Pricing Transmission Congestion in Electric Power Networks

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***Abstract*—Finding a proper way of pricing transmission congestions has an important effect on electric power market. It should promote efficiency in the day-to-day operation of the bulk power market, encourage investment in generating and transmission facilities, determine the required location of generating capacity, and determine locations of new transmission lines that should be expanded. In this paper, we consider the angular system stability problem in pricing transmission congestions. In doing so, we review transmission congestion pricing approaches, consider two congestion pricing models with the system stability constraint, and discuss which pricing scheme could provide a proper economic signal to the market.**

***Index Terms*— Congestion cost allocation, flow-based pricing, nodal pricing, power system stability, transmission congestion pricing.**

I. Introduction

TRANSMISSION in electric power networks is the ability to move large volumes of energy from where it is generated to where is needed. Currently, the actual cost of moving power is only 6 to 10% of total electric costs. But how well the transmission system works, and how well it can support an active market, profoundly affects the total cost of electricity. Although the quantity of power traded in the wholesale market went from almost nothing in 1994 to over 800 TW-h in 2000, there has been relatively little money put into the transmission system. Consequently, the transmission infrastructure is aged, resulting in "congested lines" such as increased instances of constrained systems, reduced import capability, heavily loaded lines, and voltage instability. Transmission costs are very difficult to determine and to allocate because of the complex interaction of the different components (generation, load, and transmission) of the power system. Power flows and load growth at a one location can increase transmission costs at other locations.

Power networks frequently face congestion problems on lines or interfaces. Various regulatory and market based congestion management methods are present but an economically efficient and politically implementable solution that provide the information for future improvements is still investigated. Joskow [1] points out how transmission congestions and investment have become an emergent problem while wholesale and retail market reforms have developed across the country. He reports that PJM congestion costs have grown from $53 million in 1999 to $500 million in 2003.

Transmission congestion is encountered initially in the form of thermal limits on transmission lines. However, even if each individual line meets the thermal limit, the system could be unstable because of angular stability problem. Therefore, system stability limits should be considered in operation and planning of a bulk power system. In this study we extend our first work [2] on including the stability constraints in optimal dispatch problems. We provide an economic analysis of the stability constrained model based on different congestion pricing schemes. For this purpose, we compare the nodal pricing and flow-based pricing methods.

The remaining of the paper is organized as follows. In Section II we give a brief description of three common approaches to pricing transmission congestion. In Section III, we provide two optimization models to price congestion under stability constraints. In Section IV, we discuss how congestion costs are allocated under these two models and give the economic interpretations of the congestion costs considering system stability limits.

II. Approaches To Transmission Congestion Pricing

According to the price signals they send to the market, transmission congestion pricing approaches can be classified as flat rate, marginal cost, and no price pricing. The former is the uniform price approach that has been used in pre-liberalized U.S. Markets. With this approach full cost recovery is possible but no proper economic signals are sent to the market for generation and transmission expansion.

The second approach is based on the marginal cost pricing concept and it is applied in most of the restructured U.S. markets. In this approach, the optimum dispatch is determined based on a security constrained Optimum Power Flow (OPF) model. This model assigns the price at each node as the

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marginal generation cost of that node taking into account system constraints. Two main marginal cost pricing methods, namely nodal pricing and flow-based pricing, have been debated in theory and practice. Pros and cons of these methods can be found in [3]-[7]. In the literature there are hybrid modal proposals that try to combine advantages of these models using elements from both [8], [9].

Third approach lets the market find its own equilibrium. Since this approach tries to minimize responsibilities of the central operator, a well-established market structure is required in order to ensure system reliability and efficient system operation. Wu and Varaiya [10] proposed the coordinated multilateral trading model where the system operator acts like a coordinator that provides information to the market to facilitate profitable trades.

Security-constrained OPF is the economic dispatch problem for most of the restructured power markets. This optimization model could include thermal stability limits on transmission lines, generation limits, and power balance of the system. However angular system stability, which might have a significant effect on the economic dispatch, is not considered in OPF models. In the following section, we suggest a way of incorporating system stability constraints in the OPF model.

III. Pricing Congestion under System Stability Constraints

In this section, we provide the details of two congestion pricing models based on the marginal cost pricing approach and we address the angular stability problem by using the flowgate concept.

