Sensitivity of Var Compensation Economic Benefits Considering Generator Marginal Cost

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***Abstract* – The natural gas price surged in 2004. As a result, the marginal cost of some generators burning gas also rose sharply. This paper is in response to the sharp increase in gas price and the corresponding generator marginal cost. This paper will first investigate the benefits of Var compensation including reduced losses (B_1), shifting reactive power flow to real power flow (B_2), and increased transfer capability (B_3). Then, an OPF-based quantitative approach is used to assess the three benefits. Finally, the scheme of Var economic benefits sensitivity analysis to generator marginal cost is proposed. Tests are conducted on a system with seven buses in two areas. The simulation results show that a positive relationship exists between the generator marginal cost in the load center and the Var economic benefits, and a negative relationship exists between the generator marginal cost in the generation center and the Var economic benefits.**

***Index Terms* – Var economic benefits, optimal power flow (OPF), economic benefits sensitivity analysis, generator marginal cost.**

I. Introduction

THE US power industry has been under great pressure to serve load economically since deregulation was initiated over a decade ago. Reactive power is critical to support voltage and regulate power factor in electric power systems. However, the reactive power in US power systems was not very well planned and managed, as evidenced by the Great 2003 Blackout that occurred in northeastern US and Canada in August 2003. The official final report of the Blackout indicated that "deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout [1]." Reactive power including its planning process has received tremendous interest and re-examination after the Blackout [2]. Besides the impact from the Blackout, the continuous technical advances in power electronics, such as SVC, STATCOM, D-Var, SuperVar, etc, make the application of a large amount of Var compensation more efficient and attractive [3].

Several previous works have discussed the cost [4] and the technical benefits [5-8] of dynamic reactive power compensation. However, the cost of local dynamic Var sources is unfortunately high and there is a lack of a standard method to evaluate the economic benefits. Reference [9] demonstrates a possible quantitative approach to assess the "hidden" benefits from local Var sources that there is no systematic approach for quantitative assessment. Since the economic benefit is a major concern in the system planning process, an interesting question is: what are the key factors that affect the quantitative economic benefits of Var allocation? The location and amount should definitely affect the Var economic benefits. However, this paper discusses another important factor that impacts Var economic benefits, generator marginal cost, which is closely related to the natural gas price. Since gas units are usually the marginal units that clear the electricity market dispatch during peak hours, it is important to investigate the sensitivity of Var benefit with respect to generation cost.

The U.S. natural gas industry has been restructuring for the past twenty years. Both the natural gas and electricity markets are going through deregulation. The natural gas business has a great interaction with the electricity market in terms of fuel consumption and energy conversion. References [11-14] discuss the impact of natural gas prices on electric power markets. In 2004, the natural gas price spiked, which was well above US$5/MBtu (million Btu) in most of 2004, peaked close to $8/MBtu, and averaged $6/MBtu [15]. The marginal cost of some generators burning gas also rose.

The high price of natural gas has been a great concern for those expecting to obtain benefits from the installation of reactive power compensation. Consequently, an interesting question may be raised by system planners and manufacturers: What is the impact of generator marginal cost increase on the Var economic benefits? This research work is conducted in response to the sharp increase in gas price and the corresponding generator marginal cost. The analysis focuses on two scenarios: (1) the load center generator marginal cost variation, and (2) the generator center generator marginal cost variation. The results from this research show some significant impact on economic benefits to load-serving utilities, which may increase their interests in local Var installation and influence their decision-making process.

This paper is organized as follows. Section II illustrates the possible benefits from local Var compensators using a simple two-bus system. Section III presents a more rigorous approach using economic dispatch to identify the benefits in three categories. Section IV presents Var economic benefits sensitivity analysis to generator marginal cost. Section V presents the test results for a seven-bus system with Var compensation, and Section VI presents the conclusion.

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II. Quantitative Evaluation of Reactive Power Benefit in a Two-Bus System

This section illustrated a possible quantitative approach to assess the "hidden" benefits from the Var sources at the demand side. It is called hidden benefits because there is a lack of systematic approach to quantitatively evaluate it [9]. These benefits are demonstrates with a simple two-bus model in this section and then presented with a more complicated model using Optimal Power Flow (OPF) in Section III.

