EVALUATING MARKET POWER IN CONGESTED POWER SYSTEMS

BY

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THESIS

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RED-BORDERED FORM

Coming from Australia

ABSTRACT

In this thesis, a linear programming algorithm is developed for determining a measure of market concentration in congested transmission systems. The linear program uses the effects of the congestors on the system to derate the line limits of each transmission line. The derated line limits allow for the congestor's contribution to the system flows to be taken into account when examining the available market for additional buyers and sellers in the system. The linear program uses transmission line constraints with derated line limits and generation constraints to calculate the maximum simultaneous interchange capability for a group of buyers and sellers on the system. The results of the linear program provide information regarding the maximum amount of power the buyers can import, as well as the amount of generation each seller can provide towards the simultaneous interchange. When only a few of the available sellers can participate in the maximum simultaneous interchange capability of the buyers, the market of available generation is referred to as concentrated. Each seller's contribution, as determined by the simultaneous interchange capability algorithm, can be used in determining a Herfindahl-Hirschman index (HHI) of concentration for the market. The resulting HHI value can then be compared to government standards for HHI regarding market power in the electricity industry. Finally, sample applications of the maximum simultaneous interchange capability algorithm are examined. These examples are used to discuss the ramifications of congestion on the transmission system's concentration and the usefulness of the derated line limit solution method for determining market concentration.

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NOTATION

q_i	Percentage of the market share for generator i
δP_k	Change in real power injection at bus k
δQ_k	Change in reactive power injection at bus k
δP	Total change in real power between areas
δQ	Total change in reactive power between areas
J	Power system Jacobian matrix
V	Actual bus voltage
q	Actual bus angle
δV	Change in bus voltage
δq	Change in bus angle
G_{ij}	Conductance of a transmission line from bus i to bus j
B_{ij}	Admittance of a transmission line from bus i to bus j
δP_{ij}	Change in line flow from bus i to bus j
S_{ik}	Sensitivity of line i power flow to a 1 MW increase in the bus k generation
δP_{gk}	Change in generation at generating bus k
δP_i	Change in generation of maximizing bus i
MVA	Line rating
k_j^{mn}	Sensitivity of change in flow on line mn to a change in injection at maximizer j
S^{mn}	Actual MVA flow on line mn at the operating point
δP_{ic}	Change in generation of congestor i
k_{jc}^{mn}	Sensitivity of change in flow on line mn to a change in injection at congestor j
P_{jc}	MW injection of congestor j

1. INTRODUCTION

1.1 Motivation

The electric utility industry is in a period of drastic change and restructuring, with the traditional vertically integrated electric utility structure being deregulated and replaced by a competitive market scheme. Deregulation of electric utilities has recently led to an increasing number of acquisitions and mergers as utilities prepare to compete to provide service. The United States Federal Energy Regulatory Commission (FERC) recognized the need for streamlining and expediting the processing of merger applications in the new competitive environment, and thus issued its Order 592 "Policy Statement on Utility Mergers" in December 1996 [1]. FERC's adoption of the Department of Justice/Federal Trade Commission (DOJ/FTC) *Horizontal Merger Guidelines* [2] as the framework for competition has led to strong interest in the analysis of market power issues in electricity markets.

Market power, simply defined, is the ability of a seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time. The drive to competition in the electricity industry has generated a concern that the potential benefits resulting from the removal of the traditional vertical market power could result in the development of horizontal market power. The restructuring in the electricity industry and the issuance of the FERC *Merger Guidelines* have brought about the recent interest in the study of market power issues [3], [4], [5]. Traditionally, economists study many factors of a market when determining market power, such as the structure, conduct, and performance of the market. Ultimately, the study of market power boils down to the structure of the market and the established "rules" under which the market operates.

With the coming deregulation of the electric utility industry, the determination of market power situations has become increasingly important in the interest of fair competition. Traditionally, the determination of market power in a market is dependent on essentially three steps [1], [5], [6], [7]:

- Identification of the relevant products/services
- Identification of the relevant geographic market
- Evaluation of market concentration

The determination of these three steps must be specifically defined for the electric utility industry, because the utility industry exhibits some characteristics that are slightly different from those of most other economic markets.

Typically, in market power analysis for electricity markets, FERC has considered three types of products: nonfirm energy, short-term capacity, and long term capacity [6]. Though these three product types are all important in their own way for different analyses of the electricity market, the emphasis seems to be shifting in importance to the study of the short-term energy markets [8]. A difficulty in studying short-term energy markets is that the electricity demand varies considerably over time. Therefore, in order to sufficiently search for market power situations in the electricity market, one must analyze a variety of different market conditions. For any method of determining the extent of market power in the electric utility industry to be considered effective, it must exhibit two characteristics: the electric system conditions must be capable of being changed easily, and the method must be able to quickly determine the ramifications of the changes in the market.

The identification of the geographic market is by far the most important step of conducting market power analysis on the electric utility industry. In a traditional market, the geographic market is just that, a geographic area that can be reached for distribution of a certain product. However in the electricity industry, an actual "geographic" area does not have any scope. This is because electricity must follow the constraints of the transmission system. In a sense, the geographic scope of the electricity industry is defined by the layout of the transmission system and the physical constraints of the transmission lines in the system.

In order to determine if a market power situation exists in the electricity industry, there must be some measure of market concentration. Given a measure of concentration, a threshold for market power could be defined. If the measure of any given area of the market exceeded that threshold, it could be dubbed a potential area for market power characteristics. A common measure of market concentration in economics has been the Herfindahl-Hirschman index (HHI) [7]. The HHI measures the concentration in a product market using the sum of the squares of the market shares for the firms in that market. In equation form, HHI can be defined as

$$HHI = \sum_{i=1}^{N} q_i^2 \tag{1.1}$$

where N is the number of participants in the market and q_i is the percentage of the market share for participant I [6], [9]. This index will rise as the share of capacity or output produced by a small number of firms in the market increases. The maximum HHI possible would be 10 000 for one participant with 100% of the market, whereas the HHI would be much smaller for a large number of participants with relatively equal shares of the market. The DOJ/FTC standards for horizontal market power [2] give ranges in which an HHI under 1000 represents an unconcentrated market, 1000 to 1800 represents a moderately concentrated market, and above 1800 represents a highly concentrated market. These numbers could provide a general basis for determining the effects of proposed mergers in the electric utility industry. However, although the HHI results could be useful in judging concentration and market power in electricity markets, obtaining reasonable measures of the index in electricity markets is difficult.

The easiest case of looking at the concentration of the electric utility market is to examine it without considering transmission constraints [6]. Under this assumption, the market effectively becomes the entire connected transmission system with all available generating companies as suppliers. In this situation any source could provide power to any load anywhere in the system. For a system of this type the calculation of the HHI is easy and straightforward. As an example, the HHI for the Eastern Interconnect system can be calculated using data from the 1997 Energy Supply and Demand Database from the NERC (North American Electric Reliability Council), which lists the generation capacity for both the summer and winter peaks. Using an average of the summer and winter peaks, the Eastern Interconnect system has a total capacity of 593 GW with about 650 different market participants. Ignoring the transmission constraints, the associated HHI for the Eastern Interconnect is 169.6. This is a very low HHI, and this number shows that when ignoring the transmission constraints and considering the entire Eastern Interconnect as the available market, there are no market power concerns. However, if we consider each of the NERC regions as independent markets, the HHI numbers for those areas are much higher and could possibly generate concerns [5]. Thus as the market gets smaller, the number of participants is reduced, and the HHI will grow. These results are an observation of how HHI works. The absence of transmission constraints and charges produces indices that have very limited practical use.

To appropriately define the actual market areas in the electricity industry, the transmission constraints and transmission charges must be taken into account. In order for a supplier to be considered for a market area, the supplier must be able to reach that market both economically and physically. This thesis will primarily cover the effects of the transmission constraints. The transmission constraints are responsible for physically determining the flow of power from a supplier, and thus dictate the physical "boundaries" of the supplier's market area. Of particular interest when looking for situations of market power are the effects of network flows and congestion. Congestion arises from the fact that the capacity of the transmission system has a finite value that is not easily determined. The transmission capacity is limited due to a number of different mechanisms, such as transmission line/transformer limits, bus voltage limits, transient stability constraints, and the need to maintain system voltage stability [6]. Transmission line congestion deals specifically with the impact of line limits, and a line is said to be congested anytime it is loaded at or above its MVA limit. One particular occurrence of market power in the electricity industry can arise from the existence of transmission line congestion. Therefore, this thesis will deal specifically with market power analysis in the electric utility industry due to instances of transmission line congestion.

The work presented in this thesis utilizes an optimal simultaneous interchange capability (SIC) calculation to solve the problem of determining a measure of market concentration, the HHI, for the electricity industry in order to indicate regions with market power potential under congested system conditions. The SIC algorithm utilizes the transmission constraints as well as the generation constraints of the system to determine both the maximum SIC for a given area and the amount of generation provided to the SIC from the surrounding areas. Using the results of the optimal SIC allows for a calculation of the HHI by determining each area's share of the SIC under the given system conditions. Thus a measure of market power can be determined from the results of the optimal SIC calculation.

1.2 Literature Survey

A definition of SIC and the general formalization of the optimal SIC calculations by computer were discussed in detail by Landgren et al. in 1971 [10]. The general algorithm for solving the SIC was given in a flow chart to show the program structure. In addition, a discussion of pertinent information for the SIC calculations were discussed, namely the power transfer distribution factors and the line outage distribution factors. These factors are used with the transmission constraints and generation constraints to generate a linearized formulation of the nonlinear power system. An additional paper by Landgren and Anderson [11] further discusses the SIC calculations and provides some examples of the calculation using power system information.

Given the linear nature of the power transfer distribution factors and the line outage distribution factors, the calculation of the SIC can be performed using linear programming techniques. A paper by Stott and Marinho [12] provides the general characteristics of the linear programming method as well as a problem formulation using linear programming in power systems. Although the paper does not address the use of linear programming specifically for the SIC calculations, it does give insight into setting up constraint equations from power systems for solving a linear program.

Perhaps the most comprehensive source on calculating SIC for a power system is provided by an Electric Power Research Institute (EPRI) report [13]. This report provides much information, ranging from the need for simultaneous interchange capability calculations to detailed descriptions of various optimal SIC methods. Discussions of these methods, such as linear programming, interior point methods, and Monte Carlo simulation methods, are discussed in depth with details on the advantages and disadvantages of each method, along with which methods are preferred and the reasons for the preference. Detailed appendices give complete problem formulation, including the formats of cost functions and constraint equations, and detailed descriptions of the variables necessary to perform the optimization of the SIC. This source also contains a comprehensive bibliography on the topic of SIC and the solution methods necessary for calculating the SIC of a power system, up to the publication of the report.

