.62	1.552	24.61
12	4	9	150.61	10.7	-150	0	0.611	10.7
13	4	9	150.61	10.7	-150	0	0.611	10.7
14	5	6	-75	-25	75.03	25.6	0.027	0.6
15	5	6	-75	-25	75.03	25.6	0.027	0.6
16	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
17	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
18	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
19	6	7	-762.61	-68.95	769.63	177.6	7.017	108.65
20	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46
21	6	11	50.2	-37.69	-49.99	41.15	0.204	3.46

5.3 Defining Congestions Elimination Mechanism

In order to obtain a set of lines when added that might eliminate the congestion, the followings were considered:

- Excluding Remote buses and neighbor system from the expansion process, as shown in figure 5.2
- Select any line that is connected to congested zone:
    - Lines to be added: 1-4, 2-4, 3-4, 4-5 and 4-6, as shown in figures 5.3 and 5.4.

- Select any line that connects the system across congested zone:
    - Lines to be added: 1-7, 2-7, 3-7, 1-5, 2-5 and 3-5, as shown in figure 5.5.

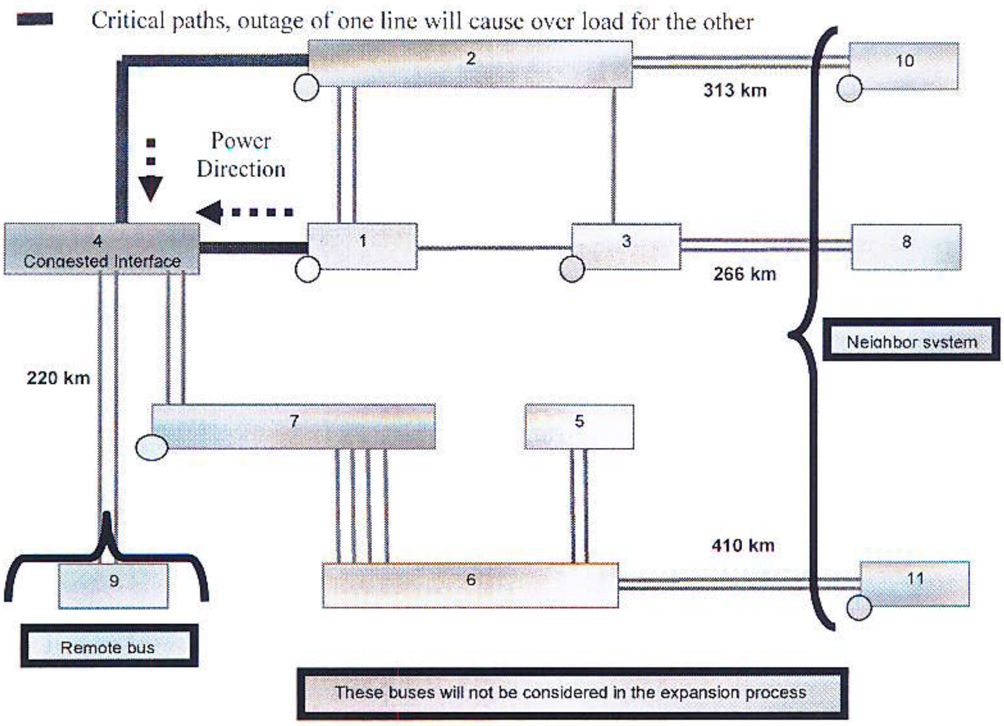
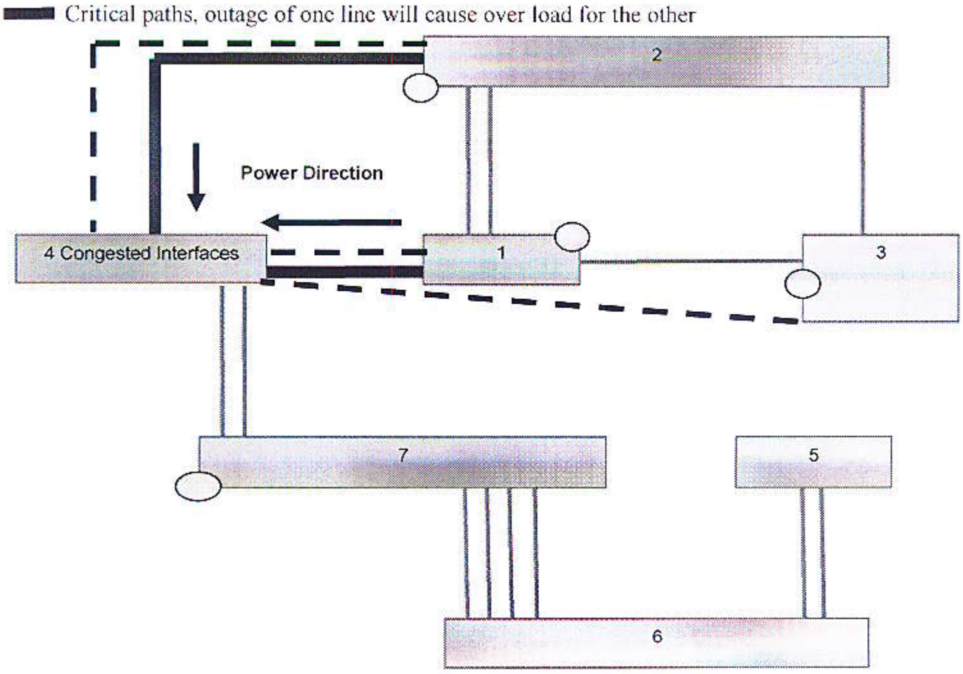


Figure 5.2
Excluded Buses from network expansion
11 bus 380 kV real system



The addition of any of the 3 - - - lines probably removes the congestion on bus No. 4

Figure 5.3
Lines that probably remove the congestion
11 bus 380 kV real system

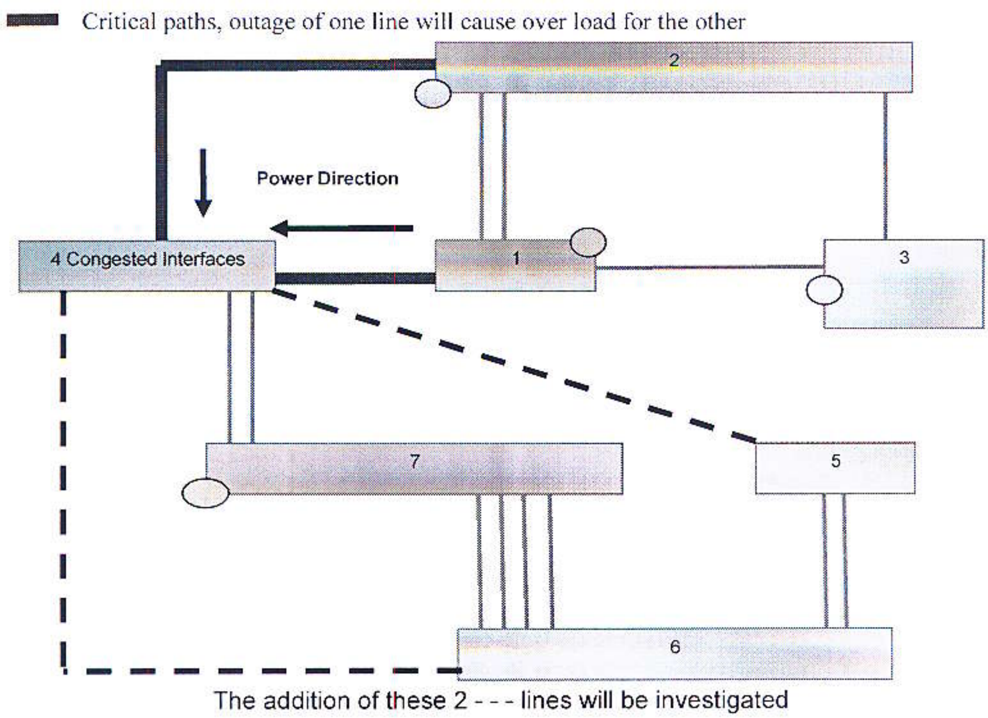


Figure 5.4
Lines under study for congestion removal
11 bus 380 kV real svstem

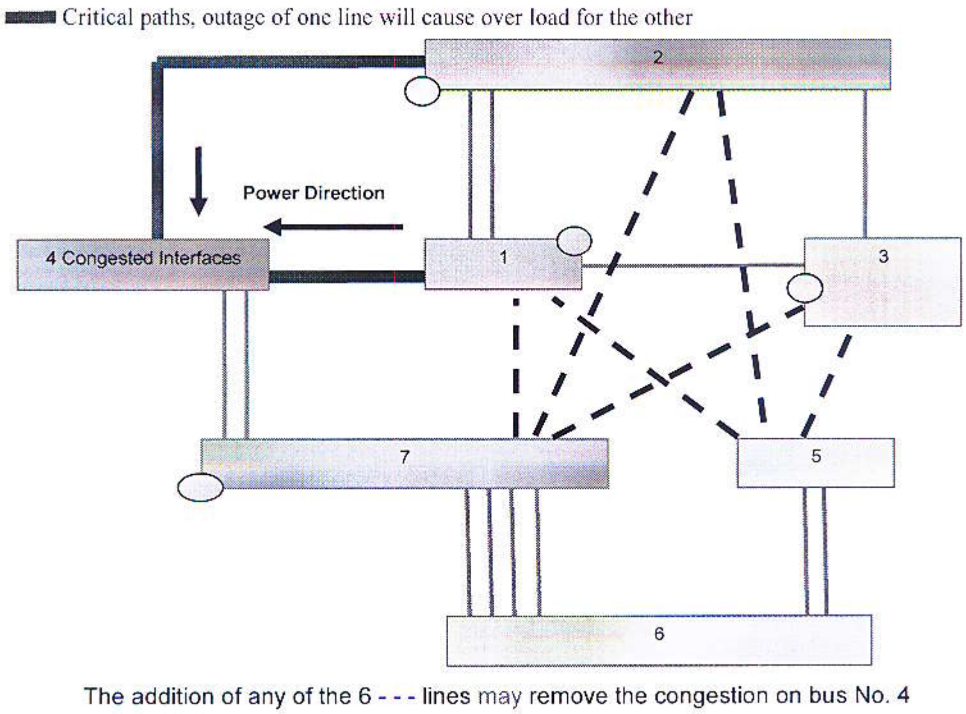


Figure 5.5
Lines under study across congested bus
11 bus 380 kV real svstem

5.4 Added line parameters

Table 5.4 shows the used lines parameters. The existing line lengths and parameters are used. Similar line parameters to the existing lines are used when the length is the same, accepting ± 10 % difference.

Table No. 5.4
Used Line Parameters
11 bus 380 kV real system

Case No.	from	to	length km	Existing / new	Line Parameters
1	1	4	45	2nd circuit	As existing 1-4
2	2	4	74	2nd circuit	As existing 2-4
3	3	4	117	new path	as 4-7
4	4	5	112	new path	as 4-7
5	4	6	132	new path	as 1-3
6	1	7	109	new path	as 4-7
7	2	7	142	new path	as 1-3
8	3	7	193	new path	as 4-9
9	1	5	146	new path	as 1-3
10	2	5	148	new path	as 1-3
11	3	5	197	new path	as 4-9

5.5 Congestion Test

Congestion Test is simply checking the branch flows during the outage of either 1-4 or 2-4 and that is after the addition of lines, one line at a time. If any lines get overloaded, then congestion still there and it fails the test.

Table 5.5 summarized the congestion test after each case. It was found that 3 out of 11 selected paths failed the congestion test.

Table No. 5.5
Congestion Test
11 bus 380 kV real system

Case No.	from	to	length km	Is Congestion removed after addition of the line?
1	1	4	45	Yes
2	2	4	74	Yes
3	3	4	117	1-4 loaded 99% when 2-4 is out
4	4	5	112	No
5	4	6	132	No
6	1	7	109	Yes
7	2	7	142	Yes
8	3	7	193	No
9	1	5	146	Yes
10	2	5	148	Yes
11	3	5	197	Yes

5.6 Added lines construction cost

For the 380 kV transmission lines construction cost, an average cost per kilometer of 586,000 $ is used.

Table 5.6 shows the construction cost for each line.

Table No. 5.6
Added Lines Construction Costs
11 bus 380 kV real system

Case No.	from	to	length km	Construction cost (Thousand $)
1	1	4	45	26,370
2	2	4	74	43,364
3	3	4	117	68,562
4	4	5	112	65,632
5	4	6	132	77,352
6	1	7	109	63,874
7	2	7	142	83,212
8	3	7	193	113,098
9	1	5	146	85,556
10	2	5	148	86,728
11	3	5	197	115,442

5.7 LMPs Calculations

The produced set of LMPs is based on the IEEE 30 bus generators cost coefficients and found to be high, as expected, as compared to the actual system range production cost as explained in case 2 system model. This output is reflecting a huge generation output from small machines, as assumed. There is a need to represent generation coefficients for the congestion calculations. To correct that, the LMP's produced are scaled back to the system production cost, which is in range of **10 – 30 $ / MWH** in real case. LMP's average was found as **140 $ / MWH**. To make it realistic and comparable energy prices, the LMPs obtained was divided by 10, and the produced values are used for the remaining of the calculations.

Produced and Corrected LMPs are shown in tables 5.7, 5.8, 5.9 and 5.10.

Table No. 5.7
LMPs ($ / MWH) using the IEEE 30 bus Gen Coefficients
11 bus 380 kV real system

Bus No	MCP	LMP's Base Case	After adding 1-4 line	After adding 2-4 line	After adding 3-4 line	After adding 4-5 line
1	86.6500	137.0309	137.1767	136.9423	136.8990	137.0184
2	86.6500	137.9903	137.8796	138.0451	137.8638	137.9800
3	86.6500	138.5000	138.5000	138.5000	138.5000	138.5000
4	86.6500	138.9961	138.2881	138.6987	138.7984	138.9857
5	86.6500	142.9200	142.1738	142.6021	142.7081	141.1171
6	86.6500	142.8177	142.0720	142.5000	142.6059	141.3391
7	86.6500	140.1819	139.4500	139.8701	139.9740	139.1642
8	86.6500	140.8894	140.8894	140.8894	140.8894	140.8894
9	86.6500	140.1705	139.4162	139.8444	139.9536	140.1693
10	86.6500	140.7082	140.5953	140.7641	140.5792	140.6977
11	86.6500	143.5640	142.8144	143.2447	143.3511	142.0736

Table No. 5.8
Corrected LMPs ($ / MWH)
11 bus 380 kV real system

		LMP's				
Bus No	MCP	Base Case	After adding 1-4 line	After adding 2-4 line	After adding 3-4 line	After adding 4-5 line
1	8.6650	13.7031	13.7177	13.6942	13.6899	13.7018
2	8.6650	13.7990	13.7880	13.8045	13.7864	13.7980
3	8.6650	13.8500	13.8500	13.8500	13.8500	13.8500
4	8.6650	13.8996	13.8288	13.8699	13.8798	13.8986
5	8.6650	14.2920	14.2174	14.2602	14.2708	14.1117
6	8.6650	14.2818	14.2072	14.2500	14.2606	14.1339
7	8.6650	14.0182	13.9450	13.9870	13.9974	13.9164
8	8.6650	14.0889	14.0889	14.0889	14.0889	14.0889
9	8.6650	14.0171	13.9416	13.9844	13.9954	14.0169
10	8.6650	14.0708	14.0595	14.0764	14.0579	14.0698
11	8.6650	14.3564	14.2814	14.3245	14.3351	14.2074

Table No. 5.9
LMPs ($ / MWH) using the IEEE 30 bus Gen Coefficients
11 bus 380 kV real system

Bus No	After adding 4-6 line	After adding 1-7 line	After adding 2-7 line	After adding 3-7 line	After adding 1-5 line	After adding 2-5 line	After adding 3-5 line
1	137.0187	137.1009	136.9310	136.7772	137.1276	136.8422	136.4729
2	137.9801	137.9273	138.0457	137.7619	137.8933	138.0791	137.4932
3	138.5000	138.5000	138.5000	138.5000	138.5000	138.5000	138.5000
4	138.9847	138.6193	138.6801	138.6191	138.4311	138.4216	138.1634
5	141.4207	141.5843	141.9761	142.2277	139.9850	140.4011	140.8915
6	141.3209	141.4829	141.8744	142.1259	140.3103	140.6496	140.9986
7	139.1478	138.8718	139.2560	139.5028	138.2907	138.5252	138.6876
8	140.8894	140.8894	140.8894	140.8894	140.8894	140.8894	140.8894
9	140.1669	139.7708	139.8397	139.7830	139.5776	139.5730	139.3172
10	140.6978	140.6439	140.7647	140.4753	140.6093	140.7988	140.2013
11	142.0561	142.2223	142.6158	142.8686	141.0367	141.3774	141.7302

Table No. 5.10
Corrected LMPs ($ / MWH)
11 bus 380 kV real system

Bus No	After adding 4-6 line	After adding 1-7 line	After adding 2-7 line	After adding 3-7 line	After adding 1-5 line	After adding 2-5 line	After adding 3-5 line
1	13.7019	13.7101	13.6931	13.6777	13.7128	13.6842	13.6473
2	13.7980	13.7927	13.8046	13.7762	13.7893	13.8079	13.7493
3	13.8500	13.8500	13.8500	13.8500	13.8500	13.8500	13.8500
4	13.8985	13.8619	13.8680	13.8619	13.8431	13.8422	13.8163
5	14.1421	14.1584	14.1976	14.2228	13.9985	14.0401	14.0892
6	14.1321	14.1483	14.1874	14.2126	14.0310	14.0650	14.0999
7	13.9148	13.8872	13.9256	13.9503	13.8291	13.8525	13.8688
8	14.0889	14.0889	14.0889	14.0889	14.0889	14.0889	14.0889
9	14.0167	13.9771	13.9840	13.9783	13.9578	13.9573	13.9317
10	14.0698	14.0644	14.0765	14.0475	14.0609	14.0799	14.0201
11	14.2056	14.2222	14.2616	14.2869	14.1037	14.1377	14.1730

5.8 LMPs Gain Calculations

The LMP's gain is simply the difference in the LMP's for each case with respect to the base case. The base case gain was compared to MCP.