A two-bus system shown in Fig. 1 is used to illustrate the systematic methodology for capturing the hidden benefits. In Fig. 1, there are a generation center with a cheap generation unit of \$20/MWh cost, a load center with a large amount of load, and an expensive generation unit of \$25/MWh cost, and a tie line with maximum transfer capability of 100 MVA at the receiving end connecting the two areas. The net load of the load center is 100 MVA with 0.9 lagging power factor, which implies 90 MW and 43.59 MVar (P_2 and Q_2, respectively).

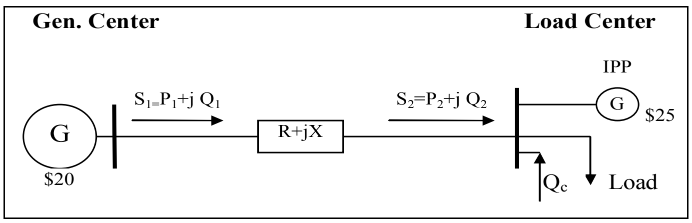

Fig. 1. A two-bus system.

The other parameters are as follows: the power base is 100 MVA; the voltage at the generation center bus is fixed at $1.0\angle 0^o$ per unit; and the line impedance is 0.02 + j0.2 per unit. The local compensation device will constantly inject Q_c = 14.01 MVar to lift the load power factor from 0.9 to 0.95, i.e., $P_2' = P_2 = 90$ MW and $Q_2' = Q_2 - Q_c = 43.59-14.01 = 29.58$ MVar. The three economic benefits are discussed below.

A. Benefit from Reduced Losses (B_1)

Injection of reactive power at the receiving end reduces the reactive power through the tie line and therefore reduces the line current. Since the real power loss is I^2R, the loss will be reduced if the current is reduced. With the consideration of the load-side voltage magnitude remains unchanged and very close to 1.0, the original line loss and the power at the delivery end without the Q_c compensation are given as follows.

$$P_{loss} = I^2 R = \frac{P_2^2 + Q_2^2}{V^2} R = \frac{0.9^2 + 0.4359^2}{1.0^2} \cdot 0.02 = 0.02\,p.u. = 2\,MW$$

$$P_1 = P_2 + P_{loss} = 90 + 2 = 92\,MW$$

After Q_c is connected, the power losses and delivery end power are as follows.

$$P'_{loss} = I^2 R = \frac{(P_2')^2 + (Q_2')^2}{V^2} R = \frac{0.9^2 + 0.2958^2}{1.0^2} \cdot 0.02 = 0.018\,p.u. = 1.80\,MW$$

$$P_1' = P_2' + P'_{loss} = 90 + 1.80 = 91.80\,MW$$

Therefore, the total loss savings at the delivery end is 0.2 MW (=92-91.8). This loss reduction represents reduced total generation. Therefore, the savings in dollars per MVar-year is \$2,501/MVar-year [= (\$20/MWh × 0.2 MW × 8760 hr/year) /14.01 MVar].

B. Benefit from Shifting Reactive Power Flow to Real Power Flow (B_2)

As previously assumed, the tie line is congested due to the maximum transfer capability of 100 MVA at the receiving end. If this is the case, it is still assumed that the limit of S_2 remains 100 MVA. This may correspond to a thermal limit or a contract MVA flow limit. Since the reactive power flow, Q_2, has been reduced due to local compensation, this makes it possible to have more real power delivered from the lower-cost generator while the 100 MVA limit is still respected because of $P_2 = \sqrt{S_2^2 - Q_2^2}$. This benefit of transferring more cheap real power while keeping the same transfer capability is classified as the benefit of shifting reactive power flow to real power flow, as in the title of this subsection.

The new real power transferred over the tie-line is given as

$$P_2 = \sqrt{100^2 - (Q_2 - Q_C)^2} = \sqrt{100^2 - 29.58^2} = 95.52\,MW$$

Hence, the additional deliverable real power is 5.52 MW. Ignoring the additional loss due to the 5.52 MW, this is the amount of additional lower-cost real power from the generation center to the load center. The economic benefit to the load-serving utility will be the 5.52 MW times the price difference between the two generators. Assuming the tie line is congested by MVA limit during 2 peak months, the savings per MVar-year due to B_2 for the load center is \$2,837/MVar-year [= (\$25/MWh - \$20/MWh) × 5.52MW × 60day × 24hr / 14.01MVar].

C. Benefit from Increased Maximum Transfer Capability (B_3)

In the previous analysis, the maximum transfer capability is assumed to be unchanged. However, it is very possible that the local Var compensation in the stressed area may increase the maximum transfer capability constrained by voltage stability. This is shown in Fig. 2.

