Pricing power system stabilisers using game theory

A. Andreoiu, K. Bhattacharya and C. Cañizares

Abstract: A method to quantify the individual contribution of power system stabilisers (PSSs) to enhance system performance is proposed. Enhancement in system performance from PSS is measured through increased system transfer capability and the margin of stability thus achieved, and considering an $N-1$ contingency criterion. The method is based on cooperative game theory and makes use of the Shapley value concept, pinpointing the importance of a particular PSS to the system performance in all possible combinations in which it can operate. Based on this quantification of the contribution of a PSS, a feasible financial compensation mechanism to pay generators for the services rendered is proposed and illustrated using a sample system. It is argued that, within a deregulated environment, it would be appropriate that generators having an online and optimally tuned PSS be regarded as PSS-control ancillary service providers.

List of symbols

C	set of possible coalitions
C_m	possible coalition of players
K_c	PSS gain
LF	load factor
n	total number of players
N	set of players
q	size of coalition
p	number of possible coalitions
PSS	power system stabiliser
T_1, T_2	PSS time constants
T_w	PSS wash-out filter time constant
μ_i	control signal from ith PSS
$v(C_m)$	payoff from coalition C_m
$w(C_m)$	weight on coalition C_m
Ψ_i	marginal contribution of PSS
ρ	payment function
ϕ	weighted average of marginal contributions of player in all possible coalitions (Shapley value)
σ_{MW}	worth of unit increase in system transfer capability
σ_C	benefit from coalition C

1 Introduction

In a deregulated environment the independent system operator (ISO) is faced with the difficult task of providing security-constrained transmission services in a fair and equitable manner. Transmission networks are subjected to increasingly heavier stress because of the various trades and transactions taking place among parties. These networks were originally designed to accommodate transactions based on only certain load/generation patterns at best. In a deregulated environment the generation and load patterns resulting from market activities are different, in principle, from the ones used in network planning, possibly worsening the security and stability margins.

Ancillary services are all those activities that are necessary for the ISO to support power transmission while maintaining reliable and stable operation. Procurement, operation and management of these services is therefore often the responsibility of the ISO. These services include regulation of frequency and tie-line power flow, voltage and reactive power control, system stability and security, maintenance of generation and transmission reserves, and many others. According to NERC Operating Policy-10 the following services are recognised as ancillary services [1, 2]:

a for maintaining generation and load balance
- (i) regulation service
- (ii) load following service
- (iii) contingency reserve service

b for bulk transmission system security
- (i) reactive power supply from generation sources
- (ii) frequency response service

c for emergency preparedness
- (i) system back start capability

From this classification NERC has recognised the governor and the excitation system of synchronous generators as ancillary service providers. Through the governor control action the generator provides regulation service *a*(i), load following service *a*(ii) and frequency response service *b*(ii); while by virtue of the excitation control action it provides reactive power service *b*(i). While this is very appropriate in the context of operating the system in a deregulated environment, there are some aspects that require further consideration.

Power system stabilisers (PSSs), which act through the excitation system of the synchronous generator and provide a supplementary control signal to damp out low-frequency oscillations, have long been accepted and recognised as essential means for stable and secure system operator [3–6].

IEE Proceedings online no. 20045247
doi:10.1049/ip-gtd:20045247
Paper first received 14th November 2004 and in final revised form 22nd June 2005

A. Andreoiu is with Department of Electrical and Computer Engineering, University of Manitoba, Winnipeg, Canada MB R3T 5V6. At the time this work was carried out, he was with Department of Electric Power Engineering, Chalmers University of Technology, Gothenburg, Sweden
K. Bhattacharya and C. Cañizares are with Department of Electrical and Computer Engineering, University of Waterloo Canada, N2L 3G1
E-mail: adrian@ee.umanitoba.ca

These devices render a service to the system by providing damping action when system disturbances influence transmission security and reliability. Although this damping action is provided through the excitation system of the synchronous generator, this is not accounted for by NERC classification since the change in reactive power due to PSS damping action is marginal (PSS essentially contributes to system stability and security by providing a *torque* component through the excitation system).

In the light of this, one can readily argue that PSS controllers provide a similar service to that provided by the governor and excitation systems in maintaining bulk transmission system security. It is therefore reasonable to argue that the PSS should also be considered an ancillary service provider, within NERC definitions, in exactly the same manner as the generator governor and excitation systems. Such a classification supports the fact that various operating authorities (e.g. WECC) require the installation of a PSS in generators connected to the grid, and at the same time recognises the importance of the services provided by these controllers, thus motivating energy suppliers to properly tune and utilise PSS to improve, instead of hinder, system security, which is a concern for system operators nowadays.

