Estimation of Power System Inertia Constant and Capacity of Spinning-reserve Support Generators Using Measured Frequency Transients

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Abstract - A procedure for estimating the inertia constant M (=2H) of a power system and total on-line capacity of spinning-reserve support generators, using transients of the frequency measured at an event such as a generator load rejection test, is presented. A polynomial approximation with respect to time is applied to the wave form of the transients in estimating the inertia constant, and a simple model based on the idea of average system frequency is assumed in estimating the capacity of the generators. Results of the estimation using the transients at 10 events show that the inertia constant of the 60Hz power system of Japan is around 14 to 18 seconds in the system load base, and the capacity of the spinning-reserve support generators is 20 to 40% of the system load. The proposed procedure is expected to be tested by Kansai Electric Power Company with increased number of events. This effort will contribute to estimate and evaluate the dynamic behavior of the system frequency in loss of generation or load.

1. INTRODUCTION

The frequency of a power system drops when the power supply of the system becomes insufficient due to a loss of major generation or tie line support. If the amount of drop is large, protection systems for low frequency may be activated in the power plants and the consequent shutdown of the plants may lead to the separation of the interconnected systems or black-out of the power system. Therefore it is important to grasp the characteristics of the frequency response of the power system to the loss of generation.

The exact approach to this subject is to develop a model for each power plant to simulate the response of its generating power to the frequency change with required accuracy. This approach recently applied to a relatively small power system is presented in [1]. At that literature, all power plants including the once-through boiler, the drum boiler and the combustion turbine in the power system are modeled, and the validity of each model is tested with measured data. Considerable efforts will be required to make a model for each power plant when one wish to apply the approach for a large power system. For interconnected power systems, moreover, information on the response of generating power plants of one's neighboring companies may not be easily available in general.

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In this paper, an approach with a different direction from the above exact approach is presented. The purpose of this approach is to estimate the inertia constant of a power system and total on-line capacity of spinning-reserve support generators, using transients of the frequency measured at an event such as a generator load rejection. This approach in cooperation with the exact approach will contribute to cultivate the insight to the behavior of frequency of a large power system.

A polynomial approximation with respect to time is applied to the wave form of the transients to restrain the influence of the oscillatory component in estimating the inertia constant. This is produced by the synchronizing power between the generators.

A simple and low order model based on the idea of average system frequency is assumed in estimating the capacity of the spinning-reserve support generators. There the difference in the dynamic response of the power output to the frequency change between the once-through boiler plants and the drum boiler plants is taken into account. The idea of the average system frequency is summarized in [2]. The difference of the dynamic response between the once-through and the drum boilers is briefly described in [3,4].

Transients of the frequency at 10 events in the 60Hz system of Japan (Fig. 1), which were measured at substations or switching stations of the 500kV system of Kansai Electric Power Company, have been used in the estimation. For each event, the amount of loss of generation or load and the system load at the event onset are known. The events are summarized in Table 1.

2. ESTIMATION OF POWER SYSTEM INERTIA CONSTANT

2.1 METHOD OF ESTIMATION

The behavior of the frequency deviation of a power system caused by a loss of generation or load is approximately represented by eq. (1). In the equation, the idea of the average system frequency is used, where intermachine oscillations due to synchronizing power and transmission performance are not considered and equivalent system inertia, generator and load are assumed.

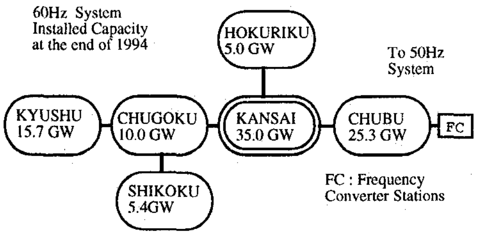


Fig. 1 60Hz Power System of Japan

$$M\frac{d(\Delta f/f_0)}{dt} + K\Delta f = -\Delta P \tag{1}$$

where Δf is the change of the frequency (Hz), ΔP is the amount of generation loss (pu in system load base), M (=2H) is the inertia constant of the system (s), f_0 is the rated system frequency (Hz), and K is the power/frequency characteristic of the system [5] (pu/Hz). The value of the power/frequency characteristic becomes large when the spinning reserve of the system is large.

As the amount of the loss is known and the frequency change at the onset of each event (t=0) is zero (Δf=0), the inertia constant (M) is given by estimating the rate of frequency change ($d(\Delta f/f_0)/dt$) at the onset from the measured transients and then using the following equation:

$$M = \frac{-\Delta P}{\left.\frac{d(\Delta f/f_0)}{dt}\right]_{t=0.0}} \tag{2}$$

The measured transients, however, contain the oscillatory component produced by synchronizing power between the generators. Thus it is necessary to restrain the influence of this component in estimating the rate of the frequency change. For this purpose, a polynomial approximation with respect to time is applied to the wave form of the transients in a sufficiently longer period than the period of the oscillatory component, namely the entire range of time in which the transients are measured (about 15 to 20 seconds from onset of the event).