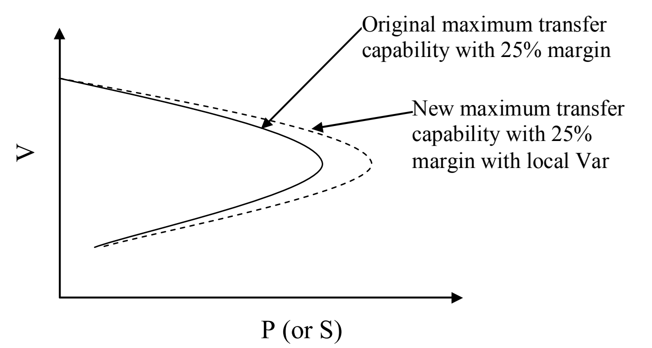

Fig. 2. The original and new transfer capability considering security margin.

There are various ways to calculate the change of transfer capability with respect to a change of system conditions [16]-[17] including local Var injection. Here, the equation of the maximum real power transfer in a two-bus model [18] is employed as follows:

$$P_{\max} = \frac{E^2(-k+\sqrt{1+k^2})}{2X}, \ \ where\, k = \frac{Q}{P}$$

It can be easily verified that the maximum transfer capacity has been improved by 15.5%. Therefore, the load center may receive 103.95 MW (90 x 1.155), which means it may receive another 8.43 MW (103.95-95.52) of lower-cost power from the generation center due to the increase of the transfer capability. Ignoring the line loss caused by this transfer capability increase, with the previously assumed 2 months of peak load, the benefit B_3 in $/MVar-year is $4,384 /MVar-year [($25/MWh - $20/MWh) x 8.43MW x 60day x 24hr / 14.01MVar].

III. Benefits From Var Source in A Multi-Bus System

The previous section illustrates the three benefits with a simple two-bus model; this section presents a generic formulation to assess the economic benefits of Var compensation via comparisons of three different cases of optimal generation dispatch. The dispatch is performed for the three cases using Optimal Power Flow (OPF) [19] with respect to transmission limits and inter-tie transfer capability limits. The three cases are as follows:

Base Case: Base system without Var compensation ($Q_c = 0$);
Case 1: Compensation is available at a given bus in a given amount and the original inter-tie transfer limit is maintained;
Case 2: Compensation is available as in Case 1 and a new inter-tie transfer limit is applied.

The objective of the OPF for the above three possible cases is to minimize the production cost. The constraints include the limits of the transmission networks. The dispatch formulation in the OPF model can be written as follows:

$$\text{Min: } \sum f(P_{Gi}) \tag{1}$$

Subject to:

$P_{Gi} - P_{Li} - P(V,\theta) = 0$ *(Real power balance)*

$Q_{Gi} + Q_{Ci} - Q_{Li} - Q(V,\theta) = 0$ *(Reactive power balance)*

$P_{Gi}^{\min} \le P_{Gi} \le P_{Gi}^{\max}$ *(Generation real power limits)*

$Q_{Gi}^{\min} \le Q_{Gi} \le Q_{Gi}^{\max}$ *(Generation reactive power limits)*

$V_i^{\min} \le V_i \le V_i^{\max}$ *(Voltage limits)*

$Q_{ci}^{\min} \le Q_{ci} \le Q_{ci}^{\max}$ *(Compensation limits)*

$\left|LF_l\right| \le LF_l^{\max}$ *(Line flow thermal limits)*

$\sum_{l\in Lt} S_l \le \sum_{l\in Lt} S_l^{\max}$ *(Tie line MVA transfer capability limits)*

where

$f(P_{Gi})$ = *generation cost function;*
Lt = *the set of tie lines;*
P_{Gi} = *generator active power output;*
P_{Li} = *load active power;*
Q_{Gi} = *generator reactive power output;*
Q_{Li} = *load reactive power;*
Q_{ci} = *Var source installed at bus i ;*
V_i = *bus voltage;*
LF_l = *transmission line flow;*
S_l = *line MVA flow.*