System security considerations are critical for healthy and efficient market operation, therefore these play an important role in system transfer capability limits. Thus system transfer capability, and hence the amount of allowable transactions in electricity markers, needs to be evaluated based on system security to ensure operational feasibility. In this context, an important issue that has emerged from deregulation is how the ISO can maintain system security at a desired level, and to do so, what system support services (ancillary services) it requires, and how such services are procured and compensated for.

Determining the cost of system security has also been of significant interest in power systems [7–13]. In most of these works, Lagrange multiplier based methods are used to analyse the different cost components. The idea of pricing security is first advanced in [8] by considering line flow constraints: contingency pricing is studied in [9], and the costs related to outages are analysed in [10]. In [11, 12] an OPF-based technique is proposed wherein possible ways of costing voltage security are discussed; the effect of minimising operating cost, reactive power generation and/or maximising loading margins are compared in these papers. In [13] a transaction security cost analysis is carried out using a risk-taking strategy that provides proper market signals to the participating players in the market. These articles concentrate on discussing the issue of pricing system security from a power-flow perspective, and there is no actual consideration of power system dynamics in general, and PSSs in particular, which is the main thrust of this paper.

In the light of all these factors, the issue of pricing the services that PSSs provide for the enhancement of system stability and security become very important, and is the main objective of this paper.

2 Background review

The problem of tuning and optimisation of PSS parameters in deregulated electricity markets is a challenging issue that has not been properly addressed yet. The issue of responsibility and coordinated tuning of PSS are among the most important issues associated with PSS services in a deregulated environment. As of now, no definite guidelines have been established by the ISOs or equivalent authorities concerning this issue. Nevertheless, some operating authorities have outlined certain rules on PSS installation requirements on synchronous generator. For example, the Western Electricity Coordinating Council requires that PSS be installed on certain synchronous generators of a given capacity and excitation system type [14].

In this paper the importance of each single PSS in a system is examined in detail and the extent to which it contributes to system stabilisation is made; evidently, a coordinated PSS setting will have a beneficial influence on system performance. While in a centralised system this matter can be solved solely through regulations, in a deregulated and competitive environment, as in the case for voltage control, giving incentives to service providers is a more logical approach. In this context it is argued that PSS-control effort being provided by generators be considered part of the system ancillary services, hence be eligible for financial compensation. Thus, as explained subsequently, the importance of a PSS in enhancing the electricity market clearing capability providing the ISO with a source operating margin is used to develop possible mechanisms for financial compensation to generators for such services.

Generally it is not a straightforward exercise to evaluate the worth and contribution of an individual PSS to system welfare due to the complexity and difficulty associated with relating the performance of a PSS to a financial cost that would quantify system welfare (savings) accrued from a coordinated PSS. Part of the complexity also arises from the way the system performance is measured and valued. To address these issues a game theoretic approach is employed.

Game theory has found recent application in power system, particularly in the context of deregulation. In [15], a game-theoretic approach is proposed to simulate the decision-making process for defining offered prices in an open market. In [16] a Nash bargaining game is used for power-flow analysis in which each transaction and its optimal price are determined to optimise the interest of individual parties. In [17] a Shapley value based method is proposed to share the transmission costs incurred to accommodate all the system loads. A similar approach is used in [18] to determine the allocation of cost savings and emission trading amongst participating utilities in an energy brokerage system.

A cooperative game theoretic approach based on Shapley values is used here to determine the marginal contribution of each PSS in the system, and hence how each PSS should be paid for the control service it provides. In other words, Shapley values are used to allocate payoffs to each player (i.e. generator equipped with PSS) in the system, depending on how important the PSS is to overall system stability and security.

It is important to emphasise that the present paper does not propose a market for PSS-control services, but rather concentrates on proposing only a payoff mechanism to generators, to entice them to participate in a cooperative environment. A competitive market for such services is infeasible at this stage because of its specialised nature, often depending on the location of generators in the system, and can give rise to market inefficiencies from gaming and strategic operations.

3 Payoff allocation to generators providing PSS-control service

In *game theory* parlance, in accordance with the way in which the players interact with one another in a given game and the extent to which they influence each other's decisions, the game can be classified into two major categories, namely *cooperative* or a *non-cooperative game*. In a *non-cooperative game*, strategies are chosen by the players independently, the rules would not allow players to join forces and coordinate actions for better outcomes. On the other hand, in a *cooperative game*, the players have strictly identical interests or certain agreements and/or other commitments are enforceable on the players [19].