As described later in (2), the adequate number of the orders of the polynomial approximation is five when the oscillatory component is rather large. Thus a polynomial approximation in the form of the following equation is used,

$$\Delta f/f_0 = A_5t^5 + A_4t^4 + A_3t^3 + A_2t^2 + A_1t \tag{3}$$

where t (s) is the time elapsed from the onset of the event.

By estimating the coefficients A_1 to A_5, the inertia constant of the power system in the system load base is obtained using the following equation:

$$M = -\Delta P/A_1 \tag{4}$$

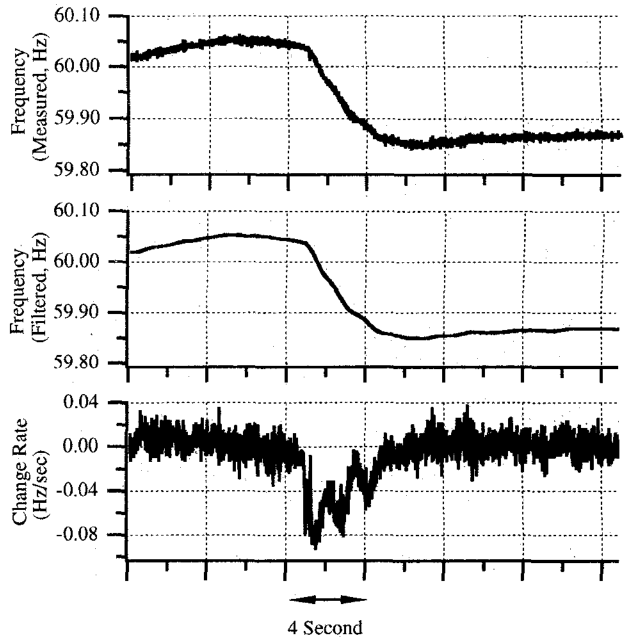


Fig. 2 Wave Form of Frequency Transients (Event (a))

The following procedure is taken in estimating the inertia constant of the power system.

(1) Identification of event onset time

The moving average processing is applied to filter the noise from the measured transients of frequency (60Hz sampling). To identify the time of the onset of the event in the wave form of the measured transients, the rate of the frequency change is taken as an indicator. More specifically, the onset of the event is identified as a time point at which the absolute rate exceeds 0.04 (Hz/sec) for the first time. The value has been determined by examining the rate of the frequency change at the 10 events.

Fig. 2 shows an example of the wave form of the frequency transients before and after the moving average processing, and the rate of change. It is found that the noise is adequately removed, and the rate of frequency change can be used as the indicator of the time of the onset.

(2) Estimation of coefficients A_1 - A_5

The coefficients are estimated by the least square method. Fig. 3 is a typical example for comparison between the polynomial approximation with varying number of orders and the measured transients where large oscillatory components are contained. As seen from the figure, the fourth or fifth order is necessary for adequate approximation of frequency change without disturbance by the oscillatory component. The fifth order has been selected for a sufficient margin in the procedure as shown in eq. (3).

2.2 RESULT OF ESTIMATION

The estimated values of the coefficients A_1 and the inertia constant of the system for each event are shown at the bottom of Table 1, where the date, time, weather, amount of loss and system load are shown in the upper part.

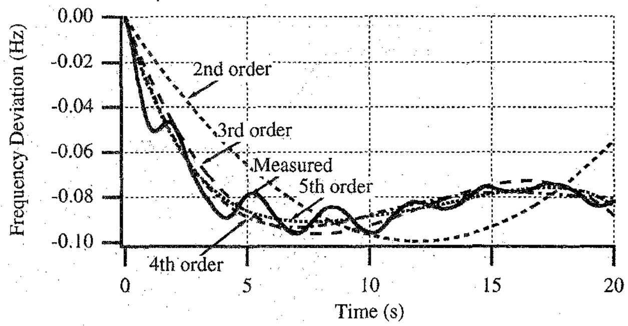


Fig. 3 Comparison among Polynomial Approximations with Number of Orders and Measurement (Event (j))