After the optimal dispatches are performed for the three cases, the benefits B_1, B_2 and B_3 can be calculated using the following approach. Assume Z_0, Z_1, and Z_2 are the fuel costs for the Base Case, Case 1, and Case 2, respectively. We have

$$B_2 = (C_L - C_G)\times \Delta P_{shift} \tag{2}$$

$$B_1 = Z_0 - Z_1 - B_2 \tag{3}$$

$$B_3 = Z_1 - Z_2 \approx (C_L - C_G)\times \Delta P_{inc\_trans} \tag{4}$$

$$B_t = B_1 + B_2 + B_3 = Z_0 - Z_2 \tag{5}$$

where

B_t = *the total benefit from local Var compensation;*
B_1 = *the benefit from reduced loss;*
B_2 = *the benefit from shifting reactive power flow to real power flow without considering change of transfer capability;*
B_3 = *the benefit from the increased transfer capability;*
C_G = *the marginal cost of the generators at the generation center;*
C_L = *the marginal cost of the generators at the load center;*
ΔP_{shift} = *the shift of reactive power flow to real power flow;*
ΔP_{inc_trans} = *the change of transferred power flow across the tie line.*

It should be noted that Eqs. (2) and (4) show that B_2 and B_3 are both linearly related to the cost difference of generators at the load center and the generation center. Also, since B_1 is generally small (at least for a congested hour when both B_2 and B_3 are applicable), the benefits are linearly related to the generation cost difference at the load center and the generation center. This can be verified in the test results.

The details to perform the benefit evaluation using Eqs. (2-5) are described as follows:

1. Perform OPF for Base Case and Case 1.
2. Calculate the reduced system losses from Base Case to Case 1, ΔP_{loss}.
3. Calculate the total reduced MW generation from Base Case to Case 1. Since this MW amount is $\Delta P_{loss} + \Delta P_{shift}$, then, ΔP_{shift} can be easily calculated.
4. Perform OPF for Case 2.
5. Apply Eqs. (2-5) to calculate the three economic benefits, B_1, B_2, and B_3.

IV. Var Economic Benefits Sensitivity Analysis to Generator Marginal Cost

The previous section has discussed the economic benefits of local reactive power compensation. This section investigates the sensitivity analysis of the economic benefit with respect to the generator marginal cost. This section is conducted in response to the sharp increase in gas price and the corresponding generator marginal cost.

The general procedure of Var benefit sensitivity analysis is implemented with GAMS (General Algebraic Modeling System) for two scenarios: (1) the load center generator marginal cost variation, and (2) the generator center generator marginal cost variation. These two scenarios have different effects on the economic benefits. Tests are performed in a standard system to verify the proposed approach. The basic procedure applied to sensitivity analysis is shown in Fig. 3. The sensitivity analysis process starts by repeatedly solving Case 1 and Case 2 models with different generator marginal costs at Bus i from b_{i1}~b_{in} (b_i is shown in Table 1). The benefits calculation includes Base Case, Case 1, and Case 2 introduced in section III.

The total fuel cost output is Z_0 in the Base Case, in which there is no Var compensation. Thus, Z_0 will not change in the entire process. If Case 1 is repeated at different generator marginal costs, b_{i1}~b_{in}, then different total fuel costs, $Z_{1,i1}$~$Z_{1,in}$, may be obtained. Then Case 2 may be repeated with b_{i1}~b_{in} as input, the corresponding output of total fuel costs in Case 2 may be written as $Z_{2,i1}$~$Z_{2,in}$. Finally, $B_{k,i1}$~$B_{k,in}$ (k = 1, 2, and 3) may be obtained following the procedure introduced in section III.

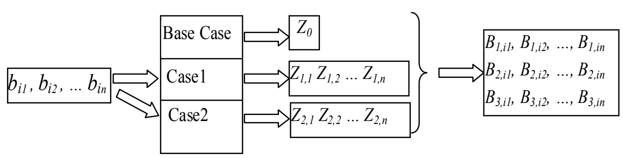

Fig. 3. GAMS scheme for sensitivity analysis.

V. CASE STUDY WITH RESULTS

A. Test System

In this section the seven-bus test system from PowerWorld [10] is used to demonstrate the test results. The diagram of the test system is shown in Fig. 4. The data for the loads, generation, transmission thermal limits, and voltage limits are shown in Table 1. The test system is divided into two areas, the Top Area (Load Center) and the Bottom Area (Generation Center), as shown in Fig. 4 and Table 2. The generators in the load center are more expensive than those in the generation center.

The interface tie lines between the two areas are line 6-2 and line 7-5. The voltage stability limit, i.e., the nose point of the P-V curve, is 464 MVA, which is lower than the sum of their thermal limits (500 MVA). If the voltage stability margin is assumed to be 25%, then the interface transfer limit is 464 *75%=348 MVA for Base Case. The OPF models for the three cases are solved by the Nonlinear Programming (NLP) solver MINOS. Var compensation is assumed to be 15 MVar at Bus 3, where the voltage in the lowest in the base case.