In most deregulated power system it would be the responsibility of the ISO or a similar entity to evolve a coordinated PSS tuning and operation strategy based on certain system-wide objective function. Therefore the PSSs operation can be modelled as a cooperative game, having as its characteristic function a benefit formulation which is based on the objective function used in the tuning process, and where one or more generators are considered together (in all possible *coalitions*) to obtain a fair revenue allocation. Thus the analysis of the worth of PSS-control ancillary service is based on two important issues: how the coalitions are formed amongst the PSSs, and consequently how the benefit from a PSS service is allocated. In these two interrelated issues, our main concern is to obtain the most likely outcome from various game situations. Particularly when it comes to distribution of the benefits due to PSS control action, the revenue corresponding to a PSS in a particular coalition is very difficult to evaluate.

An intuitively attractive solution concept for *n*-person co-operative games with transferable utility (payment, in this case) has been proposed by Shapley in 1953 [20], and is referred to as the Shapley value. The Shapley value can be defined by means of the following postulates [19]:

- *Joint efficiency*: The sum of all players' payoffs equals the value of the *grand coalition* (*n*-player coalition, which is the highest joint payoff the *n* players can achieve within the game). In this particular problem the sum of the individual payments to each PSS is what the ISO accrues as benefit by having PSSs at all generators (grand coalition).
- *Zero payoff to any dummy players*: If a player fails to contribute anything to the value of any coalition that he may join, then he is called a *dummy player*; the payoff to a dummy player is zero. In large interconnected power systems a generator that is completely isolated from the system and from other generators can be called a *dummy player* because it has no role in providing for system stabilisation service. Such a generator is not eligible to receive any payment from the ISO.
- *Symmetry*: If all players are identical they share the total system savings equally. This postulate, however, does not play a significant role in the problem studied here, since generators have different characteristics.
- *Additivity*: The payoff to any given players is equal to the sum of all payoffs that player would receive as a member of all possible coalitions. This means that the payment actually received by a generator reflects how each PSS contributes to enhancing system security, being the sum of its contribution in all possible coalitions.

Based on these concepts, in [19] the marginal contribution Ψ of a player i in a particular coalition C_m (belonging to the set of possible coalitions C) is given by

$$\Psi_i(C_m) = v(C_m) - v(C_m \backslash \{i\}), \quad \forall i \in C_m \tag{1}$$

where $v(C_m)$ is the payoff from coalition C_m. The Shapley value ϕ, which is the weighted average of the marginal contributions of a player i in all possible coalitions p, is hence given by

$$\phi_i = \sum_{m=1}^{p} w(C_m) \cdot \Psi_i(C_m), \quad \forall i \in N \tag{2}$$

where N is the set of players, and

$$w(C_m) = \frac{(n-1)!(n-q)!}{n!} \tag{3}$$

in which q is the size of a coalition (i.e. the number of players in a given coalition), and n is the total number of players in N.

Having obtained the contribution of a PSS to system benefits, a mechanism for financial compensation to synchronous generators for their PSS-control service can now be devised for the ISO. It is proposed that a payment function comprises a fixed component ρ_F, associated with PSS availability at a generator, and a variable component ρ_V, proportional to the worth of PSS in enhancing system transfer capability, i.e.

$$\rho_i = \rho_{F_i} + \rho_{V_i}, \quad \forall i \in N \tag{4}$$

The last-mentioned component is a function of the generator's Shapley value. The proposed payment function (4) then implies that a generator is entitled to the constant component of payment even if the ISO instructs that the said PSS remains offline.

An important aspect in ancillary services is the way in which they are handled and managed by the ISO. Many times, ancillary services, such as spinning reserve, regulation, etc., are part of the market clearing process and the suppliers have to simultaneously bid for energy and these ancillary services [21]. On the other hand, certain services such as reactive power support can be on long-term contracts as in the UK where biannual tenders are held to establish the contracts [22]. It is envisaged that a PSS-control ancillary service would also be on long-term contracts between generators and ISO, so that short-term price volatility due to emergency system conditions does not significantly affect the payment structure.