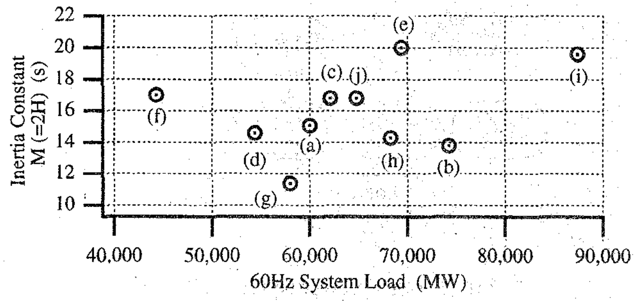


Fig. 4 Relation Between System Capacity and Inertia Constant

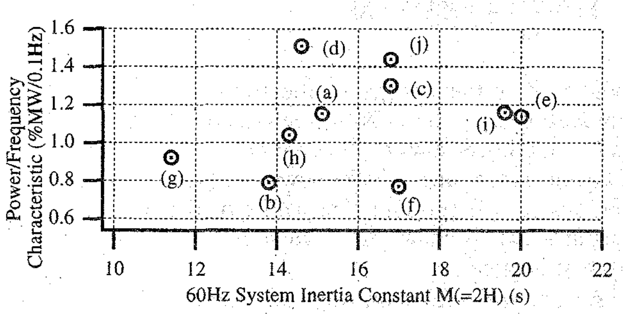


Fig. 5 Relation Between Inertia Constant and Power/Frequency Characteristic

The estimated values are larger than the value of the inertia constant of generators, which ranges from 8 to 10 seconds in the machine rated capacity base. The reason for this may be that since the system load is taken as the base of the inertia constant, when the number of generators in operation with partial load is large, the inertia constant of the system becomes large, and the inertia of customer loads is also included.

Fig. 4 shows the relation between the inertia constant and the system load. It seems that the value of the inertia constant is about 14-18 seconds, whereas further study will be necessary with increased number of events, including the correlation with the system load, season, climate, date and so on.

Fig. 5 shows the relation between the inertia constant and the power/frequency characteristic of the system, which is the K of eq. (1). The values of the characteristic have been calculated as the ratio ($-\Delta P/\Delta f$) at a transiently settled state (15 to 20 seconds after the onset of the event). As seen from the figure, there may be a positive correlation between the inertia constant and the power/frequency characteristic. Namely, the relation that "the inertia constant is large ⇔ the capacity of generators in operation with partial load is large ⇔ the spinning reserve, namely, the power/frequency characteristic of the system is large" is likely to exist. This relation may explain why the inertia constant of Event (a) is larger than that of Event (g) while the system loads of both events are similar. Further study on this will be needed.

3. ESTIMATION OF ON-LINE CAPACITY OF SPINNING-RESERVE SUPPORT GENERATORS

3.1 ASSUMPTION

A simple and low order model based on the idea of average system frequency is assumed to estimate the total on-line capacity of the spinning-reserve support generators, using the value of the inertia constant and the measured transients of the frequency. The block diagram of the model is shown in

Table 1 Estimation Results of Inertia Constant of 60Hz Power System of Japan

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Event		Nuclear gen. 100% load rejection test	Nuclear gen. 75% load rejection test	Thermal gen. trip	Nuclear gen. 50% load rejection test	Route-trip of lines from a power station	Route-trip of lines to DC rectifier station	Thermal gen. trip	Thermal gen. 100% load rejection test	Thermal gen 100% load rejection test	Thermal gen. 100% load rejection test
Date and Time		Oct. 28 '92 (Wed) 10:00	Sep. 16 '92 (Wed) 11:00	Nov. 18 '92 (Wed) 11:48	Aug. 13 '92 (Th.) 11:00	Jan. 20 '93 (Wed) 17:23	Apr. 27 '92 (Mon.) 23:14	May 11 '92 (Mon.)13:08	Jun. 11 '92 (Th.) 16:00	Aug. 23 '92 (Fri.) 15:00	Dec. 11 '92 (Fri.) 12:00
Weather and Temperature (in supply area of Kansai Electric Power Company)		Fine 18.0°C (11:00) 20.9°C (15:00)	Cloudy 28.1°C (11:00) 30.2°C (15:00)	Cloudy 14.8°C (11:00) 17.7°C (15:00	Rain 25.3°C (11:00) 28.7°C (15:00)	Fine 9.4°C (15:00) 6.4°C (18:00)	Fine 20.4°C (20:00) 11.9°C (5:00)	Fine 19.2°C (11:00) 23.7°C (15:00)	Fine 28.6°C (15:00) 25.4°C (18:00)	Fine 32.4°C (11:00) 34.5°C (15:00)	Fine 9.4°C (11:00) 10.2°C (15:00)
Known Data	Amount of Loss (MW)(%)	1,180 1.966	885 1.192	700 1.128	590 1.085	709 1.022	- 600 1.355	430 0.742	700 1.025	700 0.801	700 1.081
	60Hz System Load (MW)	60,010	74,263	62,066	54,399	69,380	44,275	57,977	68,282	87,426	64,745
Estimation	A_1 ($\times 10^{-3}$)	- 1.301	- 0.861	- 0.670	- 0.730	- 0.512	0.795	- 0.653	- 0.719	- 0.408	- 0.645
Result	M(=2H)(s)	15.1	13.8	16.8	14.6	20.0	17.0	11.4	14.3	19.6	16.8

Fig. 6 where all variables are considered to be variations from the steady state.

