

**Draft report of the sub-group constituted
by OCC to
Review the df/dt or rate of change of frequency
relay setting
In Northern Region.
May 2007**

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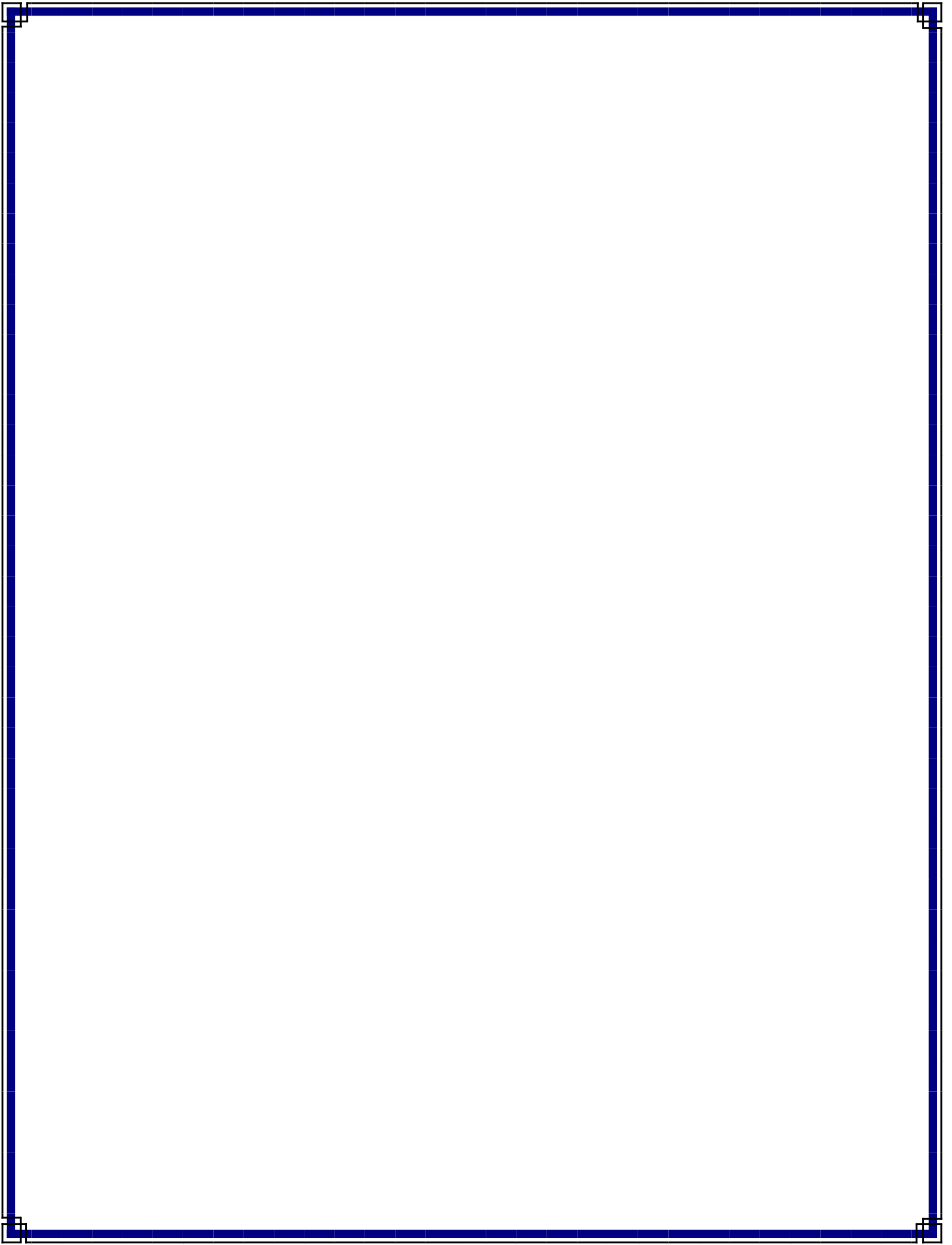
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1. Introduction/Background

The df/dt settings were carried out for the individual regions separately in past as a safety net of the respective regions. However, with the synchronous interconnection of Northern Regional grid and central grid comprising of Eastern region, Western region and North Eastern Region on 26th August 2006 at 1222 hrs the system size has increased from the order of 25000 MW to 60000 MW. Consequently inertia of the combined system has increased, resulting into lower rate of change of frequency for a given loss of generation or load. Therefore, the existing defense mechanism based on rate of change of frequency relay (or df/dt relay) for protection the system from collapse following a loss of generation has become practically ineffective. Present df/dt setting in the Northern region is as tabulated below.

Table-1 Existing df/dt relay setting in Northern Region

Northern Region	Stage	Initiating Frequency (Hz)	Hz/Sec	Load Relief (MW)
	1st	48.8	0.125	750
	2nd	49.2	0.2	1500
	3rd	49.6	0.3	1500
	4th	50.0	0.4	1250

The present sub-group has been constituted by the Operation Co-ordination Sub-Committee (OCC) of the Northern Region Power Committee (NRPC) in its 9th meeting held on 15th Dec 2006 to review the setting of df/dt relays. The sub-group was advised to submit its report by 12th Feb 2007. Due to other various pressing issues such as weather related trippings in Northern Region during January-07, February-07 and March-07, the sub-group could not finalise its recommendations.

The first sub-group meeting was organized on 18th Jan 2007 and the following was decided.

1. The combined North & Central Grid requires relief through df/dt relays to take care of network loading conditions following a large loss of generation.
2. The combined system has witnessed several incidents of loss of generation up to 1500 MW since the synchronization of Northern Grid with the Central Grid. However, in none of the above occasions, the df/dt relays with present setting have not operated. A list of such incident in the Northern Region is enclosed at annex-I.
3. It was observed that some df/dt relays have a limited storage facility for frequency data. However, this was not archived and analyzed as a matter of practice and therefore practical observation on actual df/dt recorded for different events is not available. Therefore the df/dt relay settings for the combined North-Central grid would be worked out through the following methods.

- ❑ Estimation of system inertia constant (H) from individual machine's inertia constant and MVA and assuming that all the units swing coherently (although this would strictly not be true in a real time wide spread interconnected system).
 - ❑ Estimation of system inertia constant (H) through studies and real time frequency transient response.
- 4. The operation of df/dt relay (actual response of the grid under contingencies) shall be monitored by revising the relay settings as follows:
 - ❑ Revise setting with lower slope (0.1 Hz per second or very close to it as per relay limitation) at higher frequency (i.e. 49.9 Hz) at 220 kV Gazipur and 220 kV Narela in the DTL system.
 - ❑ The RRVPN and BBMB were also requested to revise the df/dt setting as above in their system at selected few locations.
- 5. The group also felt that to have greater insight into functioning of the relay specially rate of change of frequency measuring principle and limitations if any, discussions with relay manufacturers shall be held.

Subsequent to the first meeting of sub-group on 18th January 2007, two instances of separation of Northern Region from the Central Grid have occurred. To analyze the incidents data from number of the substations is collected. It was observed that the Vindhyachal HVDC back-to-back station had a digital recording of frequency at 100ms interval. It can be appreciated that these values give us good indication of rate of change of the frequency in the system. Thus this goldmine of field data was also used to evaluate 'H' for some of the tripping incidents. The findings of the same are given at annex-I & II.

In the intervening period literature survey was carried out and work was done as decided in first meeting of the subgroup. It was observed that internationally not much literature was available on df/dt relay setting philosophy. This might be on account of its limited efficacy in large systems. The estimated values through real time data, simulation data and other findings were discussed and analyzed at second meeting of the subgroup at 10th April 2007. Based on these study, analysis and discussions this report has been prepared and covers estimation of df/dt for different situations, the measuring principle adopted for df/dt relaying, limitations and the initial recommendations of the sub-group.

It is also suggested that the findings of this sub-group might be circulated in Western, Eastern, North-East and Southern regions for their valuable comments. International experience of df/dt relaying in very large power grids might also be studied separately.

2. Estimation of rate of change of frequency (df/dt):

Power system frequency drops when the power supply in the system becomes insufficient due to loss of generation or tie line support. Overloading of the generators is followed by considerable change in system voltages, causing a

fluctuation in load power P_{elec} . In addition, the generator's governing system utilizes the spinning reserve (if available), changing P_{mech} . Thus P_{mech} and P_{elec} change in time, altering frequency 'f' and its rate of change df/dt .

While the low frequency 'f' is the final result of the power deficiency, its rate of change df/dt is an instantaneous indicator of power deficiency and can enable recognition of the MW imbalance. However, the change in machine speed is oscillatory in nature. These oscillations depend on the response of the generators and are seen differently at different locations.

If the amount of frequency drop is large, protection systems for the low frequency may be activated in the power plants and the consequent shutdown of plant may lead to the separation of the interconnected system or black-out of the power system. The time taken by the system to settle to a low frequency would depend upon the inertia of the system. Higher the inertia of the system larger would be the time and vice versa.