4 Results and analysis

4.1 Test system

A three-area interconnected power system has been used in this paper (Fig. 1) to illustrate the proposed technique. Areas I, II and III house the three major system loads- A, B and C as shown in the Figure; each load represents a

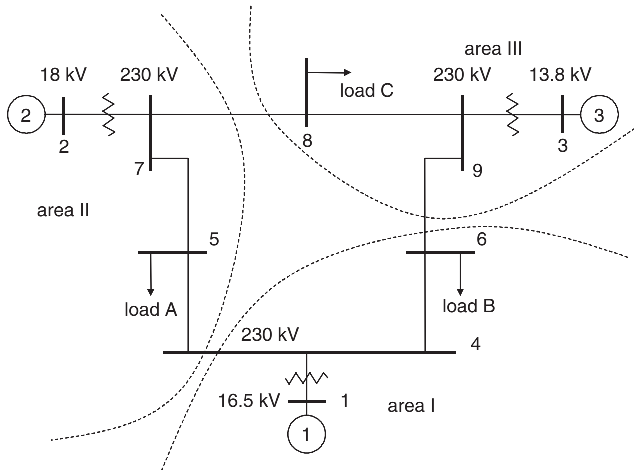

Fig. 1 *Three-area interconnected power system*

Table 1: PSS parameter settings in equivalent generators of each area

	Area I	Area II	Area III
Gain *Kc*	45.06	45.52	2.13
Time constant T_1	0.17	0.06	0.44

different load type, namely industrial, residential and commercial, respectively. Each area carries out its own generation scheduling and the schedules are available to the ISO in advance. The generators are all equipped with PSS which, for our analysis, are considered to be of the lead–lag type with gain K_c, time constants T_1 and T_2, and wash-out filter time constant T_w. The transfer-function representation of the PSS on the *i*th generator is given as follows:

$$u_i(s) = K_{c_i}\frac{sT_{w_i}}{1+sT_{w_i}}\left(\frac{1+sT_{1i}}{1+sT_{2i}}\right)^2 \Delta\omega_i, \quad \forall i \in N \qquad (5)$$

In (5) u_i is the output signal from the PSS that provides the corrective action to damp the low frequency electromechanical oscillations. The lead–lag PSS derives its input from the rotor speed deviation $\Delta\omega$.

Table 1 provides the set of PSS parameters as obtained in [23] using a given tuning technique, which is considered fixed in the present analysis, i.e. the PSS do not change. Time constant T_w and T_2 are fixed at 10 and 0.05 seconds, respectively [4].

4.2 System transfer capability and payoffs for PSS-control service

With all PSSs online, the system loading is now increased gradually and uniformly at all buses using a load factor (LF) that denotes the load increase with respect to the base load. This load increase scenario is used only to illustrate the effect of PSS on the system transfer capability and damping, which is assumed to change throughout the operating day, as illustrated in Section 4.4. The dominant eigenvalue of the system shifts towards instability as the system loading is increased, or in other words, the damping factor ξ decreases monotonically as the LF increases. A typical damping factor of $\xi = 7\%$ is considered as a cut-off value, i.e. beyond which the market shall not be cleared; such a criterion may be imposed by the ISO to maintain a reasonable margin of system security. This is demonstrated in Fig. 2.

By setting the PSSs to offline status in all possible combinations, all the *feasible coalitions* (PSSs manage to maintain the system stability) in which the three PSS may operate are obtained. Coalition C-123 denotes the coalition in which all PSSs are in service (the grand coalition); the maximum LF up to which the market may be cleared if the load would increase uniformly (the point F where the damping factor intersects the cut-off damping $\xi = 0.07$) is 1.64 pu, which corresponds to a total of 516.6 MW (system base loading is 315 MW), that in turn translates to an improvement in system transfer capability of 201.6 MW with respect to *base loading*.

Observe from Fig. 2 that, as expected, different coalitions have different effect on the system transfer capability. Consequently one can also examine their effect on system transfer capability, as explained here for coalition C-123 (Fig. 2). Thus, assuming that the worth of unit increase in system transfer capability with respect to the base loading is \$10/MW. i.e. $\sigma_{MW} = \$10/\text{MW}$, the benefit from a specific

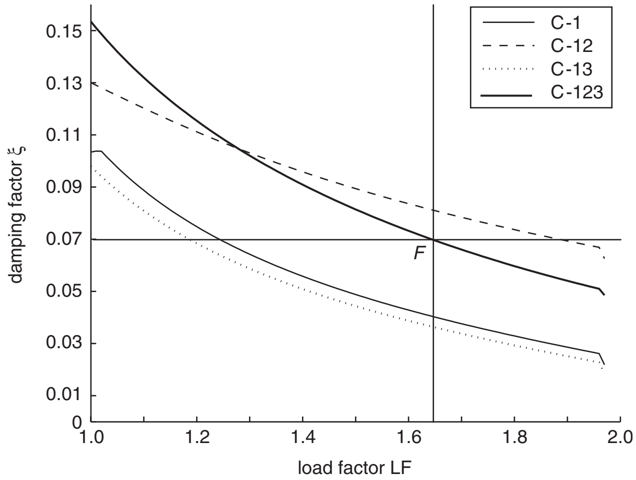

Fig. 2 *P–ξ curve for normal operating conditions (i.e. no contingencies) for uniform loading increase scenario*

PSS coalition σ_C can be calculated. The value of $\sigma_{MW} = \$10/\text{MW}$ used here is only to demonstrate the proposed method; in real system the ISO would be required to determine/negotiate the actual value σ_{MW}, i.e. the worth given to one MW increase in system capability, since this value is only being used as a relative measure of how secure the system is.

