सत्यमेव जयते

भारत सरकार Government of India

विद्युत मंत्रालय Ministry of Power

उत्तर पूर्वी क्षेत्रीय विद्युत समिति

North Eastern Regional Power Committee

एन ई आर पी सी कॉम्प्लेक्स, डोंग पारमाओ, लापालाङ, शिल्लोंग-७९३००६, मेघालय

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No.: No. NERPC/SE (O)/PCC/2023/*2083-2124* September 29, 2023

To
As per list attached

Sub: Minutes of 59th Protection Coordination Sub-Committee (PCC) Meeting

Sir / Madam,

Please find enclosed herewith the minutes of the 59th PCC Meeting held at "NERPC Conference Hall", Lapalang, Shillong on 29th August, 2023 for your kind information and necessary action. The minutes is also available on the website of NERPC: www.nerpc.gov.in.

Any comments/observations may kindly be communicated to NERPC Secretariat at the earliest.

Encl: As above

(एस. एम. आइमोल / S. M. Aimol)
निदेशक / Director

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18. ED (O&M), NHPC, NHPC Office Complex, Sector-33, Faridabad, Haryana-121003
19. Group GM, NTPC, Bongaigoan Thermal Power Project, P.O. Salakati, Kokrajhar- 783369
20. Vice President (Plant), OTPC, Badarghat Complex, Agartala, Tripura - 799014
21. ED, PGCIL/NERTS, Dongtieh-Lower Nongrah, Lapalang, Shillong -793 006
22. AGM (BD), NVVN, Core 5, 3rd floor, Scope Complex, 7 Institutional Area, Lodhi Rd., N. Delhi-3
23. Vice President, PTCIL, 2nd Floor, NBCC Tower, 15, Bhikaji Cama Place, New Delhi – 110066
24. Dy. COO, CTUIL, “Saudamini”, 1st Floor, Plot No. 2, Sector-29, Gurugram, Haryana – 122001
25. Chief Engineer, GM Division, Central Electricity Authority, New Delhi – 110066
26. Chief Engineer, NPC Division, Central Electricity Authority, New Delhi – 110066
27. Head & VP, (R&C), ENICL, IndiGrid, Windsor Building, Kalina, Santacruz (East), Mumbai- 98
28. ED, NERLDC, Dongtieh, Lower Nongrah, Lapalang, Shillong -793 006
29. CGM, AEGCL, Bijuli Bhawan, Guwahati – 781001
30. CGM, APGCL, Bijuli Bhawan, Guwahati – 781001
31. CGM, DISCOM, Bijuli Bhawan, Guwahati – 781001
32. Head of SLDC, Dept. of Power, Govt. of Arunachal Pradesh, Itanagar – 791111
33. CGM, (LDC), SLDC Complex, AEGCL, Kahilipara, Guwahati-781 019
34. Head of SLDC, MSPCL, Imphal – 795001
35. Head of SLDC, MePTCL, Lumjingshai, Short Round Road, Shillong – 793 001
36. Head of SLDC, P&E Deptt. Govt. of Mizoram, Aizawl – 796 001
37. Head of SLDC, Dept. of Power, Govt. of Nagaland, Dimapur – 797103
38. Head of SLDC, TSECL, Agartala – 799001
39. Chief Engineer (Elect), Loktak HEP, Vidyut Vihar, Kom Keirap, Manipur- 795124
40. DGM (O&M), OTPC, Badarghat Complex, Agartala, Tripura – 799014
41. Head, Transmission, KMTL, 7th Floor, Fulcrum, Sahar Road, Andheri (E), Mumbai-400099
42. Director, NETC, 2C, 3rdFloor, D21Corporate Park, DMRC Building Sector 21, Dwarka, Delhi-77.

(एस. एम. आइमोल / S. M. Aimol)
निदेशक / Director

North Eastern Regional Power Committee

Minutes

of

59th Protection Sub-Committee Meeting

Date **:** 29/08/2023 (Tuesday)

Time **:** 10:30 hrs

Venue **:** NERPC Conference Hall, Shillong

Member Secretary NERPC welcomed the participants. He impressed upon the forum that a new chapter on Protection code has been included in the IEGC 2023 and requested all the utilities to strictly follow the regulations in the Protection code. Further he informed that NPC division of CEA has prepared a draft S.O.P with respect to third party protection audit, to be conducted by NERPC, which will be put up for deliberation in the meeting. He emphasized the need of regular and diligent patrolling of the lines so that tripping of the transmission lines may be reduced.

He then requested Director NERPC to take up the agenda points

C O N F I R M A T I O N O F M I N U T E S

1. CONFIRMATION OF MINUTES OF THE 58th PROTECTION SUB-COMMITTEE MEETING OF NERPC.

Minutes of the 58th PCC Meeting held on 14th March, 2023 (Tuesday) at NERPC Conference Hall, Shillong was circulated vide no. No.: NERPC/SE (O)/PCC/2023/331-370 dated 10th April, 2023.

No comment(s)/observation(s) were received from the constituents.

The Sub-committee confirmed the minutes of 58th PCCM of NERPC

B. ITEMS FOR DISCUSSION

B.1 Protection Audit of NER:

First phase of Third-Party protection Audit (2013-14) was completed in 2015 and in Second Stage of Protection Audit (2017-18) numerous stations were covered. However, few stations are yet to be audited. Status for second phase of Protection Audit:

Name of the state/utility	Name of the station(s)/Status
Arunachal Pradesh	132/33kV Along, 132/33kV Pasighat, 220/132/33kV Deomali, 132/33kV Daporizo, 132/33kV Lekhi, 132/33kV Tippi, 132/33kV Chimpu, 132/33kV Khupi.
Assam	Completed in Nov'21.
Manipur	Yet to be intimated, i.r.o some Substations
Meghalaya	400/220/132kV Byrnihat,132kV Mawphlang, 132KV Mustem, 132kV Umiam
Mizoram	Yet to be intimated, i.r.o some Substations
Nagaland	132kV Wokha, 132kV Sanis,132kV Kiphire
Tripura	Yet to be intimated, i.r.o some Substations

In 58th PCCM, the sub-committee agreed to complete the audit of the remaining substations at the earliest. The sub-committee agreed that the audit of the substations could be done by the utilities themselves via any expert third party or by the third party as nominated by the sub-committee. If the audit had been done by the utility itself via any expert third party, then the report should be sent to NERPC and NERLDC. The forum decided to maintain a yearly record of the substations that had been audited.

NPC division of CEA has prepared a draft S.O.P for third party protection Audit. **(Annexure-B.1.1**)

NERPC has prepared a calendar for third party protection audit for reference of the constituents. (**Annexure-B.1.2**)

Deliberation of the sub-committee

The draft S.O.P for third party protection Audits (which are to be conducted by NEPRC) was deliberated and agreed upon with following modification/addition:

(a) The audit formats will be circulated to the nodal officers 2 weeks prior to the date of audit and the nodal officers of respective State/power utilities have to fill the format and submit to the NERPC secretariat within 1 week.

(b) The final audit report will be completed within 2 weeks after the completion of Audit.

(c) PGCIL/NERTS will provide the list of physical inspection/check/test to be carried out and also format for testing of equipment in the audit. The list provided by PGCIL/NERTS is attached (**Annexure- B.1.3).**

(d) The forum decided that the SOP as issued by CEA with above modification/addition will be followed for the protection Audit in NER.

The audit calendar was deliberated upon and some modifications in the list of substations to be audited was suggested. The modified list is attached as **Annexure B.1.2.**

B.2 Status of the Implementation of Third-Party Protection Audit recommendation in NER held in 2017-18:

Name of the Utility	No. of Stations covered	% of Recommendation completed as on 55th PCC meeting 11-11-2020	Current Status
Ar. Pradesh	3	0	
Assam	16	38	
Manipur	4	40	
Meghalaya	10	11	
Mizoram	3	8	
Nagaland	3	81	
Tripura	11	0	

Utilities are requested to update the current status of implementation of the Third-Party Protection Audit.

In 58th PCCM and protection sub-group held on 4th May 2023, NERPC/NERLDC requested the states to provide following documents to NERPC and NERLDC at the earliest-

i) Recommendation reports of the Audits conducted in 2017-18

ii) Progress report on implementation of recommendations

Deliberation of the sub-committee

After detailed deliberation, Member Secretary NERPC exhorted the states to provide the audit reports and compliance report w.r.t to the audits conducted in 2017-18 to NERPC and NERLDC at the earliest.

B.3 Unified Real time Dynamic State Measurement System (URTDSM) phase-II project

In the 13th NPC meeting (under the chairmanship of Chairperson CEA) at Kolkata, Powergrid is entrusted to prepare a Detailed Project Report (DPR) for the Unified Real time Dynamic State Measurement System (URTDSM) phase-II project within 3 months. This project shall cover installation of PMUs, new analytics, and up gradation of control centers.

The placement of the PMUs under phase II shall be as per the recommendations of the sub-committee constituted under the chairmanship of Member Secretary, WRPC (**Annexure-B.3**).

In view of the above, it is requested to provide the number of PMUs required in each state & Region (SLDC wise/entity wise/substations wise) as pe the PMU placement criteria as provided below within one week, by 2.09.2023.

S No	Minimum Criteria of PMU Locations for URTDSM Phase-II
1	At one end of all 400 kV and above transmission lines
2	At the HV side of all ICTs connected to 220 kV and above
3	On HV side of coupling transformer of SVC/STATCOM for measurement of HV Bus voltage and current of coupling transformer
4	At one end of line wherever FSC/ TCSC are installed.
5	On HV side of converter transformers for measuring HVAC bus voltage and current of converter transformer on each converter station.
6	On both ends of Inter-regional and trans-national tie lines and on boundary buses for such lines
7	At the Generating Transformers (GTs) at LV side (having HV side of 220kV and above) of the Generating units with capacity above 200 MW for Thermal units, 50 MW for Hydro units and 100 MW for Gas units.
8	On all 220kV substations for measuring voltage of 220 kV bus and current of two lines/transformer catering to load centers.
9	All 132 kV and above ISTS lines in NER & Sikkim and important load centers
10	At RE developer end of the evacuating line connecting the Renewable Energy Pooling Stations (PS) to point of interconnection with the grid of 50MW and above.
11	Islanding, Separating & Restoration Points- At one end of line which is connected to black start stations along with circuit breaker status via synchro phasors.
12	Fiber Optic should be covered under Phase – II for all the above locations of the URTDSM project.
13	At all ICTs, Bus reactors, Switchable line reactors of critical substations.

NERLDC informed the meeting about their request to NERPC to compose an email/letter to NPC, advocating for the inclusion of a list of 38 PMUs provided by RLDC.

The importance of these 38 PMUs for ensuring grid stability and real-time monitoring in the North Eastern Region (NER) was emphasized. These PMUs cover 132 Nodes and are considered a minimum requirement for NER

NERPC to draft and send an email/letter to NPC, supporting the inclusion of the 38 PMUs provided by RLDC, highlighting their critical importance for NER's grid infrastructure.

Deliberation of the sub-committee

Member Secretary NERPC exhorted all the state utilities and NERLDC to provide details about requirement of PMUs as per the placement criteria.

NERLDC requested MS NERPC to send a letter to NPC, supporting the inclusion of the 38 PMUs provided by RLDC, highlighting their critical importance for NER's grid infrastructure.

B.4 <u>PSS tuning procedure</u>

A sub-group was formed vide NPC Division, CEA letter number 4/MTGS/ NPC/CEA/2021/71-81 in which terms of reference (TOR) was to finalize a common procedure for PSS Tuning at all India level.

The sub-group submitted its report to the NPC Committee and the same was accepted as mentioned in the Item No.11 of the Minutes of the 13th NPC Meeting reproduced herewith, "*The report of the sub-committee (copy of report at Annexure-IX) was accepted by the NPC. The reports may be circulated for the stakeholders' consultation before implementation of recommendations of the report.*"

The report **(Annexure-B.4)** is hereby circulated for stakeholder's consultation. Kindly provide your comments, if any, by 02.09.2023.

<u>Deliberation of the sub-committee</u>

NERLDC intimated that a common procedure has also been prepared by NLDC and the same will be circulated for stakeholders' consultation (**Annexure B.4.1**). After detailed deliberation, Member Secretary NERPC requested all the generating utilities (having units with capacity more than 50MW) to study the reports of both, NLDC and the NPC sub-group, and provide comments to NERPC& NERLDC at the earliest.

B.5 <u>df/dt scheme</u>

df/dt scheme is not available in NER. The necessity of the scheme for NER may be deliberated in the forum.

<u>Deliberation of the sub-committee</u>

Forum agreed on the necessity of implementing the df/dt scheme in NER, considering the growing presence of renewable energy sources in the country and consequently reducing inertia of the grid.

AD, NERPC stated that tripping philosophy and quantum of load relief may be derived from the report of the committee on AUFLS and df/dt constituted under the chairmanship of MS, WRPC and the same has been attached as **Annexure B.5** for review of the stakeholders.

Member Secretary, NERPC directed NERLDC to prepare a plan for the implementation of the df/dt scheme in NER.

B.6 Analysis and Discussion on Major Grid Disturbances which occurred in NER grid w.e.f. June 2023 to July 2023:

Items related to Arunachal Pradesh

June'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Balipara-Tenga line tripped on 06.06.2023. (b/g:- Due to tripping of this element, Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System got separated from rest of NER Grid)	Suspected vegetation fault in phase RY-G Fault Z1 operated in 75ms opened all three phases AR not attempted. Ir=2kA,Iy=2kA In=1kA,Fault angle -58° Underlying reason for tripping of the line to be investigated	Discussed under item B.9
2.	132 kV Balipara-Tenga line tripped on 08.06.2023. (b/g:-Due to tripping of this element, Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System got separated from rest of NER Grid)	Fault in phase Y-G Fault Z1 activated and operated in 75ms opened all three phases AR not attempted. Iy=1.5kA In=1.5kA,Fault angle n -61° Underlying reason for tripping of the line to be investigated	Discussed under item B.9
3.	132 kV Daporijo - Ziro Line tripped on 10.06.2023. (b/g:- Due to tripping of this element, Daporizo, Basar, Along, Pasighat, Roing, Tezu and Namsai areas of Arunachal Pradesh Power System got separated from	**Zero end** Mal tripping as variation in current is not observed **Daporizo end DR not available**	

	the rest of NER Grid)		
4.	132 kV Balipara-Tenga line tripped on 17.06.2023. (b/g:- Due to tripping of this element, Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System got separated from rest of NER Grid)	Suspected phase R-Y Fault **Balipara end** Z1 activated and operated in 70 ms. AR not attempted/ not present Ir=2.5kA, Iy=2.4kA, Fault angle R phase – 27° **Tenga end** Z1 operated in 90ms opened all three phase Ir=290A, Iy=300A, Fault angle R phase – 15° Underlying reason for tripping of the line to be investigated	Discussed under item B.9
5.	132 kV Balipara - Tenga line tripped on 21.06.2023. (B/g:- Due to tripping of this element, Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System got separated from rest of NER Grid)	Suspected phase R-Y Fault **Balipara end** Z1 activated and operated in 85 ms AR not attempted/ not present Ir=2.55kA, Iy=2.45kA, Fault angle R phase – 29° **Tenga end** Z1 operated in 50ms opened all three phase Ir=330A, Iy=305A, Fault angle R phase – 16° Underlying reason for tripping of the line to be investigated	Discussed under item B.9

6.	132 kV Balipara - Tenga line tripped on 27.06.2023. (B/g:- Due to tripping of this element, Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System got separated from rest of NER Grid)	Suspected phase Y-B-G Fault **Balipara end** Z1 activated and operated in 85 ms AR not attempted/ not present Iy=3.55kA, Ib=4.05kA, In=3.5kA Fault angle B phase – 66° **Tenga end** Z1 operated in 50ms opened all three phase Iy=300A, Ib=200A, In=700A Fault angle R phase – 68° Underlying reason for tripping of the line to be investigated	Discussed under item B.9

July'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Lekhi - Nirjuli line tripped At 14:03 Hrs on 20.07.2023. (b/g:- Due to tripping of this element, Nirjuli area of Arunachal Pradesh Power System got separated from rest of NER Grid 132 kV Gohpur - Nirjuli line was under shutdown to avoid over loading of 132 kV Itanagar - Lekhi line).	**Lekhi Side** R-G Fault Z1 activated and operated in 90ms and opened all three phase Earth Fault relay also started (IN>2) AR not attempted/ not present Ir=2.4kA, In=1.7kA Fault angle B phase – 35° **Nirjuli end** R-Y-B-G Fault Z1 activated and operated in 45ms and opened all three phase AR not attempted/ not present Ir=407A, Ir=312A, Ir=451A, In=1.1kA Fault angle B phase –	To be discussed in Subgroup meeting

		30° Underlying reason for tripping of the line to be investigated.	
2.	132 kV Pare - Itanagar D/C lines tripped At 14:11 Hrs on 25.07.2023. (b/g:-Due to tripping of these elements, Pare HEP of Arunachal Pradesh Power System got separated from rest of the NER Grid 132 kV Ranganadi -Pare-1 and 132kV Pare - Lekhi lines were under shutdown for straightening of 132 kV Ranganadi-Lekhi/Nirjuli line and commissioning of 132 kV Pare-North Lakhimpur transmission line and LILO at Nirjuli).	**Itanagar End DR** Mal operation of CB	To be discussed in Subgroup meeting
3.	132 kV BNC-Itanagar D/C and 132 kV Lekhi-Itanagar lines tripped At 22:15 Hrs on 27.07.2023. (b/g:-Due to tripping of these elements, Itanagar area and Pare HEP of Arunachal Pradesh Power System got separated from rest of the NER Grid)	**132 kV BNC-Itanagar ckt1** **BNC End** Over current (I>1) activated and operated in 75ms and opened all three phase AR not attempted/ not present **Itanagar End** B-G Fault Vegetation fault Z1 activated and operated in 60ms and opened all three phase AR not attempted/ not present Ir=1.5kA, In=1.7kA Fault angle B phase – 68° **132 kV BNC-Itanagar ckt2** **BNC End** B-G Fault	To be discussed in Subgroup meeting

		Z2 activated and operated in 540ms and opened all three phase Earth Fault relay also started (IN>1) AR not attempted/ not present Ir=1.5kA, In=0.79kA Fault angle B phase – 75° **Itanagar End** B-G Fault Z1 activated and operated in 60ms and opened all three phase AR not attempted/ not present Ir=1.7kA, In=1.85kA Fault angle B phase – 65° **132 kV Lekhi-Itanagar** **Lekhi End** Mal operation over current relay operated (IN>1) **Itanagar End** DR is not proper Underlying reason for tripping of the line to be investigated	

Items related to Assam

June'23

Sl No	**Event**	**Discussion points**	**Deliberation of the Subcommittee**
1.	132 kV Lumshnong - Panchgram, 132 kV Hailakandi - Panchgram and 132 kV Badarpur - Panchagram lines tripped on 18.06.2023. (b/g:-Due to tripping of these elements, Panchgram	**132 kV Lumshnong - Panchgram** R-G Fault **Lumshnong end** Z1 activated and operated in 65 ms AR not attempted/ not present Ir=3.59kA,In=3.7kA Fault	To be discussed in Subgroup meeting

	area of Assam Power System got separated from rest of NER 132 kV Srikona - Panchgram line was under outage due to tower collapse since 14.01.2019)	angle B phase – 36° **Panchgram end** DR not available **132 kV Badarpur – Panchagram** **Badarpur end** AR not attempted/ not present Earth Fault (IN>1) operated in 440ms, Z3 activated Ir=3.59kA,In=3.7kA Fault angle B phase – 36° **Panchgram end** DR not available Underlying reason for tripping of the line to be investigated	
2.	132 kV BTPS - Dhaligaon D/C lines tripped on 18.06.2023. (b/g:- Due to tripping of these elements, Dhaligaon, Barpeta, Jogighopa, Gosaigaon, IOCL load and part load of Bornagar areas of Assam Power System got separated from rest of NER Grid. 132 kV Nalbari-Barpeta line was under shutdown to avoid overloading of 132 kV BTPS-Dhaligaon D/C lines and 132 kV Gosaigaon - Gauripur line was under shutdown to avoid overloading of 132 kV BTPS - Kokrajhar D/C lines)	**BTPS end** Y-G Fault AR not attempted/ not present Z1 operated in 74ms Iy=3.79kA, In=3.12kA, Angle – 46° **Dhaligaon end** AR not attempted/ not present Z1 operated on 75ms Iy=445A, In=1.05kA, Angle – 41° Underlying reason for tripping of the line to be investigated	To be discussed in Subgroup meeting