This thesis will explore the usefulness of a SIC calculation to determine possibilities of market power in a congested power system. Specifically, it will explore the use of a linear programming algorithm, together with defining congestion in a power system, to determine a measure of market concentration based on the optimal SIC of an area of the power system.

1.3 Goals of Using an SIC Calculation for Market Power Determination

The primary goal of an optimal SIC calculation for market power determination is to maximize the simultaneous interchange capability into a load pocket from some or all of the available generation sources in order to identify possible market power situations. By maximizing the SIC along a contract path,[1] it can be determined if the suppliers can sufficiently provide the needed power to the buyers. A contract path between a buyer and seller may be viewed as a direct path on paper, but on the transmission system the path that a transaction's power flow takes is defined by the transmission system. The flow of electricity in the transaction will take the path of least resistance between the buyer and seller, which usually results in the power being distributed over several transmission lines on the system before ultimately converging again on the buyer. This distribution of the power of a defined transaction represents loop flow on the system due to the transmission constraints. This concept is important in the maximum SIC calculation because the calculation depends on the transmission constraints of the

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[1] A contract path is defined as the direct path between a buyer (or buyers) and a seller (or sellers) on the transmission system.

lines in the system. If any of the affected lines, no matter how far away from the contract path, become fully loaded as a result of the transaction, then the maximum SIC for the defined contract path will be limited. Thus, the contract path defines the general direction of the flow of power in the system as far as who is the buyer and who is the seller, while the loop flows of the system about the contract path provide the limits for the optimal SIC.

The optimal SIC calculation will determine the amount of available interchange between the buyers and sellers and will determine which sellers will generate the interchange and how much each will provide in order to serve the maximum amount of power to the buyers. Under situations of congestion, it is most likely that not all suppliers will be able contribute to the maximum SIC. Scenarios where only a few of the willing suppliers can participate in a transaction due to the constraints of the system indicate that situations of market power may be occurring. Study of the SIC under congested conditions can provide insight into the causes and beneficiaries of a concentrated market.

To achieve these goals, the maximum SIC calculations will be performed using a steady-state analysis of the power system. The algorithm will utilize the transmission constraints of the system as boundary conditions on the flow on the transmission lines. The transmission constraints will be the most important aspect of the study, as they are the basis behind system congestion. Generation constraints will also be utilized in the SIC calculations as boundary conditions on the injection of the generators in the system.

1.4 Overview

The maximum SIC calculation performed in this thesis uses a primal linear programming algorithm. It will address the goals of determining the maximum SIC and identifying market concentration for an analysis of market power in a transmission system. The constraints used for the linear program will be (a) transmission constraints with modified limits to simulate system congestion and (b) generation constraints to bound the injection of the system generators.

The remainder of this thesis will discuss the development of the maximum SIC calculations and will discuss the results of these calculations as performed on a transmission system. Chapter 2 will discuss the impact of congestion on a transmission system. This will include discussions on the characteristics of power transfer, including the approximation of incremental power flows due to a transaction on the system. Chapter 3 will discuss the issue of strategic market power, along with calculations to help address the issue. Chapter 4 contains a discussion of using a maximum simultaneous interchange capability calculation with derated line limits to determine market power situations in a congested market. Chapter 5 contains examples of the maximum SIC calculations using derated line limits. Chapter 6 provides the conclusions of the study, as well as some modifications that could be included in future work in this area.

2. ASSESSING THE IMPACT OF CONGESTION ON MARKET POWER

2.1 Characteristics of Power Transfer

The most important issue to recognize when discussing the relationship of the transmission system with market power is that the transfer of power between two points does not travel in a defined path. Rather, the power disperses through several branches of the transmission system in travelling between two points on the system. Therefore, a change in the amount of power generated or consumed by defined sources and sinks on the system can result in changes in power flows throughout a large portion of the transmission network. Because the transmission network encompasses hundreds of different participants in the generation of electricity, a power transfer from a source to a sink could potentially affect numerous other parties that are not involved in the desired transfer. This phenomenon is referred to as “loop flows.” Loop flows are incredibly important when examining market power [5]. In many cases, market power may not occur in an obvious area near an electricity transaction, but rather will develop in a third-party area of the transmission system causing difficulties for areas other than the areas involved in the desired transfer. How power is distributed throughout a transmission system depends on the direction of the power flows and the characteristics of the transmission system. The characteristics of the system include such things as the megavolt-ampere (MVA) limits of the transmission lines and the electrical characteristics of each line in the system such as resistance, inductance, and capacitance. If these values are all relatively known, it is then possible and very useful to predict the effects of a transaction on the transmission network.

2.2 Predicting Incremental Power Flows from a Defined Transaction

The incremental change in power flows in the transmission network associated with a particular transaction direction has been defined by NERC as the power transfer distribution factors (PTDFs). The PTDF values are a linear approximation of how the power flows would change on the system for a particular power transfer between two points on the system. A power transfer occurs between two areas when, holding the electricity usage of each area constant, one area increases its generation and the other area simultaneously decreases its generation. The set of buses increasing their injection of power into the system will be referred to as the "source," whereas the set of buses decreasing their injection of power into the system will be referred to as the "sink." The incremental change in power flow then goes from the source to the sink. The source/sink pair is commonly referred to as a "direction." As discussed previously, the prescribed transfer does not necessarily mean that the power will flow directly from the source to the sink, but rather loop flow will occur and other areas of the system will be affected. By calculating the PTDFs of the system for the transfer, an approximation of the effects of the transfer can be readily observed throughout the entire system. The calculation of the PTDFs relies on the sensitivities of the transmission lines with respect to the voltages and angles of the buses at each end of the line, the sensitivities of each voltage and angle with respect to an incremental transfer, and the participation factors of the generators included in that transfer. The calculation of the PTDFs begins with the calculation of the change in the voltage and angle state variables. These values can be calculated using the inverse of the Jacobian matrix for the system and the change in injection of the system, as shown by Equation (2.1).

$$\begin{bmatrix} d\theta \\ dV \end{bmatrix} = J^{-1} \begin{bmatrix} dP \\ dQ \end{bmatrix} \tag{2.1}$$

The values of the real and reactive power vector are determined from the participation factors of the generators involved in the transfer. Each generator in an area has a participation factor, ranging as a percentage from 0% to 100% inclusive in the transaction. Each value of δ*P* and δ*Q* in the vector is determined from the participation factor of the associated generator with respect to all other generators in the same area. Equations (2.2) and (2.3) shows numerically how these values are computed. The subscript *k* represents the injection of the generator at bus *k*, pf represents the participation factor of a generator, δ*P* and δ*Q* represent the total change in real and reactive power between the areas in the transaction, and *N* represents the number of generators in the area containing generator *k*.

$$\delta P_k = \left(\frac{pf_k}{\sum_{i=1}^{N} pf_i} \right) \delta P \tag{2.2}$$

$$\delta Q_k = \left(\frac{pf_k}{\sum_{i=1}^{N} pf_i} \right) \delta Q \tag{2.3}$$

If the slack generator of the system is not included in the generator set for the transfer, the system losses need to be taken into account in the calculation of the change in injections. When determining the PTDFs of the system due to a defined transfer, you calculate the values based on the change in injection of the sellers and the change in injection of the buyers. If the slack generator is not included in either the set of buyers or the set of sellers, the losses need to be assigned to one or the other so that the slack generator does not contribute in any way to the defined transaction. One way to take losses into account is to assume that the seller provides 100% of the defined transaction, and then to scale the buyer change in injection according to the affect of losses. Therefore, in Equations (2.2) and (2.3), the total power changes of the sellers will remain as defined by the transaction and the total power changes of the buyers will be scaled to reflect the losses. The result of this is that the values of δP and δQ in Equation (2.1) will reflect the losses of the system, and the PTDF values will be calculated for only the generators included in the transaction, without the slack bus affecting the results.

The next step in determining the PTDFs is to compute the change in the real power flow on each transmission line with respect to the state variables of the system. Examples of the line flow equations are shown in Equations (2.4)-(2.7). In these equations, *i* represents the bus that is defined by the transfer direction as "from", and *j* represents the bus that is defined as "to."

$$\frac{\partial P_{ij}}{\partial V_i} = -2V_i G_{ij} + V_j \left[G_{ij} \cos(\theta_i - \theta_j) - B_{ij} \sin(\theta_i - \theta_j) \right] \tag{2.4}$$

$$\frac{\partial P_{ij}}{\partial V_j} = V_i \left[G_{ij} \cos(\theta_i - \theta_j) - B_{ij} \sin(\theta_i - \theta_j) \right] \tag{2.5}$$

$$\frac{\partial P_{ij}}{\partial \theta_i} = V_i V_j \left[-G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j) \right] \tag{2.6}$$

$$\frac{\partial P_{ij}}{\partial \theta_j} = V_i V_j \left[G_{ij} \sin(\theta_i - \theta_j) + B_{ij} \cos(\theta_i - \theta_j) \right] \tag{2.7}$$

Once the sensitivities have been calculated from equation sets (2.1) and (2.4)-(2.7), they can be linearly combined to obtain the change in real power flow on a line with respect to the change in system injection, as shown in Equation (2.8).

$$\frac{\partial P_{ij}}{\partial P_k} = \frac{\partial P_{ij}}{\partial V_i} \cdot \frac{\partial V_i}{\partial P_k} + \frac{\partial P_{ij}}{\partial V_j} \cdot \frac{\partial V_j}{\partial P_k} + \frac{\partial P_{ij}}{\partial \theta_i} \cdot \frac{\partial \theta_i}{\partial P_k} + \frac{\partial P_{ij}}{\partial \theta_j} \cdot \frac{\partial \theta_j}{\partial P_k} \tag{2.8}$$

A PTDF value is calculated for each line in the system using the system information with these equations. The PTDF value depicts what portion of the incremental change will flow across each transmission line in the direction of the desired transfer. Observing the PTDFs for each line allows the recognition of the impact of any given transfer on the rest of the system. Thus, PTDFs can be helpful in recognizing possible areas of the system that may be susceptible to market power under different area transfer scenarios.