However, before frequency settles to lower level, there are oscillations and these could lead to the higher line loading and consequently tripping of the generators/tie lines. Therefore it is important to grasp the characteristics of the frequency response of the power system to loss of generation in order to stabilize the system faster and avoid catastrophe. The general equation of the system behavior following a loss of generation or load is as below . refer [3]

$$\frac{2H}{f_o} \cdot \frac{df}{dt} + D \Delta f = \Delta P \quad \text{----(1)}$$

Where

- H = System Inertia Constant on system base (seconds)
- f_o = Frequency at the time of disturbance (Hz)
- df/dt =Rate of change of frequency (Hz/Sec)
- ΔP = $(P_L - P_G)/P_G$, Power change (per unit in system load base)
- P_L =Load prior to generation Loss in MW
- P_G =System Generation after Loss in MW
- D =Power/frequency characteristic of the system in pu/Hz
- Δf =Change in frequency

This general equation can be simplified by considering the damping effect to be negligible during early onset of the event. Therefore the simplified equation without significant loss of information is

$$\frac{2H}{f_o} \cdot \frac{df}{dt} = \Delta P \quad \text{----(2)}$$

Therefore, df/dt can be computed if we have the value the system inertia constant (H). The system inertia constant is defined as the kinetic energy stored in the system per MVA. The typical values of the H as given below:

Typical Inertia constant of Synchronous machines.

Sl. No.	Unit Type of Machine	H* Constant (Sec)
1	Water wheel generator	
	Slow speed (< 200 rpm)	2 to 3
	High speed (> 200 rpm)	2 to 4
2	Turbine Generator	
	Condensing 1800 rpm	9 to 6
	Condensing 3000 rpm	7 to 4
	Non-Condensing 3000 rpm	4 to 3
3	Synchronous motor with load varying from 1.0 to 5.0 and higher for heavy fly wheels	2.00

* where range is given , the first figure applies to the smaller MVA sizes.
The computation of inertia constant (H) is being described in subsequent section.

Source: I. J. Nagrath and D. P. Kothari, “Modern Power System Analysis”, 3rd edition, Tata MacGraw-Hill, New Delhi ,1980 ,page-436

3. Computation of Inertia Constant (H):

As described above, following three methods has been used to determine the Inertia Constant H (Sec) of the Interconnected North-Central Grid.

1. Based on inertia constant (**H**) of Individual Generators in the system
2. Based on rate of change of frequency, that was calculate using field data (100 milisec frequency data recorded at Vindhyachal HVDC back to back station) i.e 10 samples per second
3. Based on rate of change of frequency, calculated using simulation studies

3.1. Based on inertia constant (H) of Individual Generators in the system [1]:

Assuming the machines to be swinging coherently, the equivalent inertia constant of the multi-machine system can be calculated by adding the inertia Constant of individual machine (on System base)

$$H_{eq} = \sum (H_i \times G_{i\ mach}) / \sum G_{i\ mach} \quad (i=1 \text{ to } n) \quad \text{-----}(3)$$

$$H_{eq} = \sum (H_i \times G_{i\ mach}) / G_{system} \quad (i=1 \text{ to } n) \quad \text{-----}(4)$$

Where

- H_{eq} =System Inertia Constant on system base
 H_i =Individual Generator Inertia Constant on its own base
 G_{system} =System Size (MVA) or System Base
 $G_{i\ mach}$ =Machine rating (MVA) or machine Base
 n =total no. of machines in the system

Based on the individual generator inertia constant on its own base used the PTI-PSS/E system studies model of all India network North Central grid Inertia constant was calculated. The results obtained are as tabulated below in the system load base.

Table -1

Region	Size (GW)	Size (MVA)	H (Sec)
NORTH	29	40542	4.05
EAST	15	22483	3.60
WEST	31	42555	3.90
NORTH EAST	2	2900	5.19
North Central Grid	77	108479	3.93

Table-2

Region	Size (GW)	Size (MVA)	H (Sec)
NORTH	29	40542	4.05
CENTRAL	48	67938	3.85
North Central Grid	77	108479	3.93

3.2. Based on rate of change of frequency using field data [2,3]

Based on the study of under frequencies following generation outages system inertia can be estimated using the simplified equation of inertia (derived from swing equation) considering damping effects to be small early onset of the events.

$$\frac{2H}{f_o} \cdot \frac{df}{dt} = \Delta P$$

Where

- H = System Inertia Constant on system base (seconds)
- f_o = Frequency at the time of disturbance (Hz)
- df/dt = Rate of change of frequency (Hz/Sec)
- ΔP = $(P_L - P_G)/P_G$, Power change (per unit in system load base)
- P_L = Load prior to generation Loss in MW
- P_G = System Generation after Loss in MW

Knowing the **rate of change of frequency** following a **known loss of generation**, **system inertia constant** can be estimated using equation (3) if the **system size in MW** and **frequency prior** to event is known.

A number of incidents since NR-Central grid synchronization were analyzed. It was found that system is regularly observing the rate of change of frequency of 0.033 Hz/sec. But df/dt of 0.06Hz/sec or more is observed only when there is big loss of generation say more than 500 MW or more.

Two major incidents of loss of generation when df/dt was more than 0.06 Hz/sec were taken for inertia constant calculation.

1. Units tripping at Suratgarh (1250 MW Generation Loss) on 04-10-2006 at 1822 hrs.
2. Units tripping at Anpara (1450 MW Generation Loss) on 15-11-2006 at 1119 hrs.

On none of the occasion loss of generation up to 1500MW in the interconnected system, df/dt of more than 0.1 Hz/sec was observed. However, on one of the occasion of system split on 28th Feb 2007, 1311 hrs rate of change of more than 0.1 Hz/sec was observed. Refer Annex-I

Result of the estimation based on loss of generation field data shows that the inertia constant of the North-Central combined system is around **5.6 to 9.5 seconds** in the system load base.

Rate of change of frequency observed at NR and WR side bus of Vindhyachal are different for same incident of loss of generation. Refer Annex-II

Frequency recorded at 10-samples/second (i.e. 100 millisecond intervals) at Vindhyachal back to back station for both NR side bus as well as WR side bus was taken for analysis.

3.3. Based on rate of change of frequency using simulation studies

Power system dynamics simulation studies were carried out for measuring the frequency transients. It is observed that it contain oscillatory component. To restrain the influence of this component average of rate of change of frequency over 200 milliseconds was taken and from that inertia constant of the system was determined. Refer Annex-IV.

Result of the estimation based on loss of generation simulation shows that the inertia constant of the North-Central combined system is around **6.8 to 10.4 seconds** in the system load base. Different values of df/dt are observed at different locations for the same loss of generation. Higher value of df/dt is observed near the node where generation is lost.

4. df/dt Measurement principle by relays:

Going through the technical information provided by various relay manufacturers, it is inferred that relay adopts following measurement principles.

4.1. **The rate of change of frequency measurement is based on two successive frequency measurements and the time difference between the frequency measurements. The measured frequency value for df/dt calculation is averaged over three cycles.** The accuracy of df/dt measurement depends on the accuracy of frequency measurements. This frequency measurement is carried out through time measurement of a cycle (time between two zero crossing). The measurements static error depends on the quartz crystal's absolute accuracy. **The biggest error in frequency measurement is in the range of ± 5.6 mHz considering the time resolution of 1 micro second.** Refer Annex-V: ABB document on Frequency relay behaviour.

4.2. Some relays measure the change in frequency (Δf) over a time interval ($\Delta t=100\text{ms}$), and calculate the df/dt every 5ms. They operate when the frequency

change exceeds the setting value 50 consecutive times. Refer Annex-VI: Toshiba Corporation document on Frequency and Voltage protection.

- 4.3. Technical data sheet of AREVA manufactured MICOM relays indicates that for frequency supervised rate of change of frequency 'f + df/dt' protection accuracy is +/- 5 % or +/-55m Hz/s, whichever is greater. Refer Annex-VII

5. Initial findings and conclusion:

5.1. df/dt estimation for combined North-Central System.

The system inertia constant value based on individual generator's inertia constant as calculated above (3.93 secs) seems to be inaccurate since with this value of inertia constant frequency trend of 0.1 Hz/sec can be achieved even with a loss of only 960 MW.

From the response of df/dt relay set at **49.9 Hz /0.1 Hz per sec** as decided in the first meeting of sub group it has been observed that these relay had not operated on any of the occasion of loss of generation listed in Annex-I.

However, DTL has reported that df/dt relays with modified settings have operated on two occasions during the observation period .On one occasion it has operated on 9th Feb 2007 when there were multiple trippings going on in the system due to fog and on another occasion it has operated on 28th Feb 2007 when Northern region system (Size about 18000 MW) got separated from central grid losing about 600 MW generation through tie line.

Analysis of 100 millisecond interval frequency received from Vindhyachal also indicates that on none of the occasion of loss of generation listed in Annex-I frequency trend of more than 0.075 Hz/sec is observed.

The system inertia constant for the combined North-Central grid based on simulation studies and field data works out to about 5.6 to 10.4 sec. The wide variation in system inertia may be due to daily variation in generation dispatch and system load.

Without a significant loss of information in the result inertia constant value of 8.0 can be taken for the finding out the frequency trend following a loss of generation.

Based on this a 1500 MW loss at a frequency of 50 Hz in a 60,000 MW system would result in

$$\begin{aligned}\frac{df}{dt} &= \Delta P \cdot \frac{f_0}{2H} \\ &= 50 \times \frac{1500}{(60000-1500)} \\ &\quad 2 \times 8 \\ &= 0.08 \text{ Hz/sec}\end{aligned}$$

and, for a 2000 MW loss it would be 0.11 Hz/sec

5.2. Available df/dt relay settings:

The minimum df/dt relay setting available is 0.1 Hz/sec. Many df/dt relays have a minimum setting of 0.2 Hz/sec only. Further as mentioned in section – 4 error of +/- 5 % or +/- mHz (whichever is greater) is expected.