A. A Nodal Pricing Model

The theory of marginal cost pricing applied to power systems was first introduced by Schweppe *et al.* [11] in 1988. Hogan [12] improved the initial market design by establishing firm transmission rights as hedging instruments against the nodal price differences. Today, nodal pricing or locational marginal pricing (LMP) is used in most of the restructured power markets in the U.S such as the Pennsylvania, New Jersey, and Maryland Independent System Operator (PJM ISO) and New York Independent System Operator (NYISO). Efficient congestion management using marginal pricing is the main reason of the increased attention to the nodal pricing.

In essence, the node-based market structure can be summarized as follows.

- Market design consists of forward (day-ahead, hour-ahead) and real time markets.
- Prices are determined by a security constrained bid-based optimum power flow (OPF) model, administered by an independent system operator.
- Market participants use financial transmission rights (FTR) to hedge the risk of price difference of every node caused by congestion. FTRs are traded before the real dispatch. The system operator ensures the simultaneous feasibility condition.

The operation of the forward and real-time markets is centralized. The ISO handles the externalities of the power system by using an OPF model. The OPF model finds the most cost effective dispatch given the system limits on flows taking into account the network structure, generation costs of the generators, and the demand pattern.

Although the OPF model considers flow limits due to thermal constraints of the system, it does not include information about system's angular stability. Our experience with dynamic simulations suggests that proximity to a stability limit may be approximately predicted using a transmission flowgate [2]. Using power transfer distribution factor (PTDF), it is possible to assign a portion of generation at each node to every transmission line on the network. This allows us to define the flowgate as sum of the flows on the lines determined by simulation using PTDFs. With these PTDFs, a single inequality constraint based on flowgate total can be added to the OPF algorithm in a manner exactly analogous to that used when mitigating thermal constraints on single elements. This approach appears to be a credible first step toward incorporating stability constraints into an optimal dispatch algorithm.

For large power systems, generation-rich nodes may be surrounded by a flowgate as shown in Fig. 2.

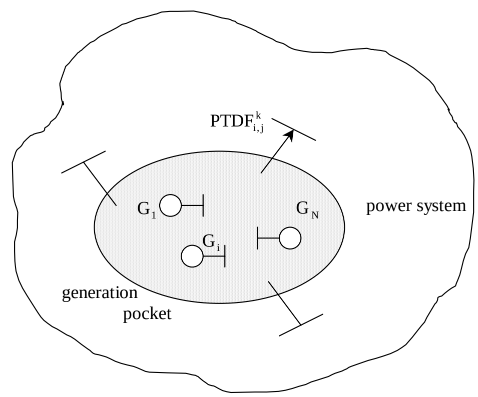

Fig. 1. Example of a generation pocket in a large power system.

In this case, the inequality constraint can be represented in the form shown in (1a) or (1b) where *i* and *j* are summed over all lines that compose the flowgate. This total flow must be kept less than some maximum limiting value, $FG^{\max}$, again determined by dynamic simulations.

$$\sum_{ij \in FG} f_{ij} \le FG^{\max} \quad (1a)$$

$$\sum_{ij \in FG} \left(\sum_{k=1}^{N} PTDF_{ij}^{k} \times g_k \right) \le FG^{\max} \quad (1b)$$

where $PTDF_{ij}^{k}$ is the portion of the flow on line *i-j* sent from node *k* to the hub, g_k denote the power output at node *k*. In concept, including (1a or 1b) in a dispatch algorithm is the same as establishing export limits for control areas and suffers from the same drawbacks where the PTDFs are dependent on

- which generating units are available for dispatch (the commitment list),
- which lines (or other branches) are out of service at any

particular time,

- the size of the power transfer being considered, and
- the point of delivery for the generated power.

In addition, using a flowgate to create a stability constraint for an optimal dispatch is subject to many assumptions regarding the relationship between power exported (from an individual machine or a generation-rich pocket) and the stability of the generators in question. These assumptions have been complicating the field of power system stability for many years and the complexities involved usually lead to the use of complete time-domain simulations for stability evaluations. Time-domain simulations are commonly used in planning studies, but the time required for these types of studies renders them unsuitable for use in bulk power operations.