It was found that buses 3 and 8 gains are zero, except for the base case. Noting that bus 3 has the most expensive generation cost in the network and bus 8 is connected only to bus 3. All other lines gains are very small, the maximum gain obtained beside the base case was found 0.2935 $ / hour at bus 5 after the addition of 1-5 line, as shown in tables 5.11 and 5.12.

Table No. 5.11
LMPs Gain ($ / MWH)
11 bus 380 kV real system

LMPs Gain

Bus No	Base Case	After adding 1-4 line	After adding 2-4 line	After adding 3-4 line	After adding 4-5 line	After adding 4-6 line
1	5.0381	0.0146	-0.0089	-0.0132	-0.0012	-0.0012
2	5.1340	-0.0111	0.0055	-0.0126	-0.0010	-0.0010
3	5.1850	0.0000	0.0000	0.0000	0.0000	0.0000
4	5.2346	-0.0708	-0.0297	-0.0198	-0.0010	-0.0011
5	5.6270	-0.0746	-0.0318	-0.0212	-0.1803	-0.1499
6	5.6168	-0.0746	-0.0318	-0.0212	-0.1479	-0.1497
7	5.3532	-0.0732	-0.0312	-0.0208	-0.1018	-0.1034
8	5.4239	0.0000	0.0000	0.0000	0.0000	0.0000
9	5.3521	-0.0754	-0.0326	-0.0217	-0.0001	-0.0004
10	5.4058	-0.0113	0.0056	-0.0129	-0.0011	-0.0010
11	5.6914	-0.0750	-0.0319	-0.0213	-0.1490	-0.1508

Table No. 5.12
LMPs Gain ($ / MWH)
11 bus 380 kV real system

LMPs Gain

Bus No	After adding 1-7 line	After adding 2-7 line	After adding 3-7 line	After adding 1-5 line	After adding 2-5 line	After adding 3-5 line
1	0.0070	-0.0100	-0.0254	0.0097	-0.0189	-0.0558
2	-0.0063	0.0055	-0.0228	-0.0097	0.0089	-0.0497
3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	-0.0377	-0.0316	-0.0377	-0.0565	-0.0574	-0.0833
5	-0.1336	-0.0944	-0.0692	**-0.2935**	-0.2519	-0.2028
6	-0.1335	-0.0943	-0.0692	-0.2507	-0.2168	-0.1819
7	-0.1310	-0.0926	-0.0679	-0.1891	-0.1657	-0.1494
8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
9	-0.0400	-0.0331	-0.0388	-0.0593	-0.0598	-0.0853
10	-0.0064	0.0056	-0.0233	-0.0099	0.0091	-0.0507
11	-0.1342	-0.0948	-0.0695	-0.2527	-0.2187	-0.1834

5.9 LMP's Averages and Averages Price Reduction

It was found that the addition of line 1-5 will produce the maximum price reduction, as compared to all other considered lines. LMP's averages and average reduction are shown in tables 5.13 and 5.14.

Table No. 5.13
LMPs Averages $ / hour
11 bus 380 kV real system

Base Case	14.0343
After adding 1-4 line	13.9932
After adding 2-4 line	14.0173
After adding 3-4 line	14.0193
After adding 4-5 line	13.9812
After adding 4-6 line	13.9835
After adding 1-7 line	13.9783
After adding 2-7 line	13.9943
After adding 3-7 line	13.9957
After adding 1-5 line	**13.9332**
After adding 2-5 line	13.946
After adding 3-5 line	13.9395

Table No. 5.14
Average Price Reduction $ / hour as compared to base case
11 bus 380 kV real system

Base Case	5.3693
After adding 1-4 line	-0.0410
After adding 2-4 line	-0.0170
After adding 3-4 line	-0.0150
After adding 4-5 line	-0.0530
After adding 4-6 line	-0.0508
After adding 1-7 line	-0.0560
After adding 2-7 line	-0.0400
After adding 3-7 line	-0.0385
After adding 1-5 line	**-0.1011**
After adding 2-5 line	-0.0883
After adding 3-5 line	-0.0948

5.10 LMP Standard Deviation

The standard deviation is used here to show how close the prices in different buses to each other. As the standard deviation gets smaller as the price profile becomes narrower. Also, the smaller standard deviation shows less congested network as well as more competitive market. The result shows that the 11 bus 380 kV real system is very competitive and narrow price profile with maximum standard deviation of 0.2129 in the base case, as shown in table 5.15.

It is noticed here that line 1-5 creates the most competitive market environment as compared to all other considered lines.

Table No. 5.15
LMP Standard Deviation
11 bus 380 kV real system

Base Case	0.2129
After adding 1-4 line	0.1906
After adding 2-4 line	0.2043
After adding 3-4 line	0.2096
After adding 4-5 line	0.1588
After adding 4-6 line	0.1612
After adding 1-7 line	0.1689
After adding 2-7 line	0.1828
After adding 3-7 line	0.1964
After adding 1-5 line	**0.1339**
After adding 2-5 line	0.1465
After adding 3-5 line	0.1677

5.11 Uplift Charges Calculations

The uplift charges are equal to the increased dispatch payments by the market to generators that are out of merit order plus system losses. For our case, it can be obtained through the difference in prices between the MCP and LMPs, in other words, it can be derived from difference in the total system cost as shown in table 5.16.

Table No. 5.16
Uplift Charges ($ / hour)
11 bus 380 kV real system

Case No.	Added Line		Total system Cost	Base Case Total system Cost	Uplift charges Saving
	from	To			
1	1	4	190,544	**191,029**	485
2	2	4	190,851		177
3	3	4	190,820		208
4	4	5	190,282		746
5	4	6	190,275		753
6	1	7	190,258		770
7	2	7	190,509		520
8	3	7	190,481		547
9	1	5	189,680		1,349
10	2	5	189,901		1,128
11	3	5	189,709		1,320

5.12 System Re-dispatch Payments(SRP) Calculations

The SRP obtained in each case are very close to the SRP in the base case, as shown in table 5.17. The difference is considered here to measure the saving in each of the added lines, as shown in tables 5.17 and 5.18. It was found that the maximum saving is when line 1-5 is added.

Table No. 5.17
System Re-dispatch Payments ($ / hour)
11 bus 380 kV real system

Base Case	3,925.04
After adding 1-4 line	3,904.60
After adding 2-4 line	3,916.36
After adding 3-4 line	3,919.16
After adding 4-5 line	3,896.48
After adding 4-6 line	3,896.20
After adding 1-7 line	3,888.36
After adding 2-7 line	3,899.28
After adding 3-7 line	3,906.00
After adding 1-5 line	3,872.12
After adding 2-5 line	3,878.84
After adding 3-5 line	3,883.32

Table No. 5.18
System Re-dispatch Payments ($ / hour) as compared to Base Case
11 bus 380 kV real system

After adding 1-4 line	-20.44
After adding 2-4 line	-8.68
After adding 3-4 line	-5.88
After adding 4-5 line	-28.56
After adding 4-6 line	-28.84
After adding 1-7 line	-36.68
After adding 2-7 line	-25.76
After adding 3-7 line	-19.04
After adding 1-5 line	-52.92
After adding 2-5 line	-46.20
After adding 3-5 line	-41.72

5.13 Congestion Revenues (CR) Calculations

The CR obtained for this case is quite significant. When there is congestion across bus No 4, the CR equals the extra flow across the congested bus times that bus power price. Obviously, when the congestion is removed the CR becomes zero. In this case, the limit across bus 4 produced from contingency analysis is 630 MW. Extra power flow across bus 4 and CR are shown in table 5.19.

Table No. 5.19
Congestion Revenues ($ / hour)
11 bus 380 kV real system

Congestion Revenues ($ / hour)		Extra flow across Bus 4 (MW)
Base Case	3509.0955	254
After adding 1-4 line	0	0
After adding 2-4 line	0	0
After adding 3-4 line	0	0
After adding 4-5 line	3412.5159	246
After adding 4-6 line	3414.0202	246
After adding 1-7 line	0	0
After adding 2-7 line	0	0
After adding 3-7 line	1250.3443	90
After adding 1-5 line	0	0
After adding 2-5 line	0	0
After adding 3-5 line	0	0

5.14 Total Congestions Cost

The total congestion cost gained by each case can be derived by calculating difference in:

- Uplift charges: total price reduction per hour, with respect to base case.
- SRP : total price reduction per hour, with respect to Market dispatch case.
- CR : total price reduction per hour, with respect to base case.

All the above calculations duration is one hour. Summary of all considered lines congestion costs is shown in table 5.20. Total Saving in Congestion Costs is in range of 3700-4900 $ / hour except for the cases that failed the congestion test, as shown in table 5.21.

Table No. 5.20
Summary of SRP & CR ($ / hour)
11 bus 380 kV real system

Case No.	After Adding	SRP	CR	Base Case SRP	Base Case CR
1	1-4 line	3904.6	0	3,925.04	3,509.10
2	2-4 line	3916.36	0		
3	3-4 line	3919.16	0		
4	4-5 line	3896.48	3412.5159		
5	4-6 line	3896.2	3414.0202		
6	1-7 line	3888.36	0		
7	2-7 line	3899.28	0		
8	3-7 line	3906	1250.3443		
9	1-5 line	3872.12	0		
10	2-5 line	3878.84	0		
11	3-5 line	3883.32	0		

Table No. 5.21
Total Saving in Congestion Costs $ / hour
11 bus 380 kV real system

Total Saving in Congestion Costs $ / hour

Case	Uplift Charges	CR	SRP	total saving
After adding 1-4 line	485	3,509.00	20.40	4,020
After adding 2-4 line	177	3,509.00	8.64	3,703
After adding 3-4 line	208	3,509.00	5.84	3,733
After adding 4-5 line	746	96.48	28.52	884
After adding 4-6 line	753	94.98	28.80	892
After adding 1-7 line	770	3,509.00	36.64	4,330
After adding 2-7 line	520	3,509.00	25.72	4,070
After adding 3-7 line	547	2,258.66	19.00	2,843
After adding 1-5 line	1,349	3,509.00	52.88	4,926
After adding 2-5 line	1,128	3,509.00	46.16	4,700
After adding 3-5 line	1,320	3,509.00	41.68	4,889

5.15 Pay Back Period PBP

The PBP for any line here is defined as the time needed to collect enough congestion saving equals to its construction cost, as shown in table 5.22.

It was found that the lines which fail the congestion test have the maximum PBP of ~5-10 years. All other lines PBP are less than 3 years with a minimum of 9 months for the case of adding 1-4 line.

Table No. 5.22
Pay Back Period PBP (months)
11 bus 380 kV real system

Pay Back Period PBP

Case	Construction cost k$	Total saving k$ / month	PBP (months)
After adding 1-4 line	26,370	2,895	9
After adding 2-4 line	43,364	2,666	16
After adding 3-4 line	68,562	2,688	26
After adding 4-5 line	65,632	637	103
After adding 4-6 line	77,352	642	120
After adding 1-7 line	63,874	3,118	20
After adding 2-7 line	83,212	2,931	28
After adding 3-7 line	113,098	2,047	55
After adding 1-5 line	85,556	3,546	24
After adding 2-5 line	86,728	3,384	26
After adding 3-5 line	115,442	3,520	33

CHAPTER 6

CONCLUSION AND FUTURE WORK

6.1 Conclusion

In this thesis a proposal of congestions relief mechanism through transmission expansion was presented as well as payment recovery process through congestions revenues.

Two study cases were considered. A contingency analysis was conducted to each case to explore the congestion that might arise from the ISO point of view. One case produced a congested paths and the other case produced a congested interface. It was observed from the results obtained that the Congestion Revenues CR is forming most of the total congestion costs. The CR forms an average of 93 % of the total congestion costs in the IEEE 30 bus test system and a 95 % in the 11 bus case. For the 11 bus 380 kv real system, it was found that the total congestion cost might be utilized to eliminate the congestion permanently in 9 months while in the IEEE 30 bus test system the PBP is 2 months only. This shows an effective fast solution for transmission congestion removal which can be applied in today's electricity markets.

In this thesis a specific operating contingency was assumed and based all the calculation on it. If the ISO uses different contingency, the result will change totally. i.e. N-1, N-2 or the loss of largest unit in the system might be different ISO worse contingencies. Besides that, the different approaches used for congestion costs calculation will add another dimension to the problem and makes it almost impossible to compare it with previews work on congestion cost recovery and congestion cost allocations.

6.2 Future Work

It is recommended for future work to consider the expansion in renewable energy sources and the granted access to transmission network regardless of transmission congestion. Also, it is recommended to include the environmental effects on congestion costs, like Co_2 emissions costs and different type of fuel pollution costs. Beside the said, the financial instruments like Financial Transmission Right (FTR), Contracts for Differences (CfD) and Transmission Congestion Contracts (TCCs) are highly affecting the congestion by introducing extra constraints. Also, the strategic bid by independent power producers is of great impact on the congestion costs.

