TRANSMISSION EFFECTS IN MARKET POWER ANALYSIS OF ELECTRICITY MARKETS

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ABSTRACT

This paper discusses the assessment of market power in bulk electricity markets, with the explicit consideration of the transmission system. In general, market power is the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time. The restructuring of the electric industry has encouraged competitive markets with the objective of reaping the benefits of lower prices and innovation that competition can provide. Such benefits are not attainable when a player utilizing the electric transmission system may exercise such market power. This paper describers the procedures for analyzing such potential situations.

Keywords: market power, transmission system constraints, congestion, merger analysis, PTDF

1. INTRODUCTION

The electric power industry throughout the world is in a period of rapid restructuring, with the traditional paradigm of the vertically integrated electric utility structure being replaced by competitive markets in unbundled electricity services. The goal of this restructuring is to reap the benefits of lower prices and innovation resulting from the establishment of competitive marketplaces for electricity products and services. However, this drive to competition has given rise to significant concerns that the potential benefits resulting from the breakup of the vertical market power of the traditional utility could, in time, be supplanted by the establishment of horizontal market power.

Market power is the antithesis of competition. It is the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time. When an entity has and exercises market power, it ceases to be a price-taker and becomes a price-maker. Market power in electricity markets has been a subject of intense interest [1], [2], [3], [16]. Most studies of market power review the structure, conduct, and performance of a market. The structure of a market affects conduct, which in turn impacts performance. Therefore, market power is inherently a problem of structure, and most indicators of market power depend on the structure of the market and the so-called *rules of the road*. The objective of this paper is to provide a discussion and concrete examples of the impact that the electrical transmission system has on the analysis market power opportunities, with particular emphasis on the impacts of transmission congestion.

2. MARKET POWER ANALYSIS IN ELECTRICITY MARKETS

The analysis of market power typically involves the following steps [4][i]:

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

For market power analysis in electricity markets a number of different products could be considered, such as non-firm energy, short-term capacity (firm energy), and long-term capacity. Here are focus is restricted to the short-term energy markets. The challenge in performing this analysis is that electricity demand varies substantially over time, and, of course, there are few economically efficient options for storing electric energy.

The second and, by far, the most difficult step in performing market power analysis for an electricity network is the determination of the geographic scope of the market for the product. In our definition the market is based on the capability of a supplier, say a generator, to deliver the product/service to a customer, say a load. The size of an electricity market is dependent upon both the physical/operational characteristics of the transmission network used to enable the movement of electricity from the supplier to the customer, and the impacts of the services in transporting this energy, including any prices charged.

The third step in performing market power analysis is the analysis of market concentration. A commonly used methodology is the Herfindahl-Hirschman index (HHI) [5], defined as:

$$\text{HHI} = \sum_{i=1}^{N} q_i^2 \qquad (1)$$

where N is the number of market participants and q_i is the percentage market share of each participant. Hence, the HHI for a monopoly would be $100^2 = 10{,}000$, while HHI would be a small number when N is large and no participant has more than say 5% market share. Under DOJ/FTC

[i] We have regrouped the fours steps in [1] into three steps by combining steps 2 and 3 -- geographic markets: identify customers who may be affected by the merger, and geographic markets: identify potential suppliers to each identified customer – into a single step of identifying the relevant geographic market.

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standards for horizontal market power [6], post-merger values of HHI under 1000 are considered to represent an unconcentrated market, while values above 1800 are deemed to be highly concentrated. Some of the subtleties of the use of the HHI measure were shown in [16].

3. MARKET POWER ANALYSIS WITH TRANSMISSION CONSTRAINTS

For electricity markets, the appropriate definition of the market is critical. Clearly both physical factors – the transmission network and its operation – and economic factors – the market structure and its rules – are determining elements in this definition. To motivate this discussion, initially consider the case in which the transmission system is not explicitly considered and no transportation charges are incurred. Thus, the extent to which any single producer can exercise market power depends then solely on its concentration of ownership relative to that of its competitors, the other producers, in the entire system.