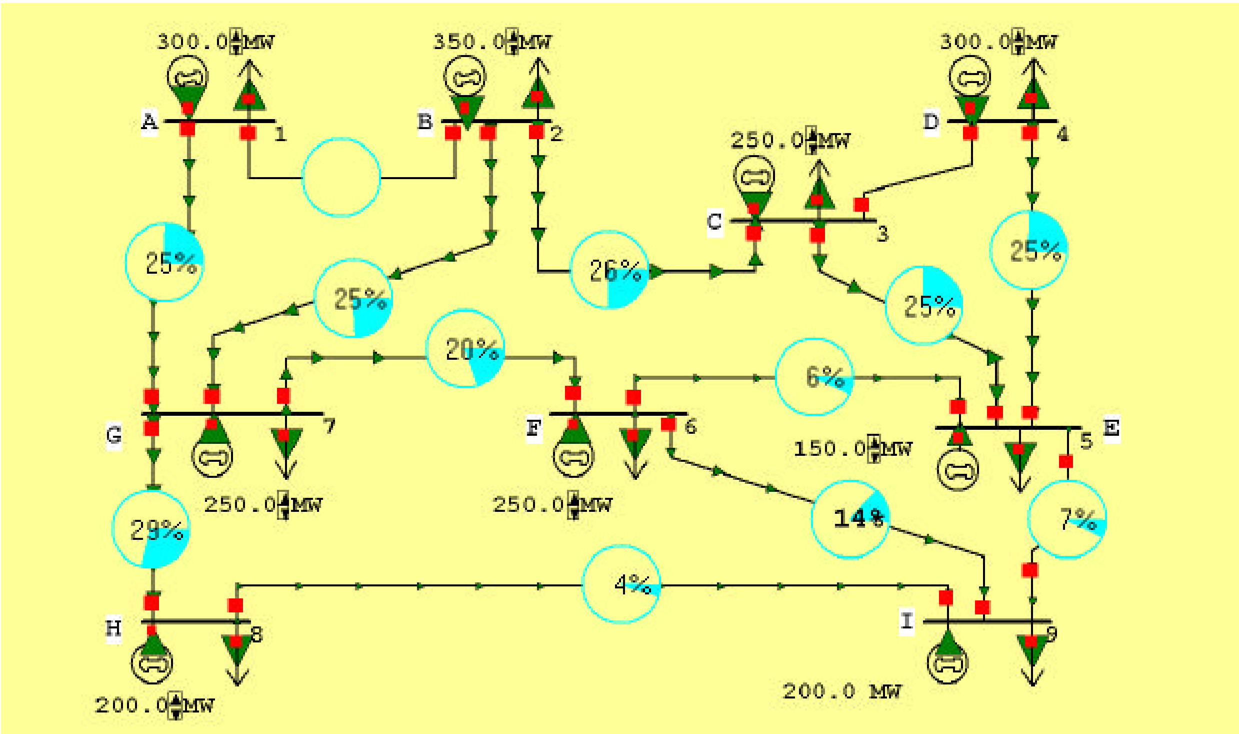

Figure 1: Nine-Bus System

For an example of PTDF calculations, consider the system in Figure 1. For simplicity, this system has been designed with the following characteristics:

1. Each bus has a single generator with a capacity of 500 MW and a single 250 MW load.
2. Each bus initially corresponds to a single market participant (a single operating area).
3. All transmission lines have an impedance of $j0.1$ per unit and an initial limit of 200 MVA.

Any two areas of the system can be chosen as participants in a transaction. As an arbitrary selection, we will choose area A to be selling power and area I to be buying power. Once the participants have been chosen, the change in the state variables can be determined from Equation (2.1) based on a 1-MW increase in area A and a 1-MW decrease in area I. If there were more than one generator in either of the areas, the participation factors of the generators would be taken into account in the calculation of the change in state variables, as was shown in Equations (2.2) and (2.3). In this example there are no generator participation factors to be taken into account because each area contains only one generator. The PTDF for each line can be calculated using Equations (2.4)-(2.8). The resulting PTDF values can be found in Table 1.

Table 1: PTDF Values for Nine-Bus Case

From Area	To Area	Percent Out of From End	Percent Into To End
A	B	43.4%	-43.4%
A	G	56.6%	-56.6%
B	C	30.2%	-30.2%
B	G	13.2%	-13.2%
C	D	10.1%	-10.1%
C	E	20.1%	-20.1%
D	E	10.1%	-10.1%
F	E	1.7%	-1.7%
E	I	31.9%	-31.9%
G	F	35.3%	-35.3%
F	I	33.6%	-33.6%
G	H	34.5%	-34.5%
H	I	34.5%	-34.5%

The PTDF values of Table 1 represent the percentage of the power injected at the selling area that flows on each particular line as it moves towards the buying area. For example, if an additional 1 MW of power was injected at area A and 1 MW of injection was removed from area I, then the flow on the line from area A to B would change by 0.434 MW. Therefore, using the PTDF percentages, the change in power flow on each line in the system for a transaction of any amount between areas A and I can be computed. The PTDFs of the system for the transaction from areas A to I can be seen in Figure 2 (the buses, generators, and loads have been replaced by ellipses representing each area).

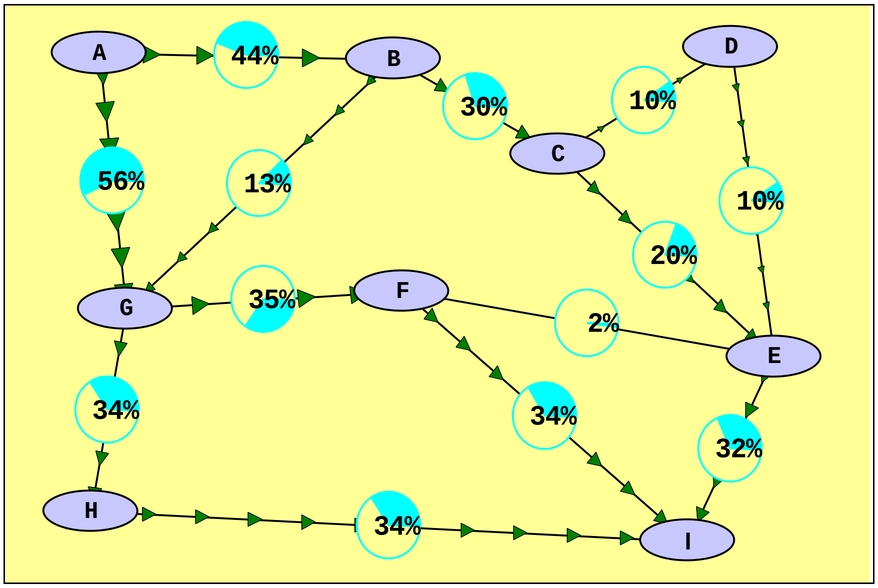

Figure 2: Nine-Bus Case PTDF Visualization for a Transaction from Area A to Area I

Visualizing the PTDF values greatly facilitates the understanding of how power flows through a transmission system. Even though the defined transaction is from area A to area I, the power does not flow directly along the contract path between the two areas. PTDFs provide an approximation of the resulting loop flows in the system, which is important information for market power analysis. This example shows that the PTDFs provide a linear estimate of the change in flows throughout the entire system, which can be used in further studies of market power issues in power systems.

3. STRATEGIC MARKET POWER

3.1 Computing Maximum Change in Line Flow

The characteristic that congestion can limit market size allows the possibility that owners of groups of generators could deliberately dispatch their generation in order to induce congestion for strategic purposes [9]. A group of generators could recognize the fact that, by distributing power in a certain manor, they could potentially reduce the number of competing generators in their area. To address this issue, the transmission system could be further examined by using a method similar to the PTDF calculations. This method involves taking a defined set of N generators and determining the maximum change in transmission that can be incurred on any transmission line in the system.

The maximum ability of a set of N generators to unilaterally control the flow on a particular line L for a lossless case can be defined as

$$\delta P_{\mathrm{i}} = \max \sum_{k=1}^{N} S_{ik}\, \delta P_{gk} \quad \text{s.t.} \sum_{k=1}^{N} \delta P_{gk} = 0 \tag{3.1}$$

$$P_{k,\min} \leq P_k + \delta P_{gk} \leq P_{k,\max} \tag{3.2}$$

where S_{ik} is the sensitivity of the line i power flow to a 1-MW increase in the bus k generation, δP_i is the change in the flow on line i, and δP_{gk} is the change in generation at generating bus k. This value is maximized by increasing the injection of the generators in the study with the most positive sensitivities and decreasing those with the most negative sensitivities as in Equation (3.1), taking into account the generator maximum/minimum megawatt limits in Equation (3.2).

It is possible that each line in the system may have a different combination of sources and sinks from the selected set of generators, because the determination of sources and sinks for maximum change in line flow is chosen based on the sensitivities for each line. The values resulting from these calculations can then be expressed as a percentage of the maximum line flow for each line in the system. This will provide a quick insight into possible problem areas in the transmission system for a set of generators and the operating scenario that causes the condition to occur.

3.2 Maximum Change in Flow Example

As a base case for an example of calculating the maximum change in line flow, we will reconsider the system shown in Figure 1. As an example, consider that we desire to know the maximum change in flow for each line of the system for an interaction between area G and area F. As discussed, once the generators have been determined, the sensitivities of the change in line flow with respect to a change in injection of each generator in the study can be computed similar to the calculations for the PTDFs. The sensitivities can then be used along with the maximum increases or decreases in injection for each of the generators to calculate the maximum changes in flow for each line (3.1). The values of the maximum change in flow for each line were calculated for the two generators at buses 6 and 7, and the results are shown in Table 2.

The important difference between these values and the PTDF values is that the maximum change in flow values are the percentages of the change in flow in relation to the maximum MVA value of each line. Consider the percentage change in flow from area A to area B. The MVA limit on each line in the system is 200 MVA; therefore, the maximum change in flow on the line from area A to area B due to generators 6 and 7 is 7.5% of 200 MVA, or 15.1 MVA. It can be seen that many of the percentage changes in flow values are considerably high, particularly on the line directly between area G and area F. Of course, this is to be expected because this line is a direct link between the two areas changing their injection, but the calculations have quantified an approximation of the magnitude of the maximum affect of generators 6 and 7 on every line in the system. The results have thus indicated possible problem areas in the system for the specific scenario of studying generators 6 and 7. As with the PTDF results, the maximum change in flow results for each line can be used for further examination of methods for predicting market power situations in a power system.

Table 2: Maximum Change in Flow Values for Nine-Bus Case

From Area	To Area	Percent Out of From End	Percent Into To End
A	B	7.55%	-7.55%
A	G	7.55%	-7.55%
B	C	22.63%	-22.63%
B	G	15.08%	-15.08%
C	D	7.55%	-7.55%
C	E	15.08%	-15.08%
D	E	7.55%	-7.55%
F	E	23.71%	-23.71%
E	I	1.08%	-1.08%
G	F	76.51%	-76.51%
F	I	24.78%	-24.78%
G	H	25.87%	-25.87%
H	I	25.87%	-25.87%

4. MARKET POWER OBSERVATION THROUGH SIMULTANEOUS INTERCHANGE CAPABILITY

4.1 Simultaneous Interchange Capability

Simultaneous interchange capability (SIC) is the capacity and ability of a transmission network to allow for the reliable movement of power to and from a utility involving any combination of its neighbors [13]. The usefulness of an SIC calculation in studying market power is that SIC can give some indication of the interaction of areas under various power system conditions. The key to using the simultaneous interchange capability in studying market power is that the calculation takes into account any combination of areas and all of the transmission constraints of the system. By maximizing the SIC into an area of the system, we can observe the optimal solution allowing the highest possible transfer from all other areas. Thus, based on the optimal SIC result, we can approximate the interaction of the areas during a transaction. In some instances, it is possible that the optimal SIC solution will show that all of a specific area's simultaneous interchange capability comes from only a few of several neighboring areas. In addition to observing the SIC under normal conditions of the system, it is beneficial to observe the SIC when some of the areas may be congesting the system, preventing other areas from gaining access to a load. Situations such as this can be deemed a market power situation of the system due to transmission constraints and the actions of participating areas.