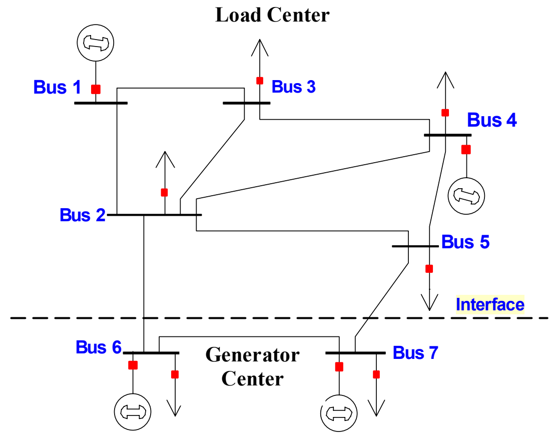

Fig. 4. Diagram of a seven-bus test system.

Table 1. Parameters of the test system

Power base: 100MVA							
Voltage base: 138kV							
Load							
Bus	1	2	3	4	5	6	7
P_L (MW)	0	100	190	150	200	50	80
Q_L (MVar)	0	40	75	50	60	20	40

Generator fuel consumption cost coefficient ($cost = a + b \times P_G$)				
Bus	1	4	6	7
a ($/hr)	798.92	814.03	515.34	400.41
b ($/MW*hr)	20	19	14	15
Marginal Cost ($/MW*hr)	20	19	14	15
Active power generation limits (MW)				
Bus	1	4	6	7
P_G^{max}	150	200	300	300
P_G^{min}	70	50	60	0
Reactive power generation limits (MW)				
Bus	1	4	6	7
Q_G^{max}	100	100	100	100
Q_G^{min}	-100	-100	-100	-100

Transmission line thermal limits (MVA)										
Line	1-2	1-3	2-3	2-4	2-5	4-3	5-4	6-2	6-7	7-5
Limit	120	100	100	100	100	120	80	250	100	250

Voltage limits (p.u.)
V_{max} =1.05 and V_{min}=0.95 for every bus.

Table 2. Load and Generations in Two Areas

Area	Bus	Gen. Cap. (MW)	Load (MW)	Margin (MW)
Load Center	1, 2, 3, 4, 5	350	640	-290
Gen. Center	6, 7	600	130	470

B. Results

This section focuses on two scenarios: (1) generator marginal cost increase in the load center, (2) generator marginal cost increase in the generator center. These two scenarios have different effects on the economic benefits.

The marginal costs of the generators at Bus 1, Bus 4, Bus 6, and Bus 7 in the Base Case are \$20/MWhr, \$19/MWhr, \$14/MWhr, and \$15/MWhr, respectively. One hundred steps will be executed to increase the generator marginal cost in this case. In total, \$10/MWhr cost increase will be tested using \$0.1/MWhr for every step. Also, it should be noted that the results combine B_1 and B_2 together to since B_1 is relatively small when both B_2 and B_3 are considered.

1) Generator marginal cost increase in load center. Generator dispatch in the Base Case versus generator marginal cost increase at Bus 1 is shown in Fig. 5. The generator at Bus 1 is already the most expensive one among the four generators. It will continue to be the most expensive one when its marginal cost increases. That is why its cost increase does not affect the dispatch as shown in Fig. 5.

In this case, the cost of the marginal generator at the load center, C_L, increases. However, the cost of the generators at the generation center, the shift of reactive power flow to real power flow, and the increased real power transfer all remain constant due to the unchanged dispatch. From Eqs (2-5), it can be concluded that B_2 and B_3 have a positive linear relationship with the Bus 1 generator marginal cost increase as shown in Fig. 6. Considering B_1 is relatively small in this case, the observed results in Fig. 6 match Eqs (2-5) very well.