5.3. Recommended df/dt settings and further work:

- The combined North Central system could have a large number of df/dt relays at minimum setting of 0.1 Hz/sec at 50 Hz /49.9 Hz based on single largest contingency. Some of the single largest contingency in the combined system are:

Sl No.	Contingency	MW Loss
1	Loss of Talchar STPS (Stage-I & Stage II)	3000
2	Loss of Vindhyachal STPs	3260
3	Loss of Korba STPS	2100
4	Loss of Singrauli STPS	2000
5	Loss of Rihand STPS	2000

Approximate load relief through such relay may be taken as 4000 MW spread over combined North Central system. Based on the proximity of loss of generation some relays will pick up and some will not because df/dt will not be same everywhere.

- Each region could have a df/dt setting at a higher value say 0.2 Hz /Sec and above as that would signify separation of system. The quantum would depend on net import by any zone/flow gate.
- Further work is required to be done in the area of employing Phasor Measurement Units (PMUs) to detect loss of generation & activating load shedding in neighbouring nodes.

6. References/Bibliography

- [1.] I. J. Nagrath and D. P. Kothari, “**Modern Power System Analysis**” , 3rd edition, Tata MacGraw-Hill ,New Delhi ,1980, pp. 435-439
- [2.] I. J. Nagrath and D. P. Kothari, “**Power System Engineering**”, Tata MacGraw-Hill , New Delhi ,1999, pp. 487
- [3.] Dwarkanath, “**Under Frequency Trend Relay as Power System Savior**”, International Seminar on “Grid Stability and Load Management”, GRIDS SAFE – 1995, 12-14 January, 1996, I.E. (I), Nagpur, India
<http://arxiv.org/ftp/nlin/papers/0409/0409036.pdf>
- [4.] T. Inoue, H. Taniguchi, Y. Ikeguchi, and K. Yoshida, “Estimation of power system Inertia Constant and Capacity of spinning reserve support generators using measured frequency transients”, IEEE Transactions on Power Systems, vol. 12 no. 1 , Feb. 1997 ,pp. 136-143
- [5.] D. P. Chassin ,Z. Huang, M. K. Donnelly, C. Hassler , E. Ramirez and C. Ray , **Estimation of WECC System Inertia Using Observed Frequency Transients**
- [6.] Anderson, Paul M. and A.A. Fouad, “**Power System Control and Stability**”, The Iowa State University Press, Ames, Iowa, 1977
- [7.] Kundur, P., “**Power System Stability and Control**, McGraw-Hill, New York, 1994

Annex-1

Analysis of incident of loss of Generation

S No	Station	Date & Time	Generation Loss in MW	Remarks	Freq prior to incident (Hz)	Df/dt (Hz/Sec) Observed at Vindhyachal North Bus	H (Sec)
1	Suratgarh	4 th Oct 2006 (1822 hrs)	1250 (750 + 500)	600 MW load throw off in Rajasthan	49.19	0.06, 0.03	5.6, 6.0
2	Singrauli	13 th Nov 2006 (1432 hrs)	800	CW pump failure	48.86	0.03	---
3	Anpara	15 th Nov 2006 (1121 hrs)	1450	Fault on 132 kV Pipri bus; Auxiliary supply failure; Flow on 400 kV Purnea-Muzaffarpur one circuit touched 1000 MW (other ckt out)	48.71	0.075	9.5
4	Farraka, Kahalgaon & Tenughat	6 th Jan 2007 (1610 hrs)	1750	Fault on 400 kV Biharsharif-Kahalgaon ckt-II fed from Biharsharif end for 2.5 minutes.	48.97	0.067	---
5	Anpara	7 th Feb 2007 (0610 hrs)	1200		49.37	0.03	---

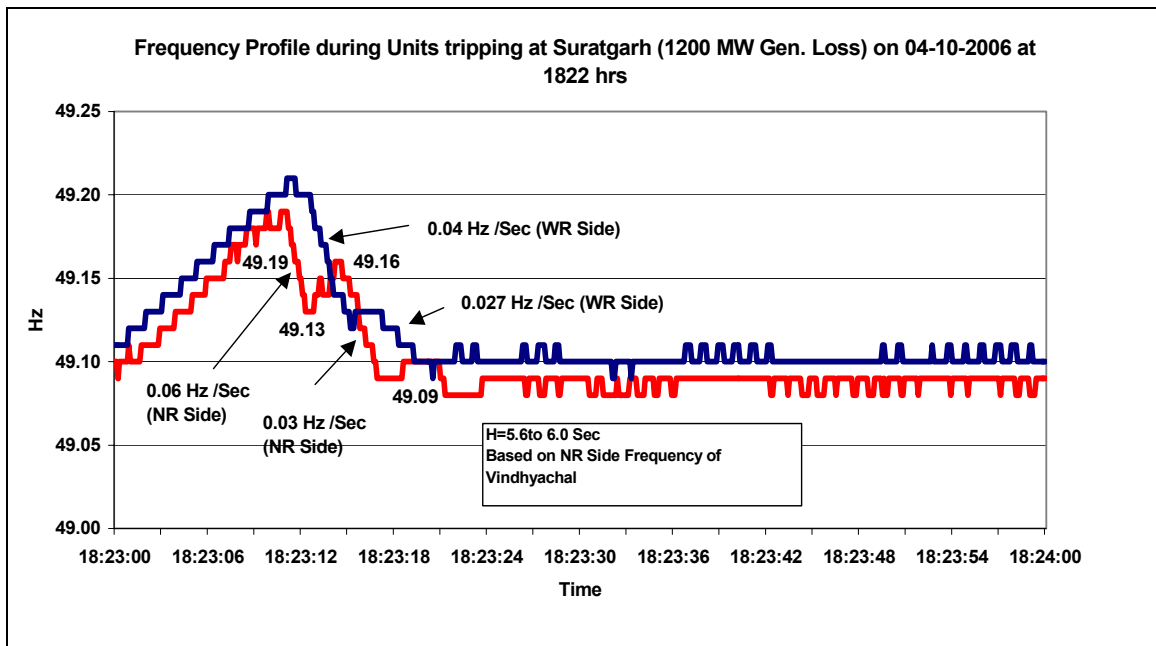
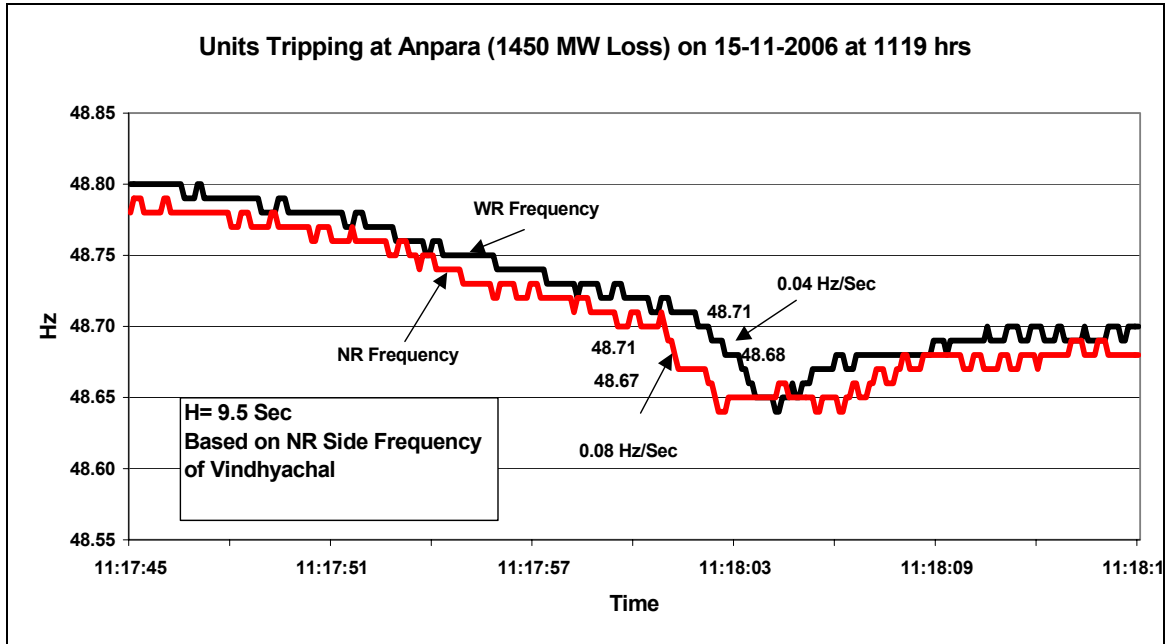
Analysis of incident of System separation

S No.	System separated	Date & Time	Loss of generation (MW)	NR Grid Size (MW)	Df/dt (Hz/Sec)
1	NR system separated from rest of the Central grid	25 th Feb 2007 (1634 hrs)	165	17500	0.014 HZ/sec (on NR Side)
2	NR system separated from rest of the Central grid	28 th Feb 2007 (1311 hrs)	600	18000	0.4 HZ/sec (on NR Side)