3.	132 kV Lumshnong - Panchgram and 132 kV Hailakandi - Panchgram lines tripped on 18.06.2023. (b/g:- Due to tripping of these elements, Panchgram area of Assam Power System got separated from rest of NER Grid 132 kV Badarpur-Panchgram line was under planned shutdown for installation, wiring, testing of distance relay. 132 kV Srikona - Panchgram was under outage due to tower collapse since 14.01.2019)	**Hailakandi End** Y phase conductor snapping **Panchgram end** DR not available **Lumshnong End** Mal operation due to conductor snapping **Panchgram end** DR not available Underlying reason for tripping of the line to be investigated	To be discussed in Subgroup meeting
4.	132 kV BTPS - Dhaligaon D/C lines tripped on 20.06.2023. (b/g:- Due to tripping of these elements, Dhaligaon, Barpeta, Jogighopa, Gosaigaon, IOCL load and part load of Bornagar areas of Assam Power System got separated from rest of NER Grid. 132 kV Nalbari-Barpeta line was under shutdown to avoid overloading of 132 kV BTPS-Dhaligaon D/C lines and 132 kV Gosaigaon - Gauripur line was under shutdown to avoid overloading of 132	**132 kV BTPS – Dhaligaon ckt 1** R-G fault **BTPS end** AR not attempted Z1 operated in 105ms Ir=3.12 kA and In= 2.41kA angle - 60.66° **Dhaligaon end** AR not attempted Z1 operated in 75ms Ir=410A and In= 305A angle - -33° **132 kV BTPS – Dhaligaon ckt 2** R-G fault **BTPS end** AR not attempted Z1 operated in 165ms	To be discussed in Subgroup meeting

	kV BTPS - Kokrajhar D/C lines)	Ir=4.69kA and In= 4.69kA, angle - 59° **Dhaligaon end** AR not attempted Z1 operated in 85ms Ir=350A and In= 988A angle - 32°	
5.	220 kV Rangia - BTPS 1 & 132 kV Rangia-Motonga lines tripped on 21.06.2023. (b/g:- Due to tripping of these elements, Rangia, Kamalpur, Amingaon, Nalbari, part load of Sishugram, and part load of Bornagar areas of Assam Power System got separated from rest of NER Grid 220kV Rangia - BTPS 2 line was declared faulty. 132 kV Rangia - Sipajhar, 132kV Rangia - Tangla and 132kV Amingaon - AIIMS lines were under shutdown to avoid overloading of 220kV Rangia - BTPS D/C lines. 132 kV Nalbari - Barpeta was under shutdown to avoid overloading of 132 kV BTPS - Dhaligaon D/C lines)	**220 kV Rangia - BTPS 1** Y-B-G fault **BTPS End** AR not attempted Z1 operated in 510ms Iy=2.05kA and Ib=1.60kA In= not available **Rangia end** Y-B-G fault Z2 operated in 540ms Iy=0.5kA and Ib=0.3kA In= 0.79kA **132 kV Rangia-Motonga lines** **DR not available**	To be discussed in Subgroup meeting
6.	132 kV BTPS - Dhaligaon D/C lines tripped At 21:06 Hrs on 21.06.2023. (b/g:- Due to tripping of	**BTPS End** Fault B-G AR not attempted Z1 operated in 67ms,	To be discussed in Subgroup meeting

	these elements, Dhaligaon, Barpeta, Jogighopa,Gossaigaon, IOCL load, Bornagar and Nalbari areas of Assam Power System got separated from rest of NER Grid. 220 kV Rangia - BTPS D/C lines were under outage due to tower collapse at loc.no. 452, 132 kV Rangia-Nalbari, 132kV Rangia- Bornagar and 132kV Gossaigaon-Gauripur lines were under shutdown to avoid overloading of 132 kV BTPS-Dhaligaon D/C lines)	Ib=5.64 kA, In=5.13 kA Angle -58°	
7.	132 kV BTPS - Dhaligaon D/C lines tripped At 22:34 Hrs on 21.06.2023. (b/g:-Due to tripping of these elements, Dhaligaon, Barpeta, Jogighopa,Gossaigaon, IOCL load, Bornagar and Nalbari areas of Assam Power System got separated from rest of NER Grid 220 kV Rangia - BTPS D/C lines were under outage due to tower collapse at loc.no. 452, 132 kV Rangia-Nalbari, 132kV Rangia- Bornagar and 132kV	**BTPS End** R-B-G Fault AR not attempted Z1 operated in 71ms Ir=2.81kA, Ib=3.38kA, In=1.96kA. **Dhaligaon END** R-B-G Fault AR not attempted Z1 operated in 88 ms Ir=0.7kA, Ib=0.5kA, In=1.5kA	To be discussed in Subgroup meeting

	Gossaigaon-Gauripur lines were under shutdown to avoid overloading of 132 kV BTPS-Dhaligaon D/C lines).		
8.	400 kV New Mariani - Misa D/C, 400 kV Balipara - Misa D/C, 400 kV Silchar - Misa 2, 220 kV Misa - Dimapur D/C, 220 kV Misa - Byrnihat(Killing) D/C and 220 kV Misa- Samaguri D/C lines tripped At 23:04 Hrs on 22.06.2023. (b/g:- Due to tripping of these elements, 400/220 kV Misa Substation and Smaguri areas of Assam Power System got separated from rest of NER Grid 400 kV Silchar - Misa 1 line was under outage because it tripped on charging attempt after shut zdown return at 20:08 Hrs on 22.06.2023).	**400 kV New Mariani – Misa** **Misa end** B-G fault Z1 operated in 41ms AR operated successfully Ib=3.76kA, In=3.74kA, Angle-77° **Mariani End** Proper DR not available **400 kV Balipara - Misa** **Balipara end** R-Y-G Fault Z3 operated in 1510ms Ir=2.19kA, Iy=1.78kA, In=0.9kA	To be discussed in Subgroup meeting
9.	132 kV Rangia-Motonga line tripped At 02:16 Hrs on 25.06.2023. (b/g:- Due to tripping of this element, Rangia area of Assam Power System got separated from rest of NER Grid 220 kV BTPS-Rangia D/C	Loss of voltage both end	To be discussed in Subgroup meeting

	lines were under outage due to tower collapse at loc.no. 452. 132kV Rangia - Sipajhar & 132kV Rangia - Tangla lines were under shutdown to avoid overloading of 132 kV Sonabil-Ghoramari & 132 kV Sonabil-Depota lines. 132 kV Rangia Kamalpur D/C lines were under shutdown to avoid overloading of 132 kV Kahilipara - AIIMS line).		
10	132 kV Rangia-Motonga line tripped At 11:50 Hrs on 25.06.2023. (b/g:- Due to tripping of this element, Rangia area of Assam Power System got separated from rest of NER Grid 220 kV BTPS-Rangia D/C lines were under outage due to tower collapse at loc.no. 452. 132kV Rangia - Sipajhar & 132kV Rangia - Tangla lines were under shutdown to avoid overloading of 132 kV Sonabil-Ghoramari & 132 kV Sonabil-Depota lines. 132 kV Rangia Kamalpur D/C lines were under shutdown to avoid low volatge at 132kV Rangia Substation).	No DR file received	To be discussed in Subgroup meeting

11.	132 kV Rangia-Motonga line tripped At 14:37 Hrs on 25.06.2023. (b/g:- Due to tripping of this element, Rangia area of Assam Power System got separated from rest of NER Grid 220 kV BTPS-Rangia D/C lines were under outage due to tower collapse at loc.no. 452. 132kV Rangia - Sipajhar & 132kV Rangia - Tangla lines were under shutdown to avoid overloading of 132 kV Sonabil-Ghoramari & 132 kV Sonabil-Depota lines. 132 kV Rangia Kamalpur D/C lines were under shutdown to avoid overloading of 132 kV Kahilipara - AIIMS line)	Loss of voltage both end	To be discussed in Subgroup meeting

July'23

Sl No	**Event**	**Discussion points**	**Deliberation of the Subcommittee**
1.	220 kV Sarusajai-Karbi Langpi 1 line tripped At 10:33 Hrs on 15.07.2023. (B/g:- Due to tripping of this element, Karbi Langpi Generating Station of Assam Power System got separated from rest of NER Grid 220 kV Sarusajai-Karbi Langpi 2 line was under	**Sarusajai end** Suspected vegetation fault in phase B-G Fault Z1 operated in 65ms opened all three phases AR not attempted. Ib=3.9kA, In=3.9kA, Fault angle -42° Underlying reason for tripping of the line to be investigated	To be discussed in Subgroup meeting

	planned shutdown since 08:52 Hrs on 15.07.2023 for maintenance of Isolator.)		
2.	132 kV Sarupathar - Golaghat line tripped At 10:00 Hrs on 04.07.2023. (b/g:- Due to tripping of this element, Sarupathar and Bokajan areas of Assam Power System got separated from rest of NER Grid 132 kV Bokajan - Dimapur(PG) line was under planned shutdown prior to event).	**Golaghat End** Proper DR not available	To be discussed in Subgroup meeting
3.	220 kV Sarusajai-Karbi Langpi 1 line tripped At 10:46 Hrs on 18.07.2023. (B/g:- Due to tripping of this element, Karbi Langpi Generating Station of Assam Power System got separated from rest of NER Grid 220 kV Sarusajai-Karbi Langpi 2 line was under planned shutdown since 08:52 Hrs on 15.07.2023 for maintenance of Isolator.)	**Sarusajai end** B-G Fault Z1 operated in 159ms. AR not attempted. Ib=3.5kA, In=3.5kA, Fault angle -26° Underlying reason for tripping of the line to be investigated	To be discussed in Subgroup meeting

Items related to Manipur

June'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Loktak - Ningthoukhong, 132 kV Imphal (PG) - Ningthoukong and 132 kV	B-G Fault **Imphal (PG) End** AR not attempted Z1 operated on 60ms	To be discussed in Subgroup meeting

	Ningthoukhong - Churachandpur D/C lines tripped on 15.06.2023. (b/g:- Due to tripping of these elements, Ningthoukhong, Churachandrapur and Thanlon areas of Manipur Power System got separated from rest of NER Grid 132kV Kakching - Churachandpur and 132kV Elangkangpokpi - Churachandpur were under tripped condition since 12:21 Hrs on 08.06.2023).	Ib=2.41kA and In=2.02kA Angle -69° Other DR not available	
2.	132 kV Loktak - Ningthoukhong, 132 kV Imphal (PG) - Ningthoukong and 132 kV Ningthoukhong - Churachandpur 1 lines tripped on 16.06.2023. (b/g:- Due to tripping of these elements, Ningthoukhong, Churachandrapur and Thanlon areas of Manipur Power System got separated from rest of NER Grid 132 kV Kakching - Churachandpur and 132kV Elangkangpokpi - Churachandpur were under tripped condition since	B-G Fault **Imphal (PG) End** AR not attempted Z2 operated on 330ms Ib=3.01kA and In=2.69kA Angle -70° Other DR not available	To be discussed in Subgroup meeting

	12:21 Hrs on 08.06.2023. Also, 132 kV Ningthoukhong - Churachandpur 2 line was under outage since 11:02 Hrs on 15.06.2023)		
3.	132 kV Ningthoukhong - Churachandpur 1 line tripped on 28.06.2023. (b/g:-Due to tripping of this element, Churachandrapur and Thanlon areas of Manipur Power System got separated from rest of NER Grid 132 kV Kakching - Churachandpur and 132kV Elangkangpokpi - Churachandpur lines were under outage since 12:21 Hrs on 08.06.2023. Also, 132 kV Ningthoukhong - Churachandpur 2 line was under outage since 11:02 Hrs on 15.06.2023)	DR File not available	To be discussed in Subgroup meeting

<u>July'23</u>

1. Blackout of Tipaimukh on 21.07.2023
   (Refer to item B.14)

Items related to Meghalaya

<u>June 2023</u>

Sl No	**Event**	**Discussion points**	**Deliberation of the Subcommittee**
1.	132 kV Khliehriat-Lumshnong line tripped At 15:24 Hrs on 08.06.2023.	R-Y-B Fault **Khleiriat end**	To be discussed in Subgroup meeting

	(b/g:- Due to tripping of this element, Lumshnong area of Meghalaya Power System got separated from rest of NER Grid 132 kV Lumshnong-Panchgram line was under planned shutdown since 05:12 Hrs on 08.06.2023).	AR not attempted Z1 operated in 71ms Ir=2.1kA, Iy=2.3kA, Ib=2.4kA	
2.	132 kV Khliehriat-Lumshnong line tripped At 15:48 Hrs on 08.06.2023. (b/g:-Due to tripping of this element, Lumshnong area of Meghalaya Power System got separated from rest of NER Grid 132 kV Lumshnong-Panchgram line was under planned shutdown since 05:12 Hrs on 08.06.2023)	R-G Fault **Khleiriat End** Z1 operated in 63ms AR not attempted Ir=3 kA,In=2.5 kA, Fault Angle-70°	To be discussed in Subgroup meeting
3.	132 kV EPIP II - New Umtru and 132 kV Umtru - New Umtru lines tripped At 22:00 Hrs on 12.06.2023. (b/g:- Due to tripping of these elements, New Umtru Generating Station of Meghalaya Power System got separated from rest of NER Grid)	**New Umtru end** Y-B-G Fault Z1 operated in 89ms AR not attempted Iy=0.8kA, Ib=0.6kA, In=1.01kA **132 kV Umtru - New Umtru lines** **New Umtru end** Y-B Fault AR not attempted Z1 operated in 77ms	To be discussed in Subgroup meeting

		Iy=1.01kA, Ib=0.8kA	
4.	132 kV Myntdu Leshka - Khleihriat D/C lines tripped At 23:01 Hrs on 13.06.2023. (b/g:- Due to tripping of these elements, Leshka Generating Stations of Meghalaya Power System got separated from rest of NER Grid)	**132 kV Myntdu Leshka – Khleihriat ckt1** **Myntdu Leshka end** R-Y-B Fault AR not attempted Z1 operates in 45ms Ir=0.8kA, Iy=0.7kA, Ib=1kA. **Khleihriat end** R-Y-B Fault AR not attempted Z1 operates in 70ms Ir=02.7kA, Iy=2.7kA, Ib=3kA. **132 kV Myntdu Leshka – Khleihriat ckt2** **Myntdu Leshka end** R-Y-B Fault AR not attempted Z1 operates in 63ms Ir=1.0kA, Iy=0.9kA, Ib=0.3kA **Khleihriat end** R-Y-B Fault AR not attempted Z1 operates in 71ms Ir=3.7kA, Iy=3.7kA, Ib=3.2kA.	To be discussed in Subgroup meeting
5.	132 kV Myntdu Leshka - Khleihriat D/C lines tripped At 03:08 Hrs on 14.06.2023. (b/g:-Due to tripping of these elements, Leshka Generating Station of Meghalaya Power System got separated from rest of NER Grid)	**Myntdu Leshka end** R-Y-G Fault AR not Attempted Z1 operated in 61ms Ir=0.6kA, Iy=0.5kA, In=0.2kA **Khleihriat end** R-Y-G Fault AR not Attempted Z1 operated in 66ms Ir=2kA, Iy=1kA, In=0.9kA	To be discussed in Subgroup meeting

July'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Khliehriat-Lumshnong line tripped At 10:40 Hrs on 23.07.2023. (b/g:- Due to tripping of this element, Lumshnong area of Meghalaya Power System got separated from rest of NER Grid 132 kV Lumshnong-Panchgram line tripped at 08:36 Hrs on 23.07.2023 and was declared faulty).	B-G Fault Vegetation Fault **Khleiriat end** AR not attempted Z3 activated and operated in 560ms Earth Fault(IN>1) and O/C Relay(I>1) also activated Ib=2.3kA, In=1.9kA Fault angle–71° **Lumshnong End** AR not attempted Z1 activated and operated in 60ms Ib=0.68kA, In=0.53kA Fault angle– 68° Underlying reason for tripping of the line to be investigated	To be discussed in Subgroup meeting

Items related to Mizoram

June'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Melriat(PG) - Zuangtui & 132 kV Zuangtui - Saitual lines tripped on 06.06.2023 at 00:10. (B/G:- Due to tripping of these elements, Zuangtui, Saitual, Serchip, Vankal and Khawzawl areas of Mizoram Power System got separated from rest of	**Melriat end** R-G Fault AR not attempted Earth Fault relay operated in 930ms (IN>1) Ir=435A In=257A angle -5° **Zuangtui End** No tripping **132 kV Zuangtui - Saitual lines** DR not available	To be discussed in Subgroup meeting

	NER Grid 132 kV Lunglei-Serchhip line was under shutdown to avoid overloading of 132 kV Aizawl-Lungmual line)		
2.	132kV Melriat(PG)-Zuangtui line tripped on 06.06.2023 at 01:58. (b/g:- Due to tripping of this element, Zuangtui, Saitual, Serchip, Vankal and Khawzawl areas of Mizoram Power System got separated from rest of NER Grid. 132 kV Lunglei Serchhip line was under shutdown to avoid overloading of 132 kV Aizawl-Lungmual line. 132 kV Zuangtui - Saitual line was under tripped condition since 00:10 Hrs on 06.06.2023)	**Melriat end** R-G Fault AR not attempted Earth Fault relay operated in 55ms (IN>1) Ir=530A In=386A angle -8° **Zuangtui End** Earth Fault relay operated in 240ms (IN>1) AR not attempted Ir=449A In=450A angle -10°	To be discussed in Subgroup meeting
3.	132kV Melriat(PG)-Zuangtui line tripped on 06.06.2023 at 13:40. (b/g:- Due to tripping of this element, Zuangtui, Saitual, Serchip, Vankal and Khawzawl areas of Mizoram Power System got separated from rest of NER Grid. 132 kV Lunglei	**Melriat end** R-G Fault AR not attempted Earth Fault relay operated in 30ms (IN>1) Ir=667A In=290A angle -9° **Zuangtui End** Earth Fault relay operated in 398ms (IN>1) AR not attempted Ir=515A In=416A angle -8°	To be discussed in Subgroup meeting

	Serchhip line was under shutdown to avoid overloading of 132 kV Aizawl-Lungmual line. 132 kV Zuangtui - Saitual line was under tripped condition since 00:10 Hrs on 06.06.2023)		

July'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	Outage of 132kV Turial Kolasib on 05.07.2023 and 06.07.2023		To be discussed in Subgroup meeting
2.	Outage of 132kV Melriat-Zuangtui on 25.07.2023		To be discussed in Subgroup meeting

Items related to Nagaland

June'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Kohima-Meluri line tripped on 26.06.2023. (b/g:- Due to tripping of this element, Meluri & Kiphire areas of Nagaland Power System got separated from rest of NER Grid)	Suspected R-G Fault **Kohima End** CB opening time 250ms but not clear from DR by which protection CB opened Fault current is very low 300A, angle -15° **Meluri End** DR Not Available	To be discussed in Subgroup meeting

July'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	Outage of 132 kV Dimapur-Kohima, 132 kV Kohima-Chiephobozou, 132 kV Kohima-Karong &132 kV Meluri-Kiphire lines on 29.07.2023	Item B.	To be discussed in Subgroup meeting

Item related to Tripura

June 23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	132 kV Monarchak - Rokhia and 132 kV Rokhia - Agartala D/C lines tripped on 09.06.2023,. Due to tripping of these elements, Rokhia area of Tripura Power System got separated from rest of NER Grid	**132 kV Monarchak – Rokhia** Y-B Fault **Monarchak end** Z1 activated and operated in 61 ms AR not attempted/ not present IY=2.5kA,IB=2.4kA **Rokhia end** CB not operated even after seeing fault current of 3.5kA	To be discussed in Subgroup meeting
2.	132 kV Monarchak - Rokhia line tripped At 07:02 Hrs on 18.06.2023. (b/g:-Due to tripping of this element, Monarchak and Rabindranagar areas of Tripura Power System got separated from rest of NER Grid 132 kV Monarchak - Udaipur line was under Planned Shutdown from	**Monarchak end** R-G Fault AR not attempted Z2 operated in 397ms Ir= 1.41kA, In=1.43kA Fault angle -67° **Rokhia End** **DR not available**	To be discussed in Subgroup meeting

	06:49 Hrs of 18.06.2023).		

July'23

Sl No	Event	Discussion points	Deliberation of the Subcommittee
1.	Outage of 132 kV 132 kV Dharmanagar - Dullavchera line on 29.07.2023		To be discussed in Subgroup meeting

Agenda items from NERLDC

B.7 Status of submission of FIR and DR & EL outputs for the Grid Events

In line with regulation 12 (1) of CEA Grid Standards Regulations and IEGC provision under clause 5.2 (r), FIR and DR & EL Outputs for each grid events are required to be submitted by concerned utilities to NERLDC for detailed investigation and analysis.

Status of uploading of FIR and DR & EL outputs in Tripping Monitoring Portal for events from 08-06-2023 to 21-08-2023 is given below:

Name of Utility	Total FIR/ DR/EL	Total FIR, DR & EL submitted			Total FIR, DR & EL submitted as NA (Not Applicable)			Total FIR, DR & EL submitted as NU (Not Available)			Total FIR, DR & EL not submitted		
		FIR	DR	EL	FIR	DR	EL	FIR	DR	EL	FIR	DR	EL
DoP, Arunachal Pradesh	78	61	48	60	0	9	7	0	4	0	17	17	11
AEGCL	187	70	96	83	0	31	35	0	3	10	117	57	59
MSPCL	67	32	1	2	0	28	28	0	1	0	35	37	37
MePTCL	63	34	47	45	0	8	9	0	0	0	29	8	9
MePGCL	100	0	50	21	0	37	36	0	3	0	100	10	43
P&ED, Mizoram	8	3	3	4	0	1	1	0	1	0	5	3	3
DoP, Nagaland	75	50	20	20	0	22	23	0	25	24	25	8	8
TSECL	71	60	40	55	0	5	3	0	15	2	11	11	11

POWERGRID	145	134	108	117	0	31	20	0	1	1	11	5	7
NEEPCO	109	68	45	45	0	34	34	0	3	2	41	27	28
NHPC	19	0	6	2	0	5	6	0	0	0	19	8	11
NTPC	10	0	2	0	0	8	6	0	0	0	10	0	4
OTPC	9	7	7	2	0	2	5	0	0	0	2	0	2
NTL	34	16	25	26	0	5	5	0	1	0	18	3	3
KMTL	1	1	1	1	0	0	0	0	0	0	0	0	0

Concerned Utilities are requested to upload Disturbance Recorder (DR), Event Logger (EL) outputs for grid events along with a First Information Report (FIR) in Tripping Monitoring Portal (https://tripping.nerldc.in/Default.aspx) for analysis purpose. In light of the cybersecurity measures implemented by Grid India to safeguard sensitive information, NERLDC has created the email address nerldcso3@gmail.com . This new account has been specifically set up to facilitate the secure exchange of DR and EL files that have previously faced blockage when sent to nerldcprotection@grid-india.in.