CHAPTER 7

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APPENDICES

Appendix A

Systems Model Data:

A1. Study Case 1 : Modified IEEE 30 bus test system

Bus Data:

Bus No	Type	Pd	Qd	Gs	Bs	area	Vm	Va	Base	zone	Vmax	Vmin
1	3	0	0	0	0	1	1	0	100	1	1.1	0.95
2	2	65.1	38.1	0	0	1	1	0	100	1	1.1	0.95
3	1	7.2	3.6	0	0	1	1	0	100	1	1.1	0.95
4	1	22.8	4.8	0	0	1	1	0	100	1	1.1	0.95
5	1	0	0	0	0	1	1	0	100	1	1.1	0.95
6	1	0	0	0	0	1	1	0	100	1	1.1	0.95
7	1	68.4	32.7	0	0	1	1	0	100	1	1.1	0.95
8	1	90	90	0	0	1	1	0	100	1	1.1	0.95
9	1	0	0	0	0	1	1	0	100	1	1.1	0.95
10	1	17.4	6	0	0	1	1	0	100	1	1.1	0.95
11	1	0	0	0	0	1	1	0	100	1	1.1	0.95
12	1	33.6	22.5	0	0	1	1	0	100	1	1.1	0.95
13	2	0	0	0	0	1	1	0	100	1	1.1	0.95
14	1	18.6	4.8	0	0	1	1	0	100	1	1.1	0.95
15	1	24.6	7.5	0	0	1	1	0	100	1	1.1	0.95
16	1	10.5	5.4	0	0	1	1	0	100	1	1.1	0.95
17	1	27	17.4	0	0	1	1	0	100	1	1.1	0.95
18	1	9.6	2.7	0	0	1	1	0	100	1	1.1	0.95
19	1	28.5	10.2	0	0	1	1	0	100	1	1.1	0.95
20	1	6.6	2.1	0	0	1	1	0	100	1	1.1	0.95
21	1	52.5	33.6	0	0	1	1	0	100	1	1.1	0.95
22	2	0	0	0	0	1	1	0	100	1	1.1	0.95
23	2	9.6	4.8	0	0	1	1	0	100	1	1.1	0.95
24	1	26.1	20.1	0	0	1	1	0	100	1	1.1	0.95
25	1	0	0	0	0	1	1	0	100	1	1.1	0.95
26	1	10.5	6.9	0	0	1	1	0	100	1	1.1	0.95
27	2	0	0	0	0	1	1	0	100	1	1.1	0.95
28	1	0	0	0	0	1	1	0	100	1	1.1	0.95
29	1	7.2	2.7	0	0	1	1	0	100	1	1.1	0.95
30	1	31.8	5.7	0	0	1	1	0	100	1	1.1	0.95

Bus data of IEEE modified 30 bus test system

Branch Data:

Branch No	From Bus	To Bus	R	X	B	Rate A	Rate B	Rate C	Ratio	Angle	Status
1	1	2	0.02	0.06	0.03	75	85	100	0	0	1
2	1	3	0.05	0.19	0.02	75	85	100	0	0	1
3	2	4	0.06	0.17	0.02	75	85	100	0	0	1
4	3	4	0.01	0.04	0	75	85	100	0	0	1
5	2	5	0.05	0.2	0.02	75	85	100	0	0	1
6	2	6	0.06	0.18	0.02	75	85	100	0	0	1
7	4	6	0.01	0.04	0	75	85	100	0	0	1
8	5	7	0.05	0.12	0.01	75	85	100	0	0	1
9	6	7	0.03	0.08	0.01	75	85	100	0	0	1
10	6	8	0.01	0.04	0	75	85	100	0	0	1
11	6	9	0	0.21	0	75	85	100	0	0	1
12	6	10	0	0.56	0	75	85	100	0	0	1
13	9	11	0	0.21	0	75	85	100	0	0	1
14	9	10	0	0.11	0	75	85	100	0	0	1
15	4	12	0	0.26	0	75	85	100	0	0	1
16	12	13	0	0.14	0	75	85	100	0	0	1
17	12	14	0.12	0.26	0	75	85	100	0	0	1
18	12	15	0.07	0.13	0	75	85	100	0	0	1
19	12	16	0.09	0.2	0	75	85	100	0	0	1
20	14	15	0.22	0.2	0	75	85	100	0	0	1
21	16	17	0.08	0.19	0	75	85	100	0	0	1
22	15	18	0.11	0.22	0	75	85	100	0	0	1
23	18	19	0.06	0.13	0	75	85	100	0	0	1
24	19	20	0.03	0.07	0	75	85	100	0	0	1
25	10	20	0.09	0.21	0	75	85	100	0	0	1
26	10	17	0.03	0.08	0	75	85	100	0	0	1
27	10	21	0.03	0.07	0	75	85	100	0	0	1
28	10	22	0.07	0.15	0	75	85	100	0	0	1
29	21	22	0.01	0.02	0	75	85	100	0	0	1
30	15	23	0.1	0.2	0	75	85	100	0	0	1
31	22	24	0.12	0.18	0	75	85	100	0	0	1
32	23	24	0.13	0.27	0	75	85	100	0	0	1
33	24	25	0.19	0.33	0	75	85	100	0	0	1
34	25	26	0.25	0.38	0	75	85	100	0	0	1
35	25	27	0.11	0.21	0	75	85	100	0	0	1
36	28	27	0	0.4	0	75	85	100	0	0	1
37	27	29	0.22	0.42	0	75	85	100	0	0	1
38	27	30	0.32	0.6	0	75	85	100	0	0	1
39	29	30	0.24	0.45	0	75	85	100	0	0	1
40	8	28	0.06	0.2	0.02	75	85	100	0	0	1
41	6	28	0.02	0.06	0.01	75	85	100	0	0	1

Branch data of IEEE modified 30 bus test system

Generators Data:

Bus No	Pg	Qg	Qmax	Qmin	Vg	Base	status	Pmax	Pmin
1	23.54	0	150	-50	1	100	1	300	0
2	60.97	0	150	-50	1	100	1	300	0
13	37	0	150	-50	1	100	1	300	0
22	21.59	0	150	-50	1	100	1	300	0
23	19.2	0	150	-50	1	100	1	300	0
27	26.9	0	150	-50	1	100	1	300	0

Generator data of IEEE modified 30 bus test system

Generators Cost coefficients:

Format type	Start up cost	Shut Down Cost	Degree	C2	C1	C0
2	0	0	3	0.02	2	0
2	0	0	3	0.0175	1.75	0
2	0	0	3	0.0625	1	0
2	0	0	3	0.00834	3.25	0
2	0	0	3	0.025	3	0
2	0	0	3	0.025	3	0

Generator Cost data of IEEE modified 30 bus test system

A2. Study Case 2 : 11 bus 380 kV real system

Bus Data:

Bus No	Type	Pd	Qd	Gs	Bs	area	Vm	Va	Base	zone	Vmax	Vmin
1	3	100	0	0	0	1	1	0	100	1	1.05	0.95
2	2	1200	300	0	0	1	1	-1.9297	100	1	1.05	0.95
3	2	800	300	0	0	1	1	1.4201	100	1	1.05	0.95
4	2	1000	300	0	0	1	1	0.3791	100	1	1.05	0.95
5	2	150	50	0	0	1	1	-8.3062	100	1	1.05	0.95
6	2	2800	300	0	0	1	0.99028	-7.8533	100	1	1.05	0.95
7	2	300	0	0	0	1	1	-0.6564	100	1	1.05	0.95
8	2	750	150	0	0	1	0.99245	-24.7225	100	1	1.05	0.95
9	2	300	0	0	0	1	1	20.7897	100	1	1.05	0.95
10	1	3700	500	0	0	1	0.97688	-17.8982	100	1	1.05	0.95
11	2	2500	500	0	0	1	1	-26.9048	100	1	1.05	0.95

11 bus 380 kV real system Bus Data

Branch Data:

Branch No	From Bus	To Bus	R	X	B	Rate A	Rate B	Rate C	Ratio	Angle	Status
1	1	2	0.001	0.0182	0	1500	1650	2000	1	0	1
2	1	2	0.001	0.0182	0	1500	1650	2000	1	0	1
3	1	3	0.0016	0.0323	0	1500	1650	2000	1	0	1
4	1	4	0.0005	0.01063	0	1500	1650	2000	1	0	1
5	2	3	0.00099	0.01196	0	1500	1650	2000	1	0	1
6	2	4	0.0009	0.0175	0	1500	1650	2000	1	0	1
7	2	10	0.00185	0.01695	0	1500	1650	2000	1	0	1
8	2	10	0.00185	0.01695	0	1500	1650	2000	1	0	1
9	3	8	0.00235	0.02465	0	1500	1650	2000	1	0	1
10	3	8	0.00235	0.02465	0	1500	1650	2000	1	0	1
11	4	7	0.00154	0.02442	0	1500	1650	2000	1	0	1
12	4	7	0.00154	0.02442	0	1500	1650	2000	1	0	1
13	4	9	0.00278	0.04863	0	1500	1650	2000	1	0	1
14	4	9	0.00278	0.04863	0	1500	1650	2000	1	0	1
15	5	6	0.00045	0.00982	0	1500	1650	2000	1	0	1
16	5	6	0.00045	0.00982	0	1500	1650	2000	1	0	1
17	6	7	0.00124	0.0192	0	1500	1650	2000	1	0	1
18	6	7	0.00124	0.0192	0	1500	1650	2000	1	0	1
19	6	7	0.00124	0.0192	0	1500	1650	2000	1	0	1
20	6	7	0.00124	0.0192	0	1500	1650	2000	1	0	1
21	6	11	0.00537	0.09096	0	1500	1650	2000	1	0	1
22	6	11	0.00537	0.09096	0	1500	1650	2000	1	0	1

11 bus 380 kV real system Branch Data

Generators Data:

Bus No	Pg	Qg	Qmax	Qmin	Vg	MVA Base	status	Pmax	Pmin
1	280.666	-6.191	2000	-2000	1.06	100	1	2700	0
2	2000	310.752	2000	-2000	1.03	100	1	2200	0
3	2000	-20.894	2000	-2000	1.03	100	1	2200	0
7	2800	207.872	2000	-2000	1.05	100	1	2800	0
10	3000	587.539	2000	-2000	1	100	1	3200	0
11	2400	587.539	2000	-2000	1	100	1	2400	0

11 bus 380 kV real system Generators Data

Appendix B

B.1 Matlab M-files:

Case study 1: Modified IEEE 30 test system

Base Case Data:

```
function [baseMVA, bus, gen, branch, areas, gencost] =
case30L3G300B75
%   CASE30    Power flow data for 30 bus, 6 generator case.
%
%   Based on data from ...
%     Alsac, O. & Stott, B., "Optimal Load Flow with Steady State
Security",
%     IEEE Transactions on Power Apparatus and Systems, Vol. PAS
93, No. 3,
%     1974, pp. 745-751.
%       With loads multiplied by 3, Gen limits set to 300 MW and
branch limit
%       set to 75 MW.
%   ... with branch parameters rounded to nearest 0.01, shunt
values divided
%   by 100 and shunt on bus 10 moved to bus 5, load at bus 5 zeroed
out.
%   Generator locations, costs and limits and bus areas were taken
from ...
%     Ferrero, R.W., Shahidehpour, S.M., Ramesh, V.C., "Transaction
analysis
%     in deregulated power systems using game theory", IEEE
Transactions on
%     Power Systems, Vol. 12, No. 3, Aug 1997, pp. 1340-1347.
%   Generator Q limits were derived from Alsac & Stott, using their
Pmax
%   capacities. V limits and line |S| limits taken from Alsac &
Stott.


%%-----  Power Flow Data  -----%%
%% system MVA base
baseMVA = 100;

%% bus data
%   bus_i   type    Pd   Qd   Gs   Bs   area    Vm   Va   baseKV   zone
Vmax    Vmin
bus = [
1   3   0       0       0   0       1   1   0   135 1   1.1 0.95;
2   2   65.1    38.1    0   0       1   1   0   135 1   1.1 0.95;
3   1   7.2     3.6     0   0       1   1   0   135 1   1.1 0.95;
4   1   22.8    4.8     0   0       1   1   0   135 1   1.1 0.95;
5   1   0      0      0     0       1   1   0   135 1   1.1 0.95;
6   1   0       0       0   0       1   1   0   135 1   1.1 0.95;
7   1   68.4    32.7    0   0       1   1   0   135 1   1.1 0.95;
8   1   90      90      0   0       1   1   0   135 1   1.1 0.95;
9   1   0       0       0   0       1   1   0   135 1   1.1 0.95;
10  1   17.4    6       0   0       1   1   0   135 1   1.1 0.95;
11  1   0       0       0   0       1   1   0   135 1   1.1 0.95;
```

```
12  1   33.6    22.5    0   0       1   1   0   135 1   1.1 0.95;
13  2   0       0       0   0       1   1   0   135 1   1.1 0.95;
14  1   18.6    4.8     0   0       1   1   0   135 1   1.1 0.95;
15  1   24.6    7.5     0   0       1   1   0   135 1   1.1 0.95;
16  1   10.5    5.4     0   0       1   1   0   135 1   1.1 0.95;
17  1   27      17.4    0   0       1   1   0   135 1   1.1 0.95;
18  1   9.6     2.7     0   0       1   1   0   135 1   1.1 0.95;
19  1   28.5    10.2    0   0       1   1   0   135 1   1.1 0.95;
20  1   6.6     2.1     0   0       1   1   0   135 1   1.1 0.95;
21  1   52.5    33.6    0   0       1   1   0   135 1   1.1 0.95;
22  2   0       0       0   0       1   1   0   135 1   1.1 0.95;
23  2   9.6     4.8     0   0       1   1   0   135 1   1.1 0.95;
24  1   26.1    20.1    0   0.04    1   1   0   135 1   1.1 0.95;
25  1   0       0       0   0       1   1   0   135 1   1.1 0.95;
26  1   10.5    6.9     0   0       1   1   0   135 1   1.1 0.95;
27  2   0       0       0   0       1   1   0   135 1   1.1 0.95;
28  1   0       0       0   0       1   1   0   135 1   1.1 0.95;
29  1   7.2     2.7     0   0       1   1   0   135 1   1.1 0.95;
30  1   31.8    5.7     0   0       1   1   0   135 1   1.1 0.95;
];

%% generator data
%   bus Pg  Qg  Qmax    Qmin    Vg  mBase   status  Pmax    Pmin
gen = [
1   23.54   0   150 -50 1   100 1   300 0;
2   60.97   0   150 -50 1   100 1   300 0;
13  37      0   150 -50 1   100 1   300 0;
22  21.59   0   150 -50 1   100 1   300 0;
23  19.2    0   150 -50 1   100 1   300 0;
27  26.9    0   150 -50 1   100 1   300 0;
];

%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio
angle   status
branch = [
1   2   0.02    0.06    0.03    75  85  100 0   0   1;
1   3   0.05    0.19    0.02    75  85  100 0   0   1;
2   4   0.06    0.17    0.02    75  85  100 0   0   1;
3   4   0.01    0.04    0       75  85  100 0   0   1;
2   5   0.05    0.2     0.02    75  85  100 0   0   1;
2   6   0.06    0.18    0.02    75  85  100 0   0   1;
4   6   0.01    0.04    0       75  85  100 0   0   1;
5   7   0.05    0.12    0.01    75  85  100 0   0   1;
6   7   0.03    0.08    0.01    75  85  100 0   0   1;
6   8   0.01    0.04    0       75  85  100 0   0   1;
6   9   0       0.21    0       75  85  100 0   0   1;
6   10  0       0.56    0       75  85  100 0   0   1;
9   11  0       0.21    0       75  85  100 0   0   1;
9   10  0       0.11    0       75  85  100 0   0   1;
4   12  0       0.26    0       75  85  100 0   0   1;
12  13  0       0.14    0       75  85  100 0   0   1;
12  14  0.12    0.26    0       75  85  100 0   0   1;
12  15  0.07    0.13    0       75  85  100 0   0   1;
12  16  0.09    0.2     0       75  85  100 0   0   1;
14  15  0.22    0.2     0       75  85  100 0   0   1;
16  17  0.08    0.19    0       75  85  100 0   0   1;
15  18  0.11    0.22    0       75  85  100 0   0   1;
18  19  0.06    0.13    0       75  85  100 0   0   1;
19  20  0.03    0.07    0       75  85  100 0   0   1;
```

```
10   20   0.09    0.21    0        75   85   100 0    0    1;
10   17   0.03    0.08    0        75   85   100 0    0    1;
10   21   0.03    0.07    0        75   85   100 0    0    1;
10   22   0.07    0.15    0        75   85   100 0    0    1;
21   22   0.01    0.02    0        75   85   100 0    0    1;
15   23   0.1     0.2     0        75   85   100 0    0    1;
22   24   0.12    0.18    0        75   85   100 0    0    1;
23   24   0.13    0.27    0        75   85   100 0    0    1;
24   25   0.19    0.33    0        75   85   100 0    0    1;
25   26   0.25    0.38    0        75   85   100 0    0    1;
25   27   0.11    0.21    0        75   85   100 0    0    1;
28   27   0       0.4     0        75   85   100 0    0    1;
27   29   0.22    0.42    0        75   85   100 0    0    1;
27   30   0.32    0.6     0        75   85   100 0    0    1;
29   30   0.24    0.45    0        75   85   100 0    0    1;
8    28   0.06    0.2     0.02     75   85   100 0    0    1;
6    28   0.02    0.06    0.01     75   85   100 0    0    1;
];

%%-----  OPF Data  -----%%
%% area data
areas = [
    1   8;
    2   23;
    3   26;
];

%% generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0
gencost = [
    2   0   0   3   0.02    2       0;
    2   0   0   3   0.0175  1.75    0;
    2   0   0   3   0.0625  1       0;
    2   0   0   3   0.00834 3.25    0;
    2   0   0   3   0.025   3       0;
    2   0   0   3   0.025   3       0;
];

return;
```