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Annex-II

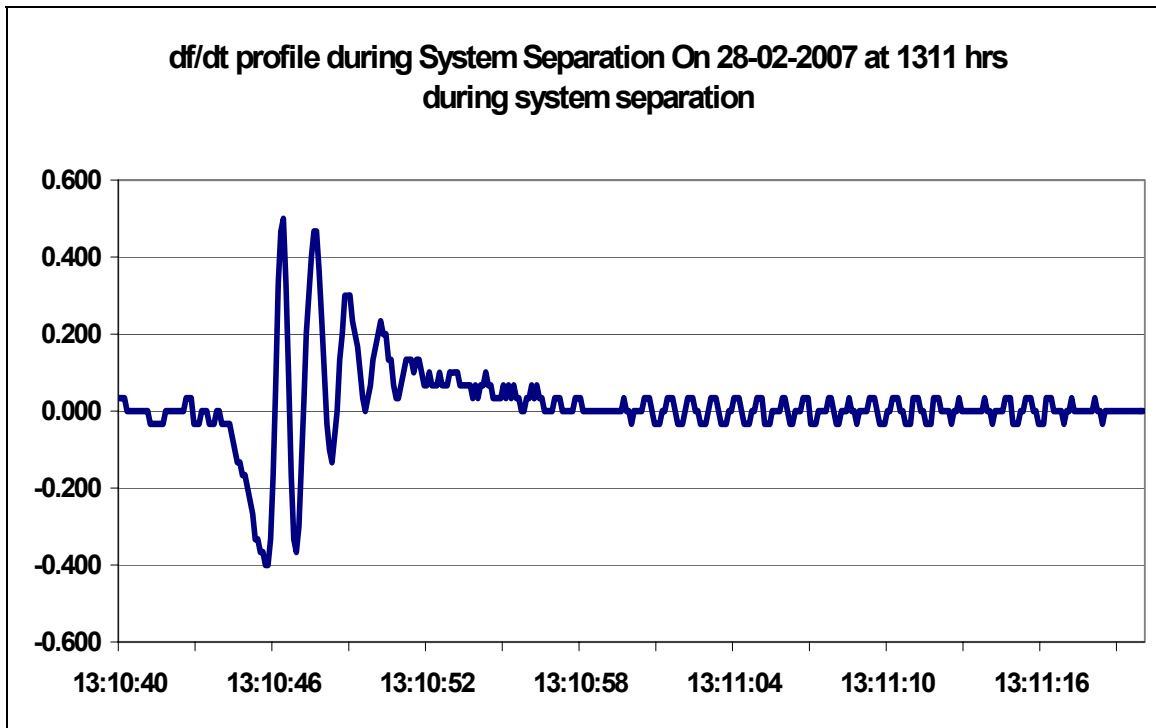
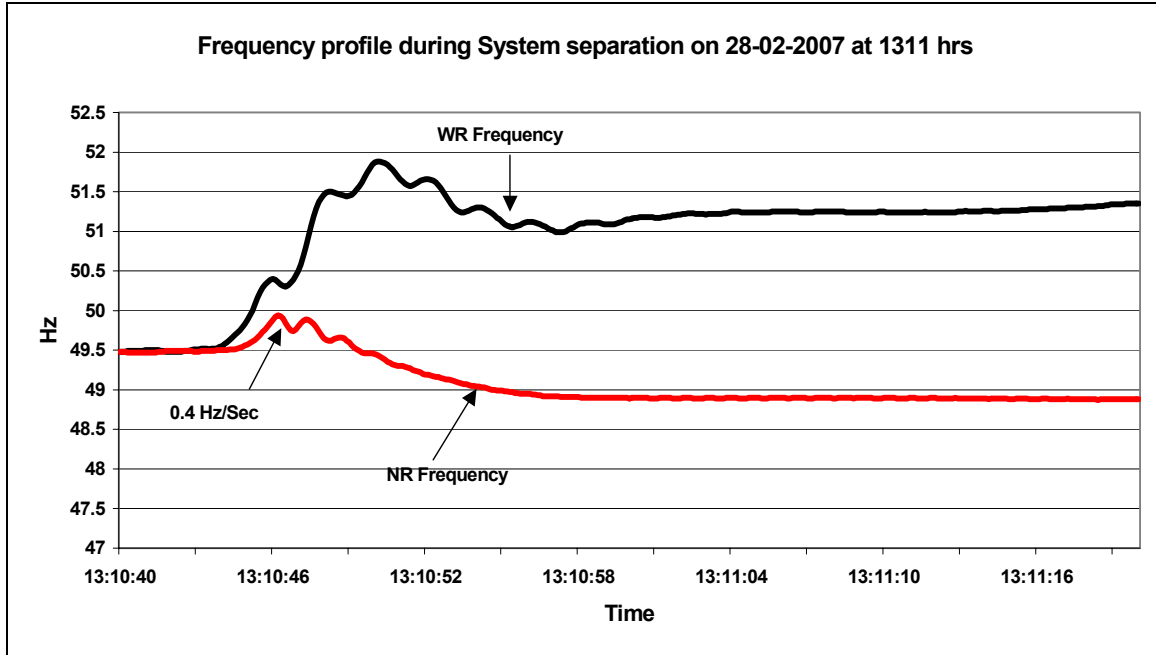
Observed Frequency response at Vindhyachal following loss of generation incident.



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Annex-III

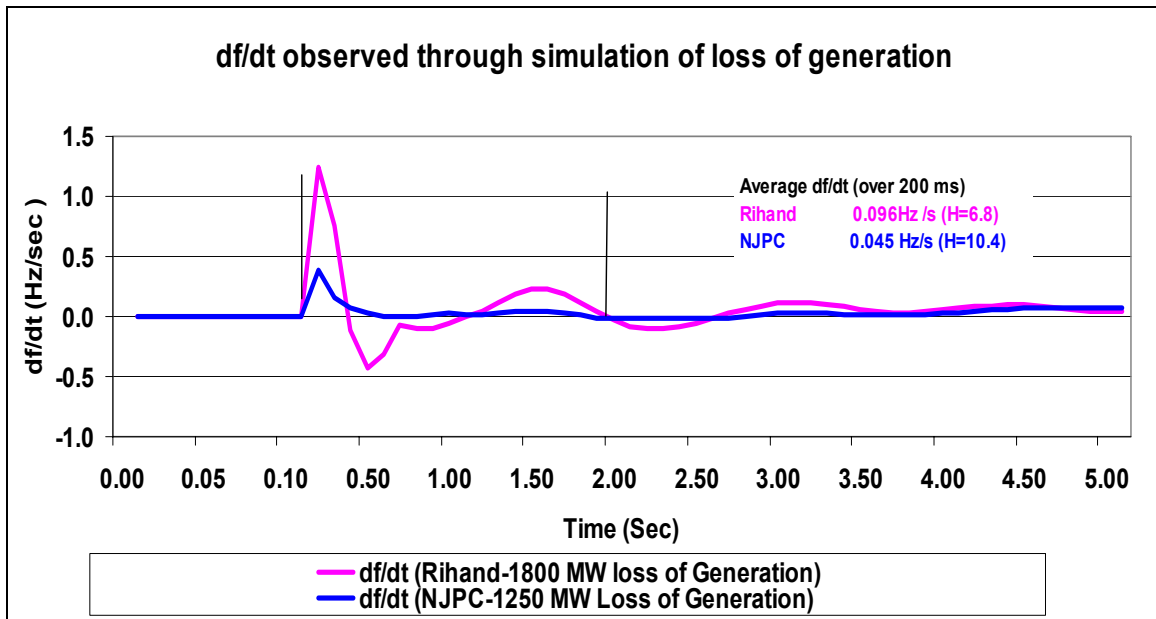
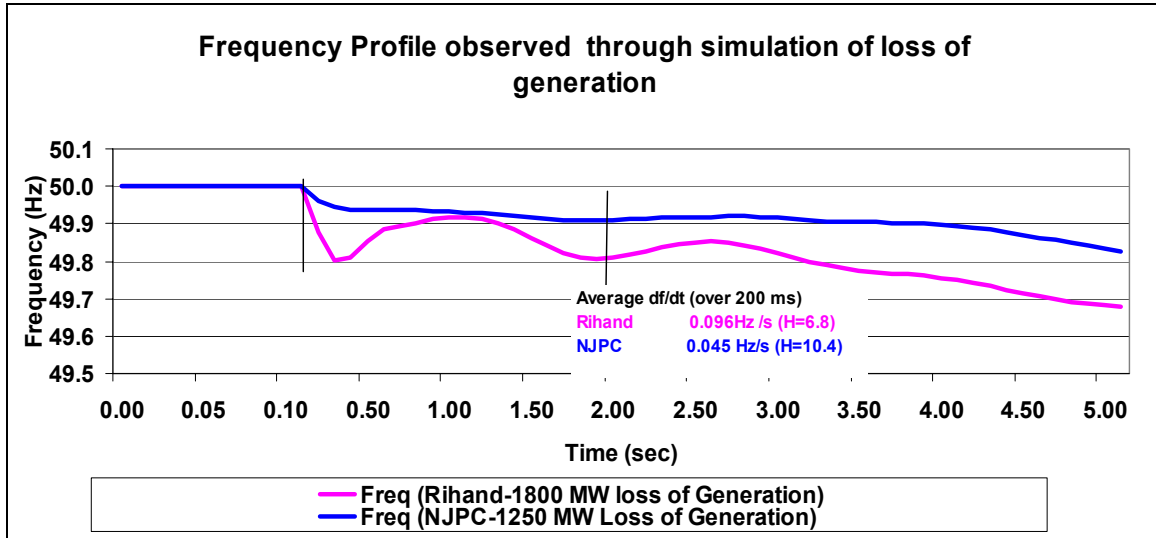
Observed frequency response at Vindhyachal following system separation.