A significant number of faults are lightning-related. The Member Secretary emphasized the need for lightning arresters, and it was noted that PSDF funding is available for the same

vegetation fault is also a significant issue, which underlines the importance of extensive/regress patrolling of transmission lines

many states not submitting DR, FIR, and EL reports in a timely manner. The Forum requested to all the SLDCs to sensitize their field teams on this issue and ensure the timely submission of FIR, DR, and EL reports to RLDCs. This is crucial for conducting root cause analysis for grid events.

NERLDC emphasized the importance of timely submission of DR and EL files for analysis, as per regulatory requirements

Deliberation of the sub-committee

Concerned utilities updated as follow-

1.Assam- due to shifting related works at Boko and Mariani there have been shortcomings in submitting the required data.

2.Tripura- Non-availability of Laptops at substations and connectivity issues hampering the submission of DR/EL in timely manner.

3. Nagaland – some DRs are missing at the substations. SLDC will coordinate with substation to address the issue.
4. MePTCL – at some substations, relays are of Siemens make and some issues are being faced in downloading from the relays. Matter has been taken up with the OEM.
5. Mizoram- informed that they will upload DR/EL for intra-state lines also.

Member Secretary stated that all States/Utilies to take a step to resolve above shortcomings and send the DR/ER data(which is mandatory) as per IEGC regulation .

B.8 <u>Non-operation of auto recloser in Important Grid Elements for transient faults w.e.f. June 2023:</u>

<u>Deliberation of the sub-committee</u>

The following were updated:

Sl. No	Name of the Line	A/R Not Operated	Date and Time	Update in 59th PCCM
1	132 kV Agartala - AGTCCPP 1&2 Line	AGTCCPP, NEEPCO	15-06-2023 23:11 Hrs	NEEPCO not present
2	220 kV Agia - BTPS 1 Line	Agia, AEGCL	20-06-2023 23:48 Hrs	Now functional
3	132 kV Jiribam - Loktak 2 Line	Loktak, NHPC	24-06-2023 18:29 Hrs	NHPC not present
4	400 kV Azara - Silchar Line	Silchar, POWERGRID	25-06-2023 15:41 Hrs	Only coordination issue. Functional
5	400 kV Byrnihat - Silchar Line	Both Ends MePTCL & POWERGRID	25-06-2023 15:41 Hrs	AR block signal was generated at Byrnihaat end due to some technical glitch. To be resolved soon. At Silchar end, DT was received, so AR was blocked.
6	220 kV Byrnihat - Misa 1 Line	Both Ends MePTCL &	26-06-2023 14:02 Hrs	Issue in PLCC at killing end.

		POWERGRID		Consultation with OEM underway for resolution
7	220 kV Samaguri - Sonapur Line	Sonapur (post fault DR window needs to be increased) AEGCL	09-07-2023 12:40 Hrs	At Sonapur end GIS related issue, coordination with OEM required. Also, DR window for the same end need to increase.
8	132 kV BTPS - Dhaligaon 1 Line	BTPS, AEGCL	16-07-2023 15:27 Hrs	Configuration done
9	132 kV Haflong - Umranshu Line	Umranshu & Haflong (due to Carrier not sent from Umranshu end) AEGCL	20-07-2023 19:16 Hrs	Relay issues at Umranshu end So no carrier was sent to Haflong end. No carrier signal received at Haflong, so Zone 2 operation at Haflong and hence no AR operation
10	132 kV Biswanath Chariali - Chimpu 1&2	BNC, POWERGRID	27-07-2023 22:15 Hrs	Z2 operated at BNC end as no carrier was received from Chimpu end. NTL not present to reply to the issue.
11	220 kV Samaguri - Sonapur Line	Sonapur, AEGCL	15-08-2023 13:19 Hrs	At sonapur end GIS related issues, OEM coordination required. Also DR window for the same end need to increase.
12	132 kV Jiribam - Pailapool Line	Pailapool, AEGCL	17-08-2023 12:04 Hrs	No carrier added tripping at Pailapool so Z2 operation and

				hence no AR operation

B.9 Frequent tripping of 132 kV Balipara- Tenga Line:

132 kV Balipara-Tenga line tripped 8 (eight) times from 01-June-2023 to 22-Aug-2023 leading to blackout in Tenga, Khupi areas and Dikshi HEP of Arunachal Pradesh Power System.

Sl No	Outage Date and Time	Revival Date and Time	Relay Indication End1	Relay Indication End2	Root Cause
1	06-06-2023 17:38	06-06-2023 18:14	DP,ZI, R-Y-E, FD:53.64 Km	No Tripping	Vegetation fault.
2	08-06-2023 09:39	08-06-2023 19:15	Backup EF	No Tripping	Vegetation fault.
3	08-06-2023 21:55	08-06-2023 22:47	DP, ZI, R-Y-B,FD:54.37km	No Tripping	Lightning fault.
4	22-07-2023 19:07	23-07-2023 13:51	DP, ZI, Y-E, FD: 52.7 kms	Under Voltage	Vegetation fault.
5	23-07-2023 18:04	23-07-2023 18:35	DP, ZI, Y-E, FD: 4.9 kms	Under Voltage	Lightning fault.
6	02-08-2023 21:52	02-08-2023 22:21	DP, ZI, R-E,FD:, 14.05 km, 3.85 kA	Z-1, Yph , 56.36 km	Lightning fault.
7	08-08-2023 20:59	08-08-2023 22:03	DP, ZI, R-B,FD:59.8 km	RB-ph, Zone-1, 32.90 km, 0.58 kA, 0.63 kA	Lightning fault.
8	21-08-2023 19:27	21-08-2023 19:49	Earth Fault Yph	Under Voltage	DR not available

Frequent tripping of the above line is a cause of concern which reduces the reliability of Tenga and Khupi area and Dikshi HEP.

DoP Arunachal Pradesh is requested to update the status of implementation of 3-phase/1-phase Auto-recloser scheme as deliberated in Protection Subgroup Meeting dated 7th June 2023.

Deliberation of the sub-committee

The forum noted that transient fault and vegetation infringement have been major reasons for large number of trippings. The forum requested DoP, Ar. Pardesh to undertake the patrolling of the line in a comprehensive manner and clear the vegetation infringement on regular basis.

B.10 Frequent tripping of 132 kV Along - Pasighat Line:

132 kV Along- Pasighat line tripped 13 times (01-June-23 to 18-August-2023).

SL No	Tripping	Relay Indication Along	Relay Indication Pasighat	DR Analysis	Root Cause
1	25-06-2023 13:02:00	Not Furnished	Not Furnished	Along: No DR file received. Wrong EL file received.	Not concluded
2	14-07-2023 13:20:00	Not Furnished	Not Furnished	Along: No DR file received. Wrong EL file received. Pasighat : Details not furnished.	Not concluded
3	14-07-2023 16:07:00	Earth Fault, Y-ph	Not Furnished	Along: As per FIR, no tripping at Along end. No DR file received. Wrong EL file received. Pasighat : Details not furnished. No visible information gathered from the submitted	Not concluded

SL No	Tripping	Relay Indication Along	Relay Indication Pasighat	DR Analysis	Root Cause
				EL file.	
4	15-07-2023 09:44:00	No Tripping	Master Relay Trip	Only .pdf file submitted instead of .evt file for Pasighat end.	Not concluded
5	28-07-2023 08:40:00	DP, ZI, R-Y, FD: 33.48 km	Not Furnished	DR submitted from Along. As per FIR-Fault beyond Yeggo Switchyard	Fault Beyond Line/Downstream Fault
6	30-07-2023 08:40:00	Earth Fault	No Tripping	DR EL Files not submitted	Not concluded
7	30-07-2023 12:04:00	Earth Fault	No Tripping	DR EL Files not submitted	Not concluded
8	02-08-2023 14:07:00	EF,Y-E	Earth fault	Along: Y-E fault of vegetation nature cleared in 1100 msecs. Pasighat: Not submitted	Vegetation
9	02-08-2023 09:07:00	EF,B-E	Not Furnished	Along: B-E fault of vegetation nature cleared in 950 msecs. Pasighat: Not submitted	Vegetation
10	04-08-2023 23:02:00	No Tripping	Not Furnished	Along: No tripping. Pasighat: DR&EL not received.	Root cause not concluded

SL No	Tripping	Relay Indication Along	Relay Indication Pasighat	DR Analysis	Root Cause
11	05-08-2023 00:15:00	Earth fault	Master Trip Relay Optd.	Along: DR submitted for 14:17 Hrs ; Pasighat: Not submitted	Not concluded
12	07-08-2023 10:11:00	Earth fault	Not Furnished	DR Files not submitted. FIR_Along:No fault found; FIR_Pasighat: Fault clear itself	Not concluded
13	08-08-2023 13:18:00	No tripping	Not Furnished	At the same time, AR successful at Along for 132 kV Along - Daporijo line. No Tripping at Along for 132 kV Along-Pasighat line.	Not concluded (DR&EL not received for pasighat end)

Hence, DoP, AP is requested to submit the root cause and remedial measures taken for all the events. Also, FIR/DR/EL reports to be uploaded regularly in Tripping Monitoring Portal (https://tripping.nerldc.in/Default.aspx) within 24 hours for proper analysis purpose.

DoP Arunachal Pradesh is also requested to update the status of implementation of 3- phase/1-phase Auto-recloser scheme as deliberated in Protection Subgroup Meeting dated 7th June 2023.

Deliberation of the sub-committee

Representative of DoP Arunachal Pradesh was not present in the meeting so issue could not be discussed.

B.11 Blackout of Boko SS of Assam on 18-August-2023:

At 10:57:05.220 Hrs on 18.08.23, B-E fault occurred in 220 kV Agia-Boko Line and fault was cleared from Boko on DEF operation within 1000 msecs and Agia on DT received.

At the same time, healthy 220 kV Azara-Boko line tripped from Azara on DEF within 1000 msecs which is unwanted.

AEGCL is requested to intimate the following:

i. Root cause of tripping of 220 kV Boko- Agia line and remedial action taken.
ii. Relay Operating Time (ROT) of Azara for the Boko line and Boko for the Agia line overlapped as per the analysis from NERLDC. Actions taken for coordination of DEF settings at Azara to be informed.

Deliberation of the sub-committee

AEGCL updated that TMS has been revised at BOKO (TMS 0.18) for Agia line and at MIRZA (TMS 0.25) for Boko line. Thus, coordination for the EF relay has been done.

The forum noted as above

B.12 Tripping of 132 kV North Lakhimpur-Dhemaji Line and North Lakhimpur-Pare Line on 08-08-2023

132 kV North Lakhimpur-Dhemaji Line tripped at 08:38 Hrs on 08.08.23, leading to blackout of Dhemaji area of Assam system with load loss of **27 MW**. As per the DR analysis, fault appears to be due to **phase clearance issue**. ***AEGCL is requested to***

i. Intimate the root cause of tripping and remedial actions taken.
ii. Implement 3- phase/1-phase Auto-recloser scheme for ensuring continuous power supply during transient faults.

At the same time, 132 kV North Lakhimpur-Pare line tripped at North Lakhimpur only on SOTF operation which is unwanted. As per root cause report shared by NTL, the Actual Setting for SOTF Overcurrent Pickup was ∞ A whereas, the setting was erroneously feed in as 2.5 A which has been rectified.

NTL is requested to share the following:

i. Masking logic for initiation of SOTF for further verification.
ii. Revised setting to PDMS portal of NERPC.

Deliberation of the sub-committee

AEGCL intimated that N. Lakhimpur- Dhemaji line tripped on phase-to-phase fault due to phase clearance issue at some locations. After detailed deliberation the forum requested AEGCL to implement 3 phase AR in N. Lakhimpur- Dhemaji line. AEGCL assured to implement the AR on the line.

The forum also requested M/s Sterlite to share the SOTF Masking logic and revised settings with NERPC and NELRDC at the earliest.

B.13 Blackout of Karong S/S of Manipur:

Blackout of Karong S/S occurred twice due to tripping of 132 kV Imphal – Karong Line & 132 kV Karong – Kohima Line as highlighted below.

Element name	Date and time	Relay Indication E1	Relay Indication E2	DR analysis
132 kV Imphal – Karong	11-08-2023 12:58 Hrs	No Tripping	Not Furnished	No DR&EL received
132 kV Karong – Kohima		Not Furnished	O/C E/F	As per DR of Kohima End: Y-E, with fault current 300A clearing in 886 msecs.
132 kV Imphal – Karong	14-08-2023 00:46 Hrs	DP,ZI,Y-E, FD:33.53km	Not Furnished	As per DR of Imphal End: DP,ZI, Y-E,FD:33.53 KM with fault current 2.5 kA cleared in 62 msecs
132 kV Karong – Kohima		DP,ZI,Y-E,FD:21.16 km	DP,ZI,Y-E,FD:35.73 km	No DR&EL received

Root cause could not be concluded due to non-submission of DR and EL output from Karong Substation. MSPCL is requested to intimate the root cause for the event and remedial actions taken.

Deliberation of the sub-committee

The forum referred the matter to protection sub-group meeting as no representative was present from Manipur in the meeting.

B.14 Blackout of Tipaimukh S/S of Manipur on 21-07-2023:

At 11:04 Hrs on 21-July-2023, 132 kV Jiribam - Tipaimukh Line and 132 kV Aizawl - Tipaimukh Line tripped leading to the blackout of Tipaimukh area of Manipur power system.

Element name	Relay Indication E1	Relay Indication E2	Root Cause
132 kV Jiribam - Tipaimukh Line	DP, ZI, B-E, FD: 24.91 kms, AR successful	No Tripping	Transient fault due to Lightning.
132 kV Aizawl - Tipaimukh Line	DP, ZIII, B-E, FD: 136km	No Tripping	

Circuit Breaker at Tipaimukh end did not clear the transient fault in 132 kV Jiribam - Tipaimukh Line. Hence, the same fault was cleared from Aizawl (PG) end after 800 msec on ZIII.

Thus, MSPCL is requested to intimate the reason for non-operation of CB at Tipaimukh for 132 kV Jiribam - Tipaimukh Line and share the remedial measures taken.

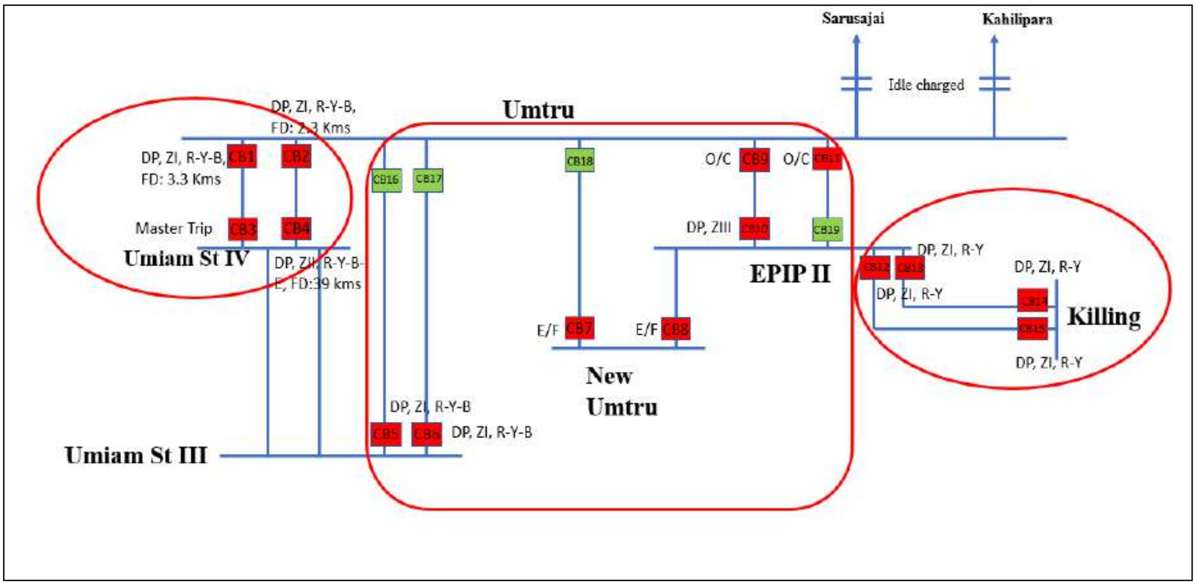
Deliberation of the sub-committee

After brief discussion, the forum strongly requested MSPCL to provide the following data to NERPC and NERLDC at the earliest-

i) DR, EL data related to the trippings
ii) Rely settings at Tipaimukh for Jiribam and Aizawl lines
iii) Root cause for non-operation of protection system at Tipaimukh for fault in the Jiribam line

B.15 Grid disturbance in Umtru & New Umtru areas of Meghalaya Power System on 23rd July'23

Grid Disturbance of category GD 1 (Generation loss: 36 MW) occurred on 23th July'23 at 20:38 Hrs resulting in blackout of Umtru & New Umtru areas of Meghalaya Power System due to tripping of multiple elements which is the cause of concern. As per the submitted DR outputs, likely solid nature of fault due to lightning occurred in three areas namely as shown below.



Sequence of Events:

- 3 phase fault was in 132 kV Umtru - Umiam St III D/C Lines which was cleared from Umiam Stg III on ZI.
- 3 phase fault was in 132 kV Umtru - Umiam St IV D/C Lines which was cleared from Umtru on ZI and Umiam Stg IV on ZII.
- Ph-Ph fault was in 132 kV EPIP II- Killing D/C Lines which was cleared from both ends on ZI.
- At the same time, Umtru and EPIP II line tripped at New Umtru on In>2 and EF within 98 msecs and 158 msecs respectively which is unwanted. Similar kinds of unwanted tripping of 132 kV New Umtru -Umtru Line from New Umtru (for fault beyond line) occurred on 15th March, 12th June and 3rd July'23 due to In>2 .

Observations:

i. Reason for non-operation of CB at Umtru for Umiam Stg III D/C lines to be intimated.

ii. MePGCL to send the relay settings of generators and lines at New Umtru and Umtru to NERPC/NERLDC as discussed in last Subgroup Meeting.

iii. As per NERPC Protection philosophy, there is no provision for High Set definite time Back up O/C and E/F settings. Hence, same may be disabled to prevent unwanted tripping.

<u>Deliberation of the sub-committee</u>

i)Regarding non-operation of protection at Umtru for Umiam stg III lines, MePGCL updated that relays have been checked and found to be ok. The forum requested MePGCL to recheck the protection system and intimate NERPC and NERLDC about the root cause.

ii) MePGCL assured the forum to send the relay settings of lines at Umtru and new Umtru to NERPC/NERLDC.

iii) The forum requested MePGCL to disable the High Set definite time Back up O/C and E/F settings as per the NER protection philosophy.

B.16 Tripping of 132 kV Khlieriat-Khlieriat-2 Line along with 132 kV Khlieriat-Lumshnong Line

At 15:24 Hrs on 8th June'23, three phase fault was in 132 kV Khlieriat-Lumshnong Line and it was cleared within 70 msec from Khlieriat on Z-1. At the same time, 132 kV Khlieriat-Khlieriat-2 Line tripped from Khleiriat(PG) on Z-1 which is unwanted. **Similar kind of event also occurred at 23:35 Hrs on 15/05/22.**

As per NERLDC record, LDP (Line Differential Protection) has been implemented on the 132 kV Khlieriat-Khlieriat-2 Line as line length is less than 10 Km. With LDP in place, distance protection should not come into operation except in case of failure in the optical fiber link or a failure in the LDP relay.

MePTCL is requested to intimate the root cause of tripping of 132 kV Khlieriat-Khlieriat-2 Line and remedial actions taken.

<u>Deliberation of the sub-committee</u>

After detailed discussion, the forum decided that on short lines with differential protection as primary protection, there should be a delay of 100msec in Zone 1 of the backup distance protection.

MePTCL inform that they will implement the revised setting shortly.

B.17 Blackout of Zuangtui area of Mizoram System on 25.07.23

Grid disturbance of category GD-1 (Load loss: 20 MW) occurred at Zuangtui and Saitual substations of Mizoram state at 13:13 Hrs of 25/07/2023 due to tripping of 132 kV Melriat(PG) – Zuangtui & 132 kV Serchip-Zuangtui lines which is the cause of concern.

As per DR analysis, highly resistive B ph fault was in 132 kV Zuangtui – Serchip line and it was cleared within 431 msec from Zuangtui on In>1 (396 A). At the same time, Melriat – Zunagtui line tripped from Melriat on In>1 (331 A)

Observation:

i. P&ED Mizoram is requested to intimate the root cause of tripping of 132 kV Zuangtui – Serchip line.

ii. ROT of EF settings at Melriat for Zunagtui line and Zuangtui for Serchip line seems low and is overlapping. So, proper coordination is to be done by POWERGRID and P&ED Mizoram to prevent unwanted tripping.