A security-stability constrained OPF problem can be represented as follows. We assume that the power grid consists of *N* buses and that at bus *k* there is a generator g_k and a load L_k. For illustrative purposes, we are using fixed load model in this work as it is used in PJM. Other models including demand elasticity are available in the literature [13]. Assuming that wide-area stability problems can be correlated to the flow on a pre-defined flowgate, the generation dispatch optimization including wide-area stability constraints can be written as shown in (2).

$$\text{Min } z = \sum_{k=1}^{N} c_k g_k \tag{2}$$

Subject to

$$\sum_{ij} S_{k,ij} \times f_{ij} + g_k = L_k \qquad (\lambda_k) \text{ for } k = 1,\ldots,N \tag{3}$$

$$f_{ij} - Y_{ij} * (\theta_i - \theta_j) = 0 \text{ for all lines } i\text{-}j \tag{4}$$

$$-f_{ij}^{\max} \le f_{ij} \le f_{ij}^{\max} \qquad (\mu_{ij}) \text{ for all lines } i\text{-}j \tag{5}$$

$$g_k^{\min} \le g_k \le g_k^{\max} \text{ for } k = 1,\ldots,N \tag{6}$$

$$\sum_{ij \in FG} f_{ij} \le \text{FG}^{\max} \tag{7}$$

The minimization of (2) is subject to power balance constraints at each bus *k* given in (3). Voltage/flow equations on each line *i-j* are shown in (4). Constraints in (5) represent thermal flow limits for all lines *i-j*, and constraints in (6) are power capacities for each generator (at bus *k*). A stability constraint shown in (7) is included to the economic dispatch problem. The variables θ_is are unrestricted. All parameters and variables are defined in

TABLE I.

The dual prices for the load balance equations (λ_k) give the LMPs for each node, LMP_k. If there are congested lines in the network, this model gives different prices at each node. The total transmission congestion rent (CR) is calculated by multiplying the amount of flow at each line times the price difference of the nodes and summing over all the lines, as represented in (8).

$$CR = \sum_{ij} \left(LMP_j - LMP_i \right) f_{ij} \tag{8}$$

TABLE I VARIABLE AND PARAMETERS DEFINITIONS

Parameters	Definition
N	Number of buses
L_k	Load at bus *k*
Y_{ij}	Susceptance of line *i-j*
$S_{k,ij}$	Incidence coefficient (-1,0, or 1) at bus *k*
c_k	Energy cost of generator *k*
$g_k^{\min}$	Minimum generation of generator *k*
$g_k^{\max}$	Maximum generation of generator *k*
PTDF^k_{ij}	PTDF at line *i-j* from node *k* to hub
$\text{FG}^{\max}$	Maximum flowgate
Variables	
g_k	Energy dispatched by generator *k*
f_{ij}	Power flow at line *i-j*
θ_k	Voltage angle at bus *k*
Dual Variables	
λ_k	Dual price of the load at bus *k*
μ_{ij}	Dual price of the line *i-j*
μ_{FG}	Dual price of the flowgate.

This rent is collected by the ISO and distributed to the Financial Transmission Right (FTR) holders according to $CR_{ij} = \left(LMP_j - LMP_i \right) f_{ij}$.

Financial Transmission Rights are used to hedge the risk of price difference of the injection and retrieval points. These rights are defined point-to-point without considering how the flow is actually transferred. It gives the holder the financial right for resulting congestion cost collected. Incentives for the transmission expansion are granted by giving the resulting FTR to the investor from an expansion investment. Since FTRs are traded in the secondary market before the actual dispatch, full hedging might not be available all the time.

B. A Flow-based Pricing Model

Chao and Peck [14], [15] introduced a flow-based transmission pricing theory in 1996. The flow-based pricing theory can be adapted to a centralized or decentralized market design. The California Independent System Operator (CAISO) and Electric Reliability Council of Texas (ERCOT) have proposed market structures essentially flow-based. One possible market design for the flow-based pricing is as follows:

- Energy and flow-based transmission rights that gives scheduling priority to the holder are traded in the forward market with multi-round auctions simultaneously. Chao-Peck [14] demonstrated that the market will reach the efficient competitive equilibrium (economic dispatch).
- During real-time market a central authority ensures the system reliability and settles the prices for the residual energy and transmission right market.

The efficient electricity system can be represented by only one hub price and congested flowgate prices. Since the number of congested lines in a network is generally much lower than the number of nodes, this method allows a more liquid market [16].

With a flow-based structure, the OPF can be represented using PTDFs. The corresponding OPF under stability

$$\text{Min } z = \sum_{k=1}^{N} c_k g_k \quad (9)$$

Subject to

$$\sum_{k=1}^{N} g_k - \sum_{k=1}^{N} L_k = 0 \qquad (\lambda) \quad (10)$$

$$-f_{ij}^{\max} \le \sum_{k=1}^{N} PTDF_{ij}^{k}\left(g_k - L_k\right) \le f_{ij}^{\max} \qquad \left(\mu_{ij}\right) \quad (11)$$

$$\sum_{ij\in FG} \sum_{k=1}^{N} PTDF_{ij}^{k}\left(g_k - L_k\right) \le FG^{\max} \qquad \left(\mu_{FG}\right) \quad (12)$$

$$g_k^{\min} \le g_k \le g_k^{\max} \quad (13)$$

The minimization of (2) and (9) are equivalent under the DC flow assumptions leading to the economic efficient market equilibrium. This model provides only one dual price for the system balance equation (10), which represents the LMP of the reference node, or hub. The locational marginal prices for other nodes can be calculated easily by using the dual prices of line flow equations (11) written for all lines *i-j* and the flowgate equation (12) as shown in (14).