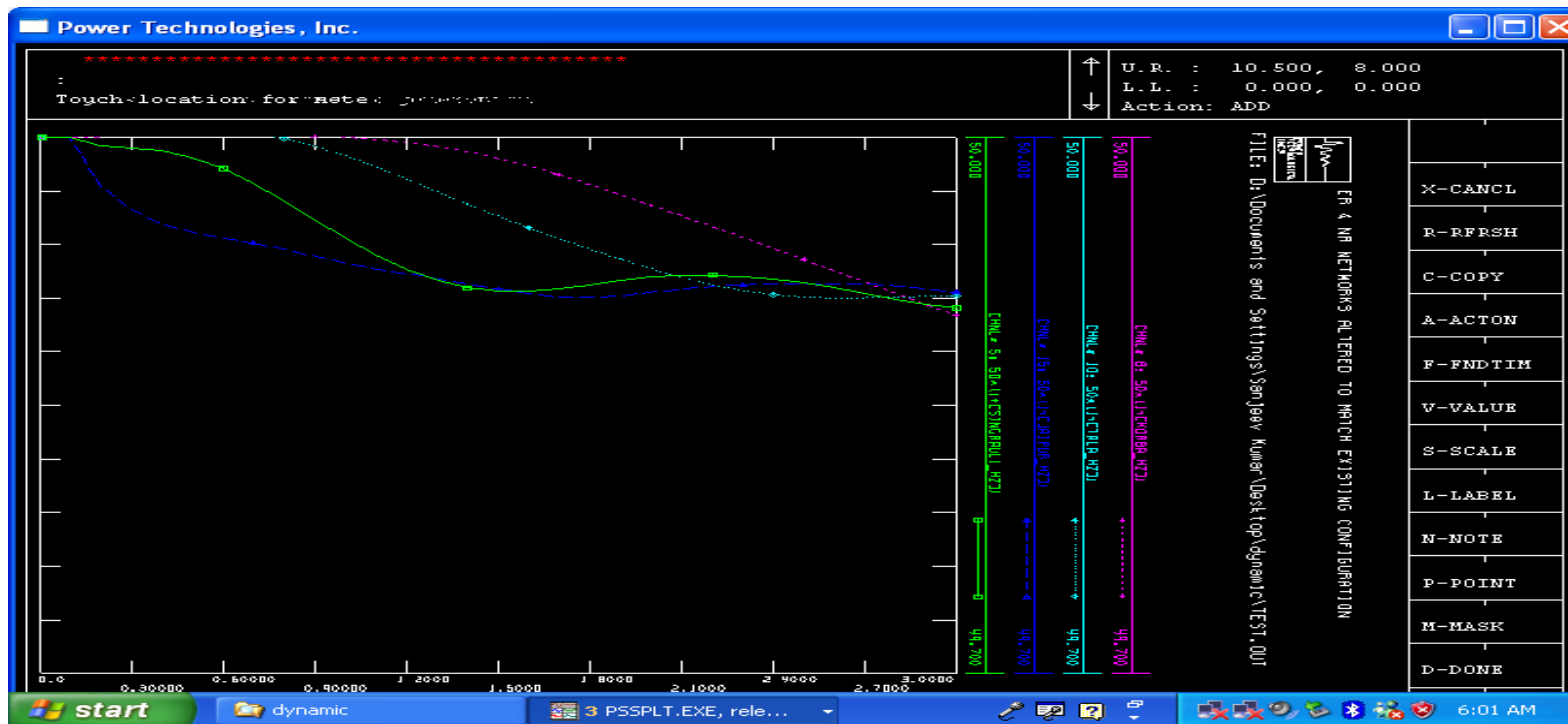
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Annex-IV

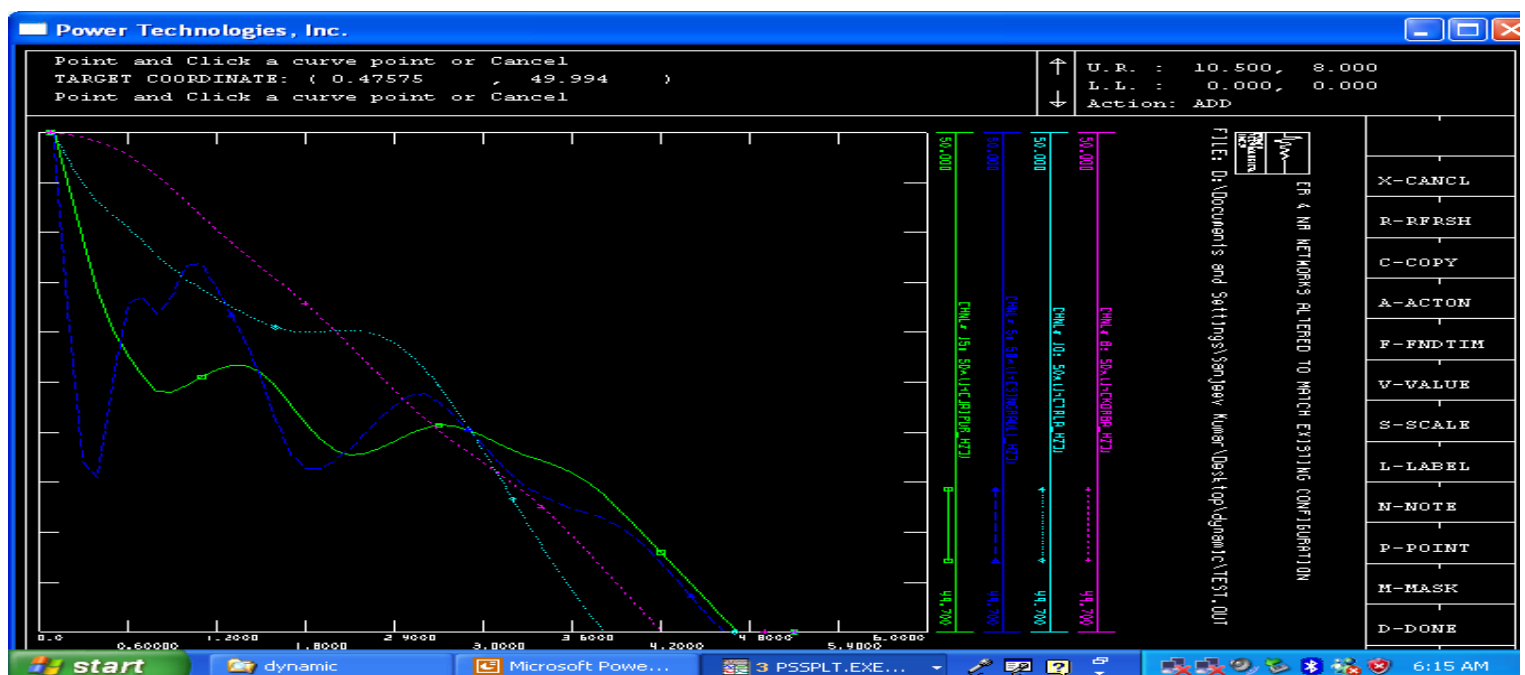
Frequency response obtained through simulation studies.



Comparison of fequency response observed at Singrauli,Tala, Korba,Jaipur through simulation for loss of 1250 MW generation at Jhakri.



Comparison of fequency response observed at Singrauli,Tala, Korba,Jaipur through simulation for loss of 1800 MW generation at Singrauli.



Annex-V

ABB document on Frequency relay behavior.

RE: Frequency relay behaviour

1. Background

According to the received information there are two different types of frequency relays in operation in the above network. These relays have been reported to give different kind of responses in a situation which was experienced locally as a disturbance by one of relay types.

The following brief discussion shows that relay responses to a network disturbance can be somewhat different when comparing the responses of the relays locating electrically in different positions in the network (e.g. S/Ss 1 and 2, figure 1)

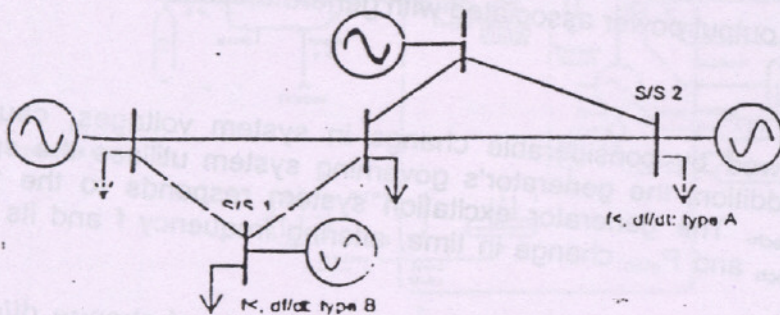


Figure 1.

ABB Transmitt Oy

Relays and Network Control

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2. Frequency behaviour of a network during disturbance: a brief case study

If losses in the machines are neglected and frequency in the system is uniform, a frequency response of the island obeys the following equation:

$$f \cdot \frac{df}{dt} = \frac{f_n^2}{2 \cdot H_{tot}} (P_{mech} - P_{elec}),$$

where

f = islands measured frequency (Hz)

f_n = nominal frequency (Hz)

H_{tot} = the composite inertia time constant (s)

P_{mech} = the total mechanical input power

P_{elec} = the total electrical output power associated with generators in the island

Overloading the generators is followed by considerable change in system voltages, causing a fluctuation in load power P_{elec} . In addition, the generator's governing system utilises the spinning reserve (if available), changing P_{mech} . The generator excitation system responds to the voltage changes, influencing P_{elec} . Thus P_{mech} and P_{elec} change in time, altering frequency f and its rate of change df/dt .

While the low frequency f is the final result of the power deficiency, its rate of change df/dt is an instantaneous indicator of power deficiency and can enable incipient recognition of the MW imbalance. However, the change in machine speeds is oscillatory in nature. These oscillations depend on the response of the generators and are seen differently at different locations.