For such systems, calculation of the HHI values is straightforward. For example in North America the HHI values can be calculated using data from the North American Electric Reliability Council (NERC), which lists generation capacity for both the winter and summer peaks. Using 1997 data (average of summer/winter peaks) the Eastern Interconnect had a total capacity of 593 GW with ownership spread among about 650 different entities. Without any consideration of the transmission network, the associated HHI for the Eastern Interconnect is about 170. Clearly, for this highly simplified conceptual case, completely ignoring consideration of transmission system constraints and transportation charges, no market power exists according to the HHI measure. Similar values for each of the NERC Reliability Councils are reported in [3].

Of course, neglecting the transmission system and its associated charges often provides an unrealistic model of the situation, particularly in a large interconnected network. A key issue, and focus of this paper, is how to incorporate the impact of the transmission system and any attendant congestion situations on market power analysis. Congestion may arise due to limitations in the "capacity" of the transmission system. The so-called available transfer capability (ATC) is finite but usually not easily determined. The ability of the transmission system to support additional transactions is a function of the network structure, generation and loads. A number of different factors, including transmission line/transformer (line) limits, bus voltage limits, transient stability constraints, and system voltage stability requirements influence the determination of this capacity. Here we just consider the impact of line limits, but the incorporation of bus voltage limits is relatively straightforward. Other limits could be directly incorporated if they can be recast in terms of line/flowgate limits. A line is said to be congested anytime it is loaded at or above its MVA limit.

A very simple case illustrating the impact of the transmission system in market power analysis is the radial single bus network modeled in Figure 1. Here the load at bus A can be served by either local generation at bus A, or generation in the rest of the electric system through the single transmission line joining it to A. The pie chart in the line shows the percentage loading on the line; here the line is loaded at 100% of its rated capacity so the pie chart is completely filled-in, with the arrows indicating the direction of flow [7].

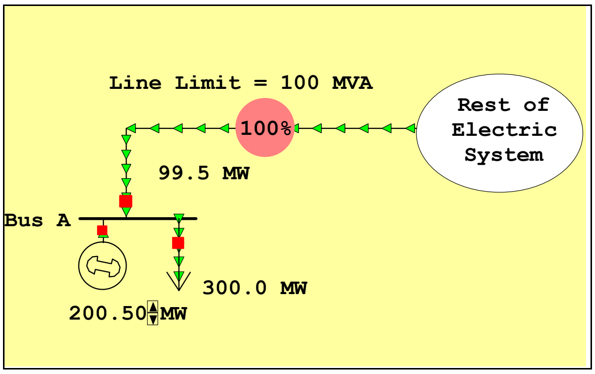

Figure 1: Radial System with Market Power

Because of this 100 MVA flow limitation on the line, the generator at bus A has complete market power anytime the load at the bus exceeds 100 MW. That is, in the short-term the only option available to the customers receiving energy at bus A is to pay the price charged by the bus A generator, or to do without. In this situation the number of participants in the generation market available to the bus A "load pocket" is effectively one. Hence, the *effective* HHI is 10,000. Note that this limitation is completely independent of generator costs and transmission tariffs. Of course, if the load is variable, such market power is only present when the bus A load exceeds the import capacity limit of the line.

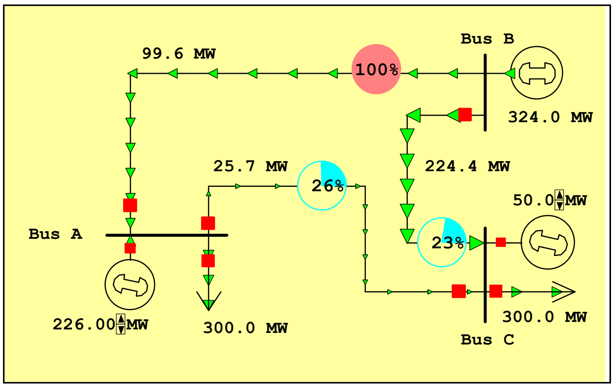

Figure 2: Three Bus Example with Import = 74 MW

If a second line were added between bus A and the rest of the system, the situation becomes substantially more complex. Bus A is no longer radially connected to the remainder of the network, but is an integral part of the network. Now the maximum power that can be imported into the bus A load pocket is not (in general) equal to the sum of the limits of the two lines joining it with the remainder of the network. The actual import capability limit depends upon both the impedance of the remainder of the network, and the particular power flows in that network. The interface (i.e., all of the lines joining bus A to the rest of the system) is congested anytime either of the two lines reaches its limit or potentially if any other line in the network does. Consequently, the import limit capability may actually be less than the smallest of the individual line limits. Such a situation is illustrated in Figure 2 for a three bus system in which 25 MWs is wheeled from bus B to bus C through bus A, decreasing its import capability to about 74 MW. This is below the 100 MVA limit of either line. Thus the network plays a determining role in the ability of bus A to import or export power to the rest of the network.