$$LMP_k = \lambda + \sum_{ij} (PTDF_{ij}^{k} \times \mu_{ij}) + \sum_{ij\in FG} (PTDF_{ij}^{k} \times \mu_{FG}) \quad (14)$$

Under the flow-based market design, the additive inverse of the dual prices μ_{ij} and μ_{FG} (p_{ij} and p_{FG}, respectively) are actually the market prices of the corresponding flow-based transmission rights. Note that when there is no congestion on a line its dual price is zero. Otherwise, it takes a negative value, which means relieving by one megawatt the line or flowgate limits, the total production cost is reduced by the amount μ. In this model, the total transmission congestion rent (CR) is calculated by multiplying the amount of flow at each line times the dual price of that line and summing over all the lines, as represented in

$$CR = \sum_{ij} \left(p_{ij} \times f_{ij} \right) + p_{FG} \times FG^{\max} . \quad (15)$$

This rent is collected by the ISO and distributed to the Flowgate Right (FGR) holders according to (16) and (17)

$$CR_{ij} = p_{ij} \times f_{ij} \quad (16)$$

$$CR_{FG} = p_{FG} \times FG^{\max} \quad (17)$$

Consequently, in both models the prices provide economic signals for generation and transmission expansion.

In the following section, we examine an example to study the effect of the system stability constraint on pricing congestion. In our study, we use the nodal and flow-based pricing models to calculate and allocate congestion costs due to the system stability constraint.

IV. Analysis and Economic Interpretations

A. Example Definition

To examine the congestion costs that occur when a stability constraint is included in the optimal dispatch model, we use a 5-bus, 4-generator power system shown in Fig. 2. The generator data for the 5-bus system are given in TABLE II and line susceptances and PTDFs are shown TABLE III. The line data is in per unit using 230 kV and 100 MVA as bases. The load at each bus is 425+j87.7 MVA. Bus 2 is chosen as the reference bus in our example.

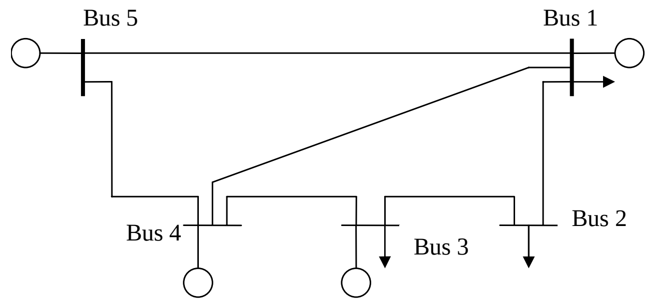

Fig. 2. 5-bus, 4-generator power system

TABLE II Generator Data

Generator	g_k^{min} (MW)	g_k^{max} (MW)	Cost ($/MWh)
G_1	55	110	14
G_3	130	520	30
G_4	100	200	25
G_5	300	600	10

TABLE III PTDFs and Line Susceptances Data

	Injection Node k					
Line	**1**	**2**	**3**	**4**	**5**	Y_{ij}
12	0.8235	0.0000	0.1765	0.3529	0.5294	72.4638
23	-0.1765	0.0000	-0.8235	-0.6471	-0.4706	18.1159
43	0.1765	0.0000	-0.1765	0.6471	0.4706	24.1546
54	0.0588	0.0000	-0.0588	-0.1176	0.5735	72.4638
41	-0.1176	0.0000	0.1176	0.2353	0.1029	72.4638
51	-0.0588	0.0000	0.0588	0.1176	0.4265	14.4928
FG	0.0000	0.0000	0.0000	1.0000	1.0000	-

Based on the system topography (see Fig. 2) and a number of dynamic simulations, the flows on lines 5-1, 4-1, and 4-3 have been identified to be correlated to the stability problem as demonstrated in [2]. These dynamic simulations also have shown that the system will remain stable for the breaker failure contingency described previously in [2] as long as the total flow over these three lines remains less than 670 MW.