Disturbance causing MW imbalance has been simulated using the following simple network:

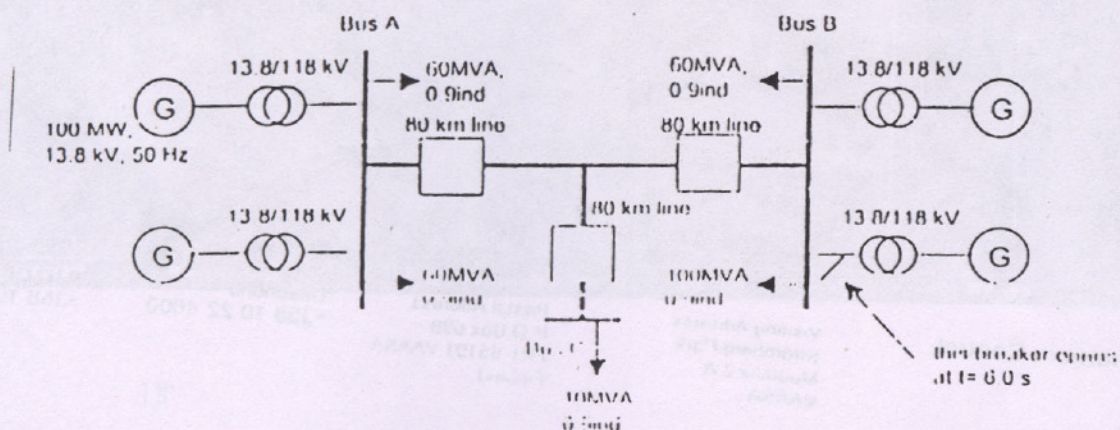


Figure 2. Simulated network. One 100 MW generator on bus B drops-off at time $t = 6.0$ sec.

The network consist of four 100 MW steam-turbine generators with exciters and governors. The generators on buses A and B are identical except that the generators on bus B has double the inertia of bus A generators. The inertia of the generators have influence on df/dt . Smaller system inertia increases the oscillation in df/dt . Buses A and B have 120 MVA, $\cos\phi=0.9$ ind, and 160 MVA, $\cos\phi=0.9$ ind passive loads respectively. Additionally, there is a 10 MVA load on Bus C. Buses are connected together with 80 km length, 110 kV overhead lines.

The network simulation was done with electrical transient simulation program PSCAD/EMTDC. The generators are modelled with accurate dynamical models, including models for excitation system and governor.

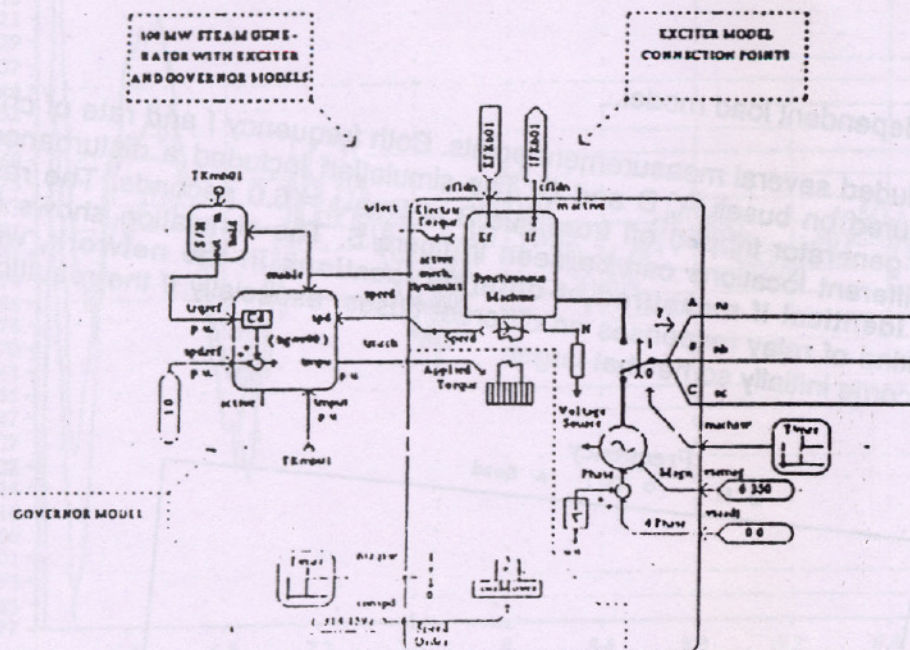


Figure 3. 100 MW steam turbine generator model with (fast) governor.

Transmission lines are modelled with travelling wave based models.

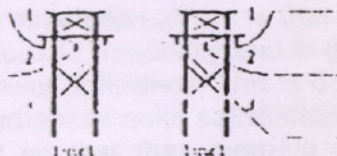


Figure 4. 80 km 110 kV overheadline model

Loads are modelled as simple passive voltage dependent loads.

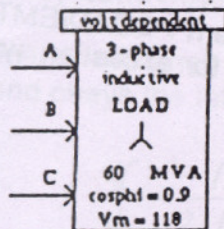


Figure 5. Passive voltage dependent load model.

The simulated network included several measurement points. Both frequency f and rate of change of frequency df/dt was measured on buses A, B and C. The simulation included a disturbance in the network, as one 100 MW generator tripped off from bus B at time $t = 6.0$ seconds. The results for measured frequency at different locations can be seen in figure 6. The simulation shows that the frequency decay is not identical if measured at different locations in the network, which can further result to different kind of relay responses on different buses, especially if the resulting power deficiency would have become initially somewhat larger.

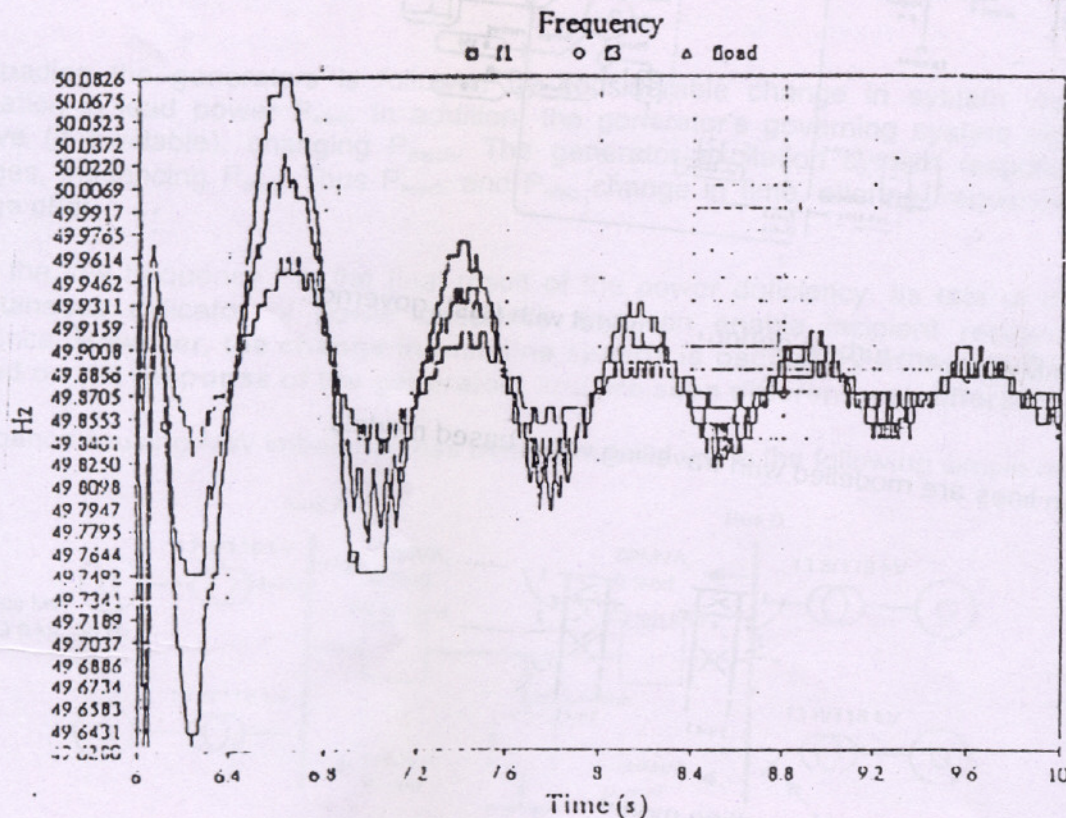


Figure 6. Frequency of the network, measured at different locations during the disturbance; $f1$ measured from bus A, $f3$ from bus B and $fload$ from bus C. The fundamental frequency is 50 Hz. Figure shows results, when generators at bus A are equipped with simple governors (constant T_{max}) and generators at bus B with fast governor.

The simulation also shows that df/dt is not identical if measured at different locations in the network.