The frequency change is represented by the inertia constant of the system (#15 of Fig. 6), the change of the governor output (#1), that of the power output of the spinning-reserve support generators (#11) and that of the power consumed by the system load (#13). The change of the power output is further represented separately for the once-through boiler (#2~#8) and the drum boiler plants (#9,10). The reason for this is that the power output response of drum boilers is generally different from that of once-through boilers since coordinated control of the boiler-turbine is adopted in most once-through boiler plants, while turbine-leading control is adopted in most drum boiler plants [3,4].

In the coordinated control, the turbine load reference is directed to reduce the MW error between the actual power output and the plant MW set-point, while the boiler control is directed to reduce the pressure error. When the deviation of the frequency exceeds a dead-band, the MW set-point is modified by frequency bias control to match the plant's governor regulation characteristic to the desired one. These responses of the coordinated control for the once-through boiler plants are typical ones for the plants commercially operated in Japan [7,8]. To simulate such general responses of the once-through boiler plants, the following blocks have been included into the model; the change rate of the load reference (#3) and the amount of change (#4) as well as the dead-band (#5), the regulation (#6) and the output limits (#7) of the frequency bias control. The frequency bias control is assumed not to be activated in the measured 10 events since the deviations of frequency are small and lie inside of the dead-band.

The hydraulic plants are represented together with the drum boiler plants since the response characteristic of the hydraulic plants is similar to that of the drums.

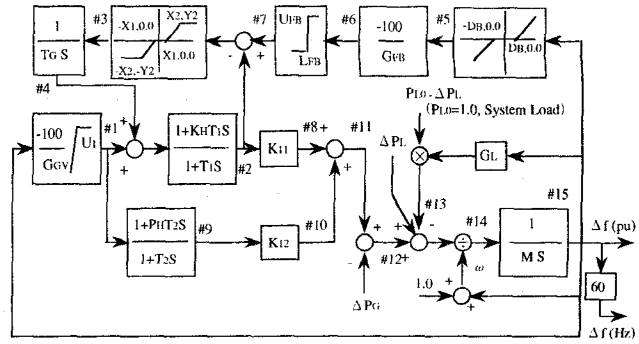
The values of the parameters of the model are assumed to be those which are considered to be general, with reference to [6,7,8], while the results of estimation in Table 1 are used for the inertia constant according to each event. The assumed values are shown in Table 2.

3.2 METHOD AND RESULTS OF ESTIMATION

(1) Results of proposed estimation method

Upon setting the above assumptions in the simple model and the values for the parameters, the total capacity of the once-through boiler plants, K_{11} (#8) and the capacity in relation to the drum boiler and hydraulic plants, K_{12} (#10) for each event is estimated by comparing measured transients of the frequency and simulation results obtained from the simple model.

An approach using a full two-dimensional search is not wise for the estimation of K_{11} and K_{12} from the aspect of efficiency of calculation, while it is difficult to calculate the sensitivity of the change of the difference between the



GGV: Governor Regulation
UI: Upper Limit of Governor Output
K11 Total Capacity of Once-through Boiler Plants
KH: Fraction of Immediately Responding Power
T1: Time Constant of Power Output Response
X1,X2, Y2: Change Rate of Turbine Load Reference
TG: Time Constant of Turbine Load Reference Response
K12: Total Capacity of Drum Boiler and Hydraulic Plants
PH: Fraction of Immediately Responding Power
T2: Time Constant of Power Output Response
M: Inertia Constant
GL: Frequency Characteristic of Load
ω: Average System Frequency
Δf: Deviation of Average System Frequency
ΔPL: Amount of loss of Load
ΔPG: Amount of loss of Generation
DB: Dead-band of Frequency Bias
GFB: Regulation of Frequency Bias
UFB: Upper Limit of Frequency Bias
UFB: Lower Limit of Frequency Bias

Fig. 6 Simple Model for Estimating Capacity of Spinning-reserve Support Generators

measurement and the simulation result to the change of K_{11} and K_{12}. Accordingly, a procedure of estimation consisting of two steps as follows has been proposed.