B. Effects of the Flowgate Constraint

In order to study the effect of the flowgate constraint we assume that we have no limits on the flows due to thermal constraints. To solve this instance of the problem, we use the models described in Section III. The results are shown for no flowgate constraint in TABLE IVA and for a flowgate limit of

670 MW in TABLE IVB. With the enforced stability limit, the system is divided into two zones as represented in Fig. 3, where nodes 4 and 5 are limited to send power to the load centers located in nodes 1, 2, and 3.

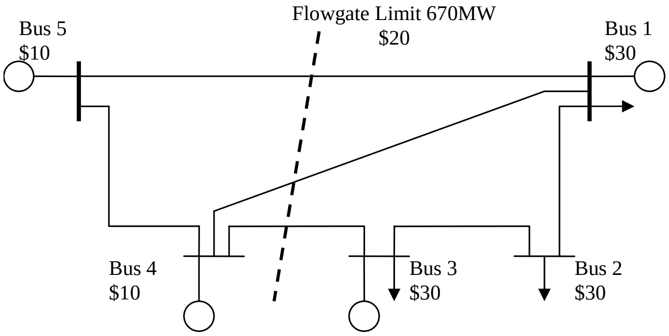

Fig. 3. Nodal prices with the stability constraint.

TABLE IVA and IVB illustrate that system stability limits cause restrictions for the generators to serve the load through the flowgate. The generators G4 and G5 are dispatched with lower LMPs of $10, rather than $30, under a binding stability limit. Although load pays the same amount ($38,250) under each scenario, there are significant revenue decreases for G4 and G5 when the stability constraint is binding. In fact, G4 is dispatched with a lower price than its cost because of the minimum generation requirements set by the problem. When G4 provides just the minimum requirement of 100 MW, there is some left-over capacity for G5. This results in marginal price for those nodes to be $10. Generation redispatch cost in TABLE IV, is the cost of the redispatch to the generators. This is simply the difference of the total production costs between two cases (congested versus uncongested). We may view this cost to be the incremental cost of enforcing the stability limit to the system.

In Fig. 4 we show the elements of load payments in terms of generator revenues and congestion costs. As the flowgate limit is tightened, revenues of G4 and G5 are reduced significantly. This causes congestion costs to increase. On the other hand, the most expensive generator of the system at node 3 receives less revenue as the flowgate is relaxed.

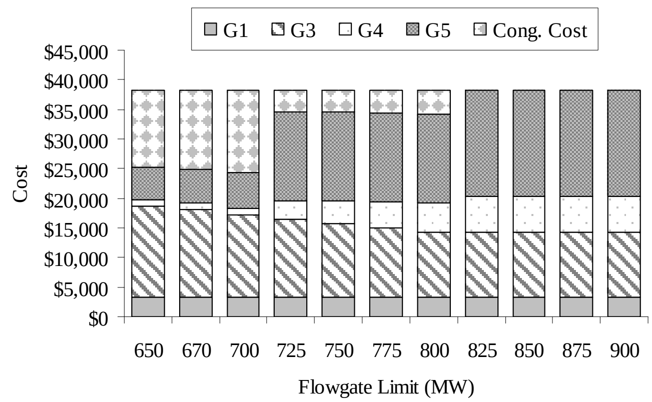

Fig. 4. Partition of the total cost to load in terms of total generation revenues and congestion costs.

TABLE IVA OPTIMUM DISPATCH WITHOUT THE STABILITY CONSTRAINT AND WITHOUT TRANSMISSION THERMAL LIMITS

No Flowgate limit	**1**	**2**	**3**	**4**	**5**	**Total**
LMP	$30	$30	$30	$30	$30	
Generation (MW)	110	0	365	200	600	1275
Total Production Cost	$1,540	$0	$10,950	$5,000	$6,000	$23,490
Total Revenue to Gen	$3,300	$0	$10,950	$6,000	$18,000	$38,250
Net Income to Gen	**$1,760**	**$0**	**$0**	**$1,000**	**$12,000**	**$14,760**
Load (MW)	425	425	425	0	0	1275
Total Cost to Load	$12,750	$12,750	$12,750	$0	$0	$38,250
	FGR Price	**MW**	**Tot FG Cong.**	**Gen Redisp.**	**Cong. Cost**	
	$0	0	**$0**	$0	$0	