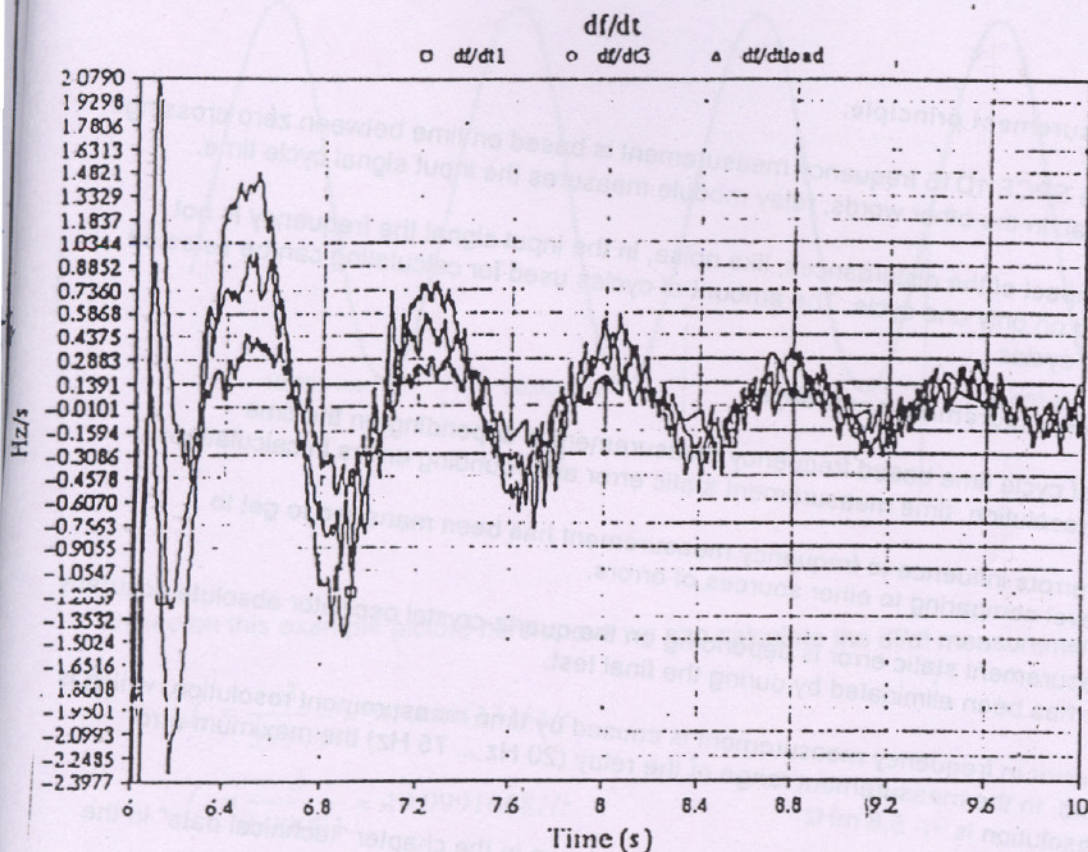


Figure 7. df/dt of the network, measured at different locations during the disturbance; $df/dt1$ is measured from bus A, $df/dt3$ from bus B and $df/dload$ from bus C. Figure shows results, when generators at bus A are equipped with simple governors (constant T_{mech}) and generators at bus B with fast governors.

Additional conclusion from the simple simulation above is that in this case the frequency relays must not have operated even if the oscillations in frequency and in df/dt would have occurred at somewhat lower frequency level due to larger power deficiency. This is due to the fact that the system seems to manage the above kind of small disturbances quite satisfactorily. And if this were the case, the relay settings would have to be selected so that they override the small changes in frequency and oscillations in df/dt .

Technical information

ABB Network Control & Protection

Frequency measurement principle:

The relay module SPCF 1D15 frequency measurement is based on time between zero crossings on the input signal. In the other words, relay module measures the input signal cycle time.

To reduce the impact of the disturbances, like noise, in the input signal the frequency is not calculated based on only one cycle. The amount of cycles used for calculating can be selected between 3 ... 20 cycles.

The frequency measurement accuracy:

The accuracy of cycle time based frequency measurement is depending on the time measurement resolution, time measurement static error and rounding errors in calculations.

The rounding errors influence to frequency measurement has been managed to get to insignificant level comparing to other sources of errors.

The time measurement static error is depending on the quartz-crystal oscillator absolute accuracy and this error has been eliminated by during the final test.

The biggest error in frequency measurement is caused by time measurement resolution, which is 1 microsecond. In the measurement range of the relay (20 Hz ... 75 Hz) the maximum error caused by resolution is +/- 5,6 mHz.

The measurement accuracy of the relay module is shown in the chapter "technical data" in the relay manual.

df/dt measurement principle

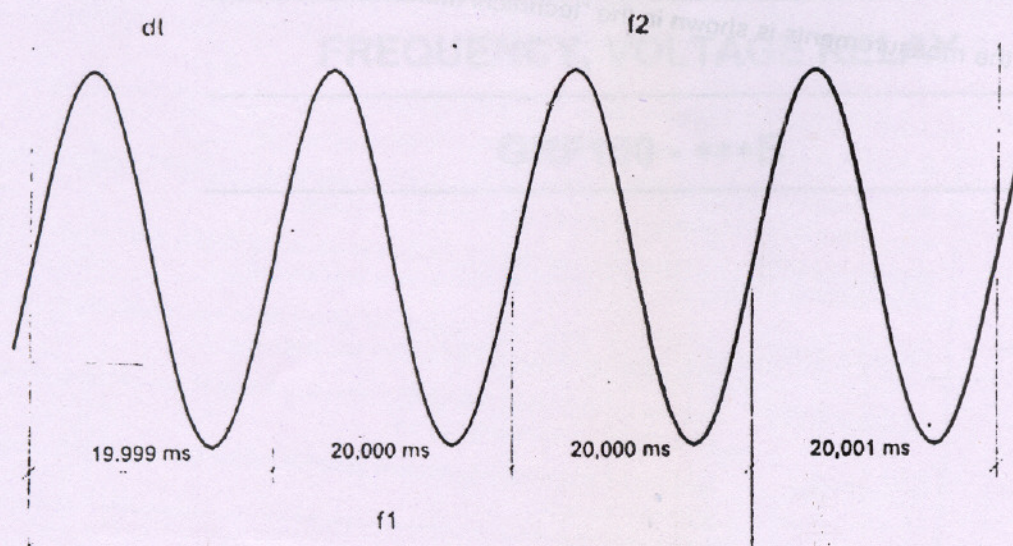
The rate of change of frequency measurement is based on two successive frequency measurements and the time difference between frequency measurements. The measured frequency value for df/dt calculations is average over three cycle.

The calculated interval of the frequency measurement (3 .. 20 cycles) setting does not have any influence on df/dt measurement.

df/dt measurement accuracy

The measurement accuracy of df/dt function is affected by same principles as in the accuracy of frequency measurement. Because the time difference between two successive frequency measurements (dt) is very short, the difference of frequencies (df) is also very little. Computationally it is a matter of two small numbers division, which is very sensitive for used word length and for the time resolution

Purely the resolution of time measurement is causing about 83 mHz/s error, when the input signal frequency is 50 Hz. How the error is developed is shown in the picture 1.



Based on this example picture here above we can calculate the df/dt measurement error.

$$f_1 = \frac{3}{59999} \approx 50.00083335 \text{ Hz}$$

$$f_2 = \frac{3}{600001} \approx 49.9991668 \text{ Hz}$$

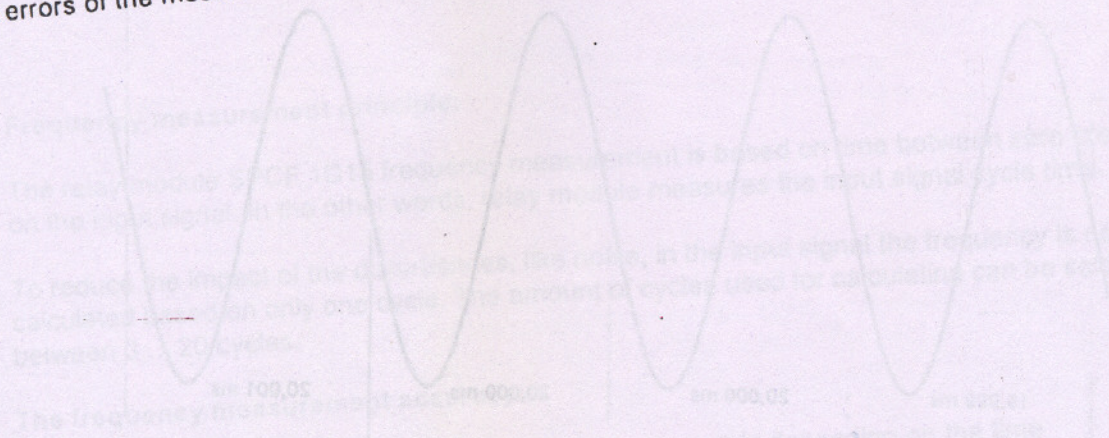
$$\Delta f = f_1 - f_2 \approx 0.001666666 \text{ Hz}$$

$$\Delta t = 19.999 \text{ ms}$$

$$\frac{\Delta f}{\Delta t} = \frac{0.00166666}{0.019999} \approx 83.33 \text{ mHz/s}$$

In this example calculation only the error caused by resolution has been taken into account. The infinite bit length error can be reduced by increasing the bit length. We are not able to increase the bit length in this case because the calculating capacity has limitations.

The errors of the measurements is shown in the "technical data" in the relay manual.



Based on this example picture, the error of the measurement is calculated. The error of the measurement is the difference between the measured value and the true value. The error of the measurement is calculated as follows:

$$\text{Error} = \frac{\text{Measured Value} - \text{True Value}}{\text{True Value}} \times 100\%$$

The error of the measurement is calculated as follows:

$$\text{Error} = \frac{10 - 10}{10} \times 100\% = 0\%$$

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$$\text{Error} = \frac{10 - 10}{10} \times 100\% = 0\%$$

Annex-VI

Extract from Toshiba Corporation document on Frequency and Voltage protection.

INSTRUCTION MANUAL

FREQUENCY, VOLTAGE RELAY

GRF100 - ***B

TOSHIBA CORPORATION

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(Ver. 2.0)

Safety Precautions

Before using this product, please read this chapter carefully.

This chapter describes the safety precautions recommended when using the GRF100. Before installing and using the equipment, this chapter must be thoroughly read and understood.

Explanation of symbols used

Signal words such as DANGER, WARNING, and two kinds of CAUTION, will be followed by important safety information that must be carefully reviewed.

DANGER

Indicates an imminently hazardous situation which will result in death or serious injury if you do not follow the instructions.

WARNING

Indicates a potentially hazardous situation which could result in death or serious injury if you do not follow the instructions.

CAUTION

Indicates a potentially hazardous situation which if not avoided, may result in minor injury or moderate injury.

CAUTION

Indicates a potentially hazardous situation which if not avoided, may result in property damage.