[Step 1] Find a value of K_{11} by the binary search method so that it gives a small absolute value of the sum of the difference between the simulation results and measured transients (simulation result - measurement, signed) at each time point from onset of the event under the condition $K_{11}=K_{12}$. The value of K_{11} is doubled to give the total on-line capacity of the spinning-reserve support generators, that is K_1.

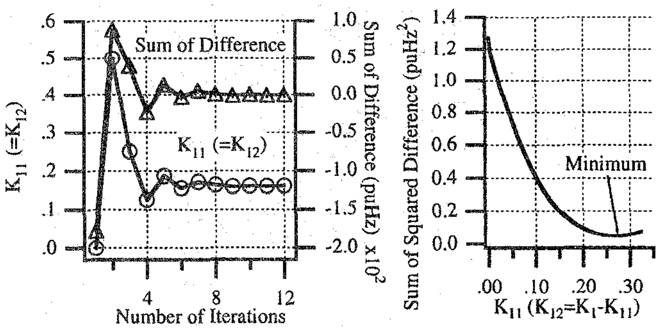
[Step 2] Set the starting value of K_{11} to 0.0 and its final value to the above K_1. Set the adjustment increment to 0.01. Find a value of K_{11} that gives the minimum value of the sum of the squared difference between the simulation results and measured transients during the adjustment under the condition of $K_{12}=K_1-K_{11}$.

The processing of step 1 is shown in the left of Fig. 7 for

Table 2 Assumed Values for Parameters of Fig. 6

Parameters	Values	Parameters	Values
G_{GV}(%)	4.0	G_{FB}(%)	4.0
U_I(puMW)	0.1	U_{FB},L_{FB}(pu)	0.05, -0.05
K_H	0.3	T_2(s)	16.0
T_1(s)	10.0	P_H	0.15
X_1,X_2(pu)	0.005, 0.055	G_L(puMW/puHz)	2.0
Y_2(pu)	0.05	M(s)	Table 1
T_G(s)	10.0	K_{11}, K_{12}	*1
D_B(Hz)	0.2		

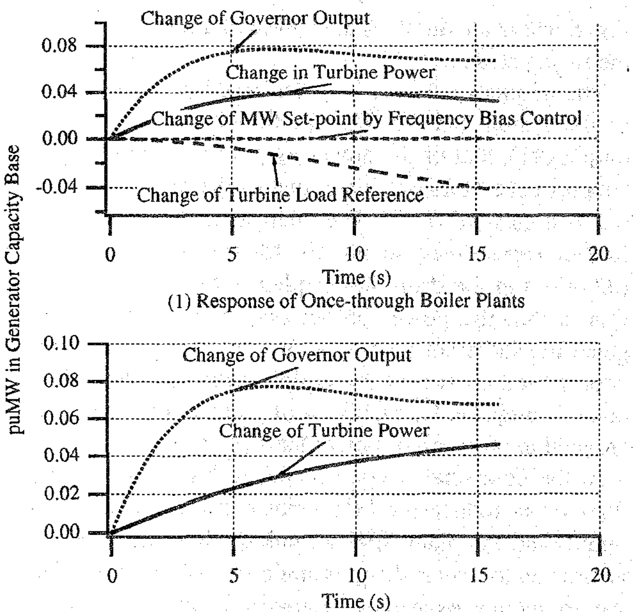
*1) The values of K11 and K12 are adjusted by comparing the measured transients and simulation results of the model.



(1) Relation between Number of Iterations, K_{11} and Sum of Difference

(2) Relation between K_{11} and Sum of Squared Difference

Fig. 7 Processing of Step 1 (left) and Step 2 (right) (Event (a))



(1) Response of Once-through Boiler Plants

(2) Response of Drum boiler and Hydraulic Plants

Fig. 9 Simulated Response of Spinning-reserve Support Generator (Event (a))

Event (a) as an example, which shows that K11 (=0.5K1) converges after about 10 iterations and the sum of the difference is nearly equal to 0.0. The processing of step 2 for the same event is shown in the right of Fig. 7. By gradually increasing K11 from the initial value, that is 0.0, the sum of the square of the difference reaches the minimum value at a point near K11=0.26. (8-a) in Fig. 8 compares the measurements and simulation results of frequency changes after the completion of step 2, which gives a good agreement between the simulation results and measurement.

Fig. 8 also compares the frequency change after the completion of step 2 with the measurement for the other events. The simulation results agree well with the measurements for all events.