We can extend the three bus example to more general situations. Consider an area A load pocket to consist of the set of loads, possibly at multiple buses, that buy power in aggregate using the network. Examples of load pockets include a municipality without sufficient internal generation, a cooperative system, or a load aggregator. The degree of market power enjoyed by a set of generators whose operation and control are under a single entity – to be henceforth called a portfolio of generators – in serving the area A load pocket depends upon the generation market available to area A. This, depends upon the characteristics of the transmission system of the network.

In our approach of determining the generation market available to a particular load pocket we use the results provided by the evaluation of the Simultaneous Interchange Capability (SIC) of the network. SIC is a measure of the amount of power that can be imported into a particular load pocket. Determination of SIC involves solving an optimization problem with the objective of selecting the generation dispatch that maximizes the amount of power that can be imported into the load pocket. Linear load flow and linear programming solutions have made SIC calculation relatively fast and easy [8-12] when appropriate assumptions are made concerning the response of the affected generation. If assumptions are made that all generators respond in such a way to maximize the interchange value, the SIC provides an upper bound on the power import capability. For the three bus system in Figure 2 the SIC value is 200 MW. This value is attained when bus B generation is 200 MW and bus C generation is 300 MW. However, the SIC result does not solve the market power problem. The principal reason for this is that the assumptions concerning the response of the generators may not hold in a competitive marketplace. All generators need not respond in a way to maximize import into a particular area. While certain generation portfolios may indeed be working to maximize the import into the load pocket, others may actually seek to minimize this value to enhance their ability to exploit a market power opportunity.

In order to understand the potential implications of this behavior on market power analysis, two interrelated issues must be discussed. First, in a networked transmission system the incremental changes in the amount of power generated and/or consumed at a set of buses can result in changes in the power flow throughout a large portion of the network. That is, a power transfer through the system can potentially impact other parties not involved in the transfer; this is commonly referred to as "third party impacts" or "loop flows". How the power distributes through the system depends upon the particular selection of the source/sink pair, as well as on the characteristics of the transmission network. This incremental change in flows associated with a particular direction has been defined by NERC as the power transfer distribution factors (PTDF)s [13]. The PTDF values provide a linear approximation of how the power flows change as a result of power transfer between the specified source/sink pair.

The second issue is that whenever a line or interface is congested, the system's ability to support additional power transfers can be limited, even for directions associated with source/sink pairs distant from the congestion. Which directions are limited depends upon whether a transfer would increase or decrease loading on the congested line.

To illustrate these two issues, consider the nine bus network shown in Figure 3. This system 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. Each transmission line has an impedance of j0.1 per unit with a limit of 200 MVA.

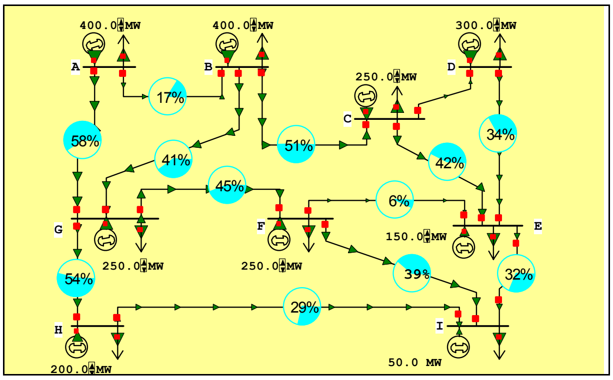

Figure 3: Nine Bus Base Case Flows

We assume each area controls its interchange and that each load can buy from any of the nine generators. For this case, the SIC value is greater than the load at each bus. Thus, the effective market encompasses the entire system, allowing for straightforward calculation of the HHI index (using generator capacity). Each of the 9 participants has 11.1% market share resulting in an HHI of 1110, indicating no market power. The flows resulting are shown in Figure 3; we refer to them as the base case.