Congestion Cost Calculations

CC Base Case:

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear
limit=60 ;          % Maximum allowable MW flow from ISO point of view
CR=0;               % CR = Congestion Revenues , part of congestion
cost
LMP=0;              % LMP including uplift charges, part of congestion
cost
SRP=0;              % SRP= system redispatch payments, part of
congestion cost
extraflow=0;        % flows over the ISO limit


% Selected set of Generation at Market Clearing Price stage

% Gen    Bus    Status     Pg        Qg        Lambda ($/MVA-hr)
%  #      #               (MW)     (MVAr)       P          Q
Gen=[
   1      1       1     167.63     0.00       6.00       0.00
   2      2       1     200.00     0.00       6.00       0.00
   3     13       1      -0.01     0.00       6.00       0.00
   4     22       1     200.00     0.00       6.00       0.00
   5     23       1      -0.01     0.00       6.00       0.00
   6     27       1      -0.01     0.00       6.00       0.00
];
MCP = [
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
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       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
       6.0000
```

```
];


% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status     Pg         Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)       P          Q
GenCR=[
   1      1      1      120.00       0.39      6.86       0.00
   2      2      1      168.19     146.84      7.00      -0.00
   3     13      1       60.00      44.29      7.39      -0.00
   4     22      1       97.73     122.24      4.75       0.00
   5     23      1       60.00      31.78      6.45      -0.00
   6     27      1       83.74      29.15      7.50      -0.00
];


%% LMP is the market LMP produced by MATPOWER,,,
LMP=[
    6.8610
    7.0000
    7.3162
    7.4077
    7.3088
    7.5211
    7.6564
   14.4848
    8.0140
    8.2612
    8.0140
    7.4030
    7.3902
    7.6175
    7.4194
    7.9170
    8.2626
    8.0955
    8.3922
    8.3842
   10.1136
    4.7512
    6.4492
    5.9458
    6.9933
    7.3819
    7.5000
    8.8622
    8.1565
    8.6621
    ];


 %% k is the market branch flows
 %Brnch    From    To     From Bus Injection     To Bus Injection
 Loss (I^2 * Z)
 %  #       Bus     Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)     P
 (MW)    Q (MVAr)
  k=[
```

1	1	2	62.78	-21.55	-62.06	20.06		0.716	2.15
2	1	3	57.22	21.94	-55.65	-18.24		1.575	5.98
3	2	4	55.13	27.70	-53.20	-24.52		1.921	5.44
4	3	4	48.45	14.64	-48.21	-13.69		0.238	0.95
5	2	5	43.99	24.53	-42.92	-22.52		1.073	4.29
6	2	6	66.04	36.45	-63.17	-30.08		2.866	8.60
7	4	6	60.45	40.45	-59.95	-38.45		0.501	2.00
8	5	7	42.92	22.52	-41.81	-20.89		1.107	2.66
9	6	7	26.84	11.50	-26.59	-11.81		0.256	0.68
10	6	8	75.00	79.46	-73.82	-74.74		1.179	4.72
11	6	9	15.58	-13.40	-15.58	14.28	-	0.000	0.88
12	6	10	8.90	-7.66	-8.90	8.42	-	0.000	0.76
13	9	11	0.00	-0.00	0.00	-0.00	-	0.000	0.00
14	9	10	15.58	-14.28	-15.58	14.73	-	0.000	0.46
15	4	12	18.17	-7.04	-18.17	7.97	-	0.000	0.93
16	12	13	-60.00	-37.85	60.00	44.29	-	0.000	6.43
17	12	14	13.26	4.03	-13.05	-3.58		0.210	0.46
18	12	15	16.37	-0.24	-16.20	0.56		0.171	0.32
19	12	16	14.94	3.59	-14.75	-3.16		0.194	0.43
20	14	15	-5.55	-1.22	5.62	1.29		0.068	0.06
21	16	17	4.25	-2.24	-4.23	2.28		0.017	0.04
22	15	18	21.08	5.60	-20.59	-4.62		0.487	0.97
23	18	19	10.99	1.92	-10.91	-1.76		0.074	0.16
24	19	20	-17.59	-8.44	17.70	8.71		0.116	0.27
25	10	20	24.93	12.28	-24.30	-10.81		0.631	1.47
26	10	17	23.03	20.37	-22.77	-19.68		0.257	0.69
27	10	21	-21.13	-36.03	21.60	37.14		0.475	1.11
28	10	22	-19.75	-25.78	20.42	27.21		0.670	1.43
29	21	22	-74.10	-70.74	75.00	72.54		0.900	1.80
30	15	23	-35.10	-14.94	36.45	17.65		1.356	2.71

```
 31      22      24      2.31     22.49    -1.81    -21.73
0.507     0.76
 32      23      24     13.95      9.33   -13.64     -8.70
0.302     0.63
 33      24      25    -10.65     10.38    11.02     -9.73
0.373     0.65
 34      25      26     10.90      7.50   -10.50     -6.90
0.398     0.60
 35      25      27    -21.92      2.22    22.41     -1.30
0.485     0.93
 36      28      27    -19.69    -14.68    19.69     17.06     -
0.000     2.38
 37      27      29     19.29      6.54   -18.49     -5.01
0.799     1.53
 38      27      30     22.36      6.86   -20.82     -3.98
1.533     2.87
 39      29      30     11.29      2.31   -10.98     -1.72
0.316     0.59
 40       8      28    -16.18    -15.26    16.48     14.31
0.299     1.00
 41       6      28     -3.21     -1.38     3.21      0.37
0.002     0.01
  ];
```

```
%% CR = Congestion Revenues Calculations
for h=2:length(k);
    extraflow(h,1) =   k(h,2) ;
    extraflow(h,4) =   k(h,3) ;
    if k(h,4)> limit
        extraflow(h,2) =   k(h,4) - limit ;
    end
    if k(h,6)> limit
        extraflow(h,3) =   k(h,6) - limit ;
    end
end

CR=zeros(length(LMP),1);
t=0;
for h=1:length(k);
    if extraflow(h,2)~= 0
        t= extraflow(h,1);
        CR(t) =  CR(t) + extraflow(h,2)* LMP(t);
    end
    if extraflow(h,3)~= 0
        t = extraflow(h,4);
        CR(t) =  CR(t) + extraflow(h,3)* LMP(t);
    end
end
% now sum of CR is the total Congestion Revenues per hour.
CR = sum(CR);
```

```
%% SRP = system redispatch payments Calculations
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost

Gain =  LMP - MCP;
AvgPriceReduction = mean(Gain)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP
TotCongCostWithRespectToBaseCase = SRP + CR
```

Congestion Cost Calculations
CC after adding 2-6 line:

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear
limit=60 ;          % Maximum allowable MW flow from ISO point of view
CR=0;               % CR = Congestion Revenues , part of congestion
cost
LMP=0;              % LMP including uplift charges, part of congestion
cost
SRP=0;              % SRP= system redispatch payments, part of
congestion cost
extraflow=0;        % flows over the ISO limtit


% Selected set of Generation at Market Base Case

% Gen    Bus    Status    Pg        Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)     P         Q
Gen=[
   1      1      1      120.00      0.39      6.86      0.00
   2      2      1      168.19    146.84      7.00     -0.00
   3     13      1       60.00     44.29      7.39     -0.00
   4     22      1       97.73    122.24      4.75      0.00
   5     23      1       60.00     31.78      6.45     -0.00
   6     27      1       83.74     29.15      7.50     -0.00
];
% Market Base Case
MCP = [
     6.8610
     7.0000
     7.3162
     7.4077
     7.3088
     7.5211
     7.6564
    14.4848
     8.0140
     8.2612
     8.0140
     7.4030
     7.3902
     7.6175
     7.4194
     7.9170
     8.2626
     8.0955
     8.3922
     8.3842
    10.1136
     4.7512
     6.4492
     5.9458
     6.9933
     7.3819
     7.5000
     8.8622
```

```
    8.1565
    8.6621
];


% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P             Q
GenCR=[
  1       1       1       120.00        3.29       6.84          0.00
  2       2       1       166.21      150.00       7.00          0.02
  3      13       1        60.00       41.96       7.29          0.00
  4      22       1        98.66      115.53       4.75         -0.00
  5      23       1        60.00       31.22       6.39         -0.00
  6      27       1        82.79       22.21       7.50          0.00
];


%% LMP is the market LMP produced by MATPOWER,,,
LMP=[
     6.8370
     7.0000
     7.2206
     7.2951
     7.2549
     7.3698
     7.5320
    14.9146
     7.8441
     8.0853
     7.8441
     7.2964
     7.2851
     7.5085
     7.3146
     7.7761
     8.0931
     7.9546
     8.2321
     8.2191
     9.8461
     4.7512
     6.3858
     5.9222
     6.9829
     7.3764
     7.5000
     8.8520
     8.1703
     8.6882
     ];


%% x is the market branch flows after adding 2nd line 2-6
%Brnch   From   To     From Bus Injection   To Bus Injection
Loss (I^2 * Z)
%  #      Bus     Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
```

k=[

1	1	2	71.05	-14.82	-70.19	13.80		0.862	2.59
2	1	3	48.95	18.11	-47.80	-16.07		1.144	4.35
3	2	4	40.56	21.58	-39.48	-20.79		1.083	3.07
4	3	4	40.60	12.47	-40.44	-11.81		0.165	0.66
5	2	5	35.63	20.25	-34.91	-19.65		0.721	2.88
6	2	6	47.56	28.14	-46.00	-25.69		1.563	4.69
7	2	6	47.56	28.14	-46.00	-25.69		1.563	4.69
8	4	6	40.17	31.77	-39.93	-30.80		0.243	0.97
9	5	7	34.91	19.65	-34.16	-18.89		0.750	1.80
10	6	7	34.65	13.86	-34.24	-13.81		0.404	1.08
11	6	8	75.00	80.38	-73.84	-75.76		1.156	4.62
12	6	9	16.11	-9.52	-16.11	10.22	-	0.000	0.70
13	6	10	9.20	-5.44	-9.20	6.05	-	0.000	0.61
14	9	11	0.00	-0.00	0.00	-0.00	-	0.000	0.00
15	9	10	16.11	-10.22	-16.11	10.59	-	0.000	0.37
16	4	12	16.95	-3.97	-16.95	4.70	-	0.000	0.73
17	12	13	-60.00	-35.76	60.00	41.96	-	0.000	6.20
18	12	14	13.17	4.26	-12.97	-3.81		0.209	0.45
19	12	15	15.89	0.61	-15.73	-0.31		0.161	0.30
20	12	16	14.28	3.68	-14.11	-3.29		0.178	0.40
21	14	15	-5.63	-0.99	5.70	1.05		0.069	0.06
22	16	17	3.61	-2.11	-3.59	2.14		0.013	0.03
23	15	18	20.70	5.50	-20.23	-4.56		0.468	0.94
24	18	19	10.63	1.86	-10.56	-1.71		0.069	0.15
25	19	20	-17.94	-8.49	18.06	8.76		0.119	0.28
26	10	20	25.30	12.37	-24.66	-10.86		0.643	1.50
27	10	17	23.67	20.24	-23.41	-19.54		0.262	0.70
28	10	21	-21.25	-31.92	21.65	32.84		0.397	0.93
29	10	22	-19.81	-23.33	20.40	24.60		0.591	1.27
30	21	22	-74.15	-66.44	75.00	68.14		0.849	1.70

```
 31        15       23    -35.27     -13.74     36.60      16.40
1.329        2.66
 32        22       24      3.27      22.79     -2.74     -22.01
0.526        0.79
 33        23       24     13.80      10.03    -13.49      -9.38
0.313        0.65
 34        24       25     -9.87      11.33     10.25     -10.66
0.382        0.66
 35        25       26     10.90       7.51    -10.50      -6.90
0.403        0.61
 36        25       27    -21.16       3.15     21.62      -2.27
0.463        0.88
 37        28       27    -19.47      -9.21     19.47      10.99
0.000        1.78
 38        27       29     19.31       6.58    -18.50      -5.02
0.815        1.56
 39        27       30     22.39       6.91    -20.82      -3.98
1.563        2.93
 40        29       30     11.30       2.32    -10.98      -1.72
0.322        0.60
 41         8       28    -16.16     -14.24     16.43      13.14
0.271        0.90
 42         6       28     -3.04       2.90      3.05      -3.93
0.004        0.01
  ];


%% CR = Congestion Revenues Calculations
for h=2:length(k);
    extraflow(h,1) =   k(h,2) ;
    extraflow(h,4) =   k(h,3) ;
    if k(h,4)> limit
        extraflow(h,2) =   k(h,4) - limit ;
    end
    if k(h,6)> limit
        extraflow(h,3) =   k(h,6) - limit ;
    end
end

CR=zeros(length(LMP),1);
t=0;
for h=1:length(k);
    if extraflow(h,2)~= 0
        t= extraflow(h,1);
        CR(t) =  CR(t) + extraflow(h,2)* LMP(t);
    end
    if extraflow(h,3)~= 0
        t = extraflow(h,4);
        CR(t) =  CR(t) + extraflow(h,3)* LMP(t);
    end
end
% now sum of CR is the total Congestion Revenues per hour.
CR = sum(CR);
```

```
%% SRP = system redispatch payments Calculations
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - MCP;
AvgPriceReduction = mean(Gain)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP
TotCongCostWithRespectToBaseCase = SRP + CR
```

Congestion Cost Calculations

CC after adding 4-6 line:

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear
limit=60 ;          % Maximum allowable MW flow from TSO point of view
CR=0;               % CR = Congestion Revenues , part of congestion
cost
LMP=0;              % LMP including uplift charges, part of congestion
cost
SRP=0;              % SRP= system redispatch payments, part of
congestion cost
extraflow=0;        % flows over the TSO limtit


% Selected set of Generation at Market Base Case

% Gen    Bus    Status     Pg         Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)       P          Q
Gen=[
   1      1       1      120.00       0.39      6.86       0.00
   2      2       1      168.19     146.84      7.00      -0.00
   3     13       1       60.00      44.29      7.39      -0.00
   4     22       1       97.73     122.24      4.75       0.00
   5     23       1       60.00      31.78      6.45      -0.00
   6     27       1       83.74      29.15      7.50      -0.00
];
% Market Base Case
MCP = [
    6.8610
    7.0000
    7.3162
    7.4077
    7.3088
    7.5211
    7.6564
   14.4848
    8.0140
    8.2612
    8.0140
    7.4030
    7.3902
    7.6175
    7.4194
    7.9170
    8.2626
    8.0955
    8.3922
    8.3842
   10.1136
    4.7512
    6.4492
    5.9458
    6.9933
    7.3819
    7.5000
    8.8622
    8.1565
```

```
    8.6621
];


% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg         Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)         P           Q
GenCR=[
  1       1       1       120.00        2.84        6.86        0.00
  2       2       1       167.45      145.45        7.00       -0.00
  3      13       1        60.00       45.30        7.40       -0.00
  4      22       1        98.14      120.56        4.75        0.00
  5      23       1        60.00       32.38        6.45       -0.00
  6      27       1        83.77       26.76        7.50       -0.00
];


%% LMP is the market LMP produced by MATPOWER,,,
LMP=[
     6.8648
     7.0000
     7.3335
     7.4286
     7.2975
     7.4901
     7.6297
    14.5819
     7.9840
     8.2329
     7.9840
     7.4166
     7.4036
     7.6298
     7.4260
     7.9126
     8.2405
     8.0888
     8.3773
     8.3657
    10.0715
     4.7512
     6.4547
     5.9478
     6.9934
     7.3840
     7.5000
     8.8629
     8.1615
     8.6715
     ];