As the market is cleared at these loading conditions, the individual generators would be entitled to an additional payment in return for providing the PSS-control ancillary service and improving the system transfer capability. Consequently, the ISO's problem is to allocate the total worth σ_C, achieved from PSS operation in a fair and rational manner. Table 2, based on each coalition's benefits σ_C outlines the application of the Shapley value criterion introduced earlier and yields the fair share of payment each PSS would be entitled to, in dollars, for a 315 MW loading level. Note that, for each PSS the values of ϕ_{PSS} denote the terms of the Shapely value (2); $\sigma_C = 0$ MW for an infeasible coalition, and dashes are used to identify for each PSS the coalitions in which it does not participate (e.g. PSS-1 does not take part in coalitions C-2, C-3 and C-23). Also, this analysis would depend on the actual market clearing conditions, i.e. actual generation and load levels, which change throughout the day.

From Table 2 it can be observed that the Shapley values, and consequently the variable payment components for areas I, II and III are \$1,480.5, \$819 and −\$283.5, respectively. This translates into a 73.44% share of the payoff to area I, 40.63% to area II and −14.1% to area III in the variable component. The negative Shapley value associated to area III denotes that it would receive a negative variable component of payment for introducing an overall detrimental effect on system transfer capability. This is evident from the fact that PSS 3 has a negative marginal in coalition C-13.

4.3 System transfer capability and payoffs considering contingencies

Once a method of determining the payoffs to participating generators is in place it would be of interest to investigate if such payoff obtained for the normal operating condition at a given time will still be a fair allocation in a contingency state when there is a change in system topology. This is important, since typically an $N-1$ contingency criterion is used to define system security levels. To this effect a set of

Table 2: Shapley value based payment allocation to generators

	C-1	C-2	C-3	C-12	C-13	C-23	C-123	Shapley value ϕ_i, \$
σ_C, \$	756.0	0	0	2,772.0	567.0	0	2,016.0	
w	1/3	1/3	1/3	1/6	1/6	1/6	1/3	
area I								
ψ, MW	75.6	–	–	277.2	56.7	–	201.6	1,480.5 (73.44%)
ϕ_{PSS_1}, MW	25.2	–	–	46.2	9.45	–	67.2	
area II								
ψ, MW	–	0	–	201.6	–	0	144.9	819.0 (40.63%)
ϕ_{PSS_2}, MW	–	0	–	33.6	–	0	48.3	
area III								
ψ, MW	–	–	0	–	−18.9	0	−75.6	−283.5 (−14.1%)
ϕ_{PSS_3}, MW	–	–	0	–	−3.15	0	−25.2	
Total payment, ρ								2,016.0

Table 3: System transfer capability considering contingencies

		CTG-1	CTG-2	CTG-3	CTG-4	CTG-5
Transfer capability, MW	C-1	0	0	0	148.05	88.2
	C-12	72.45	0	0	144.90	220.5
	C-13	0	0	0	97.65	63.0
	C-123	72.45	110.25	179.55	179.55	173.25

contingencies represented by the outage of one transmission line at a time was considered. Note that outage of line 4–5 was not included since there was no feasible power flow solution for this contingency, which would lead to a voltage collapse problem that is beyond the scope of this paper. Hence, the following contingencies are considered: 4–6, 5–7, 6–9, 7–8, 8–9, denoted by CTG-1–CTG-5 respectively.

Table 3 shows, for all feasible coalitions and considering all contingencies, the amount of power, over and above the nominal load that the system can serve without infringing any operation constraints, while $\xi \geq 0.07$ at the previous 315 MW loading level.

Based on the foregoing one can obtain the total enhancement in worth from PSS operation σ_C and consequently determine the payoffs to the generators in each contingency case, using the method of Shapley values (Table 4).

As observed in Table 4, the payoffs to the three areas vary considerably across contingencies, as expected, given that the contribution and significance of a PSS does not remain the same in all operating conditions or system configurations.