4.2 Simulation of System Congestion

One way to approximate the available generation market for a load pocket is by solving the SIC problem with various assumptions about the congestors. Congestors can be defined as any number of areas that merge or work together to load one or more transmission lines up to or near full capacity. Defining a set of congestors is arbitrary, as the results of a generator's actions change at different times and with changing loads. Once a set of congestors have been identified for an instance in the system, the maximum change in flow can be calculated for each line based on the generation limits of the congestors. The maximum change in flow is calculated as described in Chapter 3, with the set of generators chosen being the congestors.

Once the maximum change in flow has been computed for each line due to the congestors, the transmission line MVA limits can then be derated by the amount δP_i determined using Equation (3.1), which is the maximum amount by which the congestors can unilaterally manipulate the flow on line *i*. Derating the line limits serves to approximate the congestor's effects on the system's lines by reducing the capacity of the lines as seen by the remaining areas of the system. Derating the line limits should be done for both directions on the line in order to cover the possibility of defined transactions in a system causing the flow to change directions on any line in the system. Defining the line flow on the line to be from bus *a* to bus *b*, the maximum and minimum derated line limits can be calculated by determining δP_i in both directions on a line for the set of congestors in Equations (4.1) and (4.2). The limit in the reverse direction is denoted by the negative limit and is referred to as the minimum MVA limit.

$$MVA_{d,\max} = MVA_{\max} - \delta P_{i,ab} \tag{4.1}$$

$$MVA_{d,\min} = -\left(MVA_{\max} + \delta P_{i,ab}\right) \tag{4.2}$$

If a maximum SIC problem is then solved with these derated line limits, the results will provide a solution for transferring power into a chosen area under the congested conditions, and will indicate which generators the power would come from to provide the maximum SIC. Comparing the SIC results with and without derating the lines could give lower and upper bounds for the size of the available market, which in turn allows bounds on the HHI values of the market.

4.3 Maximum Simultaneous Interchange Capability

One study of simultaneous interchange capability is to compute the maximum simultaneous interchange into an area from any or all of the surrounding areas, with some of the surrounding areas attempting to congest the system. Considering the system congestion, the following approach can be followed to determine the generation market available to a particular load pocket:

1. Select the load pocket, and specify a set of congesting generators.
2. For each line of interest, use the congestor set to derate the line limits using Equations (4.1) and (4.2).
3. Using the derated line limits from step 2, solve the SIC to maximize the import of power into the load pocket, assuming all generators other than the congestors seek to maximize the import into the load pocket.

The determination of the maximum SIC into an area takes into account the area's generation level, the surrounding area's generation level and capacity, and the transmission constraints of the entire system. In an advanced study of the maximum simultaneous interchange capability, additional constraints such as voltage constraints and line or generator outages can be included. For the purpose of this study, only generation constraints and transmission constraints are initially considered. In addition, the load is considered to remain constant, i.e., examining the system at one instance in time. One approach to calculating the maximum SIC is to take a linearized approach by using the sensitivities of the change in flow on the derated transmission lines with respect to the change in injection of the generators included in the study. This concept is the same as has been discussed previously in Section 2.2 regarding PTDF's, and in Section 3.1 in regards to calculating the maximum change of flow on transmission lines. The algorithm for computing the maximum SIC uses some of the same techniques learned in those sections for setting up constraints to be used in a linear programming optimization technique.

4.3.1 Defining congestors

The first part of this study involves identifying a set of generators to consider as the congestors. Congestors can be generators completely within an area of the system, or generators contained in different areas of the system that have a significant effect on one or more transmission lines. These generators can be selected arbitrarily if desired, or specifically if certain generators in a study are known to have a significant effect on the flows in a certain part of the system. Once the congestors have been identified, the maximum change in flow on the lines in the system can be computed using Equation (3.1). If the selected generators do indeed act as congestors, then the maximum change in flow for one or more lines added to the actual flow of the line would be near the line's maximum MVA limit. If this does occur then the generators can be labeled as congestors under the current conditions of the system, and further studies can be performed on the system to determine the maximum SIC for other areas in the system. As mentioned previously, the method proposed for approximating the maximum SIC on a system being manipulated by congestors is to derate the line limits by the maximum change on each line due to the projected interaction of the congestors. Once the lines have been derated according to Equations (4.1) and (4.2), the maximum SIC can be calculated using a linear programming technique.

4.3.2 Linear programming optimization of SIC

The initial step in setting up the linear program is to identify the buses to be included in the study. Portfolios of buses can be defined as a set of buses “buying” power and a set of buses “selling” power. The linear programming algorithm will maximize the flow into the inflow buses based on the available capacity from the outflow buses and the derated transmission constraints. Once the generator portfolios have been defined, the next step of the algorithm is to obtain the actual, maximum, and minimum power injection for each generator in the study. These values will define the generation constraints of the linear program. The significance of these values is that they define the maximum and minimum amounts of the real power injection that each generator can increase or decrease depending on which portfolio they are included in, thus limiting the SIC. The generation constraints can be quantified as an inequality to be included in the linear program constraint Equation (4.3). In Equation (4.3), P_i represents the actual level of the power of generator i, δP_i represents the total change in generation of generator i, and the boundaries of the constraint are the maximum and minimum real power level of generator i.

$$P_{i,\min} \leq \delta P_i + P_i \leq P_{i,\max} \tag{4.3}$$

The next step in setting up the linear program is to obtain the maximum MVA limits and the operating point MVA flow on each line of the system. These values will allow the construction of the transmission constraint equations for the problem. Of great importance in the transmission constraint equations are the values of the sensitivities of the change in flow on the lines with respect to the changes in generation of the generators in the study. These sensitivities are the power transfer distribution factors (PTDFs) that were discussed in Section 2.2. The PTDFs are linearized sensitivities that approximately determine how flows change for a particular power transfer between different pairs of generation portfolios and load pockets. A PTDF value is calculated for each line in the system using the system information with Equations (2.1) and (2.4)-(2.8). The PTDF value depicts what portion of the incremental change will flow across each transmission line in the direction of the desired transfer.

Once the PTDFs are computed, the resulting values can be used in conjunction with the results of equations (4.1) and (4.2) to write the transmission constraints for the linear program. The transmission constraint equations can be written as an inequality as seen in

$$MVA_{d,\min} \leq \sum_{j} k_{j}^{mn}\, \delta P_{j} + S^{mn} \leq MVA_{d,\max} \tag{4.4}$$

In Equation (4.4), the values k_j^{mn} are the PTDF values where j represents the generator whose injection is associated with the sensitivity for the line from bus m to bus n, S^{mn} represents the line MVA under the current system conditions, and δP_j represents the change in power injection for generator j. For the purposes of this study, we consider the change in MVA limits to be mainly due to the change in real power flow; hence, the use of the change in real power term in the line limit constraint in Equation (4.4). In most instances, the transmission constraints become the limiting equations in the linear programming algorithm if the operating point MVA of one or more of the lines in the system are very near the derated MVA limit of the line. In that case, the maximum and minimum amount of injection of the generators in the study become much less important. Typically, in a power system there is sufficient excess generation to cover a transaction, but transmission constraints exist such that the available power cannot be accessed without overloading certain transmission lines. Consequently, concern over transmission constraints is generally more significant than the generator capacity issue when examining the issue of market power.

The final constraint for the simple linear program for calculating a maximum SIC is to ensure that the sum of the changes in injection of the generators in both the "buying" and "selling" portfolios equals zero:

$$\sum_j dP_j = 0 \tag{4.5}$$

The cost function for the linear program is the maximization (or minimization, if the flow into an area is defined as negative) of the sum of the changes in generation into the areas chosen as "buyers" in the system. The completely established linear program (for flow into an area being negative), using generation and line constraints only, can be seen in

$$\text{Minimize } \sum_i dP_i \tag{4.6}$$

Subject to:

$$\sum_j dP_j = 0 \tag{4.7}$$

$$MVA_{d,\min} \le \sum_j k_j^{mn}\, dP_j + S^{mn} \le MVA_{d,\max} \tag{4.8}$$

$$P_{i,\min} \le dP_i + P_i \le P_{i,\max} \tag{4.9}$$

This linear program can be solved using a primal simplex method, resulting in the maximum SIC into the areas defined as "buyers." Note that, in Equations (4.6)-(4.9), i represents the set of generators acting as sinks in the "buying" areas, and j represents the set of all generators selected for the study. This algorithm will also provide information about how much of the maximum SIC each "buyer" will receive and how much of the maximum SIC each "seller" will provide. In the congested case, it is expected that some of the "sellers" will provide less or no contribution to the total maximum SIC compared to the base case solution.

5. EXAMPLES OF MAXIMUM SIC WITH CONGESTION

5.1 Base Case: Nine-Bus Uncongested System

To understand the results of the congested case, the base case must be examined first. Reconsider the nine-bus system of Figure 1, shown again in Figure 3. Each area is assumed to control its interchange, with several initial base case transactions modeled as shown in Figure 3. As a starting point, we can assume that each load can buy from any of the nine generators. Thus, the effective market encompasses the entire system, allowing for straightforward calculation of the HHI (using generator capacity). Each of the nine participants has 11.1% market share, resulting in an HHI of 1110, indicating there is no market power. To verify the assumption that each load can buy from any generator, we can compute the maximum SIC for one of the areas in the system. In this case, we will assume that the area buying power is the slack area I. Using a maximum SIC linear program, the optimal results for maximizing the flow into area I with no congestion are shown in Table 3. With no congestion, the optimal solution for the SIC into area I is 25 MW from each of the remaining areas, because the first boundary limit that was reached in the linear program was the minimum generation capability of 0 MW at the slack bus. Because no other generator or line constraints were reached, the result is an equal amount of the SIC from each area.