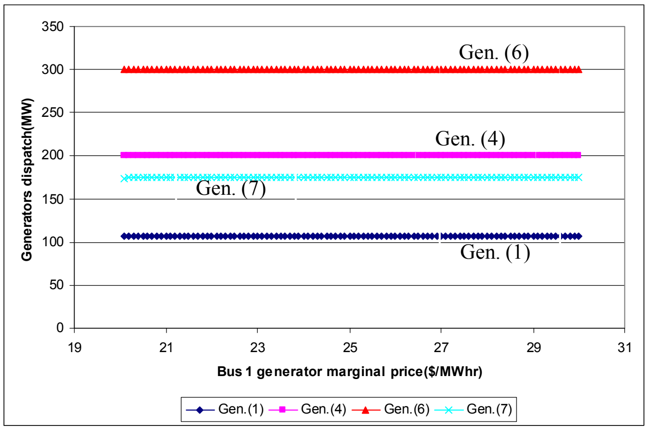

Fig. 5. Generators dispatch in Base Case versus generator marginal cost increase at Bus 1.

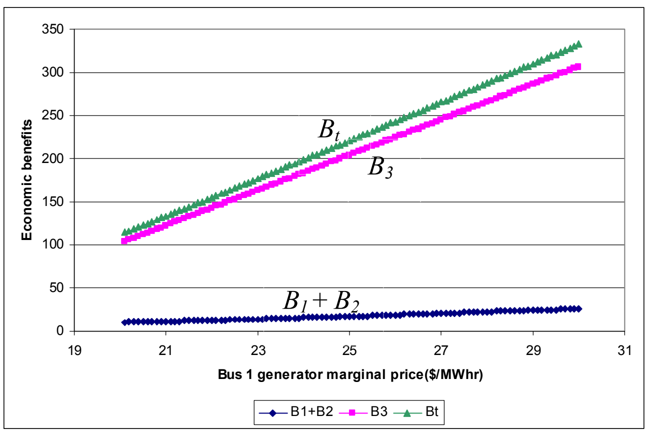

Fig. 6. Economic benefits versus generator marginal cost increase at Bus 1.

Generators dispatch in the Base Case versus generator marginal cost increase at Bus 4 is shown in Fig. 7. The generator at Bus 4 is the second most expensive one in the system. Its dispatch remains a constant at the beginning until it drops to some lower level when it becomes the most expensive generator with the marginal cost increase. At the same time, the dispatch of the generator at Bus 1 increases to compensate the dropped portion of Bus 4 generator dispatch because Bus 1 generator is cheaper than Bus 4 generator.

Different from Fig. 6 that shows a continuous increase of economic benefits when Bus 1 generator cost grows, Fig. 8 shows a different pattern of benefit variation when Bus 4 generator cost increases. In this case, B_1, B_2 and B_3 are constant at the beginning of the curve when Bus 4 generator is a non-marginal unit, i.e., fully dispatched at 200 MW. Thus, the variation of its cost does not affect its dispatch and the other generators' dispatches. This may be a little different from intuition because one might expect a change of benefit when generation cost increases. This also shows a very important feature in Var benefit sensitivity analysis. That is, the change of benefit is determined by the marginal unit(s). However, once the cost variation of a non-marginal unit is large enough such that Bus 4 generator becomes a marginal unit, then the growing pattern observed in Fig. 6 will occur, as shown in the latter part in Fig. 8.

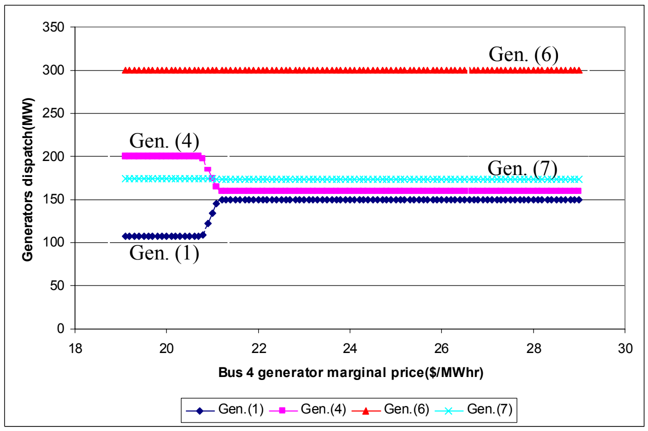

Fig. 7. Generators dispatch in base case versus generator marginal cost increase at Bus 4.