Figure 3 depicts the variable payoff shares for the generators in return from the PSS-control service for the normal operating condition and under contingencies CTG-1 to CTG-5. It is evident how the system topology affects the payment allocation, as a direct results of the impact a contingency has on PSS contribution to system security. Hence, the contribution of a PSS in various operating conditions or system configurations can be appropriately recognised and paid for using the proposed scheme.

Table 4: Payoffs to areas considering contingency conditions

		Area I	Area II	Area III
CTG-1	σ_C, \$		724.5	
	ϕ, \$	362.25	362.25	0
	ϕ, %	50	50	0
CTS-2	σ_C, \$		1,102.5	
	ϕ, \$	367.5	367.5	367.5
	ϕ, %	33.33	33.33	33.33
CTG-3	σ_C, \$		1,795.5	
	ϕ, \$	598.5	598.5	598.5
	ϕ, %	33.33	33.33	33.33
CTG-4	σ_C, \$		1,795.5	
	ϕ, \$			
	ϕ, %	1,496.3	267.8	31.5
		83.33	14.91	1.75
CTG-5	σ_C, \$		1,732.5	
	ϕ, \$	1,344.0	588.0	−199.5
	ϕ, %	77.58	33.94	−11.52

4.4 Practical application

Using the proposed Shapley value based method, the worth of the PSSs contribution can be determined in a more realistic scenario, which considers the $N-1$ security criterion. Thus, in Fig. 4, ξ for the dominant system eigenvalue in the grand coalition of PSS is plotted as a

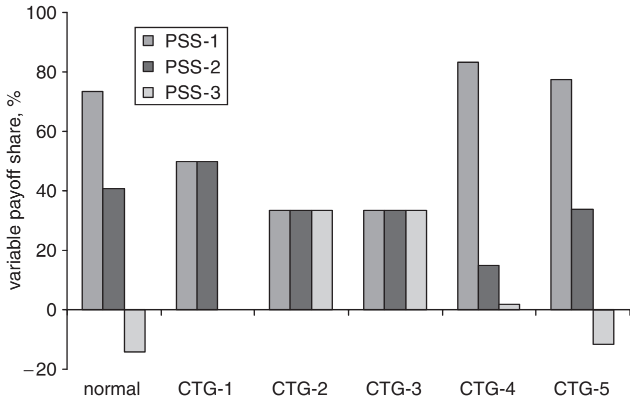

Fig. 3 *Variable payoff shares to generators for PSS-control service in different system operating conditions*