Because area I in this example was buying power from all other areas, it can be determined that the market for the load pocket at area I encompassed eight selling areas, each with equal contribution towards the maximum SIC for area I. Therefore we can compute the percentage of each selling area's contribution by dividing its megawatt contribution by the total possible SIC into area I. This percentage is the area's share of the market, because the maximum

SIC algorithm determines the available transfer from all participating generators to the load pocket, based on the transmission and generation constraints of the system. Equation (5.1) shows the HHI calculation using the maximum SIC results for the base case.

$$HHI = \sum_{1}^{8} \left(\frac{25}{200} * 100 \right)^2 \cong 1250 \qquad (5.1)$$

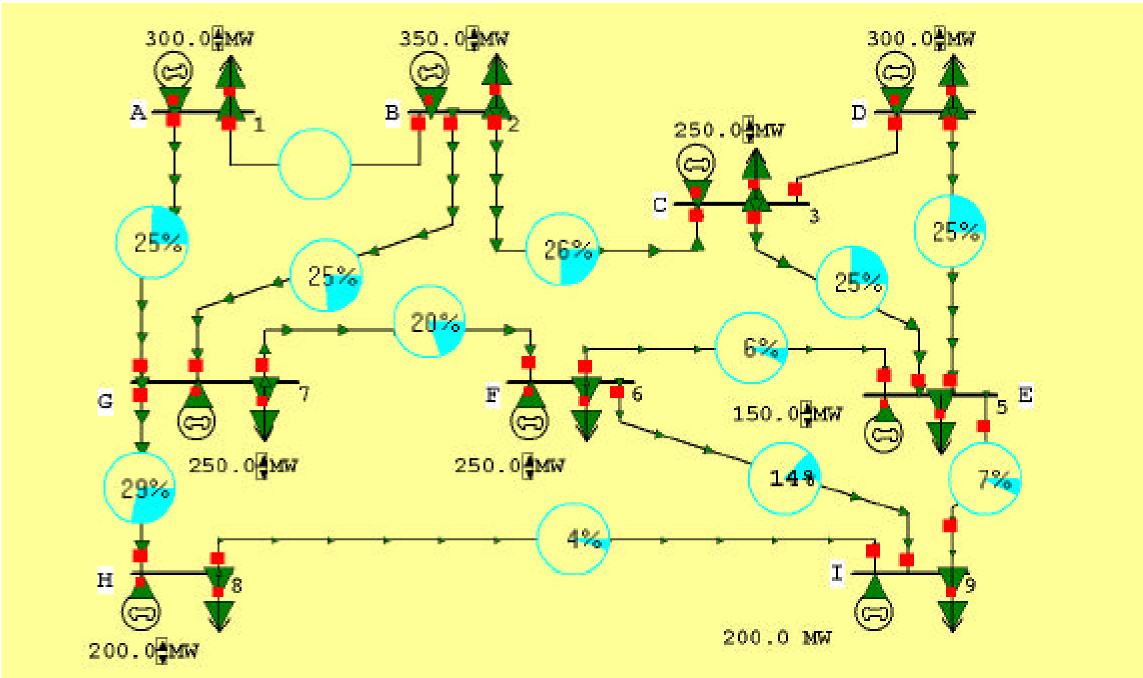

Figure 3: Nine-Bus System Flows

Table 3: Optimal SIC with No Congestion

Into Area I	200 MW
From Area A	25 MW
From Area B	25 MW
From Area C	25 MW
From Area D	25 MW
From Area E	25 MW
From Area F	25 MW
From Area G	25 MW
From Area H	25 MW

This HHI of 1250 is slightly higher than the previously determined HHI of 1170, because, in order to maximize the SIC into area I, the internal generation of area I had to reduce to its minimum allowed by constraints, in this case 0 MW. Therefore, the contribution of area I to the HHI is 0 because it is providing 0% of the load at area I. Despite the HHI being slightly higher using the maximum SIC results, the result of using the SIC to calculate the HHI still gives a good approximate measure of the market concentration for area I buying power to serve its internal load. The results verify our assumption that, under no congestion, the available market to area I encompasses the entire system, as each selling area was able to contribute to the SIC equally and without any limiting constraints.

5.2 Nine-Bus System with Congestion from Area G to Area F

With the base case results in hand, we can now move on to examining the results of calculating the maximum SIC for the system under congestion. First, we must define generators as congestors for the system. Choosing the congestors in this case is arbitrary, and the results of choosing congestors will be different for each possible combination of congestors. From the base case system shown in Figure 3, areas F and G were chosen as the congestors for this example. The maximum change in flow on each line was found using the sensitivities of the change in flow with respect to the change in generation of each line and the maximum possible changes in the generator injections from Equation (3.1). Then, each maximum line MVA of the system was derated by the maximum change in generation amount for that line, as in Equation (4.1). The resulting derated line limits, along with the differences between the actual limits and the derated limits, can be seen in Table 4.

With the derated line limits, the maximum SIC was calculated for the remaining areas of the system, effectively taking into account the effects of the congestors. The results of the optimal maximum SIC into area I from the remaining areas in the system can be seen in numerical form in Table 5 and visually in Figure 4.

Table 4: Derated Line Limits for Congestion from Area G to Area F

Line	Original Limits	Derated Limits	Difference
A to B	200 MVA	185 MVA	15 MVA
A to G	200 MVA	185 MVA	15 MVA
B to C	200 MVA	155 MVA	45 MVA
B to G	200 MVA	170 MVA	30 MVA
C to D	200 MVA	185 MVA	15 MVA
C to E	200 MVA	170 MVA	30 MVA
D to E	200 MVA	185 MVA	15 MVA
E to F	200 MVA	153 MVA	47 MVA
E to I	200 MVA	198 MVA	2 MVA
F to G	200 MVA	47 MVA	153 MVA
F to I	200 MVA	150 MVA	50 MVA
G to H	200 MVA	148 MVA	52 MVA
H to I	200 MVA	148 MVA	52 MVA

Table 5: Optimal SIC with Congestion from Area G to Area F

Into Area I	200 MW
From Area A	0 MW
From Area B	0 MW
From Area C	38.2 MW
From Area D	66.5 MW
From Area E	95.3 MW
From Area H	0 MW

These results are obtained using the assumption that derating the line limits approximates the effects of the congestors on the transmission system. There is an alternative approach to calculating the SIC that takes the congestors into account and does not derate the line limits. However, the alternative method uses two optimization routines instead of one, as in the derated line limit method, and therefore is more computationally expensive than the derated line limit method. The alternative method is discussed in detail in Appendix A. Although the alternative method is not preferred due to the increase in computation, it is a good tool to use to verify the results of the derated line limit method. The alternative method, as described in Appendix A, was also used on the nine-bus case with the congestion from area G to area F, and the results can be found alongside the results of the derated line limit method in Table 6. As can be seen from the table of results, the derated line limit method and the alternative method differ by minimal amounts. Thus, in this example, the derated line limit method is a good approximation of the congestor effects on the transmission system.

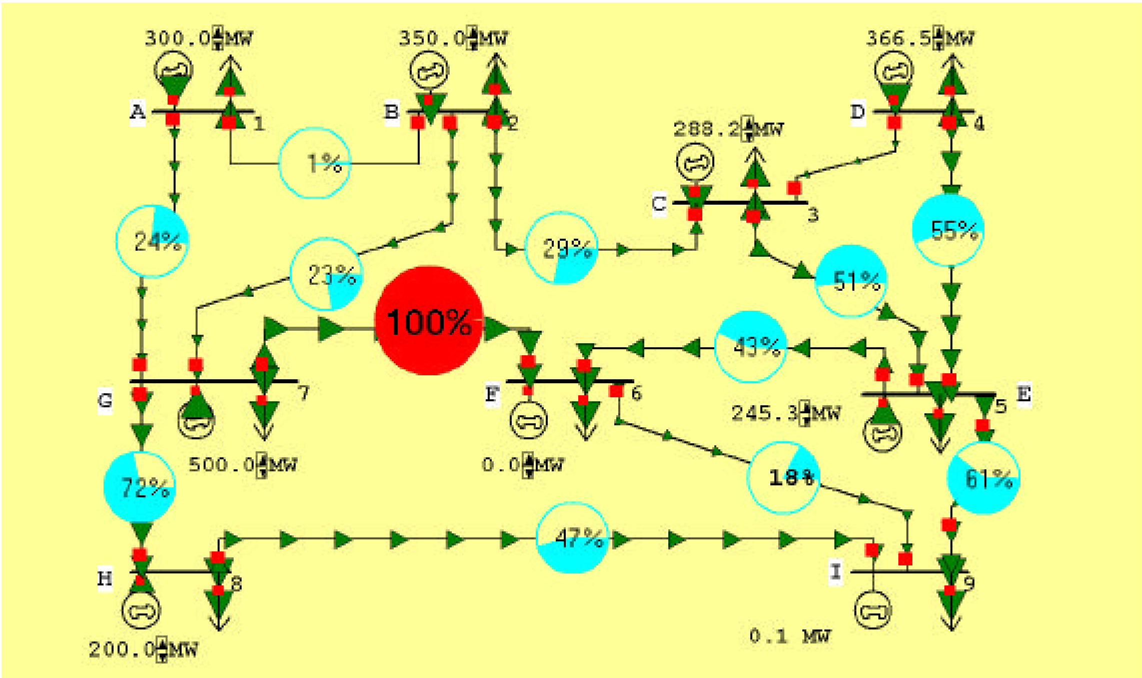

Figure 4: Nine-Bus System with Congestion from Area G to Area F

Table 6: Comparison of Congestion Effects by Two Different SIC Methods

Generator	Derated Limit Change	Alternative Change
Export from Area A	0 MW	0 MW
Export from Area B	0 MW	0 MW
Export from Area C	38.2 MW	38.3 MW
Export from Area D	66.5 MW	66.5 MW
Export from Area E	95.3 MW	95.2 MW
Export from Area H	0 MW	0 MW
Import into Area I	200 MW	200 MW

The results shown in Table 5 and Table 6 indicate that the market no longer encompasses all of the remaining areas for area I. This solution is the optimal solution for maximizing the SIC into area I. Note that generation could be bought from the other areas under the congestion caused by areas F and G, but the maximum interchange amount would be less due to the constraints on the congested system. Thus, if we consider the optimal solution as the market available to area I for providing the 200 MW transfer, we have now reduced the market from the nine participating areas (including the slack area) in the base case to four areas. The percentages of the 200 MW that the three selling areas provide can be calculated based on their contribution to the maximum SIC, and those values can be used to calculate the HHI. The percentages of the SIC of the selling areas are represented by q_i in Equation (1.1).

$$HHI = 10000 * \left[\left(\frac{38.3}{200} \right)^2 + \left(\frac{66.5}{200} \right)^2 + \left(\frac{95.2}{200} \right)^2 \right] \cong 3740 \qquad (5.2)$$

Solving Equation (5.2) (the scaling factor of 100% has been removed from each element of the sum, squared, and multiplied by the sum) results in an HHI of 3740 which, by DOJ/FTC standards [2], reveals a market power situation. In this example, the congestion of the system results in a market power situation for areas other than those causing the congestion. This could be a situation simulating a proposed merger between areas G and F in which these two areas would heavily load the previous tie line between the areas to serve the internal load of the merged area GF. While the two areas causing the congestion are not the areas benefiting from the resulting decreased market area for area I, a market power situation can be identified in other areas of the system due to the actions of areas G and F.