TABLE IVB OPTIMUM DISPATCH WITH THE STABILITY CONSTRAINT AND WITHOUT TRANSMISSION THERMAL LIMITS

Flowgate limit 670	**1**	**2**	**3**	**4**	**5**	**Total**
LMP	$30	$30	$30	$10	$10	
Generation (MW)	110	0	495	100^(1)	570	1275
Total Production Cost	$1,540	$0	$14,850	$2,500	$5,700	$24,590
Total Revenue to Gen	$3,300	$0	$14,850	$1,000	$5,700	$24,850
Net Income to Gen	**$1,760**	**$0**	**$0**	**-$1,500^(1)**	**$0**	**$260**
Load (MW)	425	425	425	0	0	1275
Total Cost to Load	$12,750	$12,750	$12,750	$0	$0	$38,250
	FGR Price	**MW**	**Tot FG Cong.**	**Gen Redisp.**	**Cong. Cost**	
	$20	670	**$13,400**	$1,100	$13,400	

(1) Minimum generation for generator 4 is 100MW.

C. Allocating congestion costs

In our model, the congestion costs consist of two components. First one is due to thermal limits imposed on the lines and the second one is due to the restriction imposed on the flowgate to control the system stability. The flow-based model assigns the total congestion cost directly to the lines that are involved. Therefore, the amount of congestion costs on those lines are calculated by multiplying the flow on that line with the dual price of the line flow limit constraint, which is referred to as the Flowgate Rights (FGR) price. In the nodal approach on the contrary, all lines are seen as the cause of congestion on some specific lines on the network. The total congestion cost is then allocated to all the lines that induce a price difference between their sink and source nodes on the network. We show in TABLE V the allocation of congestion costs corresponding to the case described in TABLE IVB. It is worth mentioning that, under the nodal congestion pricing scheme, no congestion cost is ever assigned directly to the flowgate constraint. Allocation of congestion costs due to stability limit is studied in two cases.

TABLE V ALLOCATION OF CONGESTION COSTS UNDER FLOW-BASED AND NODAL APPROACHES

	Flow-based Approach		Nodal Approach	
Line	**FGR Price**	**Cong. Cost**	**LMPj-LMPi**	**Cong. Cost**
12	\$0.00	\$0.00	\$0.00	\$0.00
23	\$0.00	\$0.00	\$0.00	\$0.00
43	\$0.00	\$0.00	\$20.00	\$5,300.00
54	\$0.00	\$0.00	\$0.00	\$0.00
41	\$0.00	\$0.00	\$20.00	\$2,550.00
51	\$0.00	\$0.00	\$20.00	\$5,550.00
FG	\$20.00	\$13,400.00	\$0.00	\$0.00
Total		**\$13,400.00**		**\$13,400.00**

D. Allocating congestion costs due to stability constraint

Now we will impose a thermal limit of 240MW on line 54 along with the flowgate constraint. As expected, both approaches produce the same results in terms of nodal prices, production costs, and total congestion cost. What differs in these two models is again the allocation of the total congestion costs to the individual lines on the network. TABLE VI summarizes the situation where the stability limit constraint is binding along with thermal-limited line 54.

TABLE VI THERMAL LIMIT ON LINE 54=240, FLOWGATE LIMIT=670

		Flow-based Approach		Nodal Approach	
Line	**Flow**	**FGR**	**Cong. Cost**	**LMPj-LMPi**	**Cong. Cost**
12	76.60	\$0.00	\$0.00	\$1.28	\$97.78
23	-348.40	\$0.00	\$0.00	\$1.28	-\$444.77
43	278.40	\$0.00	\$0.00	\$5.00	\$1,392.02
54	240.00	\$21.70	\$5,208.51	\$15.00	\$3,600.00
41	137.55	\$0.00	\$0.00	\$2.45	\$336.57
51	254.04	\$0.00	\$0.00	\$17.45	\$4,432.23
FG	670.00	\$6.28	\$4,205.32	\$0.00	\$0.00
Total			\$9,413.83		\$9,413.83

Note that \$5,208.50 out of \$9,413.83 is due to the thermal limit on line 54, and the rest is due to the flowgate limit. We may be able to trace back the lines that are responsible for the congestion (\$4,205.32) caused by the flowgate limit. In doing so, we may use either “amount of actual flow dispatched” or “PTDF values assigned to the lines” given in TABLE III as basis to allocate. This is shown in TABLE VII.