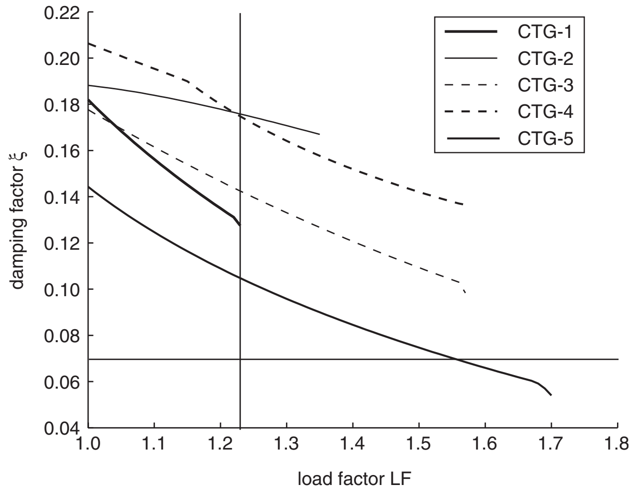

Fig. 4 *Grand coalition's damping factors during contingencies*

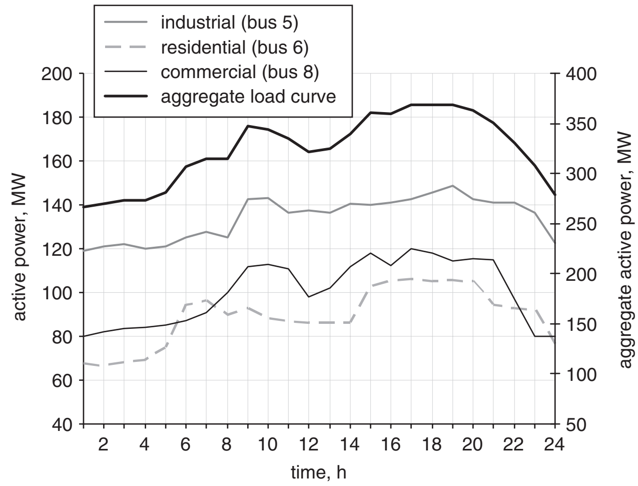

Fig. 5 *System aggregate load curve over 24-hour period*

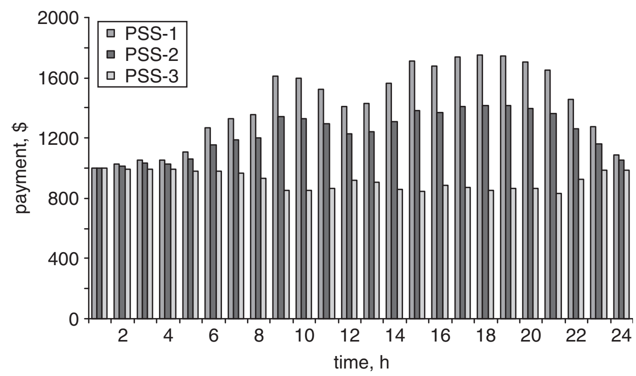

Fig. 6 *Payment allocation for PSSs over 24-hour period*

function of LF, for each contingency case. It is shown, for the grand coalition, how the contingencies affect the system from a transfer capability point of view. Evidently the worst contingency is that in which the system transfer capability is reduced to a minimum. In this example, it occurs when line 4–6 is out of service (CTG-1); hence CTG-1 is identified as the worst contingency and used here to implement the $N-1$ criterion. Observe in Table 3 that in this case the variable payoff is equally distributed between area I and area II, while no variable payoff is assigned to area III; this is fairly intuitive also, since PSS-3 from area III is not present in any of the feasible coalitions. However, area III will continue to receive the fixed component of payment ρ_F.

4.4.1 Payment allocation over 24-hour period: The total payoff to the generators for their PSS-control service over a 24-hours period, 1-hour time intervals, is now determined. The load curve used in this Section represents an actual market clearing, considering the $N-1$ security criterion and a 5% transfer reliability margin. Figure 5 shows typical daily load curves for the load buses and the aggregate system load curve used here. The $N-1$ contingency criterion used assures that the worst contingency for all loading conditions considered is CTG-1, which is reasonable for this system. Based on (4), the total payoff to each PSS is given for each hour k by

$$\rho_i^k = \rho_{F_i} + \phi_i \sigma_{MW} \Delta P_i^k, \quad \forall i \in N \tag{6}$$

where ϕ is the Shapley value (in per cent) and ΔP is the load variation in hour k. Considering a fixed payoff ρ_F of \$1000, the total payoff to each generator over a 24-hour period is determined, and the results are reported in Fig. 6. It can be observed that PSS-1 receives the highest payoff as it contributes more to the system transfer capability as discussed earlier, while PSS-3 receives less than the fixed component of payment as a result of its negative variable payoff component.

4.4.2 Practical implementation consideration: The computational burden of the proposed Shapely value based cost allocation method will be directly dependent on the size of the system. For example, in this paper a three-area system has been considered, and it has been further assumed that each area can be represented by a single synchronous generator and a PSS. Such dynamic equivalence of generators located within close electrical distances is possible, and consequently the computational size can be significantly reduced. This is also justifiable from the viewpoint of electricity markets in that the generators located in the same area are paid the same compensation for their services, because of their greater correlation and influence on the local dynamics. Further reduction in computing requirements can be brought about by reducing the number of times the method needs to be applied by dividing the load curves in classes of similar problems, i.e. identifying similar load change patterns, and by reducing the number of coalitions by filtering out the infeasible ones.

5 Concluding remarks

It is argued that PSS control action has an important impact on power system stability and security, and therefore should be regarded as a system ancillary service within the NERC Operating Policy guidelines for interconnected operations services. To this effect, a possible scheme for allocating payoffs to generators for their PSS-control services has been proposed. The payment scheme is based on cooperative game theory, using the concept of Shapley values. The system benefit accrued from a generator providing PSS-control service is allocated in a fair and rational manner, using our proposed approach, which is based on weighted marginal contribution of a PSS in all coalitions it may be part of, thus reflecting better the role and importance of that PSS to the system.

The proposed method concentrates on determining the relative contribution to system security enhancement of the various PSS present in the system, and is not directly dependent on specific dollar figures, which are assumed to be the result of contractual agreements between the service providers and the ISO. A realistic scenario represented by a 24-hour load curve, which is obtained considering three different load types and an $N-1$ contingency criterion, is also considered, demonstrating how loading conditions and system topology affect the payments to generators. Therefore it is important to recongnise the need of rescheduling the payment scheme in accordance with actual load levels and system topology.