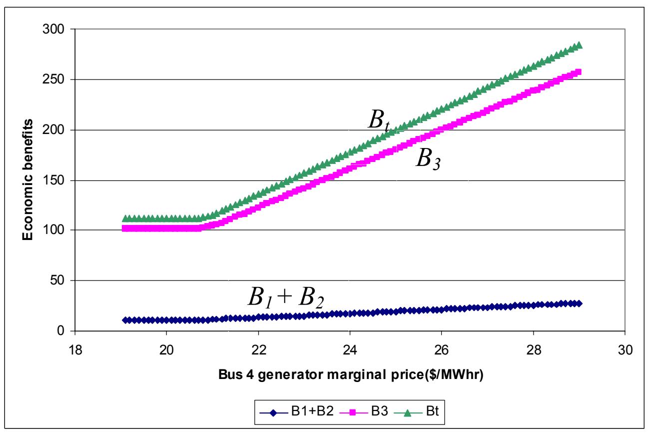

Fig. 8. Economic benefits versus generator marginal cost increase at Bus 4.

In general, the increase of generator marginal cost in the load center has positively contributed to the Var economic benefits since the generator marginal cost difference between the load center and the generation center is positively proportional to the benefits. Thus, if the fuel cost, especially the cost of marginal units, increases in the load center, the economic benefits tend to increase. In short, the Var compensation benefit will be positively impacted by the increase of generator marginal cost in the load center.

2) Generator marginal cost increase in generator center. Generators dispatch in Base Case versus generator marginal cost increase at Bus 6 is shown in Fig. 9. The Bus 6 generator is the cheapest one among all four generators. The dispatch does not change until generator marginal cost at Bus 6 exceeds that of Bus 7 generator, at which Bus 6 generator becomes a marginal unit. There is another dispatch exchange between the generators at Bus 6 and Bus 1 when the marginal cost at Bus 6 exceeds that of Bus 1; as a result, Bus 1 generator is fully dispatched. It should be noted that there is no dispatch exchange between the generators at Bus 6 and Bus 4 due to transmission limits.

Similar to Fig. 8, Var economic benefit versus Bus 6 generator cost, as shown in Fig. 10, remains unchanged at the beginning part because Bus 6 generator is fully dispatched. Afterward, it is followed by a steep decline until B_3 drops to zero. The reason of the decline is that the cost difference between the generation center and the load center, i.e., $(C_L$-$C_G)$, shrinks. The curves in Fig. 10 end as a constant when all four generators are dispatched at a fixed amount, with three generators being dispatched at their upper limits.

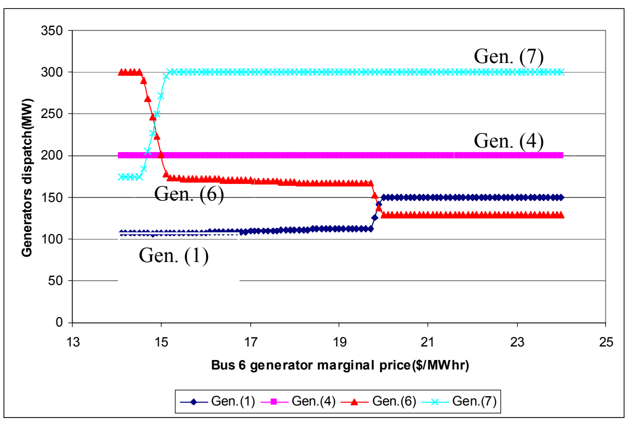

Fig. 9. Generators dispatch in base case versus generator marginal cost increase at Bus 6.

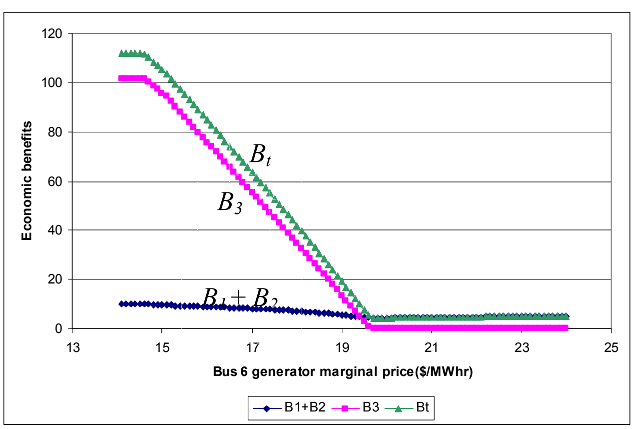

Fig. 10. Economic benefits versus generator marginal cost increase at Bus 6.

Generators dispatch in the Base Case versus generator marginal cost increase at Bus 7 is shown in Fig. 11. One dispatch exchange happens between Bus 7 generator and Bus 1 generator when the marginal cost at Bus 7 goes beyond that of Bus 1. The dispatches after the exchange all remain constant as each of the other three generators reaches its individual upper limit.