An example for the simulated response of the generator is shown in Fig. 9. As the frequency bias control is not activated (the plant MW set-point is not modified) with once-through boiler plants, the power output once increases according to the increased governor output and then slowly decreases by the run back of the turbine load reference. This tendency of the response is similar to that of an actual plant response presented in [9]. On the other hand, the power output of the drum boiler and hydraulic plants slowly increases.

Table 3 lists the values of K11, K12, and K1 (=K11+K12)

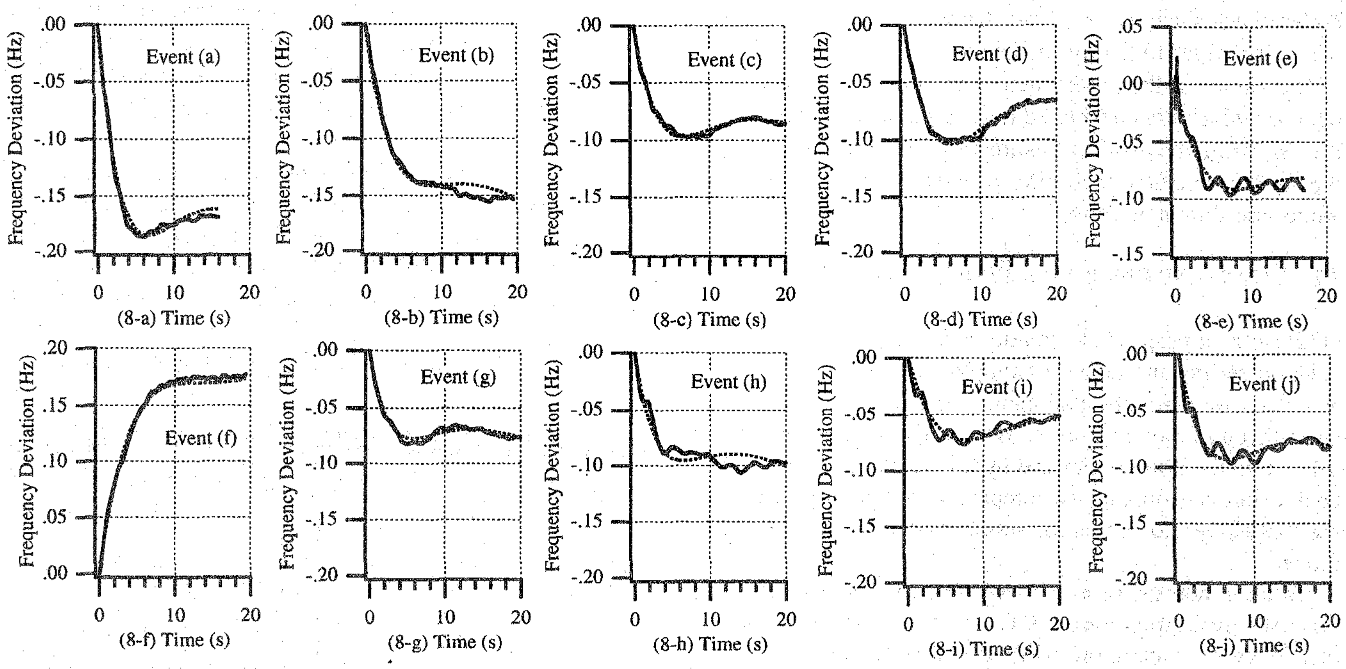


Fig. 8 Comparison of Measured Transients and Simulation Results (solid: Measured, dotted: Simulated)

Table 3 Estimation of K_{11} and K_{12} by Proposed Method

Event	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
K_{11}	0.258	0.232	0.293	0.127	0.257	0.173	0.285	0.350	0.171	0.296
K_{12}	0.130	0.0	0.140	0.310	0.130	0.040	0.020	0.0	0.240	0.140
K_1	0.388	0.232	0.433	0.437	0.387	0.213	0.303	0.350	0.411	0.436

$K_1=K_{11}+K_{12}$

after the completion of step 2. The value of the total on-line capacity of the spinning-reserve support generators, that is K_1, ranges from 0.2 to 0.4 of the system load. The value for the drum boiler and hydraulic plants, that is K_{12}, is small for the events such as Event (b) where the frequency is hardly restored, as compared with the events such as Event (d) where the frequency tends to be restored.

