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REVIEW ARTICLE

EVALUATING MARKET POWER IN CONGESTED POWER SYSTEMS

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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 de rate 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 de rated 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 Her find a hl-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 de rated line limit solution method for determining market concentration.

INTRODUCTION

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 maintainprices 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 benefitsresulting from the removal of the traditional vertical market power could result in the development of horizontal market power. 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. How ever in the electricity industry, an actual "geographic" area does not have any scope[3],[4]. 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 easure 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 is the percentage of the market shareifor participant I [6], [9].

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This index will rise as the share of capacity or output produced by as mall 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 anunconcentrated market, 1000 to 1800 represents a moderately concentrated market, and above1800 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 examineit without considering transmission constraints [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[8]. 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.

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 line arized formulation of then on linear 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 outagedistribution factors, the calculation of the SIC can be performed using linear programmingte chniques. A paper by Stott and Marinho [12] provides the general characteristics of the linearprogramming 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 todetailed 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 complet 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 method snecessary 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 ameasure of market concentration based on the optimal SIC of an area of the power system.

Goals of Using an SIC Calculation for Market Power Determination

The primary goal of an optimal SIC calculation for market power determination is tomaximize 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, it can be determined if the suppliers can sufficiently 1provide 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 A contract path is defined as the direct path between a buyer (or buyers) and a seller (or sellers) on the 1transmission 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. Undersituations 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 atransaction due to the constraints of the system indicate that situations of market power may beoccurring. 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 onstraints 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.

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 de rated 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.

ASSESSING THE IMPACT OF CONGESTION ON MARKET POWER

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 involve din the desired transfer. How power is distributed throughout a transmission system depends on the 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.

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 PTDF srelies 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 anincremental 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)

$$\begin{bmatrix} \delta\theta \\ \delta V \end{bmatrix} = J^{-1} \begin{bmatrix} \delta P \\ \delta Q \end{bmatrix} \tag{2.1}$$

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 δP and δQ 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 busk , p f represents the participation factor of a generator, δP and δQ represent the total change inreal and reactive power between the areas in the transaction, and N represents the number of generators in the area containing generator k .

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

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

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 provides100% 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 one ach 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."

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

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

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

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

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).

$$\frac{\delta P_{ij}}{\delta P_k} = \frac{\delta P_{ij}}{\delta V_i} \cdot \frac{\delta V_i}{\delta P_k} + \frac{\delta P_{ij}}{\delta V_j} \cdot \frac{\delta V_j}{\delta P_k} + \frac{\delta P_{ij}}{\delta \theta_i} \cdot \frac{\delta \theta_i}{\delta P_k} + \frac{\delta P_{ij}}{\delta \theta_j} \cdot \frac{\delta \theta_j}{\delta P_k} \quad (2.8)$$

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.

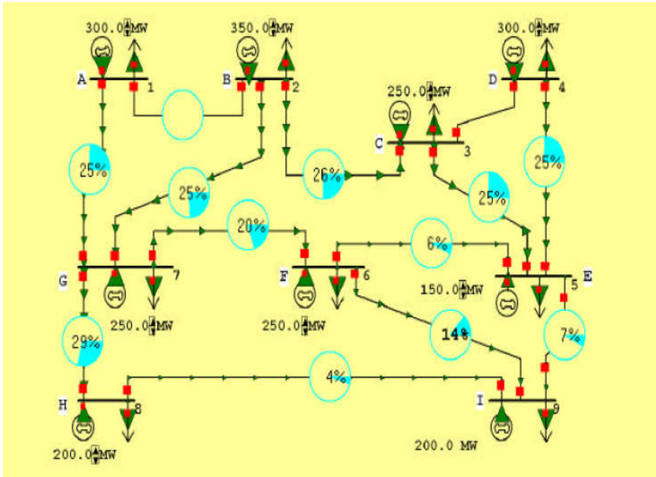


Figure 1: Nine-Bus System

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

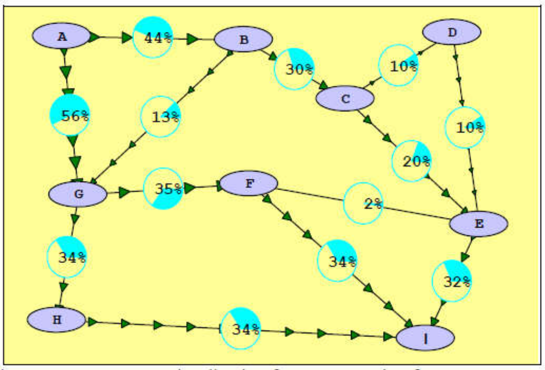
1. Each bus has a single generator with a capacity of 500 MW and a single 250 MW load.
2. Each bus initially corresponds to a single market participant (a single operating area).
3. All transmission lines have an impedance of j 0.1 per unit and an initial limit of 200MVA.

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 betaken 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 sellingarea that flows on each particular line as it moves towards the buying area. For example, if anadditional 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).



Nine-Bus Case PTDF Visualization for a Transaction from Area A to A

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

STRATEGIC MARKET POWER

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

$$\delta P_i = \max \sum_{k=1}^{N} S_{ik}\delta P_{gk} \quad \text{s.t.} \sum_{k=1}^{N} \delta P_{gk} = 0 \qquad (3.1)$$

$$P_{k,\min} \le P_k + \delta P_{gk} \le P_{k,\max} \qquad (3.2)$$

where Sik is the sensitivity of the line i power flow to a 1-MW increase in the bus k generation, I k P is the change in the flow on line i , and P 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.

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%

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