Starting from the base case flows, the PTDF values can be used to provide a linear approximation of the impact caused by a proposed power transfer between a designated source/sink pair. Note that while the PTDF values are only a linearized approximation, this approximation is usually valid over a wide variation in operating points. As an example Figure 4 shows the PTDF values for the 9 bus system for a proposed power transfer from bus A to bus I (to reduce clutter the buses/generators/loads are now shown as just an ellipse). The pie chart values in the figure now indicate the PTDF values, expressed in terms of a percentage of the power transfer amount. For example, 44% of the transaction flows along the transmission line from bus A to B, while 35% flows from G to F. The expected change in flow along the particular path is then the PTDF value multiplied by the proposed power transfer. Thus, a 50 MW transfer from A to I increases the MW flow from A to B by about 50 * 44% = 22 MW. For a different source/sink pair the PTDF values can be quite different. For example, the PTDF values for a transfer from G to F are shown in Figure 5. Note that the PTDF values for both cases indicate that the transfers would have a significant impact on almost all of the transmission line flows. Present NERC line loading relief criteria deem any transaction having a PTDF value greater than 5% on a limiting element as having a significant impact on the element's line flow.

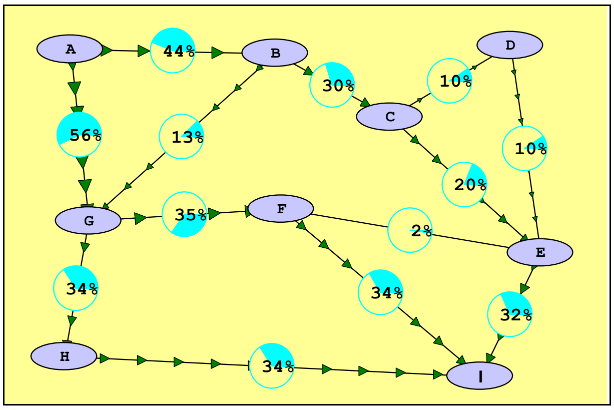

Figure 4: PTDF Values for Transfer from A to I

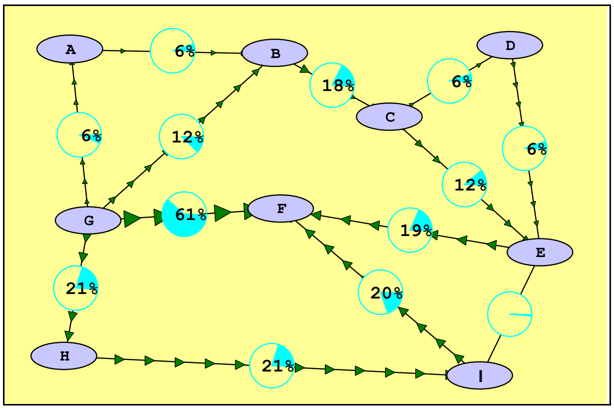

Figure 5: PTDF Values for Transfer from G to F

The PTDF values can also be used to help estimate the maximum amount of power that can be transferred for each direction or source/sink pair [13], [14]. This value is determined by recognizing that for a direction j the real power flow on any line i, P_i, following a power transfer in direction j can be approximated as

$$P_i \;=\; P_{i0} + d_{ij} P_{Tj} \qquad (2)$$

where d_{ij} is the PTDF for line i in direction j, P_{i0} is the base case flow on the line, and P_{Tj} is the magnitude of the proposed transfer. If the limit on line i is P_{imax}, the maximum power that can be transferred in direction j without overloading line i is

$$P_{Tj\,max\,i} \;=\; \frac{P_{i\,max} - P_{i\,0}}{d_{ij}} \qquad (3)$$

The maximum value of P_{Tjmax} that can be transferred without overloading any line in the set consisting of all lines in the system, Λ, is then

$$PT_{Tj\,max} \;=\; \min_{i \in \Lambda} \left[\frac{P_{i\,max} - P_{i\,0}}{d_{ij}} \right] \qquad (4)$$

With the nine bus case the maximum transfer from A to I is limited by minimum generation in area I. If this constraint is ignored, the maximum allowable additional transfer is 150 MW; the limiting element will be the line from A to G. This value can be verified using data from Figures 3 and 5. From Figure 3 we get the initial flow on the line of 58% multiplied by the 200 MVA limit = 116 MVA. From Figure 5 we get the line's PTDF of 56%. Solving for the maximum transfer, P_{max}, we get $200 = 116 + 0.56 * P_{max}$. The maximum for the G to F transfer is 180 MW, with the line from G to F the limiting element.