Deliberation of the sub-committee

After detailed discussion, it was decided that NERPC, Mizoram and PGCIL will coordinate to revise the current pick up and TMS values of backup E/F and O/C relays for Melriat-Zuangtui and Zuangtui-Serchip lines so that overlapping in relay operation may be avoided.

Sub-committee noted as above

B.18 Frequent blackout of Tuirial HEP

132 kV Kolasib-Aizawl Line tripped twice w.e.f. 5th to 6th July'23 leading to blackout in Tuirial HEP with the following relay indications-

Sl NO	Element Name	Outage Date	Outage Time	Indication Details (End1)	Indication Details (End2)	Load Affect (in MW)	Gen. Affect (in MW)
1	132KV-	06/Jul	16:10	Z-I,	Earth fault,	1	**18**

	TUIRIAL-KOLASIB-1	/2023		earth fault, 2.85KM	1.09kA		
2		05/Jul/2023	18:04	Earth fault	DP, ZIV, B-E, FD: 3.863Km	1	**18.30**

Proper analysis of the event could not be done due to non-submission/incorrect submission of FIR, DR and EL outputs.

Observations:

i. P&ED Mizoram is requested to intimate the root cause of tripping and remedial actions taken.

ii. Status of Auto-recloser operation during the event may be intimated.

Deliberation of the sub-committee

Regarding non-submission of DR/EL, Mizoram stated that the data has not been submitted from the substation end.

Forum decided that all state should have one Nodal officer. The nodal officer will ensure submission of DR within 24 hours of any event.

B.19 Blackout of Wokha S/S of Nagaland on 11-Aug-2023:

At 13:23 Hrs of 11th Aug'23, 132 kV Chiephobozou-Wokha Line and Wokha-Sanis Line tripped which led to blackout of Wokha Substation with load loss of about 8 MW.

As per DR analysis:

- At 13:23:03.48 Hrs, Y-B fault occurred in 132 kV Chiephobozou -Wokha Line and fault was cleared from Chiephobozou on Z-II (400 msec) and Wokha on Z-1(67 msec).
- At the same time, 132 kV Sanis line tripped at Wokha (within 72 msec) on O/C operation which is UNWANTED.

Observations:

i. DoP, Nagaland is requested to intimate the root cause of tripping and remedial actions taken.

ii. No carrier aided tripping was recorded at Chiephobozou for Wokha Line due to non-receipt of carrier signal. ***It is requested to implement the carrier-aided scheme to achieve faster fault clearance.***

iii. Tripping of healthy 132 kV Wokha-Sanis Line on O/C for reverse fault has already been highlighted by NERLDC and requested for checking of B/U relay directionality, CT star point, review O/C setting immediately. Status may be updated.

<u>Deliberation of the sub-committee</u>

i) Nagaland updated that Directionality of backup O/C protection at Wokha for Sanis lines has been rectified, but TMS is very low. The forum requested Nagaland to review the TMS in coordination with NERPC.

ii) Nagaland further stated that CT star point has been found to be Ok.

iii) Further the forum requested Nagaland to implement carrier aided protection in the lines at the earliest.

B.20 Ensuring Reliable Power Supply at Dimapur (Nagarjan) area:

On 02-08-2023 at 16:35 Hrs, 132 kV Dimapur(PG)- Dimapur(NL) II line tripped on Zone I due to snapping of Y-Phase jumper. This led to shifting of entire load to 132 kV Dimapur(PG)- Dimapur(NL) I Line which resulted in tripping of the line on Overcurrent. Due to the GD, load loss of 85 MW observed in the Dimapur area of Nagaland power system which is the cause of concern.

The present CT ratio of 132 kV Dimapur(PG) – Dimapur (NL) D/C is 600/1 and the present overcurrent setting of 360 A at Dimapur(NL) end with each circuit carrying capacity of 82 MVA, thus not complying with N-1 criteria.

To satisfy the N-1 contingency at Dimapur(NL), following measures may be taken by DoP, Nagaland:

i. Increase the Over current settings from 360 A to 450 A at Dimapur(NL) to cater to a maximum load of 102 MVA.

ii. Implement an SPS scheme

Suggested Logic: When current in either of the circuit crosses 360 A with time delay of 1.1 sec, load shedding of around 35 MW to be done.

<u>Deliberation of the sub-committee</u>

i) The forum requested Nagaland to increase the overcurrent setting for 132kV Dimapur (PG)-Dimapur (NL) from present 60% to 70% at Nagaland end so that cascade tripping may be avoided incase of tripping of one line. DoP Nagaland assured that the suggested setting will be implemented shortly.

ii) PGCIL highlighted that in case of high resistance fault in the Dimapur (PG)-Dimapur (NL) line, back up EF gets activated and due to high ROT of the relay, 220kV Misa-Dimapur line and upstream transformers at Dimapur and Misa get exposed to high currents for longer duration. Consequently, he requested the forum to allow making the B/U EF high set setting (I>2) enabled at Dimapur (PG) end for faster clearance of the fault in the line. The forum agreed and asked PGCIL to coordinate with NERPC for finalizing the relay settings.

B.21 Blackout of Kohima (Capital), Meluri and Kiphire areas of Nagaland on 29-July-2023:

At 13:26 Hrs on 29-July-2023, Gird Disturbance of category GD-1 (Load Loss: 13 MW, Gen Loss: 23 MW) was observed in Kohima (Capital), Meluri and Kiphire areas of Nagaland and Likimro HEP.

As per analysis, fault was in 132 kV Kohima – Meluri line and CB at Kohima failed to operate leading to clearing of fault by tripping of healthy 132 kV Dimapur (PG) - Kohima Line from Dimapur, 132kV Chiephobozou– Kohima Line from Chiephobozou and 132 kV Karong – Kohima Line from Karong.

As informed by DoP, Nagaland, CB at Kohima for Meluri feeder did not operate due to lose wiring of tripping circuit. Also, the relay panels at Kohima for all Karong/Chiephobozou/Meluri are very old resulting in frequent dust accumulation.

DoP, Nagaland is requested to maintain the relay panels on regular basis to avoid dust accumulation and ensure proper tightness/connections of the tripping circuit so that such unwanted tripping can be avoided.

<u>Deliberation of the sub-committee</u>

Nagaland informed that replacement of relay panels is being proposed. Proper maintenance with time-to-time cleaning to avoid dust accumulation is being done.

After detailed deliberation, the forum exhorted Nagaland to ensure regular maintenance of control rooms and proper tightness of the connections of the tripping circuits so that unwanted trippings can be avoided.

B.22 Frequent Tripping of 132 kV Dimapur(PG)- Kohima line:

132 kV Dimapur(PG) – Kohima tripped 8 (Eight) times from 01-July-2023 to 18-Aug-2023. Out of 8 times, total 6 times fault was in the section owned by DoP, Nagaland which has an impact on ISTS node as well.

Sl No	Tripping date and Time	Restoration date and Time	Relay Indication at Dimapur	Relay Indication at Kohima	Root Cause as per DR analysis
1	29-07-2023 13:26	29-07-2023 14:48	DP, ZIII, R-Y	No Tripping	Fault in 132 kV Kohima - Meluri
2	30-07-2023 20:36	30-07-2023 21:07	DP, ZI, R-Y, FD:23.856km	DP, ZI, R-Y, FD:31.11 km	Likely solid fault.
3	30-07-2023 21:09	30-07-2023 23:39	DP, ZI, R-B-E, FD:3.83 km	DP, ZI, R-B-E, FD: 43.50Km	Likely solid fault.
4	31-07-2023 11:58	31-07-2023 12:21	DP, ZII, B-E, FD:40 Kms	DP, ZI, B-E, FD: 16.49 Kms	Likely solid fault
5	31-07-2023 13:49	31-07-2023 14:36	DP, ZI, R-E, FD: 32.45 kms	DP, ZI, R-E, FD: 23.40 kms	Likely solid fault
6	02-08-2023 16:35	02-08-2023 17:09	No tripping	DP, ZI, Y-E, FD: 15.84 km	Fault beyond the line.
7	06-08-2023 17:46	06-08-2023 18:05	DP, ZI, B-E, FD: 19.67KM	DP, ZI, B-E, FD: 40.35KM	Vegetation fault
8	18-08-2023 18:26	18-08-2023 21:25	DP, ZI, B-E, FD:26.193 km	DP, ZI, B-E, FD:44.55km	Vegetation fault

Frequent tripping of the above line reduces the reliability of Capital area of Nagaland System.

DoP Nagaland is requested to intimate:

i. Root cause and corrective measures that has been taken.

ii. Procurement status of self-reset contact relay to enable AR as discussed in Protection Subgroup Meeting held on 07.06.23.

Deliberation of the sub-committee

i) Regarding corrective measures, DoP Nagaland updated that vegetation clearance along the line has been done along with replacement of insulators at many locations. Sr. GM NERLDC suggested DoP Nagaland to check Jumper clearances along the line.

ii) Regarding implementation of AR at Kohima end, DoP Nagaland intimated that the self-reset contact relays have been procured and AR will be commissioned shortly.

B.23 Zone I overreaching of 132 kV Agartala- AGTCCPP -2 on 12-July-2023:

At 12:58 Hrs on 12-July-2023, fault was in 132 kV AGTCCPP - PK Bari (TSECL) 2 Line and fault was cleared from AGTCCPP on Zone I and PK Bari on ZII. At the same time, healthy 132 kV Agartala - AGTCCPP 2 Line tripped from Agartala on ZI which is unwanted.

NERTS is requested to:

i. Intimate the root cause of the tripping and remedial measures taken

ii. Review the Distance Protection Zone settings at Agartala.

Deliberation of the sub-committee

NERTS intimated that the distance protection zone settings are in order. However, during the fault the relay initially picked the fault in Zone 2 but then the fault impedance locus entered Zone 1. Further, he stated that distance relay will be checked and tested at the earliest.

B.24 Tripping of 132 kV Aizawl - Kolasib Line at 18:04 Hrs on 05.07.2023

132 kV Aizawl - Kolasib Line tripped at 18:04 Hrs on 05.07.2023 which was cleared from Aizawl on ZI and Kolasib on Back up E/F.

NERTS is requested to intimate the exact root cause of the tripping and remedial measures that has been.

Deliberation of the sub-committee

NERTS updated that during pre-fault condition high voltage transients was observed in phase C at Kolasib end, due to which VT fuse failed and distance protection was blocked. Thus B/U EF operated at Kolasib end in about 450msec. Carrier was also received at Kolasib end. He further stated that the B/U EF relay is of electromechanical type and will be replaced with digital relay soon.

Forum noted as above.

B.25 Tripping of 220 kV Kathalguri-Deomali T/L along with B/C CB at AGBPP

At 02:52:52.102 Hrs on 09.08.2023, Y-B fault occurred in 220 kV AGBPP - Deomali Line and fault was cleared within 65 msec on Z-1 operation. At the same time, Bus coupler CB at AGBPP tripped on highset O/C (*Existing setting: Definite time 0 msec, Pickup 1.92 kA*) which appears to be mis-operation.

Since, protection for Bus- coupler is not mandated by any Regulation (CEA), it was recommended to AGBPP to modify the protection settings as follows:

- Disable the High set OC and EF protection (i,e I>2, In>2)
- OC and EF should be IDMT (IEC S inverse).
- TMS is to be coordinated in such a way that I>1 should tripped only after slowest Z-II time delay of connected lines say 500 msec with 200 msec margin. i.e. 700 msec
- TMS is to be coordinated in such a way that In>1 should issue trip only after slowest B/U E/F protection time delay of connected line feeders with some margin of 200 msec.

Observations:

i. DoP, AP is requested to intimate the root cause of fault in 220 kV AGBPP-Deomali line and remedial actions taken.

ii. DR digital channels of the Bus Coupler needs to be standardized properly for fruitful analysis purpose and total DR window needs to be increased to 3 sec from 1.5 sec by AGBPP, NEEPCO.

iii. Status of implementation of above recommendations for Bus-Coupler protection may be intimated by AGBPP, NEEPCO.

Deliberation of the sub-committee

The forum advised AGBPP, NEEPCO to-

i) implement the relay settings in Bus Coupler protection as recommended above at the earliest.

ii) Increase the DR window to 3 seconds from existing 1.5 seconds

B.26 Details of tripping of lines due to spurious DT signal transmission

Sl. No	Element Name	Outage Date and Time	DT Sent from	Root cause	Remedial Measures taken
1	400 kV Balipara - Bongaigaon 1 Line	20-06-2023 12:27 and 26-06-2023 12:18	Bongaigaon (NERTS)	DT Sent due to multiple DC earth fault due to water logging at Bongaigaon SS.	
2	132 kV Agartala-Rokhia-1 Line	24-06-2023 11:16	Rokhia (TSECL)	Spurious DT signal sent	
3	400 kV BgTPP - Bongaigaon 2 Line	28-06-2023 08:45	BgTPP (NTPC)	Spurious DT signal sent (No FIR/DR/EL Submitted).	
4	400 kV Biswanath Chariali - Ranganadi 1 Line	01-07-2023 16:50	Ranganadi (NEEPCO)	DT Sent due to E/M overvoltage relay maloperation	

Concerned Utilities are requested to furnish the reason of spurious DT signal transmission and corrective actions implemented to prevent repetition

Deliberation of the sub-committee

Utilities updated as follow-

Sl. No	Element Name	Outage Date and Time	DT Sent from	Root cause	Remedial Measures taken
1	400 kV Balipara - Bongaigaon 1 Line	20-06-2023 12:27 and 26-06-2023 12:18	Bongaigaon (NERTS)	DT Sent due to multiple DC earth fault due to water logging at Bongaigaon SS.	DC earth faults due to Waterlogging issue. However, Cables have now been replaced
2	132 kV Agartala-Rokhia-1 Line	24-06-2023 11:16	Rokhia (TSECL)	Spurious DT signal sent	Cable problem was there So cable replaced
3	400 kV BgTPP - Bongaigaon 2 Line	28-06-2023 08:45	BgTPP (NTPC)	Spurious DT signal sent (No FIR/DR/EL Submitted).	NTPC not Present
4	400 kV Biswanath Chariali - Ranganadi 1 Line	01-07-2023 16:50	Ranganadi (NEEPCO)	DT Sent due to E/M overvoltage relay maloperation	NEEPCO not Present

Forum noted as above

B.27 Requirement of relay Coordination due to Network Changes:

Sl. No.	Name of Element	Name of Owner	Relay settings coordination/updation required at substation	Latest Update
1	LILO of 400 kV Palatana-Surajmaninagar (ISTS) via Surajmaninagar (TSECL) bypassing	POWERGRID	Silchar, PK Bari	

	the Surajmaninagar (TSECL)			
2	132 kV Agartala-Rokhia D/C after reconductoring with HTLS	TSECL	Monarchak, SM Nagar (TSECL), Budhjungnagar, AGTCCPP	
3	220 kV Sarusajai-Mirza D/C after reconductoring with HTLS	AEGCL	Sonapur, Jawaharnagar, Agia, Boko	
4	132 kV Roing-Chapakhowa D/C	POWERGRID	Pasighat, Tezu, Rupai	
5	132 kV North Lakhimpur-Nirjuli	MUML	Lekhi, Gohpur	
6	132 kV North Lakhimpur -Pare	MUML & NEEPCO	Itanagar	
7	132 kV Nirjuli -Pare	MUML & NEEPCO	Gohpur, Itanagar, Lekhi	

Deliberation of the sub-committee

Utilities updated as follow-

Sl. No.	Name of Element	Name of Owner	Relay settings coordination/updation required at substation	Latest Update
1	LILO of 400 kV Palatana-Surajmaninagar (ISTS) via Surajmaninagar (TSECL) bypassing the Surajmaninagar (TSECL)	POWERGRID	Silchar, PK Bari	Relay setting checked. There is no effect so need not to change any setting.
2	132 kV Agartala-	TSECL		TSECL informed

	Rokhia D/C after reconductoring with HTLS		Monarchak, SM Nagar (TSECL), Budhjungnagar, AGTCCPP	that Agartala, Rokhia relay settings done after reconductoring with HTLS. For SM Nagar (TSECL), Budhjungnagar, TSECL will intimate at the earliest. NEEPCO Not present in Meeting
3	220 kV Sarusajai-Mirza D/C after reconductoring with HTLS	AEGCL	Sonapur, Jawaharnagar, Agia, Boko	Relay setting checked. There is no effect so need not to change any setting.
4	132 kV Roing-Chapakhowa D/C	POWERGRID	Pasighat, Tezu, Rupai	Required updation completed.
5	132 kV North Lakhimpur-Nirjuli	MUML	Lekhi, Gohpur	Not present in Meeting
6	132 kV North Lakhimpur -Pare	MUML & NEEPCO	Itanagar	Not present in Meeting
7	132 kV Nirjuli -Pare	MUML & NEEPCO	Gohpur, Itanagar, Lekhi	Not present in Meeting

B.28 Relay Coordination prior to First Time Charging of New/Modified Elements:

During First Time Charging of New/Modified Elements, relay settings of the new/modified elements are submitted and the details are also entered in PDMS portal of NERPC. However, for ensuring secure and reliable operation, relay settings of adjacent elements also have to be reviewed/ coordinated.

Hence, all the concerned utilities are requested to ensure proper relay coordination and submit the revised relay settings, if needed, of the adjacent elements to NERPC/NERLDC prior to charging.

FTC clearance will be issued by NERLDC only after ensuring the same.

Deliberation of the sub-committee

After due deliberation, the forum decided that FTC will only be issued after complete relay setting coordination. The forum also directed the utility, which is applying for the FTC of any element, to coordinate with concerned utilities to ensure that they complete the relay coordination before applying for FTC.

B.29 Protection Code of IEGC, 2023

Protection Code has been introduced for the first time in IEGC 2023 which will be effective from 01.10.2023. For the capacity building of the stakeholders, a brief presentation on the Regulations will be shared by NERLDC covering the aspects of Protection Code and the responsibilities of different entities. All the utilities are requested to adhere to the same for ensuring secure and reliable protection system in NER Grid.

Deliberation of the sub-committee

NERLDC made a power point presentation on IEGC 2023 Protection code, attached as **Annexure B.29**.

B.30 Standardization of Disturbance Recorder (DR) channels.

As per Regulations 17(2) of IEGC 2023, the disturbance recorders shall have time synchronization and a standard format for recording analogue and digital signals which shall be included in the **guidelines issued by the respective RPCs.**

As per the discussion in 41st FOLD Meeting dated 27.05.22, a Working Group was constituted to streamline the Disturbance Recorder (DR) Parameter Standardization. NERLDC, AEGCL and MSPCL were the members from NER. Accordingly, a detailed study of the philosophies adapted by the power utilities in India and abroad was carried out with the following terms of reference:

i. Triggering criteria of DR (Criteria for start of recording)
ii. Sampling rate to be adapted for DR to enable verification of system models and to capture harmonics related to transient conditions
iii. Recording window to cover pre-trigger, trigger (fault) and post-fault duration
iv. Data format for raw data files of DR

v. Power supply arrangement for DR and associated equipment like GPS Receive/Clock, the SCADA/EMS RTU, modems and any other equipment supplying signals to the DR

vi. Protocol for monitoring healthiness of DR including loss of supply, time synchronization

The final report of the working group has been submitted and accordingly published by FOLD.

It is suggested that the guidelines as per the report may be adopted in NER to comply with IEGC 2023 Regulations for fruitful event analysis.

Deliberation of the sub-committee

After Detailed deliberation, the forum adopted the guidelines on DR parameter standardization as per the final report of the working group. The report has been attached at **Annexure B.30**.

B.31 SPS for tripping of 132 kV Panyor-Ziro line.

The reliability of Ziro, Daporijo, Along, Pasighat, Roing, Tezu, Namsai, Chapakhowa, Ledo and Rupai area has been increased after commissioning of 132 kV Roing- Chapakhuwa DC in the month of July 2023. Since its integration into the grid on 4th July 2023, the 132kV Chapakhowa-Roing D/C line has successfully prevented at least fourteen instances of grid disturbance in Arunachal Pradesh. The details are given below.

Sl. No	Elements Tripping	Date	Time
1	132 kV Along - Pasighat Line	14-Jul-23	13:20
2	132 kV Along - Pasighat Line	14-Jul-23	16:07
3	132 kV Along - Pasighat Line	15-Jul-23	9:44
4	132 kV Daporijo - Ziro Line	19-Jul-23	12:37
5	132 kV Along - Pasighat Line	28-Jul-23	8:40
6	132 kV Daporijo - Ziro Line	30-Jul-23	8:33
7	132 kV Along - Pasighat Line	02-Aug-23	09:07
8	132 kV Along - Pasighat Line	02-Aug-23	14:07
9	132 kV Along - Pasighat Line	04-Aug-23	23:02
10	132 kV Along - Pasighat Line	05-Aug-23	00:15
11	132 kV Along - Pasighat Line	07-Aug-23	10:11
12	132 kV Along - Pasighat Line	08-Aug-23	13:18
13	132 kV Along - Pasighat Line	19-Aug-23	08:15
14	132 kV Along - Daporijo Line	22-Aug-23	08:11

Study suggests that a severe low voltage issue may arise on tripping of 132 kV Panyor-Ziro line and may lead to cascading tripping in Arunachal Pradesh powers system. In such case, SPS may be designed to isolate the downstream load of Ziro substation on tripping of 132 kV Panyor-Ziro line

Deliberation of the sub-committee

The forum agreed in-principle for the installation of SPS at Ziro to remove downstream load on –

i)tripping of 132kV Rangandi-Ziro line and

ii)Voltage at 132kV bus of Ziro falls to 118kV

As Arunachal Pradesh was not represented in the meeting, the forum decided that this issue will be discussed in the next Subgroup meeting in the presence of members from DoP, Arunachal Pradesh.