5.3 Congested Nine-Bus System with Congesting Bus F Participating in SIC

Another example that can be examined is the scenario of the two congestors G and F also trying to participate in providing power to the SIC of area I. This idea can be approximated by again calculating the maximum change in each line due to the congestors, derating the line limits, and then including the congesting generator or generators that still have available capacity. Figure 5 shows the system as before, only with area F also participating in providing power for the maximum SIC of area I. The lines are again derated by the same amounts as shown previously in Table 4. The results of the optimal SIC linear program for this case are shown in Table 7.

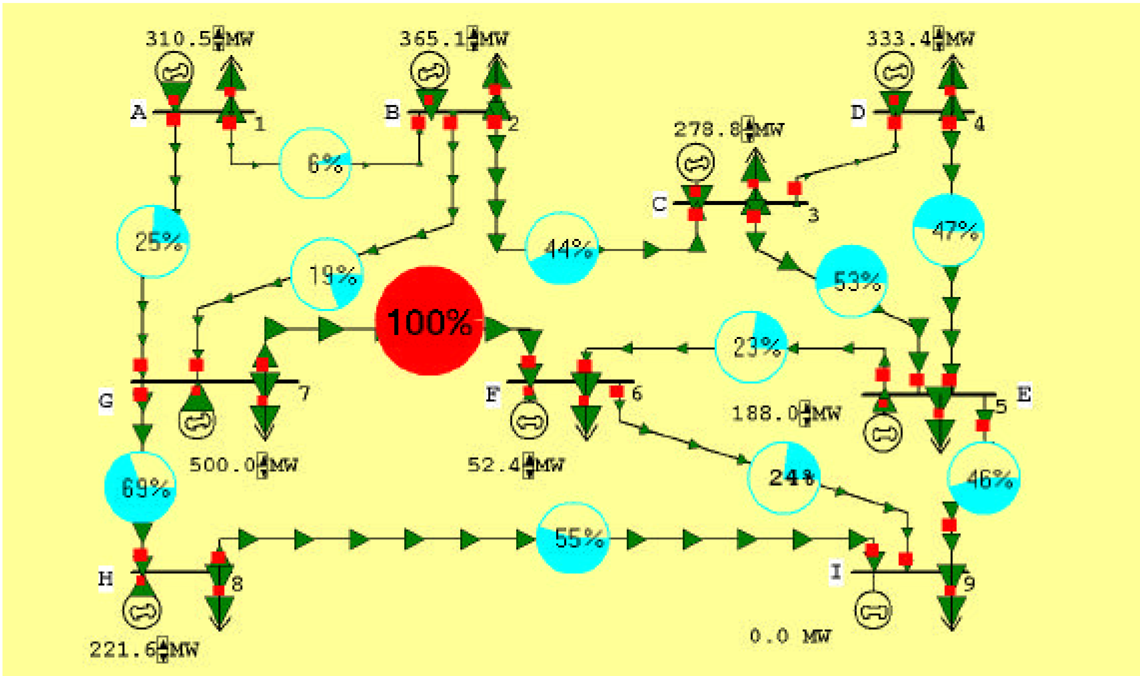

Figure 5: Nine-Bus System with Congestion from Area G to Area F, F Participating in SIC

Table 7: Optimal SIC With Congestion from Area G to Area F, F Participating in SIC

Into Area I	200 MW
From Area A	10.5 MW
From Area B	15.1 MW
From Area C	28.9 MW
From Area D	33.4 MW
From Area E	38.1 MW
From Area F	52.4 MW
From Area H	21.6 MW

The first noticeable result of this example is that every area included in the optimal SIC now has some participation in the total SIC for area I. However, for areas A and B, the amount of the SIC they contributed was not very significant. They are only able to provide a small amount of power because, as the generator in area F ramps up to provide power to area I, it simultaneously reduces the loop flow on the line from G to F. Although this is an improvement over the previous case when area F was not participating, areas A and B are still providing only about 5%

and 8%, respectively, of the total optimal SIC, a decrease from their 12.5% contributions in the uncongested system. Furthermore, notice that area F immediately became the largest supplier of power to area I at slightly more than 26% of the optimal SIC, or about 13.5% higher than in the uncongested system. If we consider areas G and F as one area, say due to a merger, it can still be seen to be an advantage for the two areas to behave as congestors as the resulting percentage of the SIC of over 26% is slightly higher than their combined percentage of 25% in the uncongested case. Thus, by approximating the effects of congestion by derating the limits on the lines, the results show that one of the congestors, which was also providing power according to the optimal SIC, was able to benefit the most compared to the other areas involved in the transaction. Calculating the HHI for this example with Equation (5.3), we see the overall HHI of the system is 1740. Although this is not as high as the HHI calculated in the previous example, it is still a high enough increase from the base case HHI to raise some concerns about the market power capability of some of the participants in the optimal SIC calculation.

$$HHI = 10000 * \left[\left(\frac{10.5}{200}\right)^2 + \left(\frac{15.1}{200}\right)^2 + \left(\frac{28.9}{200}\right)^2 + \left(\frac{38.1}{200}\right)^2 + \left(\frac{52.4}{200}\right)^2 + \left(\frac{21.6}{200}\right)^2 \right] \cong 1740 \qquad (5.3)$$

5.4 Congested System with Congesting Areas G and H Participating in SIC

Another example of using derated line limits for calculating SIC shows a much more noticeable instance of market power capability than the previous examples. Consider the system in Figure 6. This system is again similar to the previous systems, except the congestors are now areas G and H. In this example, both congestors have some available capacity left to contribute to the optimal SIC of area I, since the generator of area G did not require full capacity to congest the line between G and H as it did between G and F.

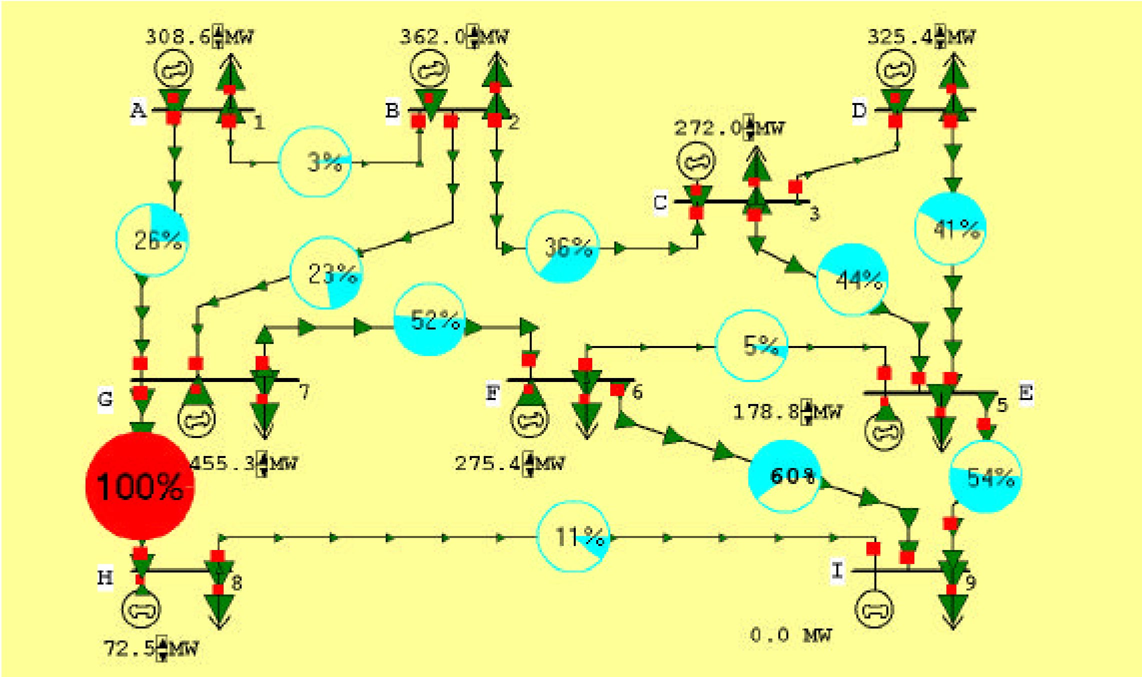

Figure 6: Nine-Bus Case with Congestion from Area G to H, G and H Participating in SIC

After derating the lines in the system as seen in Table 8, both areas G and H are included with the rest of the areas in the optimal SIC linear program, making all areas available as in the base case. The results of the optimal SIC calculation are shown in Table 9.

Table 8: Derated Line Limits for Congestion from Area G to Area H

Line	Original Limits	Derated Limits	Difference
A to B	200 MVA	193 MVA	7 MVA
A to G	200 MVA	191 MVA	9 MVA
B to C	200 MVA	179 MVA	21 MVA
B to G	200 MVA	183 MVA	17 MVA
C to D	200 MVA	193 MVA	7 MVA
C to E	200 MVA	186 MVA	14 MVA
D to E	200 MVA	193 MVA	7 MVA
E to F	200 MVA	193 MVA	7 MVA
E to I	200 MVA	172 MVA	28 MVA
F to G	200 MVA	159MVA	41 MVA
F to I	200 MVA	166 MVA	34 MVA
G to H	200 MVA	62 MVA	138 MVA
H to I	200 MVA	122 MVA	78 MVA

Table 9: Optimal SIC with Congestion from Area G to Area H, Both Participating in SIC

Into Area I	200 MW
From Area A	8.6 MW
From Area B	12.0 MW
From Area C	22.1 MW
From Area D	25.4 MW
From Area E	28.8 MW
From Area F	25.4 MW
From Area G	5.2 MW
From Area H	72.5 MW

The results of this example show that all the areas are able to participate in the optimal SIC, but that one of the congesting areas provides a far higher amount of power under the optimal solution. With areas G and H acting as the congestors, area H alone was able to provide about 36% of the optimal SIC. Moreover, areas H and G together provide about 39% of the optimal SIC. Calculating the HHI for this example using Equation (5.4), with G and H considered as one combined area, results in an HHI of 2216:

$$HHI = 10000 * \left[\left(\frac{8.6}{200}\right)^2 + \left(\frac{12.0}{200}\right)^2 + \left(\frac{22.1}{200}\right)^2 + \left(\frac{25.4}{200}\right)^2 + \left(\frac{28.8}{200}\right)^2 + \left(\frac{25.4}{200}\right)^2 + \left(\frac{77.7}{200}\right)^2 \right] \cong 2216 \quad (5.4)$$

This value of HHI is an indicator of a market power situation in favor of areas G and H. Thus, we can see that defining different sets of congestors can have a significant impact on a system. In addition, we see that it is not necessary that some of the areas in the system be excluded from the optimal SIC, as was shown in the first congestion case, for a case of market power to exist. It is sufficient to show that one area or a group of areas working together can have a high percentage of the optimal SIC and thus have apparent market power over a portion of the system.