PTDF impacts constitute important considerations in market power analysis in light of current operating practices. NERC guidelines stipulate that new transfers registering a significant PTDF value (in excess of 5%) on a congested line or interface in the direction that would increase the loading on the congested element cannot be undertaken. For example, for the nine bus system Table 1 shows the PTDF values for the line G-F (with flow from G to F taken as positive) for different suppliers sending power to the I load pocket. Consequently, if congestion were present on the line from G to F, the number of sellers that would have access to the bus I load pocket is significantly decreased. For such a case area I consumers could only buy from areas I, E and F. Therefore, the resultant HHI for area I is $3 * 33.3^2 = 3327$, indicating significant market concentration by current standards.

Results from [15] show that for markets with such small numbers of producers optimal bidding strategies require bids substantially above the producers' marginal costs. Note though that this market power only exists when a line is congested. Moreover, this congestion is one-sided. When the direction is reversed the PTDF values simply change sign[ii]. Therefore generators in I can sell to all other areas except for F.

Table 1: Line G to F PTDF Values

Seller to Buyer Direction	PTDF for Line G to F
A to I	35%
B to I	29%

[ii] In general this is true only for a lossless system, such as the one considered here, with no active single-sided limits (such as generator MW limits or transformer phase shifter limits).

C to I	11%
D to I	5%
E to I	-1%
F to I	-20%
G to I	41%
H to I	21%

4. STRATEGIC MARKET POWER

The fact that transmission congestion can limit market size creates the possibility that a portfolio of generators could be deliberately dispatched in such a way as to induce congestion for strategic purposes [16]. For example consider again the Figure 3 nine-bus case. Under the base case assumption of each load being free to select its generation and vice versa, this system has an HHI of 1110, indicating no market concentration. Next consider that areas F and G merge, creating a single entity FG, which now has a 22.2% market share. The remaining seven participants each continue to have an 11.1% share, resulting in a slightly higher HHI of 1355. However, with the portfolio of generators of the combined entity FG there is now increased capability to “manipulate” the flows throughout the system. In particular, the combined entity can redispatch its generation to deliberately induce congestion for strategic purposes.

We first examine the ability of a portfolio of generators to control the flow of power on a particular line. Assume that the portfolio has N generators which are dispatched to meet loads in the network. Hence the portfolio of generators may be redispatched in any way desired, provided the net change in generation is zero. In particular, the redispatch can be effected to modify the flow on line i. The portfolio redispatch consists of introducing changes ΔP_{Gk}, k=1,2,…,N with the constraint that the sum of these changes is zero. Let S_{ik} be the sensitivity factor of the real flow on line i corresponding to a 1 MW increase in the generation at generating bus k. The portfolio may select its redispatch so as to maximize the change in the flow on line i. Then the solution of the problem:

$$\max \Delta P_i = \sum_{k=1}^{N} S_{ik} \Delta P_{Gk} \quad \text{s.t.} \quad \sum_{k=1}^{N} \Delta P_{Gk} = 0 \qquad (5)$$

provides the redispatch that can impact the flow on line i most severely.

Let us now examine this ability to modify flows in a line in the example system. Consider the merged entity FG and the redispatch of its generation in the two constituent areas. For a change of generation in area F of ΔP_{GF}, a corresponding change of $-\Delta P_{GF}$ is made in area G. The entity FG can make the redispatch modification so as to induce congestion on line GF. This results in a blocking areas A, B, D, and H from serving the area I load. At the same time, the entity FG may continue to sell its generation in area F to serve load in area I. The redispatch that just introduces congestion on line GF is shown in Figure 6.