Agenda from P&ED Mizoram

B.32 Revision of EF TMS and OC TMS at Melriat (PGCIL)

PG Melriat end EF TMS set at 0.05 and OC TMS set at 0.09 need to be revised to higher value, since the existing settings do not provide any time frame for downstream Feeder to clear faults.

In order to enable downstream feeder to prevent faults from affecting upstream feeders, review of settings of PGCI L Melriat is propose d as below-

	Feeder	OC 1 (IEC SI)		EF 1 (IEC SI)	
		PSM (Is)	TMS	PSM	TMS
Existing	PGCIL Melriat	510	0.09	120	0.05
Proposed	PGCI Melriat	54 0	0.155	12 0	0.15

Deliberation of the sub-committee

Refer to deliberation in item no. B.17

Agenda from OTPC

B.33 Enabling of under Voltage Protection in 132 KV Line -1 & 2:

On 3rd April 23, 132 KV Palatana –Udaipur tripped at 03:57 hrs on distance protection (Z-1, 3.53 KM, Y & B Phase, 7,31 KA), at the same time Station

Transfer-2 (ST-2) incomer Breaker trip on under voltage. Which lead to tripping of important drives, No major event happened in Plant as both GBC was in Sec-1, otherwise it could have caused tripping of units.

This event may be avoided, if under voltage protection enabled in OTPC Palatana 132 KV Line -1 & 2. NERLDC may look into

Deliberation of the sub-committee

AD, NERPC highlighted that –

i) there is no regulatory requirement of undervoltage protection in Station transformers.

ii) Under Volatge protection for ST-2 operated instantaneously, which is undesirable.

After detailed deliberation, the forum requested OTPC to insert a delay of 200msec in the Under-voltage protection of ST-2. It was clarified that there should be no undervoltage protection in 132kV line 1 and 2

C. Items for Status Update

C.1 Status of auto-reclosure on z-1 operation for important lines:

In the discussions of the Sub-group on 12-04-2021 the following points were noted:

a. Auto-Reclosure is very much required for maintaining system stability, reliability and uninterrupted power supply.

b. Presently it will take some time for the state utilities to implement the PLCC and establish carrier communication between stations.

c. The operation of Auto-Reclosure on Z-I operation at the local end independent of carrier healthiness is required.

In the 57th and 56th PCC meeting the forum approved the implementation of Auto-Reclosure on Z-1 without carrier check for all lines except the lines with generating stations at both the ends and requested the utilities to implement the AR scheme at the earliest.

In 58th PCC meeting, the forum enumerated the lines where AR is to be enabled at the earliest.

Nagaland: 132kV Dimapur-Kohima line (from Kohima end)

Mizoram: 132kV Turial-Kolasib line

Manipur: 132kV Imphal-Ningthoukong

Tripura: 132kV Agartala-S M Nagar (TSECL), 132kV Agartal-Rokhia DC, 132kV Agartala-R C Nagar DC, 132kV Agartala-Budhjungnagar

Arunachal Pradesh: 132kV Balipra-Tenga, 132kV Ziro-Daporijo-Along-Pashighat link

AEGCL has updated in 58th PCCM that two 220KV substations (Jawaharnagar and Sonapur) and the 220 KV bay at Kathalguri has no auto reclosure but is expected to come up soon. Almost 60% of 132 KV substations has auto reclosure scheme and by June'23 the coverage will increase up to 90%.

Meghalaya stated in the same meeting that the petition to implement auto reclosure in all lines has been placed at MERC as the lines are very old and may snap on auto reclosing mechanism if persistent fault occurs. They stated that AR scheme has been put in place for 5 lines, but approval is required. **(Annexure C.1)**

Latest status-

Sl no	State	Important Transmission lines where AR has to be enabled at the earliest	Progress (till the sub-group held on 7.06.2023)
1.	Arunachal Pradesh	132kV Balipara-Tenga, 132kV Ziro-Daporijo-Along-Pashighat link	PLCC has to be commissioned for the links. WIP under PSDF.
2.	Assam	All 220kV and 132kV lines	At remaining 220kV substations (Jawaharnagar, Sonapur and Kathalguri), work is going on and shall be completed by June 2023. For 132kV substations status remains same as given in 58th PCCM
3.	Manipur	132kV Imphal-Ningthounkong	-
4.	Meghalaya	**Annexure (C.1)**	AR put in place for 5 lines but approval of MERC is still awaited
5.	Mizoram	132kV Turial-Kolasib line	AR implemented (TPAR)
6.	Nagaland	132kV Dimapur-Kohima line (from Kohima end)	Head office is procuring self-reset contact relay to enable the AR. Tentatively by June or July'23
7.	Tripura	132kV Agartala-S M Nagar (TSECL), 132kV Agartal-Rokhia DC, 132kV, 132kV Agartala-Budhjungnagar	scheme is under preparation and AR will be implemented by June'23

Mizoram further updated that AR is enabled in following lines also-

i. 132kV Zuangtui-Serchip line (both sides)

ii. 132kV Zuangtui-Saitual line (Zuangtui side only)

iii. 132kV Lungmual-Melrita line (Melriat side)

iv. 132kV Kolasib-Bairabi line

Deliberation of the sub-committee

Status as updated in the meeting-

Sl no	State	Important Transmission lines where AR has to be enabled at the earliest	Lates status
1.	Arunachal Pradesh	132kV Balipara-Tenga, 132kV Ziro-Daporijo-Along-Pashighat link	No representative
2.	Assam	All 220kV and 132kV lines	For 220kV sub stations- At Sonapur, GIS work underway, support of OEM required At Kathalguri, procurement of relays underway At Jawaharnagar, WIP All works at threes substations to be completed by Nov'23 For 132kV substations- 80% work completed, by Nov'23 90% to be completed
3.	Manipur	132kV Imphal-Ningthounkong	-
4.	Meghalaya	**Annexure (C.1)**	AR put in place for 5 lines but approval of MERC is still awaited. The forum suggested MePTCL to do double jumpering at critical locations to ensure integrity of the old lines Meghalaya requested MS, NERPC to write a letter to higher authorities to expedite the commissioning of the AR in the intra-state lines
5.	Mizoram	132kV Turial-Kolasib line	AR implemented (TPAR). Moreover, AR implemented in – i.132kV Zuangtui-Serchip line (both sides) ii. 132kV Zuangtui-Saitual line

			(Zuangtui side only) iii.132kV Lungmual-Melrita line (Melriat side) iv.132kV Kolasib-Bairabi line (Kolasib side only)
6.	Nagaland	132kV Dimapur-Kohima line (from Kohima end)	Procurement done. AR to be enabled shortly
7.	Tripura	132kV Agartala-S M Nagar (TSECL), 132kV Agartal-Rokhia DC, 132kV, 132kV Agartala-Budhjungnagar	WIP, to be completed by 15th September

The sub-committee noted as above

C.2 Status of TLSA installation on critical lines

i) NERTS has submitted the list of lines for installation of TLSA in 24th TCC meetings as follow-

	Name of Lines	TLA Planned	
Sr. No.	**Name of Lines**	**No. of towers**	**No. of TLA**
1.	132kV Badarpur Khlerihat	165	495
2	132KV Jiribam-Haflong	52	156
3	132KV Khleirhiat-Khlierhiat 1	30	90
4	132KV Khandong-Umrangso	12	36
5	132 Umrangso-Haflong	18	54
6	132KV Aizawl-Tipaimukh	58	174
7	132KV Aizawl-Kumarghat	53	159
8	132KV Aizawl-Kolasib	42	126
9	132KV Jiribam-Tipaimukh	54	162
10	132KV Jiribam-Loktak II	87	261
11	132KV D/C Silchar-Hailakandi I & II	42	252
12	132KV D/C Silchar-Badarpur I & II	17	102
13	132KV D/C NBC-Pavoi I&II	17	102

ii) NETC status on 400kV Silchar- Azara and Silchar-Byrnihat line

Deliberation of the sub-committee

i) NERTS intimated that TLAs are under procurement and 1100 bids have been floated.

ii) NETC not present in the meeting

C.3 Installation of line differential protection for short lines:

As per discussion in 58th PCC meeting and subsequent OCC/Sub-group meetings the status for different STUs/ISTS licensees are as follows:

Status as updated in 58th PCC/subsequent sub-groups/OCC

Name of utility	Last updated status	Latest status
AEGCL	Lines identified. Under Preparation stage.	DPR submitted to PSDF secretariat
MSPCL	Revised DPR for 132kV Imphal-Imphal-III to be submitted.	
MePTCL	Work completed Aug'21, but not commissioned.	Meghalaya to provide line-wise status progress of LDP commissioning work to NERPC and NERLDC.
P&ED Mizoram	Lines identified viz. 132kV Aizawl - Luangmual and 132kV Khamzawl - Khawiva. DPR submitted. PSDF approval awaited.	Revised DPR for the two lines have already been submitted to NERPC
DoP Nagaland	Lines identified under DPR preparation stage.	Three lines were identified, viz; (i)132kV Dimapur-Dimapur-1 & 2 ((ii) 132kV Doyang-Sanis. Work is completed for the first two lines and regarding the Doyang-Sanis line status is provided below.
TSECL	132kV 79 Tilla-Budhjungnagar. DPR to be prepared	

Regarding the 132kV Doyang-Sanis line, NEEPCO to procure and install the LDP relays and associated accessories at both the ends. DoP Nagaland will bear the cost corresponding to Sanis end. OPGW stringing work, as decided in previous PCC meetings, is under the scope of NERTS. DGM NERTS stated that he will take up the matter with ULDC team and requested the forum to refer the matter to the next NeTEST meeting.

NERTS and MePTCl have provided the status on LDP installation on lines in **Annexure C.3.**

Deliberation of the sub-committee

Status as updated by the utilities-

Name of utility	Last updated status	Latest status
AEGCL	DPR submitted to PSDF secretariat	DPR sent back by PSDF secretariat. Third party protection audit reports have to attached with the DPR
MSPCL	Revised DPR for 132kV Imphal-Imphal-III to be submitted.	To be submitted soon
MePTCL	Work completed Aug'21, but not commissioned yet. Meghalaya to provide line-wise status on progress of LDP commissioning work to NERPC and NERLDC.	Report on line-wise status on progress of LDP commissioning work submitted to NERPC and NERLDC
P&ED Mizoram	Lines identified viz. 132kV Aizawl - Luangmual and 132kV Khamzawl - Khawiva. DPR submitted. PSDF approval awaited.	Will take up with SLDC whether DPR has been submitted.
DoP Nagaland	Lines identified under DPR preparation stage. Three lines were identified, viz; (i)132kV Dimapur-Dimapur-1 & 2 ((ii) 132kV Doyang-Sanis.	LDP on Dimapur-Dimpaur lines completed. Regarding Doyang-Sanis line, NEEPCO to install LDR at Sanis end.
TSECL	132kV 79 Tilla-Budhjungnagar. DPR to be prepared	Cost estimate submitted to TIDC to arrange for ADB

		funding.

C.4 Status for SPS

	Name of SPS	SPS Trigger/Action	Utility	Latest Status/Discussion points
1.	SPS related to secure & reliable operation of Leshka HEP	Upon tripping of one circuit of 132kV Leshka-Khliehriat D/C, Leshka generation to be reduced	MePGCL	Logic and scheme has been finalized. Modification in Protection scheme of units and extending the SPS signal to the UCB by M/S Hitachi is pending. M/S Hitachi yet to communicate with MEPGCL and provide the price offer
2.	SPS related to prevention of cascading tripping in Assam power system	Triggering condition 1 (Tripping of 220kV Azara-Sarusajai DC or any one ckt	AEGCL	In 204th OCCM AEGCL updated that SPS has been implemented for both the cases, viz; outage of one circuit and outage of D/C. However, NERLDC pointed out that the designated load shedding under the implemented scheme is only 100MW but the requirement is 160MW. The forum requested AEGCL to implement additional load shedding of 60MW in the SPS.
		Triggering condition 2 (Tripping of 220kV Misa-Samaguri D/C):		In 204th OCCM, DGM, NERTS updated that the code has been freed at Samaguri end. AEGCL informed that final connection will be established after testing and added that the whole work would be completed within 15 days

Concerned utilities may please update the status.

Deliberation of the sub-committee

Status as updated in the meeting-

	Name of SPS	SPS Trigger/Action	Utility	Latest Status/Discussion points
1.	SPS related to secure & reliable operation of Leshka HEP	Upon tripping of one circuit of 132kV Leshka-Khliehriat D/C, Leshka generation to be reduced	MePGCL	Meghalaya has communicated with Hitachi and they have provided an implementation plan. Implementation of the SPS by ANDRITZ Hydro is in process.
2.	SPS related to prevention of cascading	Triggering condition 1 (Tripping of 220kV Azara-Sarusajai DC or		Implemented

	tripping in Assam power system	any one ckt	AEGCL	
		Triggering condition 2 (Tripping of 220kV Misa-Samaguri D/C):		Implemented

The sub-committee noted as above

C.5 Status against remedial actions for important grid events:

Deliberation of the sub-committee

Status updated is as below:

Sl No	Details of the events(outage)	Remedial action suggested	Name of the utility	Latest status (59th PCCM)
1.	132 kV Balipara-Tenga line in May and June	Carrier aided inter-tripping to be implemented for 132kV Balipara-Tenga-Khupi at the earliest (PLCC has to be installed on the link. Under consideration of the higher authorities)	DoP, Arunachal Pradesh. As per previous updates, Work covered under PSDF. In progress	Same status
3.	132 kV Dimapur (PG) - Dimapur (DoP, Nagaland) D/C lines on 15th, 19thjune 1st, 2ndjul	At present Bus Bar protection (at 132kV Nagarjan) has been disabled and shall be put into service after OEM visit.	DoP Nagaland (Work in progress. Will to be completed by this June.)	Bus Bar protection at 132kVNagarjan is now Operational.
4.	132 kV DoyangMokokchung line 132 kV Mokokchung - Mokochung (DoP, Nagaland) D/C lines on 30th July	Carrier inter-trip for 132kV DHEP-Mokokchung to be implemented by DoP Nagaland (NO PLCC on the line. Matter under consideration of Higher authorities)	DoP Nagaland (Work under progress. Will be completed soon.)	
5.	Leshka-Khleihriat DC multiple tripping in April to September	TLSA installation along the line to be done by MePTCL	MePTCL (DPR submitted)	Approval pending.
6.	132 kV Loktak-Jiribam line, 132 kV Loktak-	> 5MVA TRAFO (Aux. Transformer) to be	NHPC (Order to be placed	Order to be placed soon

	Imphalline,132 kV Loktak-Ningthoukhong line, 132 kV Loktak-Rengpang line &Loktak Units 1,2 and 3 on 3rdAug	repaired ->5MVA Auxiliary TRAFO panel to be repaired by NHPC	soon. Will take 6months after placing the order)	
7.	multiple tripping of 132kV Lekhi-Pare and 132kV Pare-RHEP-2 on 23rd Aug'22	DoP Arunachal Pradesh is requested to checked/reviewed the Z-1 reach setting of relay at Lekhi for Pare line urgently based on actual line impedance/line length and accordingly rectify	DoP Arunachal. Pradesh	Done with straightening of LILO at Pare for Ranagandi-Lekhi line
8.	Grid disturbance of category GD-1 (Load loss: 13MW) occurred at Karong areas of Manipur Power System at 07:41 Hrs on 4th August'22	MSPCL to check the following1. Protection setting at Karong along with circuit wirings from DPR to CB mechanism 2. Z-III setting at Imphal and its healthiness of correct operation by relay testing.	MSPCL	
9.	PLCC & protection related issues at 132kV Tipaimukh S/S	MSPCL to ensure uninterrupted service of PLCC system at 132kV Tipaimukh S/S.	MSPCL	
10.	Grid Disturbance at Loktak HEP on 03rd Aug'22	NHPC-Loktak informed that LBB has been included under R&U scheme and the same shall be commissioned by Mar'23	NHPC (LBB to be commissioned under R&U project and by the end of Nov'23)	Nov'23
11.	Multiple tripping occurred at PK Bari-PK Bari and PK Bari-Kumarghat Line on 4th July 2022.	-> Healthiness of Carrier aided POTT scheme needs to be ensured by TSECL -> LDP needs to be implemented in 132 kV PK Bari-Kumarghat Transmission line. TSECL is requested to	TSECL, NTL (->LDP to implemented by August'23 ->Inter trip at PK Bari to be configured. Will be completed by	LDP by September'23

		update the status of installation of LDP to this end -> After installation of DTPC at PK Bari end and Kumaraghat end by PGCIL, Inter-trip will now be enabled between Kumaraghat and P K Bari after TSECL assists in connection of Relay to DTPC panel at P K Bari end.	August.)	
12.	Installation of PLCC/DTPC on 220kV Balipara-Sonabil line1	PLCC to be installed on the line	AEGCL (By Sept'23)	AEGCL updated that carrier intertrip implemented in both ckts
13.	Grid Disturbance at New Umtru area of Meghalaya System on 15-03-23	MePGCL to review the I>2 setting for the New Umtru-Umtru line to prevent mis-operation for fault beyond line	MePGCL (15msec time delay for I>2 settings done by the OEM. MEPGCL to send the relay settings of generators at New Umtru and Umtru as well as that of the line to NERPC/NERLDC.)	MePGCL to disable the High Set definite time Back up O/C and E/F settings as per the NER protection philosophy. Refer to item B.15
14.	Tripping of 132 kV Aizawl - Kolasib Line at 13:30 Hrs and 132 kV Badarpur - Kolasib Line at 13:31 Hrs of 23-03-2023, leading to blackout at Kolasib substation	Auxiliary power issue at Kolasib substation which hampered carrier aided tripping of Aizawl-Kolasib line. P&ED, Mizoram to investigate into the downstream fault at Kolasib substation and send report to NERPC/NERLDC	NERTS, P&ED Mizoram	Auxiliary power issue at Kolasib resolved
15.	At 19:36 Hrs of 18-04-23, Grid Disturbance of category GD-1(Load Loss:120 MW) occurred	an SPS has to be devised for preventing overloading of the		WIP for SPS

	at Ghoramari, Depota, Rowta and Dhekiajuli areas of Assam system due to tripping of 132 kV Sonabil-Ghoramari and 132 kV Sonabil-Depota Line	lines till the lines reconductored with HTLS conductors		
16.	Review of SPS at Monarchak (item 2.22 of the sub-group held on4th May 23)	NERLDC requested NEEPCO and Tripura to implement the revised logic at Monarchak (as provided by NERLDC) and Udaipur Rokhia ends respectively	NEEPCO, TSECL (SLDC TSECL intimated that logic 1(to be configured at Udaipur and Rokhia to send DT to Monarchak) could not be implemented as there is no PLCC/OPGW connectivity in the LILO portion of Monarchak. NERLDC requested TSECL to explore installation of PLCC/FO for smooth functioning of SPS scheme for the reliability of Monarchak system)	
17.	Blackout of 220kV Salakati GSS on 18th of November, 2022	commissioning of the Bus Bar protection at 220 kV BTPS(Assam) S/S	AEGCL. In 58th PCCM Assam reported that order has been placed for Bus Bar protection relay panel and	Offline testing done. To be enabled in few days

			commissioning will be completed by April,2023	
18.	Bus Bar Protection at 220 kV Mariani (Assam) Substation	Commissioning of Bus Bar Protection at 220 kV Mariani (Assam) Substation	AEGCL	To commissioned by September end
19.	132 kV Aizawl - Tipaimukh Line tripped at Aizawl end only on received of spurious DT signal on 16th and 26th Feb'23	rectification of PLCC issues at Tipaimukh end by MSPCL	MSPCL	
20.	Outage of 220 KV Bus Bar Protection Scheme at 400/220/132 KV Killing SS	Bus-Bar protection of 220kV bus at Killing SS	MePTCL. In previous meetings MePTCL intimated that for integration of LV side bays of ICTs 3 and 4 to the BUS Bar protection panel, all the hardware's are available but integration is still pending	M/S ABBB has given offer. Board's approval awaited. To be completed in 3-4 months
21.	Multiple tripping of 132kV BTPS-Dhaligaon	Implementation of 3phase Auto reclosure on the line	AEGCL	Done
22.	Retrip configuration in LBB scheme in AEGCL Hailakandi station:	In previous sub group meeting The forum opined that the retrip scheme in the LBB protection will increase reliability of the protection system and will help in preventing mal operations in connecting feeders. AEGCL agreed to the suggestion and assured that the Retrip scheme, with time delay of 100msec	AEGCL	Logic finalized, need to be tested. Whole work may be completed within one month

		will be configured in the LBB scheme in Silchar-Hailakandi Ckt 1 & 2 at Hailakandi end.		
	Frequent tripping of 132 kV Dimapur (PG) - Kohima Line (8 times in May'23)	DoP, Nagaland informed that frequent tripping occurred due to disc insulator problems. About 30–40-disc insulators in B-Phase needs to be replaced during next shutdown from 21-06-2023. Shutdown has been applied	DoP Nagaland	Done

DATE AND VENUE OF NEXT PROTECTION SUB- COMMITTEE MEETING

The next Protection Sub-Committee meeting will be held in the month of October, 2023. The date and venue will be intimated separately.