To further verify the proposed estimation method, the full two-dimensional search method has been applied to estimate the values of K_{11} and K_{12}. In the full search method, the frequency change is simulated for each combination of values of K_{11} and K_{12} that are respectively varied from 0.0 to 0.5 in increments of 0.01 (about 2,600 combinations). The combination that gives the minimum of the sum of the squared difference between the simulation results and measurements is taken as the estimated values of K_{11} and K_{12}. The total search method takes a long time, about 40 times longer than that required by the proposed method, but the estimated value is considered to be most adequate. Table 4 shows values for K_{11} and K_{12} estimated by the total search method. The results mostly agree with Table 3, confirming the validity of the proposed method, but one can find discrepancies for some cases. For example, for Event (e), the discrepancy seems to be relatively large compared with the other events. Judging from the comparison of Fig. 8, however, even the discrepancy for Event (e) seems not to cause large difference between the simulated result and the measured transient. Further study will be needed to examine the permissible level of discrepancy.

Table 4 Estimation of K_{11} and K_{12} by Full Search Method

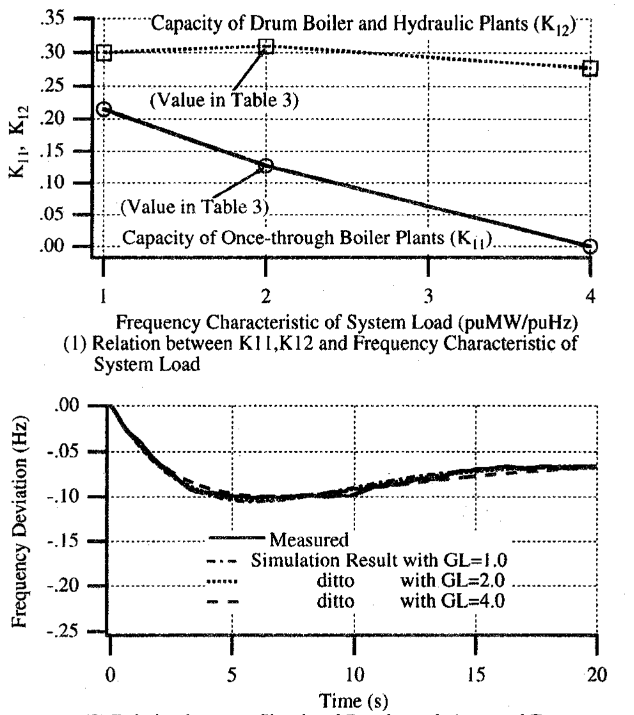
Event	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
K_{11}	0.27	0.22	0.30	0.12	0.29	0.18	0.28	0.34	0.17	0.30
K_{12}	0.11	0.0	0.13	0.31	0.08	0.02	0.02	0.0	0.26	0.13
K_1	0.38	0.22	0.43	0.43	0.37	0.20	0.30	0.34	0.43	0.43

$K_1=K_{11}+K_{12}$

(2) Effect of load frequency characteristic on the results of estimation

As the frequency characteristic of system load is not well known, it would be significant to investigate the effect of the characteristic on the results of estimation of K_{11} and K_{12}.

For the purpose, the difference between two estimations has been investigated, where the frequency characteristic of load set to twice as large as the setting (G_L in Table 2), that is G_L=4.0 (=6.667 %MW/Hz), and half of the setting (G_L=1.0) using Event (d) as an example.



(1) Relation between K_{11}, K_{12} and Frequency Characteristic of System Load

(2) Relation between Simulated Results and Assumed Frequency Characteristic of System Load

Fig. 10 Influence of Assumed Frequency Characteristic of System Load on Estimation of K_{11}, K_{12} (Event (d))

Fig. 10 shows the results of comparison. It is found that the value of the frequency characteristic of load significantly affects the estimation result of the capacity of the once-through boiler plants, namely, K_{11} becomes smaller as the frequency characteristic of load increases.

4. CONCLUSION

A procedure for estimating the inertia constant of a power system and total on-line capacity of spinning-reserve support generators, using the measured transients of the frequency, is presented. The procedure has been applied to the transients at 10 events in the 60Hz system of Japan. The consequent results of the estimation reveal the validity of the procedure and show that the inertia constant of the 60Hz power system of Japan is around 14 to 18 seconds in the system load base, and the capacity of spinning-reserve support generators is 20 to 40% of the system load.

The proposed procedure is expected to be tested by Kansai Electric Power Company with increased number of events. Furthermore, examinations on plant types of on-line spinning-reserve support generators, their operation characteristics such as response properties of the governor and frequency bias, and the frequency characteristic of the system load is also under consideration. This effort will contribute to estimate and evaluate the dynamic behavior of the system frequency in the event of a large-scale imbalance between power supply and demand.