%% k is the market branch flows after adding 2nd line 4-6
%Brnch    From    To      From Bus Injection      To Bus Injection
Loss (I^2 * Z)
%  #       Bus     Bus     P (MW)    Q (MVAr)     P (MW)    Q (MVAr)     P
(MW)    Q (MVAr)
 k=[
```

1	1	2	61.16	-21.07	-60.48	19.48	0.680	2.04	
2	1	3	58.84	23.91	-57.14	-19.76	1.691	6.43	
3	2	4	58.06	29.87	-55.91	-26.03	2.151	6.09	
4	3	4	49.94	16.16	-49.69	-15.13	0.258	1.03	
5	2	5	42.35	23.52	-41.36	-21.83	0.994	3.98	
6	2	6	62.42	34.47	-59.85	-29.02	2.563	7.69	
7	4	6	33.15	22.39	-32.99	-21.78	0.153	0.61	
8	4	6	33.15	22.39	-32.99	-21.78	0.153	0.61	
9	5	7	41.36	21.83	-40.33	-20.40	1.026	2.46	
10	6	7	28.35	12.05	-28.07	-12.30	0.282	0.75	
11	6	8	75.00	79.75	-73.83	-75.06	1.173	4.69	
12	6	9	16.32	-12.21	-16.32	13.06	0.000	0.85	-
13	6	10	9.33	-6.98	-9.33	7.72	0.000	0.74	-
14	9	11	0.00	-0.00	0.00	-0.00	0.000	0.00	-
15	9	10	16.32	-13.06	-16.32	13.51	0.000	0.45	-
16	4	12	16.51	-8.42	-16.51	9.28	0.000	0.85	-
17	12	13	-60.00	-38.76	60.00	45.30	0.000	6.54	-
18	12	14	13.08	4.01	-12.87	-3.56	0.206	0.45	
19	12	15	15.68	-0.42	-15.52	0.71	0.158	0.29	
20	12	16	14.15	3.39	-13.98	-3.00	0.175	0.39	
21	14	15	-5.73	-1.24	5.80	1.30	0.073	0.07	
22	16	17	3.48	-2.40	-3.46	2.43	0.014	0.03	
23	15	18	20.63	5.51	-20.17	-4.57	0.468	0.94	
24	18	19	10.57	1.87	-10.50	-1.73	0.069	0.15	
25	19	20	-18.00	-8.47	18.12	8.76	0.120	0.28	
26	10	20	25.37	12.37	-24.72	-10.86	0.649	1.52	
27	10	17	23.80	20.54	-23.54	-19.83	0.269	0.72	
28	10	21	-21.16	-34.99	21.61	36.05	0.454	1.06	
29	10	22	-19.77	-25.16	20.41	26.55	0.649	1.39	
30	21	22	-74.11	-69.65	75.00	71.42	0.886	1.77	

```
 31      15      23      -35.52     -15.02     36.90     17.80
1.387      2.77
 32      22      24        2.73     22.59     -2.21    -21.82
0.513      0.77
 33      23      24       13.50      9.78    -13.20     -9.16
0.299      0.62
 34      24      25      -10.69     10.93     11.08    -10.24
0.395      0.69
 35      25      26       10.90      7.51    -10.50     -6.90
0.400      0.61
 36      25      27      -21.98      2.73     22.48     -1.79
0.493      0.94
 37      28      27      -19.63    -12.96     19.63     15.12     -
0.000      2.16
 38      27      29       19.30      6.55    -18.49     -5.02
0.805      1.54
 39      27      30       22.37      6.88    -20.82     -3.98
1.544      2.89
 40      29      30       11.29      2.32    -10.98     -1.72
0.318      0.60
 41       8      28      -16.17    -14.94     16.46     13.94
0.290      0.97
 42       6      28       -3.16     -0.03      3.16     -0.98
0.002      0.01
  ];
```

```
%% CR = Congestion Revenues Calculations
for h=2:length(k);
    extraflow(h,1) =   k(h,2) ;
    extraflow(h,4) =   k(h,3) ;
    if k(h,4)> limit
        extraflow(h,2) =   k(h,4) - limit ;
    end
    if k(h,6)> limit
        extraflow(h,3) =   k(h,6) - limit ;
    end
end

CR=zeros(length(LMP),1);
t=0;
for h=1:length(k);
    if extraflow(h,2)~= 0
        t= extraflow(h,1);
        CR(t) =  CR(t) + extraflow(h,2)* LMP(t);
    end
    if extraflow(h,3)~= 0
        t = extraflow(h,4);
        CR(t) =  CR(t) + extraflow(h,3)* LMP(t);
    end
end
% now sum of CR is the total Congestion Revenues per hour.
CR = sum(CR);
```

```
%% SRP = system redispatch payments Calculations
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - MCP;
AvgPriceReduction = mean(Gain)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP
TotCongCostWithRespectToBaseCase = SRP + CR
```

Congestion Cost Calculations

CC after adding 6-8 line:

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear
limit=60 ;          % Maximum allowable MW flow from ISO point of view
CR=0;               % CR = Congestion Revenues , part of congestion
cost
LMP=0;              % LMP including uplift charges, part of congestion
cost
SRP=0;              % SRP= system redispatch payments, part of
congestion cost
extraflow=0;        % flows over the ISO limtit


% Selected set of Generation at Market Base Case

% Gen    Bus    Status     Pg          Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)        (MVAr)       P          Q
Gen=[
   1      1      1       120.00       0.39       6.86       0.00
   2      2      1       168.19     146.84       7.00      -0.00
   3     13      1        60.00      44.29       7.39      -0.00
   4     22      1        97.73     122.24       4.75       0.00
   5     23      1        60.00      31.78       6.45      -0.00
   6     27      1        83.74      29.15       7.50      -0.00
];
% Market Base Case
MCP = [
     6.8610
     7.0000
     7.3162
     7.4077
     7.3088
     7.5211
     7.6564
    14.4848
     8.0140
     8.2612
     8.0140
     7.4030
     7.3902
     7.6175
     7.4194
     7.9170
     8.2626
     8.0955
     8.3922
     8.3842
    10.1136
     4.7512
     6.4492
     5.9458
     6.9933
     7.3819
     7.5000
```

```
    8.8622
    8.1565
    8.6621
];


% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status     Pg         Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)        P         Q
GenCR=[
   1      1       1      120.00       1.07       7.92     -0.00
   2      2       1      180.00     143.96       8.08      0.00
   3     13       1       60.00      44.14       8.38     -0.00
   4     22       1      101.08     119.19       4.75     -0.00
   5     23       1       60.00      31.23       7.03     -0.00
   6     27       1       67.94      32.46       7.50     -0.00
];


%% LMP is the market LMP produced by MATPOWER,,,
LMP=[
     7.9230
     8.0782
     8.4554
     8.5623
     8.4497
     8.7209
     8.8658
     8.7939
     9.2112
     9.4573
     9.2112
     8.3950
     8.3825
     8.5900
     8.3276
     9.0158
     9.4444
     9.1539
     9.5274
     9.5387
    11.8998
     4.7512
     7.0250
     6.1562
     7.0800
     7.4711
     7.5000
     8.5723
     8.1476
     8.6453
     ];


%% k is the market branch flows after adding 2nd line 6-8
%Brnch    From    To     From Bus Injection    To Bus Injection
Loss (I^2 * Z)
```

```
% #      Bus    Bus    P (MW)   Q (MVAr)   P (MW)   Q (MVAr)   P
(MW)    Q (MVAr)
k=[
  1       1      2      60.62    -20.76    -59.96     19.13
0.667    2.00
  2       1      3      59.38     21.83    -57.70    -17.75
1.676    6.37
  3       2      4      58.63     26.97    -56.53    -23.29
2.099    5.95
  4       3      4      50.50     14.15    -50.25    -13.13
0.256    1.02
  5       2      5      45.89     24.22    -44.75    -21.95
1.137    4.55
  6       2      6      70.34     35.53    -67.21    -28.39
3.123    9.37
  7       4      6      64.79     38.87    -64.25    -36.70
0.541    2.16
  8       5      7      44.75     21.95    -43.58    -20.17
1.170    2.81
  9       6      7      25.05     12.16    -24.82    -12.53
0.234    0.62
 10       6      8      41.08     41.02    -40.75    -39.68
0.333    1.33
 11       6      8      41.08     41.02    -40.75    -39.68
0.333    1.33
 12       6      9      15.72    -13.47    -15.72     14.36    -
0.000    0.89
 13       6     10       8.98     -7.70     -8.98      8.47    -
0.000    0.77
 14       9     11       0.00     -0.00      0.00     -0.00    -
0.000    0.00
 15       9     10      15.72    -14.36    -15.72     14.82    -
0.000    0.47
 16       4     12      19.19     -7.25    -19.19      8.29    -
0.000    1.04
 17      12     13     -60.00    -37.72     60.00     44.14    -
0.000    6.42
 18      12     14      13.46      3.91    -13.24     -3.44
0.215    0.47
 19      12     15      17.21     -0.61    -17.03      0.97
0.190    0.35
 20      12     16      14.92      3.64    -14.72     -3.21
0.194    0.43
 21      14     15      -5.36     -1.36      5.42      1.41
0.064    0.06
 22      16     17       4.22     -2.19     -4.21      2.23
0.017    0.04
 23      15     18      20.88      5.69    -20.40     -4.73
0.480    0.96
 24      18     19      10.80      2.03    -10.73     -1.87
0.072    0.16
 25      19     20     -17.77     -8.33     17.89      8.60
0.117    0.27
 26      10     20      25.13     12.18    -24.49    -10.70
0.637    1.49
 27      10     17      23.05     20.32    -22.79    -19.63
0.257    0.69
 28      10     21     -21.13    -36.02     21.60     37.13
0.475    1.11
 29      10     22     -19.75    -25.77     20.42     27.21
0.669    1.43
```

```
 30      21      22    -74.10    -70.73    75.00    72.53
0.900      1.80
 31      15      23    -33.88    -15.57    35.17    18.16
1.295      2.59
 32      22      24      5.66     19.45    -5.25   -18.84
0.407      0.61
 33      23      24     15.23      8.27   -14.91    -7.60
0.323      0.67
 34      24      25     -5.94      6.39     6.07    -6.17
0.128      0.22
 35      25      26     10.89      7.50   -10.50    -6.90
0.394      0.60
 36      25      27    -16.97     -1.33    17.25     1.88
0.287      0.55
 37      28      27     -9.07    -15.94     9.07    17.26
0.000      1.32
 38      27      29     19.28      6.51   -18.49    -5.00
0.789      1.51
 39      27      30     22.34      6.82   -20.82    -3.98
1.513      2.84
 40      29      30     11.29      2.30   -10.98    -1.72
0.311      0.58
 41       8      28     -8.50    -10.63     8.60     8.98
0.102      0.34
 42       6      28     -0.46     -7.94     0.47     6.96
0.011      0.03
  ];
```

```
%% CR = Congestion Revenues Calculations
for h=2:length(k);
    extraflow(h,1) =   k(h,2) ;
    extraflow(h,4) =   k(h,3) ;
    if k(h,4)> limit
        extraflow(h,2) =   k(h,4) - limit ;
    end
    if k(h,6)> limit
        extraflow(h,3) =   k(h,6) - limit ;
    end
end

CR=zeros(length(LMP),1);
t=0;
for h=1:length(k);
    if extraflow(h,2)~= 0
        t= extraflow(h,1);
        CR(t) =  CR(t) + extraflow(h,2)* LMP(t);
    end
    if extraflow(h,3)~= 0
        t = extraflow(h,4);
        CR(t) =  CR(t) + extraflow(h,3)* LMP(t);
    end
end
% now sum of CR is the total Congestion Revenues per hour.
CR = sum(CR);
```

```
%% SRP = system redispatch payments Calculations
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - MCP;
AvgPriceReduction = mean(Gain)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP
TotCongCostWithRespectToBaseCase = SRP + CR
```

Congestion Cost Calculations
CC after adding 21-22 line:

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear
limit=60 ;          % Maximum allowable MW flow from ISO point of view
CR=0;               % CR = Congestion Revenues , part of congestion
cost
LMP=0;              % LMP including uplift charges, part of congestion
cost
SRP=0;              % SRP= system redispatch payments, part of
congestion cost
extraflow=0;        % flows over the ISO limtit


% Selected set of Generation at Market Base Case

% Gen    Bus    Status    Pg        Qg        Lambda (\$/MVA-hr)
%  #      #               (MW)     (MVAr)       P          Q
Gen=[
   1      1      1      120.00      0.39      6.86       0.00
   2      2      1      168.19    146.84      7.00      -0.00
   3     13      1       60.00     44.29      7.39      -0.00
   4     22      1       97.73    122.24      4.75       0.00
   5     23      1       60.00     31.78      6.45      -0.00
   6     27      1       83.74     29.15      7.50      -0.00
];
% Market Base Case
MCP = [
     6.8610
     7.0000
     7.3162
     7.4077
     7.3088
     7.5211
     7.6564
    14.4848
     8.0140
     8.2612
     8.0140
     7.4030
     7.3902
     7.6175
     7.4194
     7.9170
     8.2626
     8.0955
     8.3922
     8.3842
    10.1136
     4.7512
     6.4492
     5.9458
     6.9933
     7.3819
     7.5000
     8.8622
     8.1565
     8.6621];
```

```
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status    Pg       Qg        Lambda ($/MVA-hr)
%  #      #               (MW)     (MVAr)    P         Q
GenCR=[
  1       1      1        94.56    10.85     5.60      0.00
  2       2      1       120.00   128.27     5.69     -0.00
  3      13      1        60.00    47.29     6.13      0.00
  4      22      1       180.00    99.63     5.87      0.00
  5      23      1        60.00    31.44     6.02      0.00
  6      27      1        71.58    45.05     7.50     -0.00
];


%% LMP is the market LMP produced by MATPOWER,,,
LMP=[
    5.6000
    5.6949
    5.8553
    5.9034
    5.8762
    5.9318
    6.0791
   16.7769
    6.0477
    6.1072
    6.0477
    6.1411
    6.1322
    6.4073
    6.2929
    6.2360
    6.2159
    6.5205
    6.5697
    6.4686
    5.9223
    5.8668
    6.0241
    6.3800
    7.1761
    7.5630
    7.5000
    8.2350
    8.1118
    8.5780
    ];


%% k is the market branch flows after adding 2nd line 21-22
%Brnch   From   To    From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #     Bus    Bus    P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)   Q (MVAr)
 k=[
   1      1      2     55.12    -10.40      -54.60      8.33
0.514      1.54
```

2	1	3	39.44	21.25	-38.59	-20.32		0.851	3.23
3	2	4	33.91	25.66	-32.97	-25.28		0.936	2.65
4	3	4	31.39	16.72	-31.27	-16.25		0.116	0.46
5	2	5	33.36	22.61	-32.66	-22.09		0.700	2.80
6	2	6	42.24	33.56	-40.74	-31.30		1.497	4.49
7	4	6	44.00	39.55	-43.68	-38.25		0.326	1.31
8	5	7	32.66	22.09	-31.92	-21.36		0.733	1.76
9	6	7	36.92	11.49	-36.48	-11.34		0.438	1.17
10	6	8	75.00	78.35	-73.86	-73.79		1.139	4.56
11	6	9	-15.52	-9.60	15.52	10.28	-	0.000	0.68
12	6	10	-8.87	-5.49	8.87	6.08	-	0.000	0.59
13	9	11	0.00	-0.00	0.00	-0.00	-	0.000	0.00
14	9	10	-15.52	-10.28	15.52	10.64	-	0.000	0.36
15	4	12	-2.56	-2.81	2.56	2.85	-	0.000	0.04
16	12	13	-60.00	-40.53	60.00	47.29	-	0.000	6.75
17	12	14	11.16	5.09	-11.00	-4.73		0.166	0.36
18	12	15	7.59	2.84	-7.54	-2.77		0.042	0.08
19	12	16	5.10	7.25	-5.03	-7.11		0.065	0.14
20	14	15	-7.60	-0.07	7.73	0.18		0.123	0.11
21	16	17	-5.47	1.71	5.49	-1.65		0.025	0.06
22	15	18	15.93	7.81	-15.61	-7.16		0.324	0.65
23	18	19	6.01	4.46	-5.97	-4.39		0.034	0.07
24	19	20	-22.53	-5.81	22.69	6.20		0.165	0.39
25	10	20	30.12	10.23	-29.29	-8.30		0.830	1.94
26	10	17	32.87	16.74	-32.49	-15.75		0.372	0.99
27	10	21	-66.10	-31.67	67.57	35.10		1.469	3.43
28	10	22	-38.69	-18.02	39.85	20.51		1.162	2.49
29	21	22	-60.03	-34.35	60.44	35.16		0.404	0.81
30	21	22	-60.03	-34.35	60.44	35.16		0.404	0.81
31	15	23	-40.71	-12.73	42.41	16.13		1.702	3.40