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Annexure-I

List of Participants in the 59th PCC Sub-Committee Meeting held on 29.08.2023

SN	Name & Designation	Organization	Contact No.
1.	Sh. Abhishek Kalita, DM, AEGCL	Assam	08486213068
2.	Sh. A.G.Tham, AEE (MRT), MePTCL	Meghalaya	09774664034
3.	Sh. A.Shullai, AEE (GSPSD), MePGCL	Meghalaya	09436334458
4.	Sh. Thanglura Jailo, EE, MRT	Mizoram	09366269162
5.	Sh. Lalrinawma, SDO, MRT	Mizoram	09436791567
6.	Sh. Albert Ovung, EE	Nagaland	-
7.	Sh. Pulovi, SDO (transmission)	Nagaland	-
8.	Sh. Alex E. Ngullie	Nagaland	-
9.	Sh. Anil Debbarma, DGM, SLDC	Tripura	09612589250
10.	Sh. Amresh Mallick, CGM (I/C)	NERLDC	09436302720
11.	Sh. S.C.De, Sr.GM	NERLDC	09436339367
12.	Sh. Sachin Singh, Mgr	NERLDC	-
13.	Sh. Chitra Bahadur Thapa, Manager	NERLDC	08135989964
14.	Sh. Utpal Das, AM	NERLDC	07005504075
15.	Smt. Isha Das, Engineer	NERLDC	09365332774
16.	Sh. Prasanta Kanungo, CGM	PGCIL	09436302823
17.	Sh. Manas Jyoti Baishya, Ch. Manager	PGCIL	-
18.	Sh. K.B.Jagtap, Member Secretary	NERPC	09436163419
19.	Sh. S.M.Aimol, Director	NERPC	08974002106
20.	Sh. Shaishav Ranjan, DD	NERPC	08787892650
21.	Sh. Vikash Shankar, AD-I	NERPC	09455331756
22.	Sh. Somraj, AD-I	NERPC	08890766838
	NO REPRESENTATIVE	Ar. Pradesh	-
	NO REPRESENTATIVE	Manipur	**-**
	NO REPRESENTATIVE	NTPC	
	NO REPRESENTATIVE	NEEPCO	-
	NO REPRESENTATIVE	OTPC	-
	NO REPRESENTATIVE	NHPC	-
	NO REPRESENTATIVE	INDIGRID	-

सत्यमेव जयते

भारत सरकार/Government of India
विद्युत मंत्रालय/Ministry of Power
केन्द्रीय विद्युत प्राधिकरण/Central Electricity Authority
एन.पी.सी. प्रभाग/National Power Committee Division
Ist Floor, Wing-5 ,West Block-II, RK Puram, New Delhi-66

No.4/MTGS/SG/NPC/CEA/2023/ 353 Date: 18.09.2023

Subject: Standard Operating Procedure for Protection System Audit- reg.

Standard Operating Procedure (S.O.P) for Protection System Audit is enclosed herewith for your kind information and necessary action.

Enclosure: As above

Yours faithfully,

सत्येंद्र 18.09.23

(सत्येंद्र कु. दोतान / Satyendra Kr. Dotan)
Director, NPC & Member Convener (Sub-group)

Standard Operating Procedure for Protection System Audit

A protection system audit is a review and evaluation of the protection systems of a substation with an objective to verify whether required protection systems have been put in place at station by the concerned utility, and to recommend suitable measures to provide for the same.

Ministry of Power, had constituted a Committee under the Chairmanship of Chairperson CEA to examine the grid disturbances on the 30th and the 31st July 2012. One of important recommendation of the committee was conducting of extensive audit of protection system. List of sub-stations where protection audit is to be undertaken on priority basis was prepared and audited across the country. This was the beginning of protection audit across the country and large number of important 400 and 220kV substations were audited.

Keeping in view the importance of Protection System Audit, Standard Operating Procedure has been prepared for the reference purpose. It will provides a step-by-step guide for RPCs to follow during the audit process.

1. All users shall conduct third party protection audit of each sub-station at 220 kV and above (132 kV and above in NER) once in five years or earlier as advised by the respective RPC.
2. After analysis of any event, each RPC shall identify a list of substations / and generating stations where third-party protection audit is required to be carried out and accordingly advise the respective users to complete third party audit within three months.
3. The third-party protection audit report shall contain information sought in the format as per IEGC 2023 and its further amendments.
4. Annual audit plan for the next financial year shall be submitted by the users to their respective RPC by 31st October. The users shall adhere to the annual audit plan and report compliance of the same to their respective RPC.

5. **Criteria for choosing substations for third party protection audit:**

   The following criteria are generally applied during choosing a substation for protection audit.

   i. Substations/ Generating (SS/ GS) stations with frequent grid incidences or frequent maloperations or any grid occurrence in any substation which affected supply to large number of substations and caused significant load loss. In this case, third-party protection audit may be carried out within three months or as decided in the Protection sub-Committee Meeting of the RPC.

   ii. Based on request received from utilities for arranging protection audit in certain stations (e.g. for availing PSDF funding for Renovation and Upgradation of Protection system). In this case, preferably third-party protection audit may be carried out within three months.

   iii. Important 400kV and 765kV substations (SS) / Generating stations (GS) including newly commissioned SS/ GS. In this case, third-party protection audit may be carried out at a frequency decided in the Protection sub-Committee Meetings of respective RPCs.

6. **Protection audit Procedure:**

i. After identification of stations for protection audit, the same is communicated to the owner utility seeking nomination of one nodal officer for each Station.
ii. The nodal officer shall provide the details of substation for preparation of protection audit format (in line with IEGC and subsequent amendments).
iii. Meanwhile nominations shall be sought from all utilities to form regional teams for audit. Regional teams comprising of engineers from various utilities /utility (other than the team of host State) of the region shall be formed based on the no. of SS to be audited. (Each team may consists of 3 or 4 engineers from utilities other than the host utility and at the maximum a team will be able to audit 3 to 4 stations in 7-9 days or so)
iv. Once the team details and list of stations to be audited is finalised the details of nodal officers, team members , list of stations to be audited by each team is shared to all for further coordination regarding planning and conduction of audit.
v. Based on the inputs received from nodal officer regarding the list of elements in the substation to be audited, protection audit formats shall be prepared by RPC (in line with IEGC) and circulated to nodal officer. The nodal officer along-with the substation engineers shall fill the audit format and furnish the same along-with various attachments sought as part of the audit format within a week or so. List of attachments shall be given in the covering page of audit format.
vi. The filled in audit format along-with the received annexures shall then forwarded to the audit team by the nodal officer and any further clarification regarding the format or attachments shall be taken up by the audit team with the nodal officer under intimation to RPC.
vii. The SS/ GS shall be audited based on the data filled in audit format checking for compliance of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022, Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 & CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, CERC regulations and amendments to the same, approved guidelines of RPC, best practices in industry, report of the Task Force on Power System Analysis Under Contingencies and as per the "Model Setting Calculations For Typical IEDs Line Protection Setting Guide Lines Protection System Audit Check List Recommendations For Protection Management Sub-Committee on Relay/Protection Under Task Force For Power System Analysis Under Contingencies" etc.
viii. After conduct of audit, the shortcomings observed in the audit shall be discussed in detail with the nodal officer and substation engineers and recommendations are finalised.
ix. The filled in audit format along-with the recommendations and attachments shall be finalised and final protection audit report RPC (in line with IEGC) shall be compiled.
x. Final protection audit report shall be discussed in Protection Coordination Committee and recommendations may be accepted/deleted/modified as per the scope of audit and compliance of various regulations/guidelines etc.
xi. The recommendations of all SS audited shall be inserted into audit recommendations database and update regarding recommendations shall be sought from respective utilities.
xii. Action plan for rectification of deficiencies detected, if any, shall be submitted to the respective RPC and RLDC and monthly progress will be submitted.

xiii. The travel expense from place of duty to Substation/Generating Station to be audited shall be borne by respective Auditor (Parent Organisation). The expense for boarding, lodging any travel of the team during the audit period shall be borne by the organisation owning the Substation/Generating Station.

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Annexure B.1.2

Protection and UFR Audit Calendar (October'23-April'24) - NER

Sl. no	State	Protection Audit Station	Planned Audit date (Protection + UFR)	UFR stations
1.	Arunachal Pradesh	Daporizo (132/33kV)	13th - 17th January'23	132kV Lekhi
		Along (132/33kV)		132k/11kV Tippi
		Pashighat (132/33kV)		33kVBandardawa
		Roing (132/33kV)		132/33kV Chimpu
		Chimpu (132/33kV)		33kV Yupia
				132/33kV Daporijo
		Khuppi (132/33kV)		33kV Dumporizo
		Tenga (132/33kV)		
2.	Assam	Sonabil (220/132kV)	15-19th March'24	Samaguri (220/132/33)
		Agia (220/132/33kV)		Sankardev (132/33)
		Sarusajai (220/132/33kV)		Azara (132/33)
		Samaguri (220/132/33)		Tinsukia (220/132/33)
		BTPS (220/132/33)		Panisokua (132/33)
		Other stations already covered in protection Audit carried out in 2021		CTPS (132/33)
				Nalkata (132/33)
				Garmur (132/33)
				Dhaligaon (132/33)
				Bilasipara (132/33)
3.	Manipur	Karong (132/33kV)	12-16th April'24	KHUMAN LAMPAK (33/11kV)
		Imphal (132/33kV)		YAINGANGPOKPI (132/33kV)
		Jiribam (132/33kV)		SANGAIPROU (33/11kV)
		Rengpang (132/33kV)		WANGJING (33/11kV)
		N. Thoubal (400/132kV)		
		Churchandpur (132/33kV)		
		Kakching (132/33kV)		
		Tipaimukh (132/33kV)		
4.	Meghalaya	Byrnihaat (400/220/132kV)	16-20th December'23	Ampati (132/33)
		Mawphlang (132/33kV)		Nangalbibra (132/33)
		Mustem (132/33kV)		Mendipathar (132/33)
		Umiam stg I (132/33kV)		Mawphlang (132/33)
		Umiam stg III (132/33kV)		Rongkhon (132/33)
		Umiam (132/33kV)		Nongstoin (132/33)
		EPIP I (132/33kV)		Mawlyndep (132/33)
		EPIP II (132/33kV)		Mustem (132/33)
5.	Mizoram	Kolasib (132/33kV)	11-15th February'23	Luangmual (132/33kV)
		Zuangtui (132/33kV)		Shimui (132/33kV)
		Luangmual (132/33kV)		Zuangtui (132/33kV)
		Serchip (132/33kV)		
6.		Kohima (132/33kV)		Dimapur (132/66/33 kV)
		Wokha (132/33kV)		Mokokchung (132/33)

	Nagaland	Sanis (132/33kV)	11-15th November'23	Kohima (132/33kV)
		Chepouzou (132/33kV)		
		Mokokchung (132/33kV)		
		Dimapur (132/33kV)		
7.	Tripura	Rokhia (132/33kV)	21st-24th October'23	Ambassa (132/33kV)
		Agartala (132/33kV)		Dhalabil(132/33kV)
		SM Nagar(132/33kV)		Udaipur (132/33kV)
		P K bari (132/33kV)		Rokhia (132/33kV)
		Udaipur (132/33kV)		
		Kumaraghat (132/33kV)		
		Ambassa (132/33kV)		
		Dharmangar (132/33kV)		
		Budhjungnagar (132/33kV)		
		Dhalabil (132/33kV)		

Annexure B.1.3

Annexure – I sdgdsfgsdfg

SOP for protection audit

1. Circulation of all formats for self audit to all concerned utilities/stations.
2. Submission of self-audit reports to NERLDC/NERPC by concerned utilities/stations.
3. Physical audit of stations by 3rd party.
4. Preparation of audit reports by the 3rd party audit team immediately after completion of audit & submitting it to the station.
5. Submission of audit report to NERPC.

Annexure-II

Draft Physical Audit Inspection Report

SUBSTATION

1. Transformers:
    a. Check oil level – Main Tank, OLTC & Bushings (if applicable)
    b. Check Silica Gel condition
    c. Check operations of fans
    d. Check alarms of RTCC panel
    e. Check Online DGA condition (if installed)

2. Reactors:
    a. Check oil level – Main Tank, Bushings (if applicable)
    b. Check Silica Gel condition
    c. Check Online DGA condition (if installed)

3. CT:
    a. Check oil leakage
    b. Check MB internal conditions
    c. Check star point – double earthing to be avoided.
    d. Check plugging of all holes in MB.

4. CVT :
    a. Check oil leakage
    b. Check MB internal conditions
    c. Check star point – double earthing to be avoided.
    d. Check LMU condition & cabling to PLCC panels (if available)
    e. Check plugging of all holes in MB.

5. Surge Arrester :
    a. Erath pit numbering along with previous earth resistance measurement & next due date to be marked.
    b. Surge counters to be checked for healthiness (mA reading to be available in surge counter).

6. Switchyard :
    a. Cable trench covers to be available in good condition
    b. Check availability of proper illumination in switchyard.
    c. Gravel spreading to be available in switchyard
    d. Switchyard to be free of any vegetation growth.
    e. Bay naming plates to be available
    f. All equipments to be marked for proper identification baywise.

7. DG :

a. Auto Run feature to be checked.
b. Diesel consumption record to be available.
c. Check DG exhaust pipe height as per norms.
d. Check for DG oil leakage.

8. PLCC :
   a. Availability for all 132kV & above feeders to be checked.
   b. Pending alarms to be checked.
   c. Gain level (AGC) to be checked.

9. Circuit Breaker :
   a. SF6 gas pressure to be checked.
   b. SF6 gas consumption record to be maintained.
   c. Leakage from pneumatic CB to be checked.
   d. Operation counters to be checked for healthiness.
   e. Any pending alarms to be checked for CB in CRP/SAS.

10. Isolator & earth switches :
   a. Check MB for cleanliness & plugging of all holes.
   b. Operating handles to be available.
   c. Proper demarcation of earth switches to be done.

11. SCADA :
   a. Availability of GPS.
   b. Availability of functional ACs for control room & relay kiosks.
   c. Time Sync to be checked.
   d. Remove any feeder protection relay from SCADA ring by disconnecting the fibre. Relay should get disconnected from SCADA ring in NMS & alarms to be recorded in event list.
   e. Check for any persisting alarms of SCADA.
   f. Simulate AR block alarm in case PLCC fail/Carrier Out condition.

12. Protection :
   a. Check Line Diff Relay Installation completion (if applicable).
   b. Check whether Line Diff function is in service (if OPGW is available between terminal ends)
   c. Check DR triggered for time sync.
   d. AR to be implemented for all 132kV lines & above.
   e. Check for any pending bus bar block alarm.
   f. Check all relays are in ON condition.
   g. Check for any non functional/damaged electromechanical relays still in service.
   h. Lamp Test for mimic panel.

13. Battery & battery charger :
   a. Battery voltage (+ve to E & -ve to E) – check for any earth fault.
   b. Battery bank voltage drop test to be carried out by switching off ac supply (To be discussed for possibility)

c. AC to be installed if VRLA batteries are used.
d. Battery earth fault relay to be installed in DCDB.
e. Check earth fault relay settings (3mA & instantaneous).
f. Check all LEDs of battery charger are in working condition.

14. Fire Fighting :
    a. Availability of functional fire fighting system for Xmers & Reactors.
    b. Availability of updated refilled fire fighting cylinders.
    c. Availability of fire fighting system for control room.
    d. Check fire fighting alarms (if possible)

15. GIS :
    a. Check AHU system is functional or not.
    b. SF6 gas consumption record to be maintained.
    c. GIS hall to be clean & free of dust.

16. Safety :
    a. Prevailing safety procedure to be recorded.
    b. First aid kit to be available.
    c. All safety PPEs to be available.
    d. Emergency contact details to be available in control room.

17. Test kits :
    a. List of testing kits to be available as per norms.
    b. Calibration of all kits to be updated.

TRANSMISSION LINE

1. Visual inspection :
    a. Vegetation growth on tower body.
    b. ROW corridor to be free from vegetation growth.
    c. Check for any tower shape abnormalities – like bending etc.
    d. Check for any visible member missing.

Annexure-IV 13th NPC

Annexure B.3

Report of the Sub-Committee on PMU Placement and Analytics under URTDSM Phase II

National Power Committee

CEA

Acknowledgement

The Committee acknowledges the cooperation extended by RPCs, POSOCO, PGCIL and CTU for giving their valuable inputs to finalize the recommendations for the URTDSM Project Phase - II.

The Committee also acknowledges and extends gratitude to the sincere efforts of Shri Deepak Sharma EE WRPC and Shri Sachin Bhise EE WRPC, for their inputs and suggestions and putting all the inputs in proper perspective & giving shape to this report.

The committee would also like to thank Sh. Rahul Shukla, Chief Manager, NLDC and Sh. Aman Gautam, Manager, NLDC for the painstaking efforts taken to provide comments and help in the drafting of the report.

The committee puts on record the efforts of Dr Rajeev Gajbhiye, Sh. Prashant Navalkar and Sh. Gopal Gajjar from IIT Bombay who provided valuable inputs and feedback on the URTDSM Phase I and futuristic applications that can be developed.

The committee also acknowledges the efforts of M/s PRDC for arranging presentation of EPG USA and giving perspective of applications developed and used worldwide.

(Rishika Sharan) Chief Engineer (NPC), CEA	Please refer Note-1 (Sunita Chohan) CGM (GA&C), PGCIL	(Vivek Pandey) G. M., NLDC
(Nutan Mishra) Sr. G. M., CTUIL	13/10/2022 (Saumitra Mazumdar) Director (IT & CS), CEA	07/10/2022 (Shyam Kejriwal) S. E., ERPC
(P Suresh Babu) S. E., TS SLDC	T. 12/x/22 T. Sivakumar S.E., TANTRANSCO	(Abdullah Siddique) Chief Manager, SRLDC
(Len J B) E. E., SRPC	(Srijit Mukherjee) Deputy Director, NERPC	(Himanshu Lal) Deputy Director, NPC
(P. D. Lone) S. E., WRPC & Member Convener		(Satyanarayan S.) Member Secretary, WRPC & Chairperson

Summary of the Report

- Initially a Pilot Project was implemented by POSOCO with 52 Phasor Measurement Units (PMUs) installed all over the Country progressively from 2008 to 2010. Based on the experience gained in Pilot Projects, a Feasibility Report was prepared for Nation-wide development of WAMS namely Unified Real Time Dynamic State Measurement (URTDSM) Project. A Detailed Project Report (DPR) was prepared in 2012 for implementation of 1740 PMUs on Pan-India basis. The Project was agreed for implementation in a Joint Meeting of all the five Regional Standing Committees on Power System Planning held on 5th March 2012. Also, it was decided that the project of installation of the PMUs will be taken up in two stages.
- CERC granted in principle approval for the project in Sept'2013 with 70% funding from PSDF & 30% equity from POWERGRID. CERC granted in principle approval for the implementation of URTDSM Phase-I and advised to take up Phase-2 after receiving feedback on Phase-I performance from POSOCO. POWERGRID took up the implementation of URTDSM Project in Jan'2014 and 1409 PMUs are installed in Phase-I of the Project (the increase in quantity of PMUs was due to addition of new bays etc. at the substations). Nodal PDC at strategic substations, Master PDC at all SLDCs, super PDC at 5 RLDCs, Main & backup PDC at NLDC have been installed and are fully functional. PMUs are installed at only those 400 kV lines which had connectivity of the fibre optic network.
- Data of these PMUs is being utilized by power system operators as an analytical tool for better system operation in real time as well as for off-line analysis. Operators are also utilizing various facilities provided under the project which includes the GUI application supplied by GE and 6 analytics have been deployed by IIT-B.
- In the 10^{th} NPC Meeting held on 9^{th} April 2021 it was decided to form a sub-committee, *under the Chairmanship of Member Secretary, WRPC with representatives from POSOCO, CTU, POWERGRID, all RPCs/NPC.* ***The Sub-Committee was entrusted to recommend uniform philosophy of PMU locations, new analytics and requirement of up gradation of Control Centre under URTDSM project and submit its recommendations to the NPC.***
- The sub-committee held 3 meetings. The first meeting was held on 10.12.2021 and the second meeting was held on 31.05.2022. In both the meetings IIT Bombay gave presentation on the analytics developed in URTDSM Phase-I, improvements in these analytics and futuristic analytics that can be undertaken under URTDSM Phase-II.

- The EPG group presentation was arranged by PRDC in the second meeting held on 31.05.2022 and the EPG LLC, USA highlighted various application analytics which are deployed by power Utilities worldwide and are being used.
- The third meeting of the sub-committee was held on 14.09.2022 to discuss the finalised draft report of the sub-committee.
- PGCIL has expressed some reservations on the recommendations of the sub-committee. The same are attached at *Annexure – 9*.
- Based on the above discussions, the report has been broadly divided into 6 Sections
  - Section-1 briefly explains the background discussions that took place in various meeting for implementation of the PMU/WAMS project on pan India basis and the progress and hardware implementation of the Phase-I of the URTDSM project.
  - Section-2 briefly explains the OEM online and offline applications and its use.
  - Section-3 deals with the PMU placement criteria and status of Phase-I analytics.
  - Section-4 outlays various issues regarding hardware, application & analytics faced in the Phase-I of the URTDSM project and feedback of stakeholders.
  - Section-5 describes in brief discussions took place on requirement of PMUs that took place in regional levels, various new applications/analytics that can be taken up in Phase-II of the project.
  - Section-6, the recommendations of the sub-Group on improvement of Phase-I applications/analytics/hardware optimisation required to be taken up Phase-II, placement/requirement of PMUs in phase-II and new applications/analytics required to be implemented in Phase-II of the URTDSM project.