5.5 Nine-Bus System with Congestion from Area G to Area H

Again consider the case of areas G and H congesting the system as seen in Figure 7. In this case, areas G and H are only congesting the system and are not participating in the SIC calculation for area I. The lines are again derated by the values shown in Table 8. If you compare this example to the base case, you will note that besides the change in generation of the congestors, only one other area, area E, changes its generation according to the SIC calculation. The results of the SIC calculation are shown in Table 10. The results of the derated line limit method can also be compared to the alternative method algorithm described in Appendix A for verification of the results. The alternative algorithm of Appendix A was performed on this case, and the results comparing the two methods are shown in Table 11.

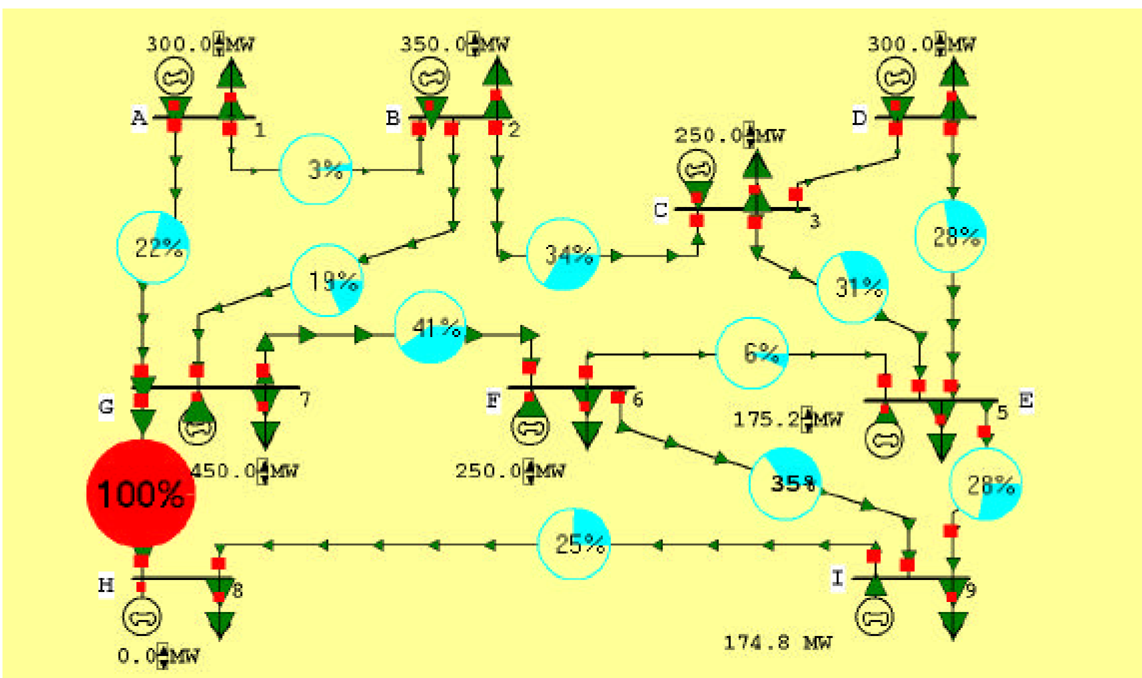

Figure 7: Nine-Bus System with Congestion from Area G to Area H

Table 10: Optimal SIC with Congestion from Area G to Area H

Into Area I	200 MW
From Area A	0 MW
From Area B	0 MW
From Area C	0 MW
From Area D	0 MW
From Area E	25.3 MW
From Area F	0 MW

Table 11: Comparison of GH Congestion Effects by the Two SIC Algorithms

Generator	Derated Limit Change	Alternative Change
Export from Area A	0 MW	0 MW
Export from Area B	0 MW	0 MW
Export from Area C	0 MW	0 MW
Export from Area D	0 MW	0 MW
Export from Area E	25.3 MW	25.7 MW
Export from Area F	0 MW	0 MW
Import into Area I	200 MW	200 MW

From the maximum SIC calculation for area I with areas G and H congesting the system, we can see that for area I to import as much power as possible it would be limited to buying power from area E only. This is an extreme case of market power in favor of the congestors. In this case only area E can transfer power into area I, which gives an HHI calculation of 7760 as shown in Equation (5.5):

$$HHI = 10000 * \left[\left(\frac{25.3}{200} \right)^2 + \left(\frac{200 - 25.3}{200} \right)^2 \right] \cong 7760 \tag{5.5}$$

Another noteworthy result of this example is that the congestion of the system also limits the maximum transfer into area I to approximately 25 MW. This is drastically reduced from the 200 MW maximum SIC for the previous examples, requiring the slack generator of the system to pick up the remaining 175 MW of load in area I. This is an obvious case of the congestors minimizing the maximum SIC into area I and preventing any transactions from occurring between area I and most of the remaining areas in the system. Transactions from other areas could occur, but based on the simulation of the congestion on the system through the derated line limits the amount of SIC into area I would be smaller for any other combination of transferred power other than the maximum SIC scenario determined for this example.

5.6 Thirty-Bus System with Congestion

Finally, we will examine a slightly larger case in order to evaluate the results of the maximum SIC calculations and market power determination on a bigger system. The base case system is shown in Figure 8. In this system, buses 10 and 17 are in a position where they could work together to heavily load the line between them. An interesting case to look at in this example would then be to determine the maximum SIC for bus 13 from the three buses that fall below buses 10 and 17 in the system, namely buses 22, 23 and 27. The remaining generators in this system can be considered passive bystanders for this example. The line limits of the 30-bus system were derated as in the previous examples, and can be seen in Table 12. The maximum SIC was determined for this scenario, with the results of the calculation shown in Table 13, and the congested system shown in Figure 9.

Table 12: Derated Line Limits for the Thirty-Bus System

Line	Original Limits	Derated Limits	Difference
1 to 2	130 MVA	129.9 MVA	0.1 MVA
1 to 3	130 MVA	129.9 MVA	0.1 MVA
2 to 4	65 MVA	64.9 MVA	0.1 MVA
2 to 5	130 MVA	129.9 MVA	0.1 MVA
2 to 6	65 MVA	64.9 MVA	0.1 MVA
3 to 4	130 MVA	129.9 MVA	0.1 MVA
4 to 6	90 MVA	89.6 MVA	0.4 MVA
4 to 12	65 MVA	64.5 MVA	0.5 MVA
5 to 7	70 MVA	69.9 MVA	0.1 MVA
7 to 6	130 MVA	129.9 MVA	0.1 MVA
8 to 6	999 MVA	998.9 MVA	0.1 MVA
6 to 9	65 MVA	64.7 MVA	0.3 MVA
6 to 10	32 MVA	31.8 MVA	0.2 MVA
28 to 6	32 MVA	31.9 MVA	0.1 MVA
28 to 8	32 MVA	31.9 MVA	0.1 MVA
9 to 10	65 MVA	64.7 MVA	0.3 MVA
9 to 11	65 MVA	65 MVA	0 MVA
10 to 17	16 MVA	11.4 MVA	4.6 MVA

Table 12: Continued

10 to 21	32 MVA	31.9 MVA	0.1 MVA
10 to 22	32 MVA	31.9 MVA	0.1 MVA
12 to 13	65 MVA	65 MVA	0 MVA
14 to 12	32 MVA	32 MVA	0 MVA
15 to 12	32 MVA	32 MVA	0 MVA
12 to 16	32 MVA	31.5 MVA	0.5 MVA
15 to 14	16 MVA	16 MVA	0 MVA
15 to 18	25 MVA	25 MVA	0 MVA
17 to 16	16 MVA	15.5 MVA	0.5 MVA
18 to 19	16 MVA	16 MVA	0 MVA
19 to 20	32 MVA	32 MVA	0 MVA
22 to 21	50 MVA	49.9 MVA	0.1 MVA
22 to 24	25 MVA	24.9 MVA	0.1 MVA
24 to 23	16 MVA	16 MVA	0 MVA
25 to 24	16 MVA	15.9 MVA	0.1 MVA
26 to 25	16 MVA	16 MVA	0 MVA
27 to 25	16 MVA	15.9 MVA	0.1 MVA
28 to 27	65 MVA	64.9 MVA	0.1 MVA
27 to 29	16 MVA	16 MVA	0 MVA
27 to 30	16 MVA	16 MVA	0 MVA
29 to 30	16 MVA	16 MVA	0 MVA

Table 13: Optimal SIC with Buses 10 and 17 Congesting

Into Bus 13	4.38 MW
From Bus 22	0 MW
From Bus 23	0 MW
From Bus 27	2.07 MW

Again, for verification of the derated line limit method, the alternative method of Appendix A was performed on the 30-bus case, and the results comparing the two methods are shown in Table 14.

Table 14: Comparison of Bus 10 to Bus 17 Congestion for the Two SIC Methods

Generator	Derated Limit Change	Alternative Change
Export from Bus 22	0 MW	0 MW
Export from Bus 23	0 MW	0 MW
Export from Bus 24	2.07 MW	2.07 MW
Import into Bus 13	4.38 MW	4.38 MW