```
   32       22       24       19.28       8.81      -18.83      -8.14
0.445        0.67
   33       23       24        7.99      10.51       -7.80     -10.12
0.187        0.39
   34       24       25        0.53      -1.80       -0.52       1.81
0.006        0.01
   35       25       26       10.88       7.48      -10.50      -6.90
0.381        0.58
   36       25       27      -10.36      -9.29       10.54       9.64
0.186        0.36
   37       28       27      -19.56     -19.42       19.56      22.35      -
0.000        2.92
   38       27       29       19.22       6.39      -18.47      -4.96
0.748        1.43
   39       27       30       22.26       6.67      -20.83      -3.99
1.432        2.69
   40       29       30       11.27       2.26      -10.97      -1.71
0.295        0.55
   41        8       28      -16.14     -16.21       16.45      15.24
0.309        1.03
   42        6       28       -3.10      -5.20        3.11       4.18
0.006        0.02
   ];
```

```
%% CR = Congestion Revenues Calculations
for h=2:length(k);
    extraflow(h,1) =   k(h,2) ;
    extraflow(h,4) =   k(h,3) ;
    if k(h,4)> limit
        extraflow(h,2) =   k(h,4) - limit ;
    end
    if k(h,6)> limit
        extraflow(h,3) =   k(h,6) - limit ;
    end
end

CR=zeros(length(LMP),1);
t=0;
for h=1:length(k);
    if extraflow(h,2)~= 0
        t= extraflow(h,1);
        CR(t) =  CR(t) + extraflow(h,2)* LMP(t);
    end
    if extraflow(h,3)~= 0
        t = extraflow(h,4);
        CR(t) =  CR(t) + extraflow(h,3)* LMP(t);
    end
end
% now sum of CR is the total Congestion Revenues per hour.
CR = sum(CR);
```

```
%% SRP = system redispatch payments Calculations
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*GenCR(h,6);
end
end
SRP = 0.1*SRP;  % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - MCP;
AvgPriceReduction = mean(Gain)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP
TotCongCostWithRespectToBaseCase = SRP + CR
```

Appendix C

C.1 Matlab M-files:

<u>Case Study 2: 11 bus 380kV real system</u>

<u>Base Case Data:</u>

```
function [baseMVA, bus, gen, branch, areas, gencost] = case11SEC
%CASE11       reduced 11 bus 380 kv real system

 %%-----  Power Flow Data  -----%%
%% system MVA base
baseMVA = 100;

%% bus data
%    bus_i    type     Pd   Qd   Gs   Bs   area     Vm   Va   baseKV   zone
Vmax     Vmin
bus = [
1   3    100       0    0    0    1    1         0            100 1    1.05
0.95;
2   2    1200      300  0    0    1    1         -1.9297      100 1    1.05
0.95;
3   2    800       300  0    0    1    1         1.4201       100 1    1.05
0.95;
4   2    1000      300  0    0    1    1         0.3791       100 1    1.05
0.95;
5   2    150       50   0    0    1    1         -8.3062      100 1    1.05
0.95;
6   2    2800      300  0    0    1    0.99028  -7.8533      100 1    1.05
0.95;
7   2    300       0    0    0    1    1         -0.6564      100 1    1.05
0.95;
8   2    750       150  0    0    1    0.99245  -24.7225     100 1    1.05
0.95;
9   2    300       0    0    0    1    1         20.7897      100 1    1.05
0.95;
10  1    3700      500  0    0    1    0.97688  -17.8982     100 1    1.05
0.95;
11  2    2500      500  0    0    1    1         -26.9048     100 1    1.05
0.95;
];
```

```
%% generator data
%   bus Pg   Qg   Qmax    Qmin    Vg   mBase    status  Pmax    Pmin
gen = [
1   280.666 -6.191  2000    -2000   1.06    100 1   2700    0;
2   2000    310.752 2000    -2000   1.03    100 1   2200    0;
3   2000    -20.894 2000    -2000   1.03    100 1   2200    0;
7   2800    207.872 2000    -2000   1.05    100 1   2800    0;
10  3000     587.539    2000    -2000   1   100 1   3200    0;
11  2400     587.539    2000    -2000   1   100 1   2400    0];

%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio
angle   status
branch = [
1   2   0.001   0.0182  0   2000    2000    2000    1   0   1;
1   2   0.001   0.0182  0   2000    2000    2000    1   0   1;
1   3   0.0016  0.0323  0   2000    2000    2000    1   0   1;
1   4   0.0005  0.01063 0   2000    2000    2000    1   0   1;
2   3   0.00099 0.01196 0   2000    2000    2000    1   0   1;
2   4   0.0009  0.0175  0   2000    2000    2000    1   0   1;
2   10  0.00185 0.01695 0   2000    2000    2000    1   0   1;
2   10  0.00185 0.01695 0   2000    2000    2000    1   0   1;
3   8   0.00235 0.02465 0   2000    2000    2000    1   0   1;
3   8   0.00235 0.02465 0   2000    2000    2000    1   0   1;
4   7   0.00154 0.02442 0   2000    2000    2000    1   0   1;
4   7   0.00154 0.02442 0   2000    2000    2000    1   0   1;
4   9   0.00278 0.04863 0   2000    2000    2000    1   0   1;
4   9   0.00278 0.04863 0   2000    2000    2000    1   0   1;
5   6   0.00045 0.00982 0   2000    2000    2000    1   0   1;
5   6   0.00045 0.00982 0   2000    2000    2000    1   0   1;
6   7   0.00124 0.0192  0   2000    2000    2000    1   0   1;
6   7   0.00124 0.0192  0   2000    2000    2000    1   0   1;
6   7   0.00124 0.0192  0   2000    2000    2000    1   0   1;
6   7   0.00124 0.0192  0   2000    2000    2000    1   0   1;
6   11  0.00537 0.09096 0   2000    2000    2000    1   0   1;
6   11  0.00537 0.09096 0   2000    2000    2000    1   0   1;
];

% rates are set to 2000 MW to obtain an optimized solution even if
the flow is exceeding the thermal limits..............

 %%-----  OPF Data   -----%%
%% area data
areas = [
    1   1];

%% generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0

gencost = [
    2   0   0   3   0.02    2       10;
    2   0   0   3   0.0175  1.75    10;
    2   0   0   3   0.0625  1       10;
    2   0   0   3   0.00834 3.25    10;
    2   0   0   3   0.025   3       10;
    2   0   0   3   0.025   3       10;    ];

return;
```

```
% Base case Congestion costs calculations

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status     Pg        Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)      (MVAr)      P          Q
Gen=[
   1      1      1      2000.00     -6.19     86.65      0.00
   2      2      1      2000.00    310.75     86.65      0.00
   3      3      1        -0.01    -20.89     86.65      0.00
   4      7      1      5600.01    207.87     86.65      0.00
   5     10      1      2000.00    587.54     86.65      0.00
   6     11      1      2000.00    587.54     86.65      0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status     Pg        Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)      (MVAr)      P          Q
GenCR=[
   1      1      1      2700.01    226.64    137.03      0.00
   2      2      1      2200.01    479.55    137.99      0.00
   3      3      1      1006.80    572.33    138.50      0.00
   4      7      1      2800.01    950.47    140.18      0.00
   5     10      1      2560.00    601.86    140.71      0.00
   6     11      1      2400.01    582.30    143.56     -0.00
];


%% k is the market branch flows
%Brnch    From    To     From Bus Injection      To Bus Injection
Loss (I^2 * Z)
%  #      Bus     Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)      P
(MW)    Q (MVAr)
 k=[
  1        1       2     418.03      -8.50     -416.45     37.36       1.586
28.86
   2        1       2     418.03      -8.50     -416.45     37.36
1.586      28.86
   3        1       3     321.33      -0.76     -319.83     31.00
1.498      30.25
   4        1       4    1442.62     244.39    -1432.91    -37.97
9.709     206.42
```

```
  5       2     3    230.47    -16.16    -229.99     21.95
0.479      5.79
  6       2     4    451.32    121.00    -449.54    -86.34
1.782     34.66
  7       2    10    575.56      0.00    -570.00     50.93
5.559     50.93
  8       2    10    575.56      0.00    -570.00     50.93
5.559     50.93
  9       3     8    378.31    109.69    -375.00    -75.00
3.307     34.69
 10       3     8    378.31    109.69    -375.00    -75.00
3.307     34.69
 11       4     7    290.63    -98.32    -289.26    120.04
1.370     21.72
 12       4     7    290.63    -98.32    -289.26    120.04
1.370     21.72
 13       4     9    150.60     10.47    -150.00      0.00
0.599     10.47
 14       4     9    150.60     10.47    -150.00      0.00
0.599     10.47
 15       5     6    -75.00    -25.00      75.03     25.60
0.027      0.60
 16       5     6    -75.00    -25.00      75.03     25.60
0.027      0.60
 17       6     7   -762.61    -68.95     769.63    177.60
7.017    108.65
 18       6     7   -762.61    -68.95     769.63    177.60
7.017    108.65
 19       6     7   -762.61    -68.95     769.63    177.60
7.017    108.65
 20       6     7   -762.61    -68.95     769.63    177.60
7.017    108.65
 21       6    11     50.20    -37.69     -49.99     41.15
0.204      3.46
 22       6    11     50.20    -37.69     -49.99     41.15
0.204      3.46
  ];

%% LMP is the market LMP after the addition of 1-4 line,,,
LMP=[
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP;  MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contingencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
```

```
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ;
CR = ( crossflow - limit )*LMP(CongBus);

%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - MCP
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 1-4 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status      Pg          Qg          Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P            Q
Gen=[
   1      1       1      2000.00       -6.19      86.65         0.00
   2      2       1      2000.00      310.75      86.65         0.00
   3      3       1        -0.01      -20.89      86.65         0.00
   4      7       1      5600.01      207.87      86.65         0.00
   5     10       1      2000.00      587.54      86.65         0.00
   6     11       1      2000.00      587.54      86.65         0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg          Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P            Q
GenCR=[
   1      1       1      2700.01      240.02     137.18        -0.00
   2      2       1      2200.01      406.89     137.88         0.00
   3      3       1      1000.58      571.88     138.50        -0.00
   4      7       1      2800.01      884.35     139.45        -0.00
   5     10       1      2560.00      601.86     140.60        -0.00
   6     11       1      2400.01      582.30     142.81        -0.00
];


%% k is the market branch flows
```

```
%Brnch   From   To    From Bus Injection   To Bus Injection
Loss (I^2 * Z)
%  #     Bus    Bus    P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)   Q (MVAr)
 k=[
  1      1      2    312.58     -9.08    -311.69     25.22     0.887
16.14
  2      1      2    312.58     -9.08    -311.69     25.22
0.887    16.14
  3      1      3    279.66     -2.37    -278.52     25.28
1.135    22.91
  4      1      4    847.60    130.27    -844.26    -59.37
3.335    70.90
  5      1      4    847.60    130.27    -844.26    -59.37
3.335    70.90
  6      2      3    278.21    -18.78    -277.51     27.22
0.698     8.43
  7      2      4    194.06     75.23    -193.71    -68.36
0.354     6.88
  8      2     10    575.56     -0.00    -570.00     50.93
5.559    50.93
  9      2     10    575.56     -0.00    -570.00     50.93
5.559    50.93
 10      3      8    378.31    109.69    -375.00    -75.00
3.307    34.69
 11      3      8    378.31    109.69    -375.00    -75.00
3.307    34.69
 12      4      7    290.53    -66.77    -289.26     86.98
1.274    20.21
 13      4      7    290.53    -66.77    -289.26     86.98
1.274    20.21
 14      4      9    150.59     10.32    -150.00      0.00
0.590    10.32
 15      4      9    150.59     10.32    -150.00      0.00
0.590    10.32
 16      5      6    -75.00    -25.00      75.03     25.60
0.027     0.60
 17      5      6    -75.00    -25.00      75.03     25.60
0.027     0.60
 18      6      7   -762.61    -68.95     769.63    177.60
7.017   108.65
 19      6      7   -762.61    -68.95     769.63    177.60
7.017   108.65
 20      6      7   -762.61    -68.95     769.63    177.60
7.017   108.65
 21      6      7   -762.61    -68.95     769.63    177.60
7.017   108.65
 22      6     11     50.20    -37.69     -49.99     41.15
0.204     3.46
 23      6     11     50.20    -37.69     -49.99     41.15
0.204     3.46
  ];

%% LMP is the market LMP after the addition of 1-4 line,,,
LMP=[
  137.1767
  137.8796
  138.5000
  138.2881
  142.1738
  142.0720
```

```
  139.4500
  140.8894
  139.4162
  140.5953
  142.8144
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;            % Maximum allowable MW flow across Congested bus
CongBus=4;             % from ISO point of view
crossflow=0;           % considered contengencies = outages of 1-4 or
2-4
                        % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 1-5 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status      Pg          Qg        Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
Gen=[
  1       1       1      2000.00       -6.19      86.65       0.00
  2       2       1      2000.00      310.75      86.65       0.00
  3       3       1        -0.01      -20.89      86.65       0.00
  4       7       1      5600.01      207.87      86.65       0.00
  5      10       1      2000.00      587.54      86.65       0.00
  6      11       1      2000.00      587.54      86.65       0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg        Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
GenCR=[
  1       1       1      2700.01      279.88     137.13      -0.00
  2       2       1      2200.01      439.95     137.89      -0.00
  3       3       1       992.94      573.05     138.50      -0.00
  4       7       1      2800.01      722.89     138.29      -0.00
  5      10       1      2560.00      601.86     140.61      -0.00
  6      11       1      2400.01      571.04     141.04       0.00
];


%% h is the market branch flows
```

```
%Brnch    From    To      From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #      Bus     Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
   1        1      2     343.40      -9.10    -342.33      28.58
1.070      19.48
   2        1      2     343.40      -9.10    -342.33      28.58
1.070      19.48
   3        1      3     294.42      -1.85    -293.16      27.25
1.258      25.40
   4        1      4    1009.32     181.81   -1004.55     -80.40
4.770     101.41
   5        1      5     609.47     118.13    -603.88      -5.21
5.593     112.91
   6        2      3     271.18     -18.41    -270.52      26.43
0.663       8.01
   7        2      4     262.37     101.20    -261.72     -88.65
0.646      12.55
   8        2     10     575.56       0.00    -570.00      50.93
5.559      50.93
   9        2     10     575.56       0.00    -570.00      50.93
5.559      50.93
  10        3      8     378.31     109.69    -375.00     -75.00
3.307      34.69
  11        3      8     378.31     109.69    -375.00     -75.00
3.307      34.69
  12        4      7     -17.46     -75.89      17.55      77.28
0.088       1.39
  13        4      7     -17.46     -75.89      17.55      77.28
0.088       1.39
  14        4      9     150.60      10.41    -150.00       0.00
0.595      10.41
  15        4      9     150.60      10.41    -150.00       0.00
0.595      10.41
  16        5      6     226.94     -22.39    -226.72      27.29
0.224       4.90
  17        5      6     226.94     -22.39    -226.72      27.29
0.224       4.90
  18        6      7    -611.73     -72.44     616.23     142.08
4.498      69.65
  19        6      7    -611.73     -72.44     616.23     142.08
4.498      69.65
  20        6      7    -611.73     -72.44     616.23     142.08
4.498      69.65
  21        6      7    -611.73     -72.44     616.23     142.08
4.498      69.65
  22        6     11      50.18     -32.42     -49.99      35.52
0.183       3.10
  23        6     11      50.18     -32.42     -49.99      35.52
0.183       3.10
   ];