Table of Contents

List of Annexure

1. Background of the URTDSM Project

1.1 Background

In the 10th NPC Meeting held on 9th April 2021 it was decided to form a sub-committee, the relevant extract of the minutes of the above meeting is reproduced below.

"*After deliberations, NPC decided that a Sub-Committee would be formed under the Chairmanship of Member Secretary, WRPC with representatives from POSOCO, CTU, POWERGRID, all RPCs/NPC.* ***The Sub-Committee shall discuss on the uniform philosophy of PMU locations, new analytics and requirement of up gradation of Control Centre under URTDSM project and submit its recommendations to the NPC.***

Consequently, the sub-committee was formed vide NPC Letter NO. 4/MTGS/NPC/CEA/2021/285-298 dated 20.09.2021 (letter enclosed at *Annexure – I*) based on nominations received at NPC.

1.2 URTDSM Project Phase-I

a) A Pilot Project was implemented with 52 Phasor Measurement Units (PMUs) installed all over the Country progressively from 2008 to 2010. Based on the experience gained in Pilot Projects, a Feasibility Report was prepared for Nation-wide development of WAMS namely Unified Real Time Dynamic State Measurement (URTDSM) Project. A Detailed Project Report (DPR) was prepared in 2012 for implementation of 1740 PMUs on Pan-India basis.

b) The Project was agreed for implementation in a Joint Meeting of all the five Regional Standing Committees on Power System Planning held on 5th March 2012.

c) Also, it was decided that the project of installation of the PMUs will be taken up in two stages.

Table 1: Proposed Stage- I

Region	Sub-stations		No of Transmission line		PMU		Nodal PDC	MPDC	SPDC	Main & B/U NLDC
	ISTS	STU	ISTS	STU	ISTS	STU				
NR	74	42	394	224	206	120	6	9	1	
WR	49	18	456	135	234	71	11	4	1	
ER	51	31	395	149	202	79	4	5	1	
SR	57	16	338	90	178	47	6	4	1	
NER	9	5	69	24	36	13	0	3	1	
Total	240	111	1652	622	856	330	27	25	5	
	351		*2274*		*1186*		*57*			*2*

Stage-I: Installation of PMUs at the locations where Fibre Optic communication is available or would be made available under microwave frequency vacating program and regional strengthening program by 2014-15 along with installation of PDCs at all SLDCs, RLDCs, NLDC, NTAMC, strategic locations in State, remote consoles at RPCs, CEA, CTU and other locations.

Table 2 : Proposed Stage- II

Region	Sub-stations		No of Line		PMU	
	ISTS	STU	ISTS	STU	ISTS	STU
NR	9	55	40	211	21	111
WR	11	58	64	280	33	145
ER	-	13	-	50	-	26
SR	3	55	10	199	5	105
NER	9	17	26	45	14	23
Total	32	198	140	785	73	410
	230		*925*		*483*	

Stage-II: Installation of PMUs at balance locations along with communications links.

d) The stage wise deployment of PMUs and PDCs is given as under

i. The project was approved with the above tabulated infrastructure in stage – I & II.

ii. Phase-I: 1186 PMUs at 351 substations (communication existing) - Rs. 278.89 Crs.

iii. Phase-II: 554 PMUs at 301 substations (with installation of 11,000 Kms OPGW) - Rs.377 Crs.

iv. Phasor Data Concentrators with 6 Analytical Software at 32 Control centres considering requirement of both i.e., Phase-I & Phase-II.

e) CERC granted in principle approval for the project in Sept'2013 with 70% funding from PSDF & 30% equity from POWERGRID. CERC granted in principle approval for the implementation of URTDSM Phase-I and advised to take up Phase-2 after receiving feedback on Phase-I performance from POSOCO.

f) POWERGRID took up the implementation of URTDSM Project in Jan'2014 and 1409 PMUs are installed in Phase-I of the Project (the increase in quantity of PMUs was due to addition of new bays etc. at the substations). The list of PMUs installed is given at *Annexure – II*.

g) In line with agreed philosophy in Joint Meeting of all the five Regional Standing Committees on Power System Planning, POWERGRID took up the requirement of URTDSM Phase – II in all Regional Power Committees. During the discussion on finalization of PMU quantity for URTDSM phase–II, requirement of additional measurements emerged. POSOCO also desired additional Analytical software using PMU data.

2. Applications under URTDSM Phase-I

2.1 PMU based real time monitoring applications:

PMU based visualization helps not only operators of affected control areas, but also in alerting neighbouring operators of a stressed grid. In the real time grid operation, PMUs data are being utilized for following purposes:

a) Real time event and alarm processing: WAMS System provides spatio-temporal aggregation of the events, magnitude related violations in frequency, Positive Sequence Voltage Magnitude, Rate of Change Frequency (ROCOF) and Angular Difference. These are processed in real time at each second in batch processing to alert the operator.

b) Visualization of frequency, Rate of change of frequency, Voltage, Power flows and Angle difference monitoring through trending at high resolution, helps in taking early actions by control room.

c) Visualization of angular difference data, real-time angular separations, Real time monitoring and analysis, obtaining angular differences.

d) Geographical network diagram provides information about the system through visual objects representing network elements, contours, rubber band zooming, panning, flyouts and pods through sub second resolution measurements and its variation in real time.

e) Contour display allows overview of the voltage/frequency profile for the entire grid, Voltage Contour visualization, Voltage contour variation before and after generator trip allows real time monitoring of voltages across all the nodes. Frequency contour identifies the coherent group of generators during incidents of low frequency oscillations in the grid.

f) Oscillatory Stability Management (OSM): Oscillation Stability Management (OSM) helps in monitoring the low frequency oscillations or small signal stability issues in the system, the oscillation frequency related information like, dominant mode frequency, energy and damping helps the operator in taking real time necessary actions by identifying root cause of oscillation. The OSM provides the information pertaining to negatively damped modes. OSM module extracts oscillatory stability parameters from small, random movements of the power system that are continuously occurring, mainly due to load changes in configured frequency, angle difference and active Power signals. Low frequency oscillations and damping ratios are obtained using Auto Regressive Moving Average (ARMA) analysis of the measured signal. The dominant modes of oscillation are extracted, and key parameters identified – mode frequency, amplitude, and decay time. It also shows the mode shape (Right Eigen Vector) and mode chart for better Analysis of Oscillation in the system.

2.2 Off-line Applications/usages:

Some of the off-line usages are given as follows:

a) Primary frequency Response assessment requires high resolution data of frequency for any event. The monitoring of pattern of frequency posts any incident involving load/generation imbalance helps in identifying the percentage of ideal response achieved in event.

b) The oscillation detection, using UTRDSM system is used to provide necessary feedback to generators for taking corrective actions. The poorly damped oscillations indicate the review of controller settings in power system stabilizers of units.

c) The high sampling rate of PMU data helps in validations of responses and fine tuning of various power system elements.

d) The high-resolution data helps in validating the actions of system protection schemes and also parameter variations across the grid.

e) The high-resolution data helps in monitoring the operation of various transmission line protection schemes which operate in sub-second time horizon with the lines having high fault clearing times can be reported to entity along with RPC for early resolution.

f) Synchro phasor has helped to find the issues in time synchronization in event loggers, disturbance recorders details submitted by utilities also for checking of sequence of operation of the events etc.

g) PMU also helped RLDCs in validating the Power system stabilizer tuning process with high sampled data. It has provided feedback in form of oscillation/power swing where PSS tuning is required to be carried out and based on these generators had been informed.

h) PMU data was utilized in monitoring of power system during site testing of power transformers at National High Power Testing Laboratory (NHPTL) at Bina station.

The transient stability was monitored for the period of test shot. The PMU based data provided inputs on fault clearing time, faulty phases and short circuit MVA during tests.

i) Post-Disturbance Analysis: It is required to assemble and study the signals from various PMUs that are dispersed throughout the grid for the analysis. The time-synchronized PMU data from different locations of grid, helps in understanding and reconstructing the event.

3. PMU Placement criteria & Analytics in Phase – I and its status

3.1 PMU locations under Phase – I

During the Joint Meeting of all the five Regional Standing Committees on Power System Planning held on 5th March 2012, following PMU placement philosophy was decided:

a) All 400 kV stations in State and ISTS grids.

b) All generating stations at 220 kV and above.

c) HVDC terminals and inter-regional and inter-national tie lines.

d) Both ends of all the transmission lines at 400kV and above: State and ISTS sector.

3.2 Status of Phase – I (Broad configuration of PMUs, PDCs and infrastructure used)

a) The PMUs procured are having 2 set of voltage, 2 set of current measurement & some (16) digital input configuration.

b) The utilization of measurement inputs of PMU depends on the bay configuration at substations. In cases where there is one line & ICT or reactor only, one set of current input is utilized, and other input remains unutilised.

c) The PMUs are measuring line and bus voltages as per the configuration of installation. PMUs installed are of the Measurement class and wired up in the metering core of CVT/CT.

d) Nodal PDC at strategic substations, Master PDC at all SLDCs, super PDC at 5 RLDCs, Main & backup PDC at NLDC have been installed and are fully functional.

e) POSOCO's initial pilot project & States PMUs were also integrated with the URTDSM project.

f) POSOCO has informed that the PMUs were installed at only those 400 kV lines which had connectivity of the fibre optic network.

g) The List of PMUs installed in phase – I of the projects is attached at *Annexure – II.* A region wise map of the existing placement of PMUs (pictorial representation of PMUs installed is attached at *Annexure III.*

h) The number of PMUs installed on 132kV lines is 5nos., 220kV lines is 179nos., 400kV Lines is 1093nos., 765kV lines is 148nos.

3.3 Present functionalities under URTDSM:

Data of these PMUs is being utilized by power system operators as an analytical tool for better system operation in real time as well as for off-line analysis. Operators are also utilizing various facilities provided under the project.

The PMU data can be used for real time monitoring of the system and taking decisions. Under para 3.4, below the potential of the WAMS project in real time system monitoring and taking decisions is highlighted.

3.4 Existing features of URTDSM

a) Time Series Derivation Framework (TDF) TDF is the user interface of the Historian Application provided by OEM M/s GE and is being used in Control room to plot the events which occurred during last one year (at NLDC, six months at RLDCs level) to analyse details of events and its characterization. Data Storage limitations are constraints in storing historian data for longer duration.

b) Spectral Analysis (using E-Tera Phasor Analytics) Spectral analysis of PMU data enables revealing which frequencies occur in system and how they change as a function of time. Spectral analysis provides an intuitive and visual way of representing changes in power system parameters at 8 different frequency and time instances. Mainly three types of spectral trends are provided in e-terra Phasor Analytics:

   i. Power Spectral Density (PSD): Power Spectral Density (PSD) is very useful tool to identify oscillatory signals in time series data and their amplitude. It also tells at which frequency ranges variations are strong that might be quite useful for further analysis.

   ii. Coherency: Coherency, is a measure of frequency domain correlation between two signals. Coherency is always greater than zero and less than one, if two signals are loosely correlated in the frequency domain, the coherency tends to be close to zero. If there is strong correlation, the coherency tends to be close to unity.

   iii. Cross Spectral Density (CSD): Cross spectral Density as a measure of frequency domain covariance between two signals and is related to transfer function between two signals.

3.5 Analytics under Phase – I

a) Under URTDSM phase I, following 6 Analytics were developed in association with IIT Bombay:

   i. Line Parameter Estimation
   ii. Vulnerability Analysis of Distance Relay (VADR)
   iii. Linear State Estimator
   iv. Supervised Zone-3 distance protection scheme to prevent unwanted tripping of backup distance relay
   v. CT/CVT Calibration
   vi. Control for improving system security

b) Presently, first 6(six) Analytics have been deployed at control centres under URTDSM with regular updates being installed based on feedback received from constituents. Training for WR and SR constituents for all analytics has been completed.

3.6 Utilization of PMU data for taking real time decisions and offline Analysis at RLDCs and NLDC:

a) PMU helped in synchronization of NEW-SR grid by helping control room operator in taking appropriate decisions in time through the access of high-resolution data in real time.

b) The availability of PMU visualization helped in taking informed decisions in real time when any abnormality was observed in PMU placed on AC side of HVDC converter station

c) The availability of PMU data at LV side of pooling station of RE based generation sources helped in monitoring the operation in real time. The various power electronic based controls in RE generation plant for low voltage ride through (LVRT), reactive support at pooling station and power park control are closely monitored using PMU data.

d) The transmission system has also observed integration of state of art power electronic devices, these devices act in time span of milliseconds. The response can be observed at control centres with availability of PMU data. The response of FACTS devices is observed well with PMU placed at coupling transformer of STATCOM/SVC.

e) Power-system restoration: The PMUs are well-suited for online monitoring of angles, and thus are helpful for the operator during a power restoration by monitoring of standing phase angle (SPA) difference across a breaker, which connects two adjacent stations whose excessive difference can damage equipment.

4. Feedback on applications/Analytics under Phase – I

4.1 Improvements required in the Existing PMUs data Streaming/GUI

Improvements in the various applications/functionalities available in present system, if carried out can enhance its utilization. List of such improvements are given below, which are purely based on operational experience of existing system:

a) Improvement required in the visualization /GUI

i. Adding trends of phase voltage and current: It is only possible to plot trend of positive sequence voltage, frequency, df/dt, angle difference, MW and MVAr in real-time. It shall be possible to plot trend of phase voltages and currents also in real-time. Need to display phase voltage instead of positive sequence voltage. The phase voltages are required to identify the faulty phase and helps in real time in understanding the issue.

ii. Capability to visualize data for larger time window: Real-time trend given to operator has the capability of plotting real-time values up to the interval of 15 minutes only at its native resolution (25 samples/sec). For the data beyond 15 10 minutes duration operator needs go to TDF application to fetch data and see the details. TDF application is not very user friendly which leads to inconvenience to Real-time operator. There should be a single user interface, through which user can visualize real-time as-well-as historical data as per their interest and interval/duration.

iii. Trending system is having a capability to show only 8 signals and if additional signal is added in same trend window, then it results in freezing or display crash causing limited overview of the system.

iv. PMU with high sampling rate required a few locations: General data storage/display rate of PMU is 25 samples/sec, so as per Nyquist criteria oscillation of 12.5Hz can be detected. However, the PSD display in Phasor Analytics detects modes up to 4Hz only. OSM should be able to captures oscillation up to 12.5 Hz. It is needed to extend the monitored frequencies, to also cover sub-synchronous resonance, very low frequency governor modes and control modes. Higher sampling rate is needed for these applications. In addition, PDC should have capabilities to store data of higher sample rate PMU apart from existing 25 Hz. Present system allow only storage of 25 Hz data only.

v. Option to select reference angle: There should be an option to the selection of reference angle by the user (real-time as-well-as historical) and visualization of other data w.r.t same. Data stored in historian must be RAW data, so that visualization can be done as per the user requirement w.r.t any station. The angular difference values are in reference to a particular node and when the data is dumped in excel for analysing any past event, it is important that reference node is known However in many cases it is not available so make it difficult to find the reference node.

vi. Font and axis size: Formatting of PMU snapshots arrangements should be user friendly so that it could efficiently utilized for daily reporting control room shift. The auto-scaling and adequate font size need to be ensured in PMU

vii. Portability of display: Visualization is an essential part for URTDSM system which requires better interface and flexibility for real time operation. This needs advanced development platforms for retrieval and visualisation of phasor data based on the requirement of the operator in real time. Portability of display to be used in different applications may be ensured for easy reporting

viii. Non-generation of alarms: The real time applications sometimes fail to detect the oscillations. The Modes Applet and Analyst chart show normal state and Alarm/ Alert states are not observed even though Oscillations were present in the system. E-terra vision is having an issue of alarm processing as per user requirement, as and when alarm detects in a group of signals and returns to normal values in few sets of signals in group, then this alarm processing engine is clueless, what to report to operator.

ix. Freezing of display: Visualization screen gets sluggish on certain occasion when trending feature and replay feature is heavily used by operators.

x. Integration with different make of PMU: Interoperability of different PMU manufacturers has been a concern and is progressively taken up post commissioning through firmware upgrades etc. This interoperability aspect may be addressed.

xi. Logic based analytical tools: Logic based analytical tools may be implemented for enhanced situational awareness. Further improvement in alarm-based features with the different mathematical and logical conditions can be carried out.

xii. Modal analysis issues in URTDSM Analytics:

- Baselining of modes from OSM engine is a separate engineering activity and is must to set limits for mode amplitude, damping and selecting mode bands for alerting operators. However, this activity was not part of the current system.
- High noise in PMU: It has been observed that higher order frequency (near to 4 Hz) shows low damping and lower order frequency (near 0.1 Hz) shows high damping. High Noise in some of the PMU's data is another issue and the same has been flagged to GE also. The severity of noise in data is quite high in some cases. Such noisy data will result in bad Analytics and poor performance and utilization and confidence in the system. Some automated tool to be developed for such type of error detection.

b) OSM related issues:

i. Right Eigen Vector plot of modes not observed though it is seen that during that time Inter, Intra, Local and Intra Plant modes were present in the system as reported by existing pilot PMUs. Move upwards in oscillation section.

ii. Availability of statistical functions like a) Mean b) Median c) Standard Deviation d) Maximum e) Minimum and f) Average Values against each of the available parameters in PMUs. Also, the user should be able to generate Box & Whisker plots against each of the available parameters in PMU.

c) System Utilisation related issues

i. Data storage is currently configured to store 1 YEAR data irrespective of the space utilization – Storage only utilized up to ~20% only. Needs review for utilization up to 70% irrespective of time.

ii. 16 Digital slots are currently available in each PMU where only 5 are used rest can be utilized for isolator points of line, BUS, and line reactors etc., helps to improve LSE RESULTS.

iii. Each PMU can monitor 2 elements, spare slot available can be used to integrate new lines / ICT from same substation (Non- SAS SUBSTATIONS)

d) Infrastructure related issues

i. Voltage discrepancy in voltage measurement is observed in some PMU's, it's almost 5 to 10 kV difference in consecutive phases due to that positive sequence voltage is not accurate to take the decision by operator in real time. Some 12 logic/tool must be developed to detect such measurement errors and generate alarms as well. Utilities need to be sensitized for managing issues related to measurement devices.

ii. Standby communication links have not been implemented in URTDSM project. In case of any issue with communication channel, data loss has been observed on several occasions. Considering the importance of PMUs data in real time grid operation and post facto grid event analysis, it is recommended to implement main and standby philosophy in data communication between PMU & PDC and between PDC & PDC to avoid any data loss.

iii. Frequent time synchronization issues arise in PMU's data due to the GPS issue. In few Stations GPS time synchronization source was shared among the PMUs with some intermediate converters/extenders, which use to have record of going faulty, so there is need for strengthening of GPS source and stringent daily monitoring by substation on daily basis.

iv. Loss of PPS (Pulse per second) is a common cause in case of URTDSM PMUs, mainly due to the disturbance of PPS cable during maintenance activities. Infra issue

v. Dead band defined in PMU data for frequency, voltage and df/dt, it sometimes led to discrepancy in values.

e) Historian

Access to historian data through autonomous software interface is a must requirement for any new WAMS infrastructure. An important API requirement is to get a snapshot of complete PMU measurements at a given timestamp. This is not supported by the present URTDSM historian. In Phase-II, it should be ensured that this kind of feature is available in new historian. The interface should follow well established industry open standards that support both Windows and Linux operating systems to avoid any shortcomings in applications due to lack of inter-connectivity between applications of different vendors.

4.2 Analytical Application Software's developed by IIT Bombay

IIT Bombay (IITB) and POWERGRID have initiated a joint project "Synchro phasors Analytics for Electrical Transmission Systems". Under the project, development of following six analytics by IITB was envisaged. All six analytics have been installed at control centres under URTDSM with regular updates being installed based on feedback received from constituents. Further, Linear State Estimator (LSE) and Line Parameter Estimation are installed but the performance is not satisfactory. The summary and limitations of the envisaged/installed applications is given below:

a) Line Parameter Estimation Application of total least squares (TLS) method is used to estimate line parameters moving window technique to use voltage, current, active, and reactive power measurements from PMUs and other measuring devices to estimate the positive sequence parameters of an equivalent pi(π) model.

b) Online vulnerability analysis PMU measurements can be used to identify relays that are vulnerable to insecure tripping. In this application, each PMU on Transmission line measurements shall create a virtual relay mimic and relays are termed as vulnerable relays if the margin between their operating characteristics and the distance protection zone boundary is very low, a vulnerability index is presented where the vulnerable relays are ranked based on their risk. The errors get introduced when input relay settings are not validated.