6 Acknowledgment

This work was supported by the Elektra program of Elforsk AB, Sweden.

7 References

1 'NERC interconnected operation services reference document', North American Electric Reliability Council, 2002, [online]. Available: www.nerc.com
2 Bhattacharya, K., Bollen, M.H.J., and Daalder, J.E.: 'Operation of restructured power system' (Kluwer Academic, USA, 2001)
3 Kundur, P.: 'Power system stability and control' (McGraw Hill, 1994)
4 Kundur, P., Klein, M., Rogers, G.J., and Zywno, M.S.: 'Application of power system stabilizers for enhancement of overall system stability', *IEEE Trans. Power Syst.*, 1989, **4**, (2), pp. 614–626
5 Hoang, P., and Tomsovic, K.: ' Design and analysis of an adaptive fuzzy power system stabilizer', *IEEE Trans. Energy Convers.*, 1996, **11**, pp. 455–461
6 Abdel-Magid, Y.L., and Abido, M.A.: 'Optimal multiobjective design of robust power system stabilizers using genetic algorithms', *IEEE Trans. Power Syst.*, 2003, **18**, pp. 1125–1132
7 Strbac, G., Ahmed, S., Kirschen, D., and Allan, R.: 'A method for computing the value of corrective security', *IEEE. Trans. Power Syst.*, 1998, **13**, (3), pp. 1096–1102
8 Schweppe, F.C., Caramanis, W.C., Rabors, R.D., and Bohn, R.E.: 'Spot pricing of electricity' (Kluwer Academic, 1988)
9 Kaye, R.J., Wu, F.F., and Varaiya, P.: 'Pricing for system security', *IEEE Trans. Power Syst.*, 1995, **10**, (2), pp. 575–583
10 Alvarado, F., Hu, Y., Ray, D., Stevenson, R., and Cashman, E.: 'Engineering foundations for the determination of security costs', *IEEE Trans. Power Syst.*, 1991, **6**, (3), pp. 1175–1182
11 Rosehart, W.D., Cañizares, C.A., and Quintana, V.: 'Multi-objective optimal power flows to evaluate volatage security costs in power networks', *IEEE Trans. Power Syst.*, 2003, **18**, (2), pp. 578–587
12 Milano, F., Cañizares, C.A., and Ivernizzi, M.: 'Multiobjective optimization for pricing system security in electricity markets', *IEEE Trans. Powre Syst.*, 2003, **18**, (2), pp. 596–604
13 Chen, H., Cañizares, C.A., and Singh, A.: 'Transaction security cost analysis by Take-risk strategy'. Proc of Conf. on Power Systems Computation (PSCC), Spain, June 2002
14 Western Electricity Coordinating Council, 'Policy statement on power system stabilizers' [online]. Available: www.wecc.biz
15 Ferrero, R.W., Shahidehpour, S.M., and Ramesh, V.C.: 'Transaction analysis in deregulated power systems using game theory', *IEEE Trans. Power Syst.*, 1997, **12**, pp. 1340–1347
16 Bai, X., Shahidehpour, S.M., Ramesh, V.C., and Erkeng, Y.: 'Transmission analysis by Nash game method', *IEEE Trans. Power Syst.*, 1997, **12**, pp. 1046–1052
17 Tan, X., and Lie, T.T.: 'Application of the shapley value on transmission cost allocation in the competitive power market environment', *IEE Proc.- Gener., Transm. Distrib.*, 2002, **149**, (1), pp. 15–20
18 Chattopadhyay, D.: 'An energy brokerage system with emission trading and allocation of cost savings', *IEEE Trans. Power Syst.*, 1995, **10**, (4)
19 Harsanyi, J.C.: 'Rational behaviour and bargaining equilibrum in games and social situations' (Cambridge University Press, Cambridge, 1977)
20 Shapley, L.: 'Contribution to theory of games', *Ann. Math. Studies*, 1953, **2**, (28), pp. 307–317
21 Alvey, T., Goodwin, D., Ma, X., Streiffert, D., and Sun, D.: 'A security constrained bid clearing system for the New Zealand wholesale electricity market', *IEEE Trans. Power Syst.*, 1998, pp. 340–346
22 The National Grid Company plc., 'NGC Reactive Market Report: Fifth Tender Round for Obligatory and Enhanced Reactive Power Services', May 2000
23 Andreoiu, A., and Bhattacharya, K.: 'Robust tuning of power system stabilisers using a genetic algorithm based method', *IEE Proc.- Gener.-Transm. Distrib.*, 2002, **149**, pp. 585–592