%% LMP is the market LMP after the addition of 1-5 line,,,
LMP=[
   137.1276
   137.8933
   138.5000
   138.4311
   139.9850
   140.3103
```

```
  138.2907
  140.8894
  139.5776
  140.6093
  141.0367
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;            % Maximum allowable MW flow across Congested bus
CongBus=4;             % from ISO point of view
crossflow=0;           % considered contengencies = outages of 1-4 or
2-4
                        % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 1-7 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen     Bus    Status     Pg        Qg       Lambda ($/MVA-hr)
%  #       #               (MW)     (MVAr)       P          Q
Gen=[
  1       1       1     2000.00     -6.19     86.65       0.00
  2       2       1     2000.00    310.75     86.65       0.00
  3       3       1       -0.01    -20.89     86.65       0.00
  4       7       1     5600.01    207.87     86.65       0.00
  5      10       1     2000.00    587.54     86.65       0.00
  6      11       1     2000.00    587.54     86.65       0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen     Bus    Status     Pg        Qg       Lambda ($/MVA-hr)
%  #       #               (MW)     (MVAr)       P          Q
GenCR=[
  1       1       1     2700.01    165.94    137.10       0.00
  2       2       1     2200.01    444.65    137.93       0.00
  3       3       1     1001.75    572.12    138.50       0.00
  4       7       1     2800.01    936.11    138.87       0.00
  5      10       1     2560.00    601.86    140.64       0.00
  6      11       1     2400.01    582.30    142.22      -0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To     From Bus Injection    To Bus Injection
Loss  (I^2 * Z)
%  #       Bus     Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
  1        1       2     354.25      -9.07     -353.11      29.80
1.139      20.73
  2        1       2     354.25      -9.07     -353.11      29.80
1.139      20.73
  3        1       3     296.47      -1.78     -295.20      27.53
1.276      25.75
  4        1       4    1080.71     188.88    -1075.25     -72.83
5.459     116.05
  5        1       7     514.34      -3.02     -510.64      61.62
3.695      58.60
  6        2       3     260.28     -17.83     -259.67      25.21
0.611       7.38
  7        2       4     294.83     102.88     -294.03     -87.40
0.796      15.48
  8        2      10     575.56       0.00     -570.00      50.93
5.559      50.93
  9        2      10     575.56       0.00     -570.00      50.93
5.559      50.93
 10        3       8     378.31     109.69     -375.00     -75.00
3.307      34.69
 11        3       8     378.31     109.69     -375.00     -75.00
3.307      34.69
 12        4       7      34.05     -80.30      -33.94      82.05
0.110       1.75
 13        4       7      34.05     -80.30      -33.94      82.05
0.110       1.75
 14        4       9     150.60      10.42     -150.00       0.00
0.595      10.42
 15        4       9     150.60      10.42     -150.00       0.00
0.595      10.42
 16        5       6     -75.00     -25.00       75.03      25.60
0.027       0.60
 17        5       6     -75.00     -25.00       75.03      25.60
0.027       0.60
 18        6       7    -762.61     -68.95      769.63     177.60
7.017     108.65
 19        6       7    -762.61     -68.95      769.63     177.60
7.017     108.65
 20        6       7    -762.61     -68.95      769.63     177.60
7.017     108.65
 21        6       7    -762.61     -68.95      769.63     177.60
7.017     108.65
 22        6      11      50.20     -37.69      -50.00      41.15
0.204       3.46
 23        6      11      50.20     -37.69      -50.00      41.15
0.204       3.46
 ];

%% LMP is the market LMP after the addition of 1-7 line,,,
LMP=[
  137.1009
  137.9273
  138.5000
  138.6193
  141.5843
  141.4829
```

```
  138.8718
  140.8894
  139.7708
  140.6439
  142.2223
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 2-4 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status    Pg        Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)     P          Q
Gen=[
  1       1      1      2000.00     -6.19     86.65      0.00
  2       2      1      2000.00    310.75     86.65      0.00
  3       3      1        -0.01    -20.89     86.65      0.00
  4       7      1      5600.01    207.87     86.65      0.00
  5      10      1      2000.00    587.54     86.65      0.00
  6      11      1      2000.00    587.54     86.65      0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status    Pg        Qg        Lambda ($/MVA-hr)
%  #      #               (MW)      (MVAr)     P          Q
GenCR=[
  1       1      1      2700.01    167.77    136.94      0.00
  2       2      1      2200.01    554.89    138.05      0.00
  3       3      1      1005.65    573.50    138.50      0.00
  4       7      1      2800.01    907.06    139.87     -0.00
  5      10      1      2560.00    601.86    140.76     -0.00
  6      11      1      2400.01    582.30    143.24     -0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To     From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%   #      Bus     Bus      P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
1      1        2     478.64       -7.33    -476.56       45.16        2.078
37.83
   2        1       2     478.64       -7.33    -476.56       45.16
2.078       37.83
   3        1       3     346.57        0.47    -344.82       34.72
1.743       35.19
   4        1       4    1296.16      181.96   -1288.39      -16.78
7.769      165.18
   5        2       3     206.53      -14.75    -206.14       19.41
0.385        4.65
   6        2       4     297.75       89.67    -296.96      -74.32
0.789       15.35
   7        2       4     297.75       89.67    -296.96      -74.32
0.789       15.35
   8        2      10     575.56       -0.00    -570.00       50.93
5.559       50.93
   9        2      10     575.56       -0.00    -570.00       50.93
5.559       50.93
  10        3       8     378.31      109.69    -375.00      -75.00
3.307       34.69
  11        3       8     378.31      109.69    -375.00      -75.00
3.307       34.69
  12        4       7     290.56      -77.66    -289.26       98.34
1.304       20.67
  13        4       7     290.56      -77.66    -289.26       98.34
1.304       20.67
  14        4       9     150.59       10.37    -150.00        0.00
0.593       10.37
  15        4       9     150.59       10.37    -150.00        0.00
0.593       10.37
  16        5       6     -75.00      -25.00      75.03       25.60
0.027        0.60
  17        5       6     -75.00      -25.00      75.03       25.60
0.027        0.60
  18        6       7    -762.61      -68.95     769.63      177.60
7.017      108.65
  19        6       7    -762.61      -68.95     769.63      177.60
7.017      108.65
  20        6       7    -762.61      -68.95     769.63      177.60
7.017      108.65
  21        6       7    -762.61      -68.95     769.63      177.60
7.017      108.65
  22        6      11      50.20      -37.69     -50.00       41.15
0.204        3.46
  23        6      11      50.20      -37.69     -50.00       41.15
0.204        3.46
   ];

%% LMP is the market LMP after the addition of 2-4 line,,,
LMP=[
136.9423
   138.0451
   138.5000
   138.6987
   142.6021
   142.5000
```

```
  139.8701
  140.8894
  139.8444
  140.7641
  143.2447
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;          % Maximum allowable MW flow across Congested bus
CongBus=4;           % from ISO point of view
crossflow=0;         % considered contengencies = outages of 1-4 or
2-4
                      % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 2-5 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status    Pg         Qg         Lambda ($/MVA-hr)
%  #      #               (MW)       (MVAr)      P          Q
Gen=[
   1      1      1      2000.00     -6.19      86.65       0.00
   2      2      1      2000.00    310.75      86.65       0.00
   3      3      1        -0.01    -20.89      86.65       0.00
   4      7      1      5600.01    207.87      86.65       0.00
   5     10      1      2000.00    587.54      86.65       0.00
   6     11      1      2000.00    587.54      86.65       0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status    Pg         Qg         Lambda ($/MVA-hr)
%  #      #               (MW)       (MVAr)      P          Q
GenCR=[
   1      1      1      2700.01    189.46     136.84       0.00
   2      2      1      2200.01    592.16     138.08       0.00
   3      3      1       997.34    575.27     138.50       0.00
   4      7      1      2800.01    738.35     138.53       0.00
   5     10      1      2560.00    601.86     140.80       0.00
   6     11      1      2400.01    570.44     141.38      -0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To     From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #       Bus    Bus     P (MW)    Q (MVAr)    P (MW)    Q (MVAr)     P
(MW)    Q (MVAr)
 k=[
   1        1      2     516.96      -6.28     -514.53     50.40
2.424      44.12
   2        1      2     516.96      -6.28     -514.53     50.40
2.424      44.12
   3        1      3     364.59       1.46     -362.66     37.48
1.929      38.94
   4        1      4    1201.51     200.55    -1194.78    -57.48
6.729     143.07
   5        2      3     196.97     -14.17     -196.62     18.40
0.350       4.23
   6        2      4     202.26     106.35     -201.84    -98.06
0.426       8.29
   7        2      5     478.73      99.18     -475.26    -29.16
3.469      70.03
   8        2     10     575.56       0.00     -570.00     50.93
5.559      50.93
   9        2     10     575.56       0.00     -570.00     50.93
5.559      50.93
  10        3      8     378.31     109.69     -375.00    -75.00
3.307      34.69
  11        3      8     378.31     109.69     -375.00    -75.00
3.307      34.69
  12        4      7      47.71     -82.65      -47.58     84.74
0.132       2.09
  13        4      7      47.71     -82.65      -47.58     84.74
0.132       2.09
  14        4      9     150.60      10.42     -150.00     -0.00
0.596      10.42
  15        4      9     150.60      10.42     -150.00     -0.00
0.596      10.42
  16        5      6     162.63     -10.42     -162.52     12.92
0.114       2.49
  17        5      6     162.63     -10.42     -162.52     12.92
0.114       2.49
  18        6      7    -643.83     -65.39      648.79    142.22
4.962      76.83
  19        6      7    -643.83     -65.39      648.79    142.22
4.962      76.83
  20        6      7    -643.83     -65.39      648.79    142.22
4.962      76.83
  21        6      7    -643.83     -65.39      648.79    142.22
4.962      76.83
  22        6     11      50.18     -32.14      -49.99     35.22
0.182       3.09
  23        6     11      50.18     -32.14      -49.99     35.22
0.182       3.09
  ];

%% LMP is the market LMP after the addition of 2-5 line,,,
LMP=[
  136.8422
  138.0791
  138.5000
  138.4216
  140.4011
  140.6496
```

```
  138.5252
  140.8894
  139.5730
  140.7988
  141.3774
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 2-7 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status     Pg          Qg         Lambda  ($/MVA-hr)
%  #      #                (MW)        (MVAr)      P           Q
Gen=[
   1      1       1     2000.00      -6.19       86.65        0.00
   2      2       1     2000.00     310.75       86.65        0.00
   3      3       1       -0.01     -20.89       86.65        0.00
   4      7       1     5600.01     207.87       86.65        0.00
   5     10       1     2000.00     587.54       86.65        0.00
   6     11       1     2000.00     587.54       86.65        0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status     Pg          Qg         Lambda  ($/MVA-hr)
%  #      #                (MW)        (MVAr)      P           Q
GenCR=[
   1      1       1     2700.01     201.48      136.93       -0.00
   2      2       1     2200.01     482.45      138.05        0.00
   3      3       1     1004.45     573.60      138.50        0.00
   4      7       1     2800.01     929.79      139.26       -0.00
   5     10       1     2560.00     601.86      140.76        0.00
   6     11       1     2400.01     582.30      142.62       -0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To    From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #      Bus     Bus    P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
    1        1      2    476.26      -7.39    -474.20      44.84
2.058       37.45
   2        1      2    476.26      -7.39    -474.20      44.84
2.058       37.45
   3        1      3    345.91       0.44    -344.17      34.62
1.736       35.06
   4        1      4   1301.58     215.81   -1293.68     -47.98
7.894      167.83
   5        2      3    208.38     -14.87    -207.99      19.60
0.392        4.73
   6        2      4    305.17     109.87    -304.32     -93.17
0.859       16.70
   7        2      7    283.75      -2.23    -282.58      25.82
1.169       23.59
   8        2     10    575.56      -0.00    -570.00      50.93
5.559       50.93
   9        2     10    575.56      -0.00    -570.00      50.93
5.559       50.93
  10        3      8    378.31     109.69    -375.00     -75.00
3.307       34.69
  11        3      8    378.31     109.69    -375.00     -75.00
3.307       34.69
  12        4      7    148.40     -89.87    -147.97      96.79
0.437        6.92
  13        4      7    148.40     -89.87    -147.97      96.79
0.437        6.92
  14        4      9    150.60      10.44    -150.00      -0.00
0.597       10.44
  15        4      9    150.60      10.44    -150.00      -0.00
0.597       10.44
  16        5      6    -75.00     -25.00      75.03      25.60
0.027        0.60
  17        5      6    -75.00     -25.00      75.03      25.60
0.027        0.60
  18        6      7   -762.61     -68.95     769.63     177.60
7.017      108.65
  19        6      7   -762.61     -68.95     769.63     177.60
7.017      108.65
  20        6      7   -762.61     -68.95     769.63     177.60
7.017      108.65
  21        6      7   -762.61     -68.95     769.63     177.60
7.017      108.65
  22        6     11     50.20     -37.69     -49.99      41.15
0.204        3.46
  23        6     11     50.20     -37.69     -49.99      41.15
0.204        3.46
  ];

%% LMP is the market LMP after the addition of 2-7 line,,,
LMP=[
    136.9310
  138.0457
  138.5000
  138.6801
  141.9761
  141.8744
```

```
  139.2560
  140.8894
  139.8397
  140.7647
  142.6158
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 3-4 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status      Pg          Qg        Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
Gen=[
  1      1      1      2000.00      -6.19     86.65      0.00
  2      2      1      2000.00     310.75     86.65      0.00
  3      3      1        -0.01     -20.89     86.65      0.00
  4      7      1      5600.01     207.87     86.65      0.00
  5     10      1      2000.00     587.54     86.65      0.00
  6     11      1      2000.00     587.54     86.65      0.00
];
MCP = [
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
   86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg        Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
GenCR=[
1       1       1     2700.01     186.86    136.90     -0.00
   2     2      1      2200.01     455.86    137.86     -0.00
   3     3      1      1006.63     658.21    138.50      0.00
   4     7      1      2800.01     919.07    139.97     -0.00
   5    10      1      2560.00     601.86    140.58      0.00
   6    11      1      2400.01     582.30    143.35     -0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To      From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #       Bus     Bus      P (MW)    Q (MVAr)    P (MW)    Q (MVAr)     P
(MW)    Q (MVAr)
 k=[
 1       1       2     432.58      -8.27    -430.88      39.17      1.698
30.90
   2       1      2     432.58      -8.27    -430.88      39.17
1.698      30.90
   3       1      3     362.17       1.32    -360.26      37.11
1.904      38.43
   4       1      4    1372.69     202.08   -1363.96     -16.47
8.731     185.61
   5       2      3     318.45     -20.80    -317.54      31.85
0.915      11.05
   6       2      4     392.20      98.31    -390.86     -72.36
1.335      25.95
   7       2     10     575.56       0.00    -570.00      50.93
5.559      50.93
   8       2     10     575.56       0.00    -570.00      50.93
5.559      50.93
   9       3      4     127.82      69.88    -127.52     -65.18
0.296       4.70
  10       3      8     378.31     109.69    -375.00     -75.00
3.307      34.69
  11       3      8     378.31     109.69    -375.00     -75.00
3.307      34.69
  12       4      7     290.58     -83.39    -289.26     104.34
1.321      20.94
  13       4      7     290.58     -83.39    -289.26     104.34
1.321      20.94
  14       4      9     150.59      10.40    -150.00       0.00
0.594      10.40
  15       4      9     150.59      10.40    -150.00       0.00
0.594      10.40
  16       5      6     -75.00     -25.00      75.03      25.60
0.027       0.60
  17       5      6     -75.00     -25.00      75.03      25.60
0.027       0.60
  18       6      7    -762.61     -68.95     769.63     177.60
7.017     108.65
  19       6      7    -762.61     -68.95     769.63     177.60
7.017     108.65
  20       6      7    -762.61     -68.95     769.63     177.60
7.017     108.65
  21       6      7    -762.61     -68.95     769.63     177.60
7.017     108.65
  22       6     11      50.20     -37.69     -49.99      41.15
0.204       3.46
  23       6     11      50.20     -37.69     -49.99      41.15
0.204       3.46
   ];