TABLE VII FLOWGATE CONGESTION ALLOCATION

	Flow-based Allocation		PTDF-based Allocation	
Line	**Flow**	**Cong. Cost**	**ΣPTDFij**	**Cong. Cost**
43	278.40	\$1,747.43	1.1177	\$2,350.14
41	137.55	\$863.37	0.3382	\$711.12
51	254.04	\$1,594.52	0.5441	\$1,144.06
Total	670	\$4,205.32	2	\$4,205.32

As shown in TABLE VI and TABLE VII, it is evident that significant differences exist in allocating the congestion costs. Our critical question here is which allocation scheme offers a correct price signal to the market. The flow-based allocation represents actual use of the line and so generates proper economic signals. However, the actual allocation proportions are time-dependent because the flows vary over time. In the PTDF-based scheme the proportions are fixed (time-invariant). So, congestion costs could be easily allocated using these numbers. Therefore, this allocation scheme can offer a practical solution. However, this may not send appropriate economic signals. We further investigate this issue in future research.

E. Effects of Flowgate Limit on Total Cost to Load and Generators

We now consider the situation where different stability limits are imposed by increasing the maximum flowgate capacity from 650 MW through 900 MW. In order to see the effects with and without transmission line thermal limits, four cases are considered. Lines 54, 51, and 12 are limited for that purpose, one at a time.

As shown in Fig. 5, when the maximum flowgate limit is increased, the total cost of power production tends to decrease. With a flow limit imposed on line 51, the flowgate constraint does not have any impact on the total cost of dispatch as it becomes redundant. The total cost of power generation decreases immediately when the flowgate limit reaches 660 MW, and stays the same afterwards. The line 51 has a capacity limit, and the flow constraint for line 51 is binding. As line 51 is on the flowgate, the flowgate constraint cannot reach its limit and becomes inactive. Therefore, the flowgate constraint has no effect on the dispatch in this case.

When there are no transmission line thermal limits for any line, or there is a limit only on line 54 or 51, the total cost of generation dispatch decreases significantly. This is because of the fact that when the flowgate limit is increased, it becomes possible to dispatch a cheaper generator. It is the same idea with relieving a constrained line in the network.

With the thermal limit on line 54, the total generation cost decreases as the flowgate limit increases up to 700 MW. Fig. 5 shows that, after the limit passes 700 MW, the generation cost becomes stable for all maximum flowgate values. This is because the dispatch stays the same when the flowgate limit is relieved to 700 MW. In this situation, the network acts as if there was no flowgate limit. However, we can still observe the price differences at different nodes, and the congestion costs to occur, as in Fig. 6, because of the constrained transmission line 54.

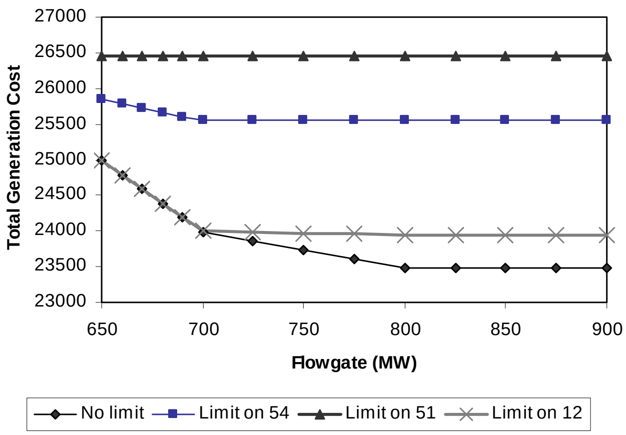

Fig. 5. Total cost of power production (objective function).

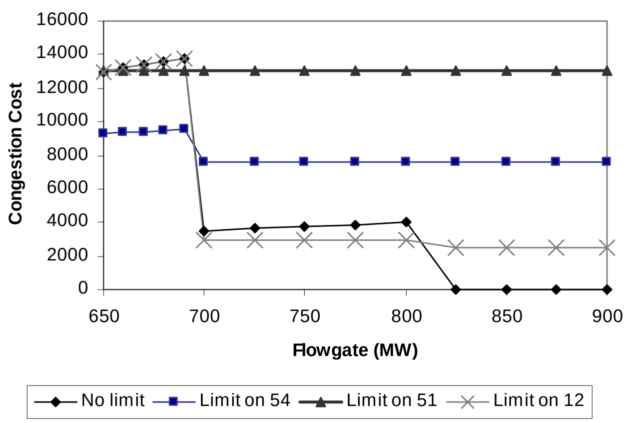

Fig. 6. Total congestion cost.

The most interesting case is with thermal limit on line 12. For example, after the stability limit reaches 700 MW, the dual price of the flowgate limit changes from -20 to -0.63. This results in a dramatic decrease in the total congestion cost. The same kind of decrease in congestion cost can be seen with the no transmission limit case; however, in that case after the flowgate reaches 825 MW, there is another decrease in congestion cost. This is because there is no other source of congestion for the no limit case. We also observe that line 12 causes congestion regardless of the flowgate limit.