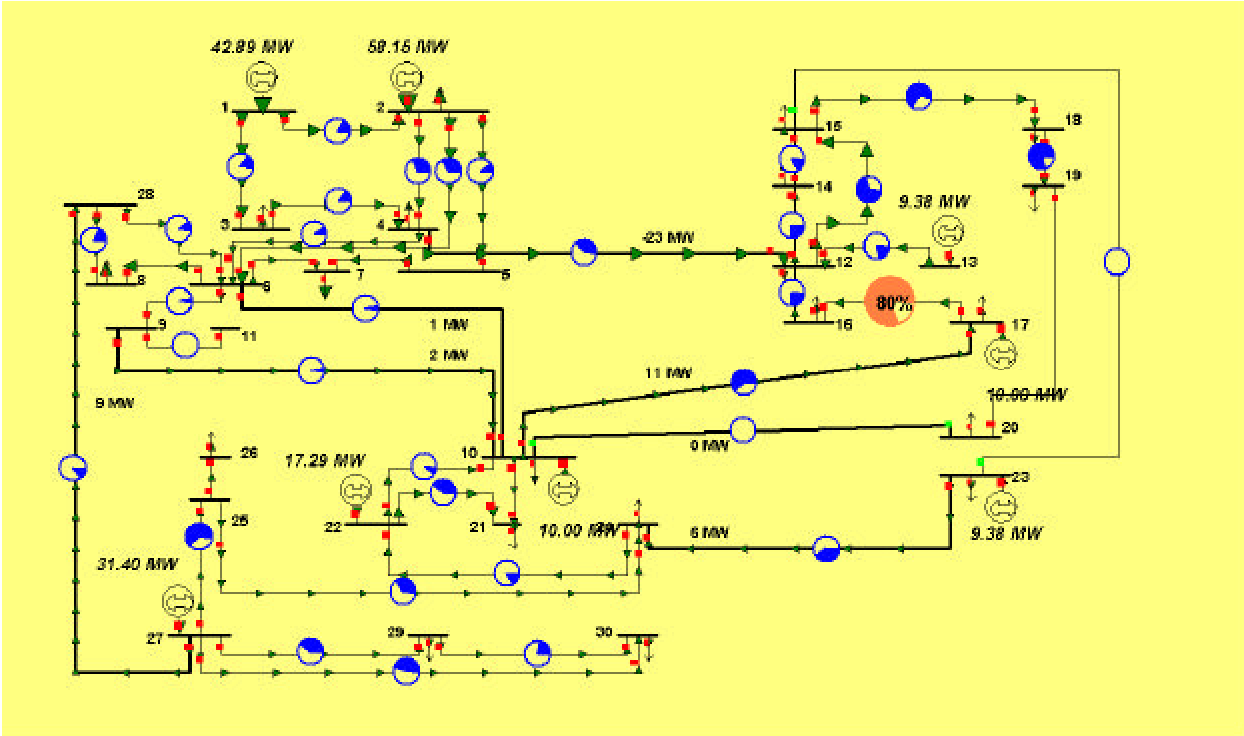

Figure 8: Thirty-Bus System Base Case

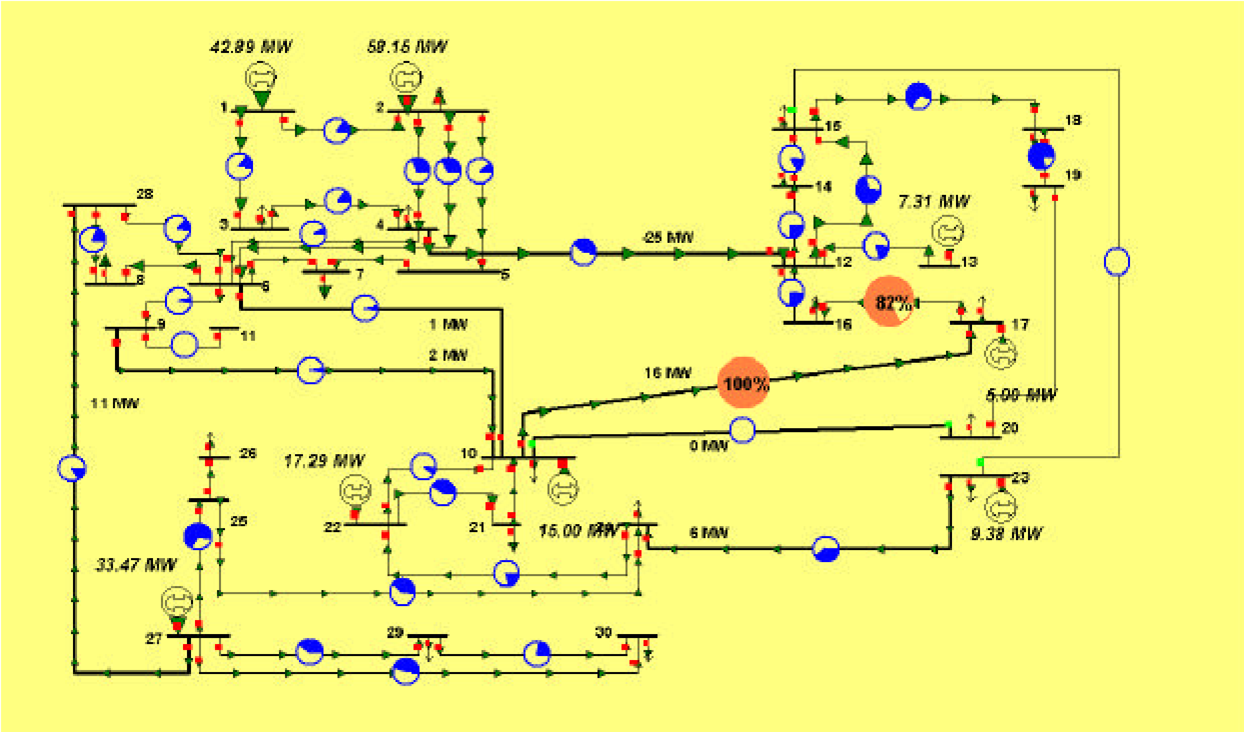

Figure 9: Thirty-Bus Sytem with Congestion from Bus 10 to Bus 17

The results of this example show that, despite all three of buses 22, 23, and 27 wishing to sell to bus 13, optimally only bus 27 has the opportunity to provide any power under the current system conditions. Calculating the HHI for this example as shown in Equation (5.6) results in an HHI of 5015 for the generators participating in the transaction, because only one of the three sellers and the internal generation of the buyer were able to contribute to the SIC. Before, the congesting action of buses 10 and 17 the HHI was 3333 as shown in Equation (5.7), since all three generators selling power could supply all of the SIC into the buying area.

$$HHI = 10000 * \left[\left(\frac{2.07}{4.38} \right)^2 + \left(\frac{4.38 - 2.07}{4.38} \right)^2 \right] \cong 5015 \tag{5.6}$$

$$HHI = 10000 * \left[\left(\frac{1.46}{4.38} \right)^2 + \left(\frac{1.46}{4.38} \right)^2 + \left(\frac{1.46}{4.38} \right)^2 \right] \cong 3333 \tag{5.7}$$

While even the HHI for the uncongested case is relatively high by FERC/DOJ standards, it can be seen that congestion of the system would even further restrict the size of the available market for the buying area. Due to the congestion of buses 10 and 17, the maximum contribution to the SIC available was only 2.07 MW, even though bus 7 was capable of purchasing 4.38 MW from the three willing providers. Thus by congesting the system, buses 10 and 17 now have an advantage, and could exercise market power by choosing to sell power to bus 13 at a higher rate.

6. CONCLUSION

The goal of the research for this thesis was to formulate a method of calculating the market concentration for a transmission system under congestion using a simultaneous interchange capability calculation. The derated line limit method proposed for calculating the optimal SIC has worked fairly well in identifying the market for a given load pocket, hence enabling a market power concentration determination. The derated line limit method has also shown the characteristic of being somewhat less computationally expensive than an alternative solution method, while obtaining very similar results.

Many applications of the derated line limit maximum SIC method are shown in Chapter 5. Comparing the results of the Hirfindahl-Hirschman index (HHI) calculations for the congested examples with those for the base case show how derating the line limits and calculating the maximum SIC for an area of the system provides an approximation of the changes to the system. In each of the congested cases, a different scenario of participating areas in an interchange were examined, and the HHI was increased a significant amount in each case. The results also show the amount of power each area would provide to a maximum simultaneous interchange under congestion, making it fairly easy to identify the dominating areas in the interchange. The recognition of the dominating firms is the purpose for examining the issue of market power in the electric utility industry. With that in mind, we can see that the idea of derating the transmission lines in the system to approximate the effects of the congestors on the lines in the system, followed by calculating a maximum SIC, may have some merit in locating areas of market power in a congested system.

There are a couple of factors that should be noted when considering these results. First, it is important to note that the solution of the linear program for the SIC is the optimal solution. That does not mean that, under actual purchasing activity by the buying area, the buying area will choose to buy its power in the exact manner outlined in these examples given the different scenarios. The results are simply the best results for the buying area if the area chooses to buy as much power as possible. Second, a lot of remaining constraints were not considered in this preliminary study. Such things as voltage constraints and system contingencies were not considered, nor was any economic data considered. This study was conducted solely to examine the worst-case effects on the market area of a system due to transmission constraints.

In future work on a derated line limit method for identifying possible areas of market power, there are a few items that could be addressed. As mentioned, particular types of constraints were not used in the maximization routine in this thesis. Therefore, future work could implement such things as voltage constraints and economic data. Another item that could be addressed is that losses could be incorporated into the system and into the solution method. The cases under study for this thesis were lossless systems, to aid the development of the initial solution algorithm. A third issue that could be addressed could be how to apply a derated line limit solution method to a system that already has a system element violating a constraint at the system operating point. This issue may need to address the use of contingency analysis simultaneously with a variation of the derated line limit method in order to observe the effects of further congestion beyond the contingency point of a system.

An issue generated in this thesis that may be an excellent source for future research is the use of the maximum simultaneous interchange capability results as an indicator of the available market in a power system. In this thesis, the change in generator injections calculated using an

SIC calculation were used in calculating a HHI measure of market share. The HHI was used because it is a standard for calculating market shares in any type of market. Future research could be implemented to examine the usefulness of SIC calculation results in determining market shares in a power system. Additional research could be performed comparing HHI used in this thesis with new or different methods of calculating market shares using the results of the SIC method outlined in this thesis.

APPENDIX A: METHOD FOR VERIFYING RESULTS

The method for verifying the results of the derated line limit optimal SIC calculations is to perform two linear programs, using the results of the first in the second. The first linear program uses the line constraints and generation constraints of the system to maximize the flow between the congestors of the system. This linear program focuses only on the participation of the congestors in the constraints and calculations. Shown below is the first linear program of this double linear program method.

$$\text{Minimize} \quad \sum_{ic} dP_{ic} \tag{A.1}$$

Subject to

$$\sum_{jc} dP_{jc} = 0 \tag{A.2}$$

$$MVA_{d,\min} \le \sum_{jc} k_{jc}^{mn}\, dP_{jc} + S^{mn} \le MVA_{d,\max} \tag{A.3}$$

$$P_{jc,\min} \le \Delta\, dP_{jc} + P_{jc} \le P_{jc,\max} \tag{A.4}$$

This linear program obtains a solution for the maximum changes in generation for the congestors for a defined congestion direction. Once the solution for the congestors is determined, the results can be used in a second linear program to calculate the maximum simultaneous interchange capability.

The following linear program is the second of the double linear programming method. This linear program, shown below, takes the results of the first linear program for the congestors and uses those results as constants in the transmission line constraint equations. These additional values in the line constraints, as well as the use of the actual line limits instead of derated line limits, are the only changes in this linear program from the one used in the derated line limits method. By using the constant values of the congestors from the first linear program in the constraint equations for the maximum SIC, we have accounted for the affect of the congestors on the transmission system as constants multiplied by their power transfer distribution factors. Therefore, the results of the second linear program will again give the maximum SIC into the buying areas and determine the combination of sellers that provide the injection for the SIC.

$$\text{Minimize} \quad \sum_i dP_i \tag{A.5}$$

Subject to

$$\sum_j dP_j = 0 \tag{A.6}$$

$$MVA_{d,\min} \le \sum_j k_j^{mn}\, dP_j + \sum_{jc} k_{jc}^{mn} C_{jc} + S^{mn} \le MVA_{d,\max} \tag{A.7}$$

$$P_{j,\min} \le dP_j + P_j \le P_{j,\max} \tag{A.8}$$

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