Fig. 12 demonstrates the economic benefits versus generator marginal cost increase at Bus 7. Its trend is very similar to Fig. 10 except that the beginning constant part of the curve as Bus 7 generator is not fully dispatched initially. Thus, the economic benefits drop with the $(C_L$-$C_G)$ shrinking from the start until the generators at Buses 1, 4, and 6 are all fully dispatched. The marginal cost increase in the generator center could be attributed to the Var benefits decrease. In other words, the increased tie line transfer capability may be worthless if no cheaper power is ready to be transferred.

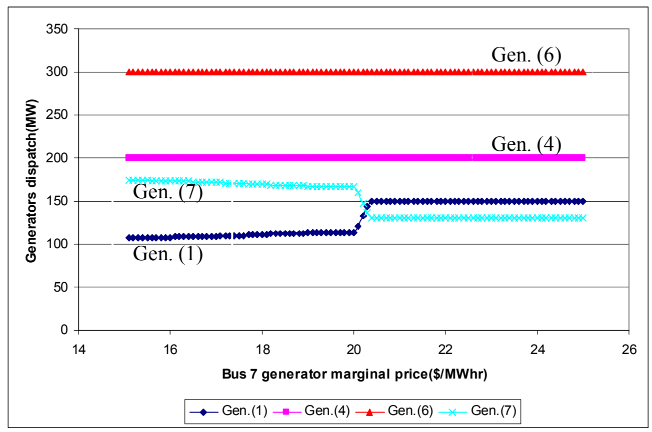

Fig. 11. Generators dispatch in base case versus generator marginal cost increase at Bus 7.

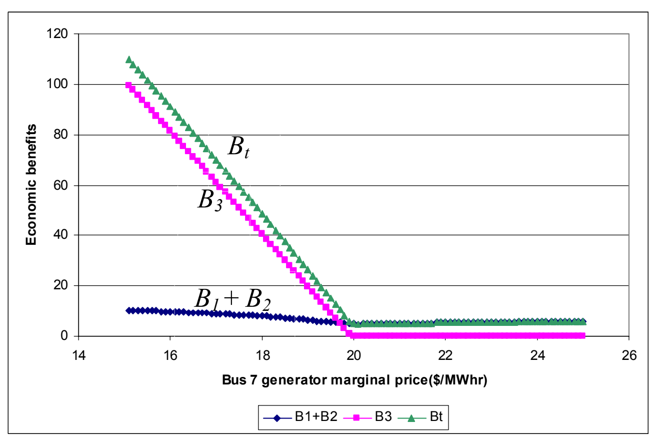

Fig. 12. Economic benefits versus generator marginal cost increase at Bus 7.

VI. CONCLUSIONS

Since the late 1990s, restructuring in electric power systems has resulted in a large addition of gas-fired generation capacity, with over 200,000 MW of new gas-fired capacity built at a cost of more than US$100 billion [15]. Unfortunately, the natural gas price surged in 2004. As a result, the marginal cost of some generators burning gas also rose. This paper investigates the impact of generator marginal cost increase on the Var economic benefits. The conclusions and discussions based on this research are summarized as follows.

- The major and quantifiable economic benefit may be classified into three categories: reduced losses, shifting reactive power flow to real power flow, and increased transfer limit.
- The sensitivity analysis of Var economic benefits with respect to the generator marginal cost can be used to predict the Var benefits change if the fuel price varies. This is particularly important if there are units like gas turbine generators in a power system, because they are usually the marginal units to clear electricity market dispatch, especially during peak hours.
- The interesting trend revealed in the benefits sensitivity analysis is that in general a positive relationship exists between the generator marginal cost in the load center and the Var economic benefits, and a negative relationship exists between the generator marginal cost in the generation center and the Var economic benefits. The reason of such relationship is that the generator marginal cost difference between the load center and the generation center is positively proportional to the benefits.
- In general, the generators in the load center are more expensive gas turbine generators whose cost is easily affected by the fuel price, so the positive relationship between the marginal cost and the benefits is typical. Usually, the generators in the generation center are low-cost hydro or coal-fire generators whose cost is insensitive to the fuel price.
- Generator fuel cost variation is usually not equally applied to all units in both generation center and load center. In addition, different generation company may have different efficiency in reducing marginal cost after deregulation. Further researches are necessary to investigate the Var benefit sensitivity in a much larger power system with complicated combination of gas units, coal-fire units, hydro unit, etc.

VII. References

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IX. Biographies

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