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BIOGRAPHY

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DISCUSSION

Lambert Pierrat, (SM, IEEE General Technical Division, Electricité de France, 37, rue Diderot - 38040 Grenoble Cédex, France).The results presented in this paper are interesting, because they permits on one side to describe the performance find in a large power system, on the other side to verify the validity of whole equivalent inertial system (generators and loads). My question and comments are about the next following points:

1 - Inertia constant : for the 10 events showed in table 1, the measured values are between 11.4 and 20 s ; we say that the apparent inertia constant obtained using the equation (1) is always higher than the intrinsic inertia constant of the generators groups and the spinning-reserves due to the dynamic behaviour of the loads, during the perturbation.

Have the authors calculate, for the 10 events, the ratio between theoretical and measured inertia constants ?

2 - Relationships between the parameters : despite the small size of the statistical sample (n = 10), the observation of Fig. 4 and Fig. 5 gives some interesting information. The authors indicate the existence of one positive correlation between the inertia constant and the power/frequency characteristic (Fig. 5). A priori, the same positive correlation its possible to exists between the inertia constant and the system load (Fig. 4). However that impression must be statistically justified.

Did the authors calculate the mutual correlation coefficients between the 3 variables that intervene in the Fig. 4 and Fig. 5 ?

3 - Inertia constant identification : to eliminate the influence of the oscillations due to the synchronizing power of the generators, the authors identified one average exponential trajectory with a polynomial approximation of order five (Fig. 3). After the equation (4), the first terms of the polynomial must correspond to the serie of the exponential function.

From what order of the polynomial, the serie diverges from the serie of the theoretical exponential function ? What is the criterion used to characterize the quality of the identification procedure?

4 - Equivalent inertia constant : the search for the time constant of order one it's a delicate problem. The sense of the equivalence must be correctly defined, because the order one is an approximation of the reality. If I suppose that the parasitic oscillation can be represented by an equivalent noise superposed to the mean time constant, the mean observed trajectory tends to the exponential function, when the parasitic oscillation is removed. So, the identified time constant can be interpreted in an energetic sense.

What is the equivalence used to define the time constant from equation (3) ?

I would like to thank the authors, for their contribution, and their responses to this discussion.

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T. Inoue, H. Taniguchi, Y. Ikeguchi, K. Yoshida:

We would like to thank Mr. Pierrat for his interest in our paper and for his valuable comments. The following are our responses to the specific discussion he has risen.

1. Inertia constant

The amount of the system load (MW) is used as the base of the power system inertia constant (sec) as described in the equation (1). In each event, the amount is almost equal to the total power output of the on-line generators. Thus in the case that the number of the generators operated in the partial power is large, the system inertia constant becomes larger than the generator intrinsic inertia constant which generally ranges from 7 to 10 (sec) based on each rated capacity.

In Japan, nuclear generators are operated in constantly the full power, but the fossil-fired and hydraulic generators are usually operated in the partial power depending on the amount of system load and so on. Along with this, inertia of the system load is included in the system inertia constant. Thus the result that the system inertia constant in Table 1 is larger than the range of the generator inertia constant itself seems to be not improper.

As the 60Hz interconnected power system of Japan consists of six electric power company systems (Fig. 1), the system operating condition outside the Kansai system may not be easily available. Thus we did not calculate the system inertia constant by summing up each generator inertia constant and operation power in each event.

2. Relationship between the parameters

We once calculated the mutual correlation coefficient between the inertia constant and the power/frequency characteristic (Fig. 5) using a general software. The calculated coefficient implies the positive correlation, but the standard deviation of the coefficient is so big that we gave up the statistical evaluation then. This situation was the same with that for Fig. 4. When the number of the events is getting large, we will try the statistical evaluation.

3. Inertia constant identification

The measured frequency transient in each case contains the component of oscillation. We considered the oscillation is the well-known inter-system oscillation, and determined the order of the polynomial function by comparing the curve of polynomial function to the measured curve with visual judgment from the engineering viewpoint. We think the determination process is adequate, judging from the measured curve and simulation curve (Fig. 3 and Fig. 8).

As pointed out by the discusser, the use of exponential function is reasonable. We will try to use the exponential function along with the polynomial function in the next step.

4. Equivalent inertia constant

The influence of the loss of generation or load on the system frequency is propagated sequentially from the place of the origin of the loss toward the further place in the power system through the synchronizing power. Thus the phase of oscillation of the frequency change is not identical over the system in general, and the oscillation produced by synchronizing power affects the time derivative of the frequency at time zero at each place in each event.

However, average of the change excluding the oscillatory component may be considered to be identical over the system. Therefore the idea of the average system frequency is commonly used in the load-frequency studies, and as described in the paper the oscillatory component in the measured frequency transients is excluded in estimating the equivalent system inertia constant. The power system inertia constant in the paper is considered as this sense.

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