F. Effects of Flowgate Limit on Total Amount Paid to Generators

Fig. 7 shows the total amounts that are paid to the generators. In the case where there are no line flow limits other than the flowgate, it is interesting to observe that the amounts paid to the generators are increasing even though the stability limit is relaxed. Before the flowgate limit reaches 700 MW, the generator at node 5, which is the cheapest generator, cannot supply all of its capacity. Therefore, the LMPs at nodes 4 and 5 stay at \$10, whereas the other nodes have a price of \$30. When the limit exceeds 700 MW, G5 runs out of its generating capacity and therefore we need to borrow the capacity from the generator at node 4. Then the price at nodes 4 and 5 becomes \$25, and this results in an increase of the total amount paid to the generators. When the flowgate limit is close to 825 MW, the limit is not binding anymore. Then, the price at each node is \$30, and the generators receive the highest amount.

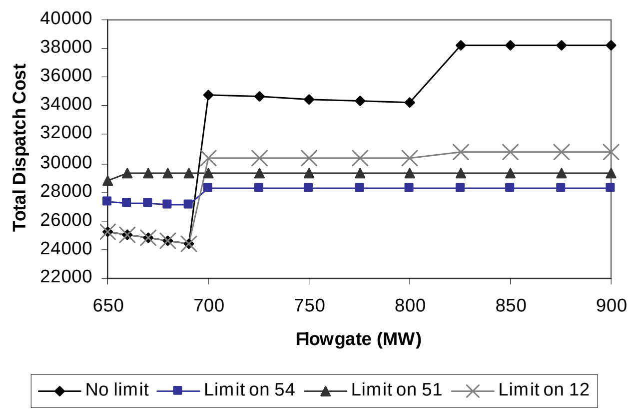

Fig. 7. Total amount paid to the generators.

As mentioned before, the flowgate constraint has an effect on the nodal prices, just as the other transmission line limits. In order to visualize this effect, we consider Fig. 8 which displays the LMPs at the four different situations.

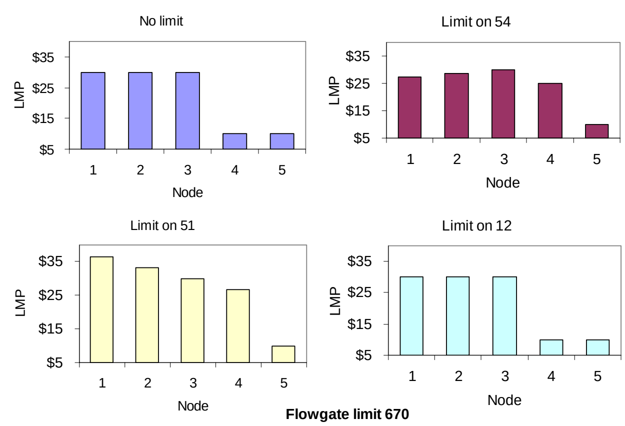

Fig. 8. Changes in LMPs for different transmission thermal limits

By examining Fig. 8, the nodes that are less affected from the stability limit are nodes 1, 2, and 3. Node 3 has no change on the prices in any situation.

V. Conclusion

This paper examined transmission congestion pricing on power networks with flowgate-based stability constraints. Two basic congestion pricing methods, namely nodal pricing and flow-based pricing, currently applied in power markets, are considered for analyzing the effects of a flowgate-based stability constraint on prices. Two optimization models related to these methods have been formulated and solved for a sample test system.

The difference of these pricing models is the allocation of the total congestion costs to the lines on the network. In the flow-based method, the congestion cost collected from the market is assigned only to the lines that are congested, including the flowgate. On the other hand, in the nodal pricing method a line that induces a price differential, between its sink and source nodes, is allocated a congestion cost. Therefore, the latter never assigns congestion cost to the stability constraint, whereas this constraint may be the principal cause of the transmission congestion on the network. The issue of which allocation scheme provides a correct economic signal to the market needs further investigation in the future research.

Further, effects of the stability constraint on the total cost of generator dispatch, total cost to load, and total congestion cost were analyzed. The total congestion cost varies depending on the maximum flowgate value. Binding flowgate constraints affect the nodal prices and the congestion costs that are allocated to the lines in both pricing schemes. Increasing the maximum flowgate value relieves the congestion on the lines, thus provides lower total congestion cost.

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