%% LMP is the market LMP after the addition of 3-4 line,,,
LMP=[
136.8990
  137.8638
  138.5000
  138.7984
  142.7081
  142.6059
```

```
  139.9740
  140.8894
  139.9536
  140.5792
  143.3511
    ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Congestion costs calculations after the addition of 3-5 line

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status      Pg          Qg         Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
Gen=[
  1       1       1     2000.00      -6.19      86.65       0.00
  2       2       1     2000.00     310.75      86.65       0.00
  3       3       1       -0.01     -20.89      86.65       0.00
  4       7       1     5600.01     207.87      86.65       0.00
  5      10       1     2000.00     587.54      86.65       0.00
  6      11       1     2000.00     587.54      86.65       0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status      Pg          Qg         Lambda ($/MVA-hr)
%  #      #                (MW)       (MVAr)        P           Q
GenCR=[
  1       1       1     2700.01     200.34     136.47      -0.00
  2       2       1     2200.01     466.46     137.49      -0.00
  3       3       1     1001.65     683.39     138.50      -0.00
  4       7       1     2800.01     797.61     138.69       0.00
  5      10       1     2560.00     601.86     140.20      -0.00
  6      11       1     2400.01     573.85     141.73      -0.00
];


%% h is the market branch flows
```

```
%Brnch   From   To    From Bus Injection   To Bus Injection
Loss (I^2 * Z)
%  #      Bus    Bus    P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
  1      1      2    455.54     -7.84    -453.66     42.11      1.883
34.27
  2      1      2    455.54     -7.84    -453.66     42.11
1.883    34.27
  3      1      3    424.90      5.47    -422.28     47.43
2.621    52.90
  4      1      4   1264.02    210.56   -1256.57    -52.24
7.447   158.32
  5      2      3    452.88    -26.25    -451.03     48.57
1.848    22.32
  6      2      4    303.33    108.48    -302.49    -92.01
0.847    16.47
  7      2     10    575.56     -0.00    -570.00     50.93
5.559    50.93
  8      2     10    575.56     -0.00    -570.00     50.93
5.559    50.93
  9      3      5    318.36     68.01    -315.68    -21.26
2.672    46.74
 10      3      8    378.31    109.69    -375.00    -75.00
3.307    34.69
 11      3      8    378.31    109.69    -375.00    -75.00
3.307    34.69
 12      4      7    128.93    -88.31    -128.58     93.93
0.354     5.62
 13      4      7    128.93    -88.31    -128.58     93.93
0.354     5.62
 14      4      9    150.60     10.44    -150.00     -0.00
0.597    10.44
 15      4      9    150.60     10.44    -150.00     -0.00
0.597    10.44
 16      5      6     82.84    -14.37     -82.81     15.03
0.031     0.67
 17      5      6     82.84    -14.37     -82.81     15.03
0.031     0.67
 18      6      7   -683.69    -65.65     689.29    152.44
5.605    86.79
 19      6      7   -683.69    -65.65     689.29    152.44
5.605    86.79
 20      6      7   -683.69    -65.65     689.29    152.44
5.605    86.79
 21      6      7   -683.69    -65.65     689.29    152.44
5.605    86.79
 22      6     11     50.18    -33.74     -49.99     36.93
0.188     3.19
 23      6     11     50.18    -33.74     -49.99     36.93
0.188     3.19
   ];

%% LMP is the market LMP after the addition of 3-5 line,,,
LMP=[
 136.4729
  137.4932
  138.5000
  138.1634
  140.8915
  140.9986
```

```
  138.6876
  140.8894
  139.3172
  140.2013
  141.7302
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour ; but when this line is added
the bus
% becomes un-congested, i.e. CR = 0
CR = ( crossflow - limit )*LMP(CongBus);
CR = 0;
%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear

% Selected set of Generation at Market Clearing Price stage
% Gen     Bus     Status      Pg          Qg          Lambda ($/MVA-hr)
%  #       #                 (MW)        (MVAr)        P           Q
Gen=[
   1       1       1      2000.00      -6.19       86.65        0.00
   2       2       1      2000.00     310.75       86.65        0.00
   3       3       1        -0.01     -20.89       86.65        0.00
   4       7       1      5600.01     207.87       86.65        0.00
   5      10       1      2000.00     587.54       86.65        0.00
   6      11       1      2000.00     587.54       86.65        0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen     Bus     Status      Pg          Qg          Lambda ($/MVA-hr)
%  #       #                 (MW)        (MVAr)        P           Q
GenCR=[
   1       1       1      2700.01     211.59      136.78       -0.00
   2       2       1      2200.01     471.19      137.76       -0.00
   3       3       1      1005.95     589.43      138.50       -0.00
   4       7       1      2800.01     936.91      139.50       -0.00
   5      10       1      2560.00     601.86      140.48       -0.00
   6      11       1      2400.01     582.30      142.87        0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To     From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #       Bus    Bus     P (MW)   Q (MVAr)    P (MW)   Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
  1        1       2     436.84     -8.20     -435.11     39.71     1.732
31.51
  2        1       2     436.84     -8.20     -435.11     39.71
1.732     31.51
  3        1       3     373.34      1.97     -371.32     38.86
2.023     40.84
  4        1       4    1352.98    226.01    -1344.45    -44.59
8.534    181.42
  5        2       3     342.10    -21.90     -341.05     34.65
1.055     12.75
  6        2       4     377.02    113.67     -375.75    -89.05
1.266     24.61
  7        2      10     575.56      0.00     -570.00     50.93
5.559     50.93
  8        2      10     575.56      0.00     -570.00     50.93
5.559     50.93
  9        3       7     161.70     -3.46     -161.04     14.99
0.660     11.54
 10        3       8     378.31    109.69     -375.00    -75.00
3.307     34.69
 11        3       8     378.31    109.69     -375.00    -75.00
3.307     34.69
 12        4       7     209.50    -93.63     -208.74    105.76
0.765     12.13
 13        4       7     209.50    -93.63     -208.74    105.76
0.765     12.13
 14        4       9     150.60     10.45     -150.00     -0.00
0.598     10.45
 15        4       9     150.60     10.45     -150.00     -0.00
0.598     10.45
 16        5       6     -75.00    -25.00       75.03     25.60
0.027      0.60
 17        5       6     -75.00    -25.00       75.03     25.60
0.027      0.60
 18        6       7    -762.61    -68.95      769.63    177.60
7.017    108.65
 19        6       7    -762.61    -68.95      769.63    177.60
7.017    108.65
 20        6       7    -762.61    -68.95      769.63    177.60
7.017    108.65
 21        6       7    -762.61    -68.95      769.63    177.60
7.017    108.65
 22        6      11      50.20    -37.69      -49.99     41.15
0.204      3.46
 23        6      11      50.20    -37.69      -49.99     41.15
0.204      3.46
  ];

%% LMP is the market LMP after the addition of 3-7 line,,,
LMP=[
  136.7772
  137.7619
  138.5000
  138.6191
  142.2277
  142.1259
```

```
  139.5028
  140.8894
  139.7830
  140.4753
  142.8686
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour
CR = ( crossflow - limit )*LMP(CongBus);

%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost

Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear

% Selected set of Generation at Market Clearing Price stage
% Gen     Bus    Status      Pg          Qg         Lambda ($/MVA-hr)
%  #       #                (MW)        (MVAr)        P           Q
Gen=[
   1       1       1      2000.00      -6.19        86.65        0.00
   2       2       1      2000.00     310.75        86.65        0.00
   3       3       1        -0.01     -20.89        86.65        0.00
   4       7       1      5600.01     207.87        86.65        0.00
   5      10       1      2000.00     587.54        86.65        0.00
   6      11       1      2000.00     587.54        86.65        0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen     Bus    Status      Pg          Qg         Lambda ($/MVA-hr)
%  #       #                (MW)        (MVAr)        P           Q
GenCR=[
   1       1       1      2700.01     244.72       137.02       -0.00
   2       2       1      2200.01     490.56       137.98       -0.00
   3       3       1       999.93     573.16       138.50       -0.00
   4       7       1      2800.01     822.58       139.16       -0.00
   5      10       1      2560.00     601.86       140.70       -0.00
   6      11       1      2400.01     575.47       142.07        0.00
];


%% k is the market branch flows
```

```
%Brnch    From    To    From Bus Injection    To Bus Injection
Loss (I^2 * Z)
%  #      Bus     Bus    P (MW)    Q (MVAr)    P (MW)    Q (MVAr)    P
(MW)    Q (MVAr)
 k=[
    1        1      2     419.00      -8.48     -417.40      37.47
1.593      28.99
   2       1      2     419.00      -8.48     -417.40      37.47
1.593      28.99
   3       1      3     323.59      -0.65     -322.07      31.33
1.520      30.68
   4       1      4    1438.42     262.33    -1428.73     -56.20
9.696     206.13
   5       2      3     235.11     -16.43     -234.61      22.45
0.499       6.03
   6       2      4     448.59     132.03     -446.81     -97.32
1.785      34.71
   7       2     10     575.56      -0.00     -570.00      50.93
5.559      50.93
   8       2     10     575.56      -0.00     -570.00      50.93
5.559      50.93
   9       3      8     378.31     109.69     -375.00     -75.00
3.307      34.69
  10       3      8     378.31     109.69     -375.00     -75.00
3.307      34.69
  11       4      5     478.37      33.05     -475.01      20.21
3.359      53.26
  12       4      7      47.98    -100.27      -47.80     103.13
0.180       2.86
  13       4      7      47.98    -100.27      -47.80     103.13
0.180       2.86
  14       4      9     150.60      10.51     -150.00       0.00
0.601      10.51
  15       4      9     150.60      10.51     -150.00       0.00
0.601      10.51
  16       5      6     162.51     -35.11     -162.39      37.72
0.120       2.62
  17       5      6     162.51     -35.11     -162.39      37.72
0.120       2.62
  18       6      7    -643.90     -76.61      648.90     154.08
5.003      77.46
  19       6      7    -643.90     -76.61      648.90     154.08
5.003      77.46
  20       6      7    -643.90     -76.61      648.90     154.08
5.003      77.46
  21       6      7    -643.90     -76.61      648.90     154.08
5.003      77.46
  22       6     11      50.19     -34.50      -49.99      37.73
0.191       3.24
  23       6     11      50.19     -34.50      -49.99      37.73
0.191       3.24
   ];

%% LMP is the market LMP after the addition of 4-5 line,,,
LMP=[
  137.0184
  137.9800
  138.5000
  138.9857
  141.1171
  141.3391
```

```
  139.1642
  140.8894
  140.1693
  140.6977
  142.0736
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;           % Maximum allowable MW flow across Congested bus
CongBus=4;            % from ISO point of view
crossflow=0;          % considered contengencies = outages of 1-4 or
2-4
                       % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour
CR = ( crossflow - limit )*LMP(CongBus);

%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost

Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```

```
% Market Clearing Price and Base case Congestion Re-dispatch

clear

% Selected set of Generation at Market Clearing Price stage
% Gen    Bus    Status     Pg          Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)        (MVAr)       P          Q
Gen=[
  1       1       1      2000.00      -6.19      86.65      0.00
  2       2       1      2000.00     310.75      86.65      0.00
  3       3       1        -0.01     -20.89      86.65      0.00
  4       7       1      5600.01     207.87      86.65      0.00
  5      10       1      2000.00     587.54      86.65      0.00
  6      11       1      2000.00     587.54      86.65      0.00
];
MCP = [
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
    86.6500
];

LMPbase = [
  137.0309
  137.9903
  138.5000
  138.9961
  142.9200
  142.8177
  140.1819
  140.8894
  140.1705
  140.7082
  143.5640
];
% Selected set of Generation at Congestion Re-dispatch stage

% Gen    Bus    Status     Pg          Qg        Lambda  ($/MVA-hr)
%  #      #                (MW)        (MVAr)       P          Q
GenCR=[
  1       1       1      2700.01     242.10     137.02      0.00
  2       2       1      2200.01     488.96     137.98     -0.00
  3       3       1      1000.03     573.15     138.50     -0.00
  4       7       1      2800.01     838.12     139.15      0.00
  5      10       1      2560.00     601.86     140.70     -0.00
  6      11       1      2400.01     576.76     142.06      0.00
];


%% k is the market branch flows
%Brnch    From    To     From Bus Injection     To Bus Injection
Loss (I^2 * Z)
```

```
%   #       Bus    Bus     P (MW)     Q (MVAr)    P (MW)      Q (MVAr)      P
(MW)    Q (MVAr)
 k=[
  1        1        2    418.96      -8.48    -417.37      37.47       1.593
28.99
   2        1       2    418.96      -8.48    -417.37      37.47
1.593      28.99
   3        1       3    323.55      -0.65    -322.03      31.32
1.519      30.67
   4        1       4   1438.54     259.72   -1428.84     -53.70
9.691     206.03
   5        2       3    235.05     -16.42    -234.55      22.45
0.499       6.02
   6        2       4    448.58     130.45    -446.80     -95.81
1.782      34.64
   7        2      10    575.56      -0.00    -570.00      50.93
5.559      50.93
   8        2      10    575.56      -0.00    -570.00      50.93
5.559      50.93
   9        3       8    378.31     109.69    -375.00     -75.00
3.307      34.69
  10        3       8    378.31     109.69    -375.00     -75.00
3.307      34.69
  11        4       6    434.70      28.97    -431.82      29.15
2.879      58.12
  12        4       7     69.87    -100.24     -69.65     103.70
0.218       3.46
  13        4       7     69.87    -100.24     -69.65     103.70
0.218       3.46
  14        4       9    150.60      10.51    -150.00      -0.00
0.601      10.51
  15        4       9    150.60      10.51    -150.00      -0.00
0.601      10.51
  16        5       6    -75.00     -25.00      75.03      25.59
0.027       0.59
  17        5       6    -75.00     -25.00      75.03      25.59
0.027       0.59
  18        6       7   -654.65     -77.53     659.83     157.68
5.176      80.15
  19        6       7   -654.65     -77.53     659.83     157.68
5.176      80.15
  20        6       7   -654.65     -77.53     659.83     157.68
5.176      80.15
  21        6       7   -654.65     -77.53     659.83     157.68
5.176      80.15
  22        6      11     50.19     -35.10     -49.99      38.38
0.193       3.28
  23        6      11     50.19     -35.10     -49.99      38.38
0.193       3.28
   ];

%% LMP is the market LMP after the addition of 4-6 line,,,
LMP=[
137.0187
   137.9801
   138.5000
   138.9847
   141.4207
   141.3209
   139.1478
   140.8894
```

```
  140.1669
  140.6978
  142.0561
     ];
% scaling back the energy price to match real power prices.
LMP=0.1*LMP; LMPbase = 0.1*LMPbase ; MCP =0.1*MCP;
%% CR = Congestion Revenues Calculations
limit=630;            % Maximum allowable MW flow across Congested bus
CongBus=4;             % from ISO point of view
crossflow=0;           % considered contengencies = outages of 1-4 or
2-4
                        % effect is over load on the other circuit
for h=1:length(k);
    if k(h,2) == CongBus && k(h,4) > 0
        crossflow =   crossflow - k(h,4) ;
    end
    if k(h,3)== CongBus && k(h,4) < 0
        crossflow =   crossflow + k(h,4) ;
    end
end
crossflow = - crossflow;
% whatever exceeds the limit across congested bus times congested
bus LMP
% is Congestion Revenues CR per hour
CR = ( crossflow - limit )*LMP(CongBus);

%% SRP = system redispatch payments Calculations
SRP=0;
dif = Gen(:,4) - GenCR(:,4);
for h=1:6
if dif(h) > 0;
    SRP = SRP + dif(h)*0.1*GenCR(h,6);
end
end
SRP = 0.1*SRP ; % 10% lost profit/hour to be paid back for de-
selected Gen's

%% Calculation of Gain, Standard Deviation and Total Congestion
Cost
Gain =  LMP - LMPbase
AvgPriceReduction = mean(Gain)
AvgLMP = mean(LMP)
LMPstDev = std(LMP)
CongestionRevenues = CR
systemRedispatchPayments = SRP

Output= [AvgPriceReduction AvgLMP LMPstDev CR SRP ]
```