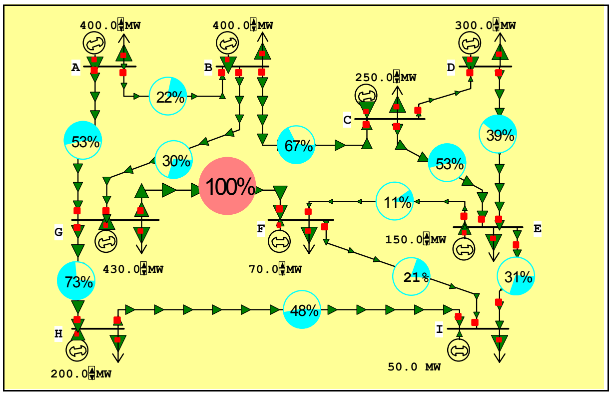

Figure 6: Area FG Blocking Area I Market

A market participant’s physical ability to create congestion depends upon the mechanism used to obtain transmission access/dispatch generation, the portfolio of available generation, and the current system operating point. From FG’s point of view, the best mechanism for transmission access/generation might be one in which it had complete priority in access to transmission line G to F, such as that given a utility when serving its native load. At the other end of the spectrum might be a bid-based ISO. However even with such an ISO, area FG could still devise a bidding strategy which allowed it to achieve congestion on line G to F, and hence sell into a relatively constrained area I. The success of such a strategy would, of course, depend upon expected system loading.

A strategy of deliberately creating congestion could certainly involve additional costs to the congestor. Contributing factors to the cost are how far it must deviate from a purely economic dispatch or bidding strategy. The increase in profit is then the difference between the additional income gained from the congestion and the costs incurred in creating the congestion. The congestor would only pursue such a strategy if they had a reasonably good expectation of profit.

From a long term perspective market participants should certainly be cognizant in procuring their generation portfolios of both their own, and the ability of their competitors, to engage in such strategic behavior. Likewise those involved with devising market rules, approving generation portfolios, and policing the system, must also be aware of such strategic behavior.

5. MARKET POWER ASSESSMENT

Assessment of market power requires determination of the generation market available to each load pocket, or conversely, the load market available to each generation portfolio, taking into account the potential for strategic behavior by one or more market participants. Thus the problem has two sets of players, those who are seeking to sell to the load and hence will try to maximize the power transfer to the load pocket (the Maximizers), and those seeking to prevent others from gaining access to the load (the congestors or the Minimizers). Conceptually, the problem requires solution of a noncooperative game in which the two players simultaneously seek the best possible outcome assuming the worst possible choice by the other [17]. A solution approach based upon an game theoretic notions could be computationally taxing and maybe untractable for large systems.

Here we propose to approximate this solution by a practical approach of solving the SIC problems with simplified assumptions about the impact of the congestors. Once a set of congestors has been specified, the results of equation (5) could be used to derate the limits on each line i by the amount ΔP_i. Please note that ΔP_i is the maximum amount by which the congestors can unilaterally manipulate the flow on line i. If the SIC problem is solved using these assumptions, the results provide the minimum amount of power that can be imported into the load pocket. The reason this value is a minimum is because the congestors could not simultaneously modify the flow on all the affected lines by that line's maximum amount ΔP_i. Hence we propose the following algorithm 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 line limits using equation (5).
3. Using the derated line limits from step 2, solve the SIC to maximum 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 SIC results then provide a measure of the size of the generation market available to the load market, and hence the degree of market concentration.