2.5 Characteristics of Measuring Elements

2.5.1 Frequency Elements

Underfrequency and overfrequency element

Underfrequency element UF operates when a power system frequency stays under the setting value.

Overfrequency element OF operates when a power system frequency stays over the setting value.

These elements measure the frequency and check the underfrequency or overfrequency every 5 ms. They operate when the underfrequency or overfrequency condition is detected 16 consecutive times.

Both UF and OF elements output is invalidated by undervoltage block element (UVBLK) operation during undervoltage condition.

Figure 2.5.1 shows characteristics of UF and OF elements.

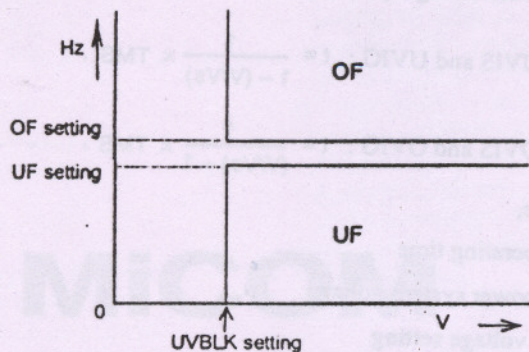


Figure 2.5.1 Underfrequency and Overfrequency Element

Frequency rate-of-change element

The frequency rate-of-change element calculates the gradient of frequency change (df/dt). GRF100 provides two rate-of-change elements, a frequency decay rate element and a frequency rise rate element. These elements measure the change in frequency (Δf) over a time interval ($\Delta t=100\text{ms}$), as shown Figure 2.5.2 and calculate the $\Delta f/\Delta t$ every 5 ms. They operate when the frequency change exceeds the setting value 50 consecutive times.

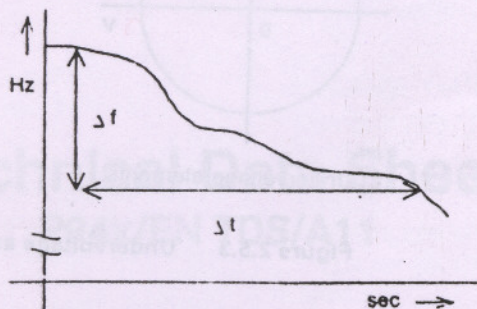


Figure 2.5.2 Frequency Rate-of-Change Element

2.5.2 Undervoltage and Overvoltage Elements

Phase-to-phase undervoltage elements UVS, UVHSS, UVIS and phase-to-ground undervoltage elements UVG, UVHSG and UVIG operate when a power system voltage stays under the setting values.

Phase-to-phase overvoltage elements OVS and OVIS and phase-to-ground overvoltage element OVG and OVIG operate when a power system voltage stays over the setting values.

These elements measure the voltage and check the undervoltage or overvoltage every 5 ms. They operate when the undervoltage or overvoltage condition is detected 2 consecutive times.

Figure 2.5.3 shows characteristics of undervoltage elements and overvoltage elements. The UVIS, UVIG, OVIS and OVIG have inverse time characteristics, and their characteristics are expressed by the following equations.

$$\text{UVIS and UVIG : } t = \frac{1}{1 - (V/V_s)} \times \text{TMS} .$$

$$\text{OVIS and OVIG : } t = \frac{1}{(V/V_s) - 1} \times \text{TMS} .$$

where,

t = operating time

V = power system voltage

V_s = voltage setting

TMS = time multiplier setting

Figure 2.5.4 shows operating time characteristics of UVIS, UVIG, OVIS and OVIG.

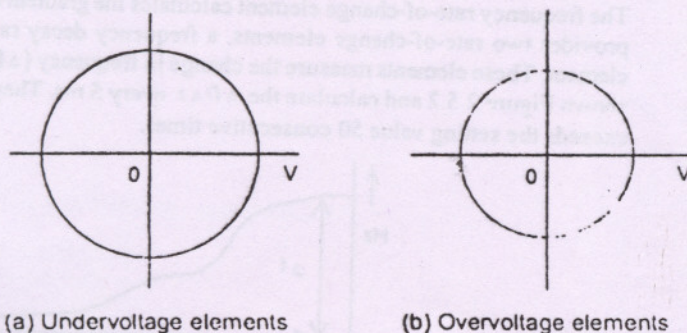


Figure 2.5.3 Undervoltage and Overvoltage Elements

Annex-VII

Extract from Technical data sheet of AREVA manufactured MICOM relays.



MiCOM

P941, P943

Frequency Based Load Shedding Relays

Technical Data Sheet

P94x/EN TDS/A11

Date:	20th January 2006
Hardware Suffix:	A or C
Software Version:	10 or 11
Connection Diagrams:	10P94yxx (y = 1 or 3) (x = 01 to 06)

Protection Functions

Over/Under Frequency 'f+t' Protection [81U/81O]

Accuracy

Pick-up: Setting $\pm 10\text{mHz}$

Drop-off:

Setting $+20\text{mHz}$, $\pm 10\text{mHz}$ (underfrequency)

Setting -20mHz , $\pm 10\text{mHz}$ (overfrequency)

Operating timer:

$\pm 2\%$ or 50ms whichever is greater

Operating & Reset Time

Operating time* (underfrequency):

$< 100\text{ms}$ for F_s/F_f ratios less than 2

$< 160\text{ms}$ for F_s/F_f ratios less than 6

$< 230\text{ms}$ otherwise

Operating time* (overfrequency):

$< 125\text{ms}$ for F_s/F_f ratios less than 2

$< 150\text{ms}$ for F_s/F_f ratios less than 30

$< 200\text{ms}$ otherwise

Reset time*: $< 200\text{ms}$

* Reference conditions: Tested using step changes in frequency with Freq.

Av.Cycles setting = 0 and no intentional time delay.

F_s/F_f ratios as stated, where:

F_s = start frequency - frequency setting

F_f = frequency setting - end frequency

Frequency Supervised Rate of Change of Frequency 'f+df/dt' Protection [81RF]

Accuracy

Pick-up:

Setting $\pm 10\text{mHz}$ (frequency threshold)

Setting $\pm 3\%$ or $\pm 10\text{mHz/s}$, whichever is greater (df/dt threshold)

Drop-off (frequency threshold):

Setting $+20\text{mHz}$, $\pm 10\text{mHz}$ (underfrequency)

Setting -20mHz , $\pm 10\text{mHz}$ (overfrequency)

Drop-off (df/dt threshold, falling frequency):

Setting $+0.005\text{Hz/s}$, $\pm 10\text{mHz/s}$

(for settings between 0.01Hz/s and 0.1Hz/s)

Setting $+0.05\text{Hz/s}$, $\pm 5\%$ or $\pm 55\text{mHz/s}$, whichever is greater

(for settings greater than 0.1Hz/s)

Drop-off (df/dt threshold, rising frequency):

Setting -0.005Hz/s , $\pm 10\text{mHz/s}$

(for settings between 0.01Hz/s and 0.1Hz/s)

Setting -0.05Hz/s , $\pm 5\%$ or $\pm 55\text{mHz/s}$, whichever is greater

(for settings greater than 0.1Hz/s)

Operating & Reset Time

Instantaneous operating time:

$< 125\text{ms}$ for Freq.Av.Cycles setting = 0

Reset time:

$< 400\text{ms}$ for df/dt.Av.Cycles setting = 0

Independent Rate of Change of Frequency 'df/dt+t' Protection [81R]

Accuracy

Pick-up:

Setting $\pm 3\%$ or $\pm 10\text{mHz/s}$, whichever is greater

Drop-off (falling frequency):

Setting $+0.005\text{Hz/s}$, $\pm 10\text{mHz/s}$

(for settings between 0.01Hz/s and 0.1Hz/s)

Setting $+0.05\text{Hz/s}$, $\pm 5\%$ or $\pm 55\text{mHz/s}$, whichever is greater

(for settings greater than 0.1Hz/s)

Drop-off (rising frequency):

Setting -0.005Hz/s , $\pm 10\text{mHz/s}$

(for settings between 0.01Hz/s and 0.1Hz/s)

Setting -0.05Hz/s , $\pm 5\%$ or $\pm 55\text{mHz/s}$, whichever is greater

(for settings greater than 0.1Hz/s)

Operating timer:

$\pm 2\%$ or 50ms whichever is greater

Operating & Reset Time

Operating time*:

$< 200\text{ms}$ for ramps $2\times$ setting or greater

$< 300\text{ms}$ for ramps $1.3\times$ setting or greater

Reset time*: $< 250\text{ms}$

* Reference conditions: Tested with df/dt.Av.Cycles setting = 0, for df/dt settings greater than 0.1Hz/s (positive or negative, as relevant) and no intentional time delay.

Average Rate of Change of Frequency 'f+Df/Dt' Protection [81RAV]

Pick-up:

Setting $\pm 10\text{mHz}$ (frequency threshold)

Setting $\pm 0.1\text{Hz/s}$ (Df/Dt threshold)*

Drop-off:

Setting $+20\text{mHz}$, $\pm 10\text{mHz}$ (falling frequency)

Setting -20mHz , $\pm 10\text{mHz}$ (rising frequency)

Operating timer:

$\pm 2\%$ or 30ms whichever is greater

* Reference conditions: To maintain accuracy the minimum time delay setting, Dt, should be:

$Dt > 0.375 \times Df + 0.23$ (for Df setting $< 1\text{Hz}$)

$Dt > 0.156 \times Df + 0.47$ (for Df setting $\geq 1\text{Hz}$)

Operating Time

Typically $< 125\text{ms}$ with Freq.Av.Cycles = 0