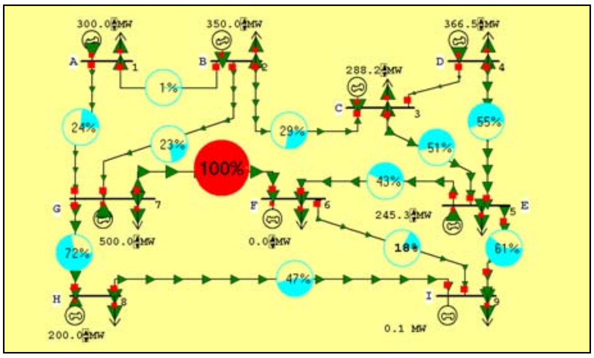

Figure 7: Nine-Bus System with Congestion from G to F

As an example, Figure 7 again shows the Figure 6 case of area FG attempting to block the import of power into I from other areas. Here the line limits were first derated using (5). Results of these derated limits are shown in Table 2. The SIC algorithm was then solved using the derated limits with the assumptions that all the other generators in the system (i.e., all but the generators at F and G) are redispatched so as to increase the net import of power into area I. SIC results are shown in Table 3. Note that the Figure 7 results differ from those shown in Figure 6. This is because in the Figure 6 case the assumption is that FG initially congests the line between G and F; then subsequently the only areas that can sell into area I are those with negative PTDF values on the line from G to F. This is analogous to the case where each area independently dispatches its generation. In contrast, in the Figure 7 case the system is assumed to be dispatched simultaneously, analogous to what might occur in an ISO. For such a situation Area I could receive at least some power from Areas C and D as well as from Areas E, F and G.

Table 2: Derated Line Limits

Line	Original Limits	Derated Limits
A to B	200 MVA	185 MVA
A to G	200 MVA	185 MVA
B to C	200 MVA	155 MVA
B to G	200 MVA	170 MVA
C to D	200 MVA	185 MVA
C to E	200 MVA	170 MVA
D to E	200 MVA	185 MVA
E to F	200 MVA	153 MVA
E to I	200 MVA	198 MVA
F to G	200 MVA	47 MVA
F to I	200 MVA	150 MVA
G to H	200 MVA	148 MVA
H to I	200 MVA	148 MVA

Table 3: SIC Results for Figure 7 Case

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

As a second example, Figure 8 shows the case of again importing power into area I, but with areas G and H as a single entity. Here area I is limited by GH's actions to only being able to import from area E or from entity GH. Here a congesting action by GH could be particularly drastic because area I can only import a maximum of 25 MWs from area E. For any amount beyond this value I would have to dependent on local generation or deal with areas GH. Thus GH have, in essence, achieved complete market power to supply area I.

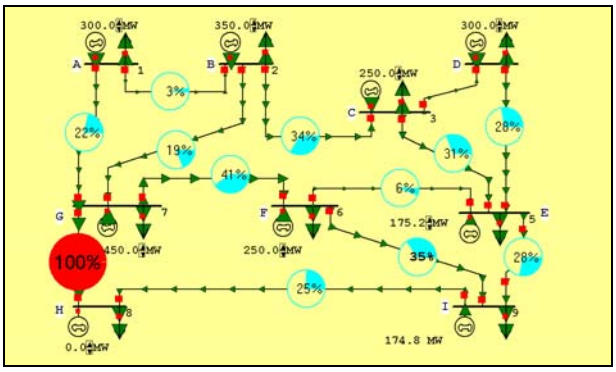

Figure 8: Nine Bus System with Congestion from G to H

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Table 4 : Derated line Limits Due to GH Congestion

Line	Original Limits	Derated Limits
A to B	200 MVA	193 MVA
A to G	200 MVA	191 MVA
B to C	200 MVA	179 MVA
B to G	200 MVA	183 MVA
C to D	200 MVA	193 MVA
C to E	200 MVA	186 MVA
D to E	200 MVA	193 MVA
E to F	200 MVA	193 MVA
E to I	200 MVA	172 MVA
F to G	200 MVA	159MVA
F to I	200 MVA	166 MVA
G to H	200 MVA	62 MVA
H to I	200 MVA	122 MVA

Table 5: SIC Results for Figure 8 Case

Generator	Change
Export from Area A	0 MW
Export from Area B	0 MW
Export from Area C	0 MW
Export from Area D	0 MW
Export from Area E	25.3 MW
Export from Area H	0 MW
Import into Area I	200 MW

6. CONCLUDING REMARKS

This paper has provided illustrations of market power opportunities in networks and the explicit consideration of the effects of congestion. Given the importance of the network structure in bulk power markets, the explicit consideration of both the physical and the operational constraints, and the economic aspects of transmission services and generation markets is critical to correctly assess market power opportunities in specific situations. The consideration of market concentration by itself is inadequate, in most cases, for the assessment of market power opportunities. As is clear from the various examples, the transmission network plays a pivotal role in potential market power situation. In fact, it is possible for players in interconnected systems to exercise market power without a dominant position of market concentration. The unbundling of electricity services has created a number of interrelated markets. The interrelationships of these markets, and their impacts on potential market power, will be explored in future papers.

7. ACKNOWLEDGEMENTS

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