Comment : The Zone-3 power swing blocking setting is available in all the relays and has been reported as implemented by all the utilities as per recommendation of the Committee on the blackout of 2012. Further, the Load encroachment tripping in Zone-3 can be addressed through proper setting of Zone-3 in the relay, which has also been reported to be complied by all the Utilities as per the recommendation of the Committee on the blackout of 2012. This application does not have relevance if metering cores are used.

c) Linear State Estimation PMU has the capability to directly measure the magnitude and angle of bus voltage and current. If enough voltage and current phasors are measured to make the network observable, state estimation could become linear. The measurements are voltage phasor and current phasor, and states are voltage phasor. A state estimator, essentially, removes the errors from the measurements and converts them into states. The control centre can make use of it, to make decisions on system economy, quality, and security. So far, the application is working with some errors and further testing is under progress to identify the bugs.

Comments:

Linear State Estimator Application is not having sub second measurements from ICTs, GTs, bus couplers and bus sectionalizes, due to which most of the time LSE is creating many electrical islands, and the voltage estimates at each bus are not matching the *measurements from the same bus. Due to deviation in estimates and less user-friendly application, acceptability in real time operation is very low.*

The network database is not updated constantly and the state estimation with incomplete data becomes difficult. Data base should be taken from existing EMS system. Sub seconds measurements need to be taken.

IIT-B: *The issues are focused particularly on LSE, but the changes suggested will also help in improving the results of other analytics like Line Parameter Estimation and instrument transformer calibration (LPE-RMC) and vulnerability assessment of distance relays (VADR). Feedback provided by IIT Bombay based on the WRLDC WAMS Project is as follows.*

i. *The network editor is used to enter static power system data that is used in LSE. The existing database was found to have missing / wrong data. kV lines. Lines have wrong values for R & X Values of 400 kV as well.*
ii. *PMU Mapping Errors: Some PMUS has both voltage and current channels mapped wrongly. One current channel is mapped to line voltage*
iii. *Wrong Polarity in PMU data There are lines where it is suspected that either one end PMU polarity is wrong or there is some other more serious gross error. These errors can be verified by comparing the P and Q measurements of these PMU measurements with corresponding SCADA measurements. Here it must be noted that we can identify such errors only in the transmission lines that have PMUs connected to both ends.*
iv. *Apart from these, there are following lines that give unrealistic results when state estimation is performed using their measurements. The error could be in entering their transmission line data, or their PMU measurements or even the PMU channel mapping. Transmission lines that can be checked in this way, some have wrong polarity and other have some other serious measurement issue that make overall state estimation results poor.*
v. *Some of the lines are parallel lines originating and terminating to the same substations. Hence it is possible that topology or transmission line data of such lines may be wrong. Many of these lines could have been tapped at some place, resulting in LILO but the database has not been modified. Hence special care must be taken on such lines to verify their data.*
vi. *Reduced observability: As a result of elimination of all the bad current measurements, many substations that have PMUs installed, all current*

measurements associated with that substation cannot be used. The bad measurement has a significant impact on degrading the LSE observability.

vii. *Almost 50 percent of the PMU data comes under list of bad data. This is a very high proposition for any state estimation analytics. Hence it is suggested that each of the suspected measurements is systematically checked and eliminated in step-by-step manner. It is possible that many of the above-mentioned measurements are in fact correct, but the nature of LSE analytics which impact neighbouring measurements also, make them suspect. So, after clearing some of the obvious bad data that could be identified, the same exercise as this one must be repeated to see if some of the measurements that were identified as bad data get reclassified as valid. The errors identified in database and PMU channel mapping must be eliminated first.*

Expanded observability concept** : **It is required to estimate the state of the buses where PMUs have not been installed through one or more PMUs installed at remote ends of the substation. This will avoid islands formation in the system due to measurements not available at those locations. The voltage and angle measured through the PMUs at remote locations (one or more locations) can be used to estimate the voltage and angles of these buses, if the line parameters are known. This feature should be developed and deployed in the LSE enhancement.

d) CT/CVT Calibration It is difficult to ascertain accuracy of any instrument transformer at site, once it is installed. State estimation techniques can perform "soft calibration" of these instruments to reduce errors in state estimation and identify any gross error if present in instrument transformer.

Comments: The performance of this analytic is required to be ascertained with actual on-site testing of CT/CVTs.

e) Supervised Zone-3 Distance Protection:

Distance relays are widely used for transmission line protection. These relays also provide remote backup protection for transmission lines. However, there are a few issues with backup protection as provided by distance relays

- Zone-3 based remote backup protection schemes are dependable but not secure.
- A relay mal-operation can act as a catalyst or even trigger a system collapse situation.

- Incorrect Zone 3 relay operation may be a consequence of either
  - quasi-stationary events like load encroachment, overload, undervoltage etc., or
  - electromechanical oscillations like power swings.

To overcome the problems mentioned above, an adaptive remote backup protection scheme using output of the linear least square state estimator was envisaged under analytics of phase I.

At present metering core of CT, CVT is used as inputs to the PMUs. In the event of faults, the metering class CTs generally get saturated, therefore the measurements obtained from these CTs are erroneous. Since these inputs are provided to the PMUs, any application using the transient data during the un-cleared fault period may not give desired results. The results of these analytic needs to be corroborated with the DRs obtained from the field. If protection class CT cores would have been wired up to the PMUs, this analytic would have provided reliable results. The comments at b) above are valid for this analytic also.

f) Control Schemes for Improving System Security: This analytic has been installed.

4.3 Issues in Phase – I analytics and observations:

The problems faced in the analytics have been detailed above. Analytics at 4.2 Sr. No. 1), 2), 4) & 5) needs further investigation and decision as to whether continue the development. If the results of these analytics are found to be consistent with the observations made through the DR analysis and PMU data of the local PMUs installed near the disturbance points of a sufficient number of disturbances, then these analytics could be put to use. Analytics at 4.2 Sr, No. 1) Line Parameter Estimation & 4) CT/CVT CALIBRATION are least useful from system point of view and therefore it is recommended that wherever opportunity exists, these analytics can be used for estimation of line parameters and CT/CVT calibrations. Additional PMUs required exclusively for these two analytics are not required to be included for future scope. Similarly, analytic at Sr.No. 2) Online vulnerability Analysis and analytic at Sr. No. 5) Supervised Zone-3 Distance Protection are of protection class analytics, however the PMUs and CT/CVTs used are of metering class and therefore these analytics are prone to give erroneous results as described above. Hence additional PMUs required exclusively for these two analytics are not required to be included for future scope and the facility developed so far can be used, wherever possible. LSE, which is partly functioning, needs to be developed further, so that the same can be put to use and other deliverable analytics could further be taken up. For this, following needs to be taken care in the phase II.

4.4 Improvements needed to address above issues:

a) PMUs should not only be limited to post event analysis and should be employed for state of analytics such as Dynamic State Estimation, threats forecasting and alarming systems in real time, if possible, control systems for real time control of active/reactive power etc.

b) Several equipment's such as ICTs, Bus Couplers were not configured in the LSE. Also, PMUs were not provided on ICTs, Bus reactors, Switchable line reactors and some important substations where Fibre Optic connectivity is not available. Lack of observability & lack of communication link also led to problems in PMUs LSE.

c) Logic based analytical tools for enhanced situational awareness, Advance development platforms for retrieval and visualization of phasor data, etc. may be added in the existing system, so that system operators' visualization can be enhanced to take appropriate decisions.

d) POSOCO informed that the POSOCO pilot project & States PMUs were also integrated with the URTDSM project. However, the data was not complete, and it led to formation of Islands and therefore State estimation of complete system is not available with the existing installed PMUs. There are network modifications happening and the data was not regularly updated/made available in the system since the same is required to be updated in SCADA network database & PMU LSE database. The network and the network topology database need to be updated by putting extra effort and therefore the network database of PMU based LSE can be exactly aligned with the actual system

e) Additional PMUs should be installed at substations which are critical from system point of view, by laying of the Fibre Optic under Phase – II of the URTDSM project.

f) An engine can be developed which will enable the SCADA topology and network database to be imported in the PMU based LSE. The database should be common for both the systems (SCADA & PMU LSE).

5. Phase – II of URTDSM

5.1PMU Placement Criteria

Inputs and views of POSOCO, IIT-B, RPCs and recommendations in various meetings on placement of PMUs under phase-II, are briefly outlined below.

a) **CTU**: During the Standing Committee on Communication System Planning in Power Sector (SCCSPPS) held on 09.03.2021, **CTU** in its agenda item suggested that the above criteria need to be reviewed in respect of NER & Sikkim as most of the transmission lines in NER & Sikkim are at 132kV/ 220 kV level. The **CTU** proposed that following locations may also be included for PMU placement:

   i. All 132 kV and above ISTS lines in NER & Sikkim
   ii. All 132 kV and above ISGS in NER & Sikkim.
   iii. (Additional factor of "distance between such stations" for extent of Wide Area Measurement also to be accounted for Placement in NER.)

   Tentative additional quantity of PMUs required in NER - 120 nos. and in Sikkim- 22 nos. Details of links for PMU placements in NER & Sikkim are attached at *Annexure IV* and *Annexure V* respectively. This requirement of PMUs in NER and Sikkim may be included in the upcoming URTDSM Phase-II project.

   Matter was discussed with IIT Mumbai & POWERGRID and it being mentioned that NERLDC may validate the list enclosed as Annexure IV & V for NER Lines/ Links w.r.t. the significance of Transmission Lines for NER network in view of expected Voltage Upgrade of Lines/ Generating Station Connectivity, Ownership / Tie Lines/ etc.

b) **NRPC**: NRPC (in 45th TCC, 48th NRPC meeting) and SRPC (in TCC & 37th SRPC meeting) proposed following additional PMU locations beyond the already agreed philosophy in standing committee:

   i. Generating Transformers (GTs) at LV side (having HV side of 220kV and above).
   ii. FACTS devices such as STATCOM, SVC, FSC, TCSC etc.
   iii. HVDC Convertor transformers
   iv. Phase Shifting Transformers
   v. Renewable Energy Pooling Stations (PS).

c) **POSOCO:** POSOCO in its feedback report on the URTDSM Project dated March 2021 has suggested following:

i. Placement at all Inter-regional lines.

ii. HVDC & FACTS Devices - At both ends of Interconnecting lines between HVDC side AC switchyard with connecting AC Sub Station, all convertor Transformer (HV Side), at STATCOM/SVC/ station Coupling Transformer (LV&HV Side) including STATCOM/SVC.

iii. Renewable Energy Generation Pooling Points.

iv. On all outgoing feeders including bus sectionalize or tie line between two stages of generating stations having different tariffs or different ownership or both

- High Voltage (HV) side & Low Voltage side of Transformers
- Reactive Power sources & Sinks shall be measured through Synchro phasor
- All CB and isolators shall be wired to Synchro phasor device as digital signals

v. Islanding, Separating & Restoration Points- At both ends of line connected black start stations or 28 restoration path lines (both ends including CB and isolators).

vi. Points where State Estimation error chances are high

- Substation shall have Three phase Bus voltage measurements through PMUs & Circuit breakers and isolator position shall be wired to PMU (for Linear State Estimator) for topology processing and full observability
- Reactive Power sources & Sinks shall be measured through Synchro phasor to avoid MVAR mismatch in Linear State Estimation.
- All 765/400 kV, 400/220 kV Interconnecting Transformers (ICT) should have PMU on both sides (LV & HV).

vii. Power Flow Gates – High power corridors need to have PMU Placements.

viii. Major Load Centres - PMUs should be installed at appropriate radial load feeding substations so that the load sensitivities to system frequency and voltage changes can be monitored.

ix. Angular Difference Monitoring Locations.

x. Major Generating Stations-

- At 400 kV and above Generating stations (132 kV in case of NER).
- Individual Unit of rating 200MW and above for Coal/lignite, 50MW and above for gas turbine and 25 MW and above for Hydro units shall have

PMU placed at the terminals of the generator(s) at either the HV or LV side of the Generator Transformers.

- In case of plant having multiple units, PMU can be placed on 50 percent of the units

xi. System Protection Scheme Monitoring

xii. Experience based locations known for small signal stability related issues.

The details of above are given at *Annexure – VI.*

d) **POWERGRID:** POWERGRID informed that the impact of additional PMUs locations and WAMS analytics, as proposed above, will be as follows:

i. The number of PMUs initially envisaged in Phase II would increase to about 2500.

ii. This increase in number of PMUs will also affect the performance of Phasor Data Concentrator (PDC) and other equipment at the Control Centre Location at SLDC, RLDC and NLDC, RPCs which may also need upgradation / installation.

iii. The additional WAMS analytics shall also require additional hardware.

iv. In view of the increase in PMU population, the existing configuration of Nodal PDC, MPDC, SPDC & Main & B/U NLDC also needs to be seen whether these additional PMUs can be accommodated in the infrastructure of Phase-I. Also, it needs to be seen whether the Nodal PDC, MPDC, SPDC & Main & B/U requires up-gradation or additional hardware is required for accommodating the additional PMUs in Phase-II.

v. Communication related issues are also required to be considered to accommodate the additional PMUs under Phase-II.

e) **Observations**: The number of PMUs initially envisaged in Phase II would increase, if the above philosophy is taken into consideration. This increase in number of PMUs will also affect the performance of Phasor Data Concentrator (PDC) and other equipment such as Historian etc. at the Control Centre Location at SLDC, RLDC and NLDC, RPCs/NPC which may also need up gradation / installation. The additional WAMS analytics shall also require additional hardware.

5.2 New Analytics under URTDSM Project Phase - II.

The proposed analytics under Phase-II of URTDSM is outlined below.

a) **NRPC & SRPC**: Additional WAMS analytics for URTDSM Phase – II were proposed by NRPC (in 45th TCC, 48th NRPC meeting) and SRPC (in TCC & 37th SRPC meeting) as follows:

   i. Real time Automated Event Analysis tool
   ii. Oscillation Source location tool/engine.
   iii. Real time Inertia Estimation Tool
   iv. big data analytics tool/engine

b) **POWERGRID**: POWERGRID has suggested following analytics for the Phase – II:

   i. Real time Automated Event Analysis tool (using AI, Machine learning and big data)
   ii. Event monitoring for early warning system (using AI, Machine learning and big data)
   iii. *WAMS based contingency analysis and static security assessment*
   iv. Oscillation Source location
   v. Response of Windfarm and solar PV farms for LVRT, reactive power etc.
   vi. Control of HVDC and STATCOM for damping system oscillations

The details are given in Annexure – VII.

c) **POSOCO**: POSOCO in its feedback report on the URTDSM Project dated March 2021 has suggested following analytics based on analytics being used in foreign power grids:

   i. Voltage Stability Monitoring: Measurement based dynamics provide voltage sensitivities; monitoring of key corridors or load pockets; scatter plots for power voltage and power-angle monitoring.
   ii. Detection of disturbances: Recognition of short circuits by watching the currents, and indication of loss of load, or loss of generation by watching the frequencies.
   iii. Online monitoring of Inertia.
   iv. Identification of source of Oscillation.
   v. Identification of stressed corridors.
   vi. ROCOF calculation over variable window.
   vii. Island identification/detection.
   viii. Locating contributions to poorly damped or unstable oscillations.
   ix. Model Validation.

x. Higher frequency sub-synchronous oscillation analysis and early warning of resonance.

xi. Big Data Analytics

The details are given in *Annexure – VIII*.

6. Recommendations

The recommendations of the sub-group have been grouped under following categories:

6.1 Improvements in applications available in URTDSM-I

6.2 New applications for deployment in URTDSM-II.

6.3 Improvements in system infrastructure

6.4 Minimum criteria for PMU placement under URTDSM-II.

6.1 Following improvements are recommended in applications available in URTDSM-I:

a) Graphical User Interface for visualization of system dynamics

URTDSM Phase-I has a graphical user interface for visualization of power system dynamic parameters. Following improvements are recommended in PMUs data Streaming/GUI in future applications:

i. **Trending of phase voltage and current:** Based on the selection made by the operator in real time it shall be possible to trend phase voltages or positive sequence voltage and currents in real-time.

ii. **Trending of all dynamic power system parameters**

iii. **Option to select reference angle:** There should be an option to the selection of reference angle of any node by the user (real-time as-well-as historical) and visualization of other data w.r.t same.

iv. **Capability to visualize data for larger time window:** There should be a single user interface, through which user can visualize real-time as-well-as historical data as per their interest and interval/duration.

v. **Trending window:** Trending system should have a capability to show more than 8 signals without freezing of results or display crash causing limited overview of the system.

vi. **Font and axis size:** Formatting of PMU snapshots arrangements should be user friendly. The auto-scaling and adequate font size need to be ensured in PMU

vii. **Portability of display:** Advanced development platforms for retrieval and visualisation of phasor data based on the requirement of the operator in real time. Portability of display to be used in different applications may be ensured for easy reporting

viii. **Non-generation of alarms:** Alarm processing as per user requirement.

ix. **Freezing of display:** Visualization screen should not get sluggish when trending feature and replay feature is heavily used by operators.

x. **Integration with different make of PMU:** The interoperability of different PMU manufacturers needs to be addressed.

xi. **Logic based analytical tools:** Logic based analytical tools may be implemented for enhanced situational awareness. Further improvement in alarm-based features with the different mathematical and logical conditions needs to be implemented.

xii. Modal analysis issues in URTDSM Analytics:

Baselining of modes to set limits for mode amplitude, damping and selecting mode bands for alerting operators needs to be implemented.

xiii. Automated tool for detection of bad Analytics and poor performance due to errors because of High Noise in some of the PMU's data.

xiv. Display of data for a larger time horizon (more than 5 minutes at present) shall be possible. There shall be a feature to permit the operator to select the sampling rate to display the data.

xv. User shall have facility to update charts with primary & secondary axis assignment before viewing/downloading images.

xvi. User shall have the facility to make customize displays for monitoring & data retrieval. Further in one screen multiple display facility shall be provided.

xvii. Downloading of historical data should be made more user friendly

At present in Time derivation framework for downloading a signal data many other signals are getting downloaded. For example, one signal of MW is selected for one transmission line for desired period, then it is downloading time, type of signal, status, type of data, feeder name and MW values for desired period, whereas only required information was time & MW for desired duration. Time Series Derivation Framework (TDF) shall have feature to download only desired information. If multiple signals are selected, then they are being downloaded in series which is consuming a lot of the time to just re-arrange the data during analysis. For example, if MW value is selected for two feeders for desired duration, then when data is downloaded, it is coming in series one below to other. Then we need to first filter for feeder-1, copy it and again filter for feeder-2 and then plot. However, downloaded data should have been downloaded in three columns one time, feeder-1_MW, feeder-2_MW only for desired period.

TDF shall have facility to provide only required multiple feeder data for same time period in columns instead of in rows for desired period.

b) Oscillation Detection, monitoring and analytics

The application shall have following capabilities:

i. Capability to detect power system oscillations from dynamic measurements - active power, reactive power, system frequency, voltage phase angle difference and others

ii. Capability to monitor, classify oscillation modes in real time – Intra Plant modes (0.01 to 0.15 Hz), Inter area (0.15 to 1.0 Hz), Local (1 to 5 Hz) and HVDC/FACTS Controller (5 Hz and higher)

iii. Real-time display for oscillation monitoring: Capability to provide simultaneous visualization of the multiple modes (mode frequency, mode damping, mode phase, energy, amplitude etc.) to the operator on a dashboard.

iv. Detecting the dominant and poorly damped modes from the selected power system signals

v. Alarms – Provide a tool to generator alarm if pre-defined mode amplitude and damping limits, set for the safe operation of the power system, are exceeded.

vi. Alarm Settings – Ability for user to define alarm persistence settings (seconds) for mode alarm thresholds

vii. Map Displays – Location and Severity of Oscillation Modes

viii. Oscillation Severity- Show energy of oscillations by locations contributing to a specific oscillatory mode

ix. Oscillation location –Identify the source of the oscillation and display root causes such as: Generator PSS, AVR, controller issues Wind/ Solar controller issues System resonant conditions HVDC/FACTS device controller issues.

- Pinpoint the oscillation source to a generating plant/unit
- Area-wise identification of source location
- Help in identifying event root cause
- Event severity in terms of oscillation energy and affected areas
- Provide oscillation frequency
- List of locations with highest oscillation energies
- Plots of key metrics relevant to the event

x. Statistical functions- Mean, Median, Standard Deviation, Maximum, Minimum and Average Values against each of the available parameters in PMUs. The user should be able to generate Box & Whisker plots against each of the available parameters in PMU.

xi. Logic based analytical tools for enhanced situational awareness, Advance development platforms for retrieval and visualization of phasor data, etc. needs to be added in the existing system.

c) Linear State Estimator

The Linear State Estimation analytics is the most important application which forms base for all the analytics like Contingency analysis, Vulnerability analysis, System Security analysis, Control Schemes for Improving System Security etc. The LSE analytics provided in the URTDSM Phase-I requires significant improvement in the following aspects for gainful utilization by the operators in real-time.

i. **Database Integration:** An engine shall be provided to enable the SCADA topology and network database to be imported in the PMU based Linear State Estimation. The database should be common for both the systems (SCADA & PMU LSE) so ease database management.

ii. **Bad data detection and conditioning:** Substation Level State Estimation could be considered for conditioning bad measurement within substation. A multi-layer system that is both model-less and model-based to deal with bad data detection and conditioning. In the model, raw PMU Measurements should be compared to LSE's model-based estimations in real-time for determination of the quality and usability. The LSE should also include the ability to condition bad data with estimated results. The application should be capable of bad data detection through plausibility checks, validation and conditioning. It should provide features to checking and correcting PMU channel mapping. Polarity of PMUs connected to both ends should be corrected by utilities.

iii. **Observability analysis:** It should include the capability to quantify the full extent of the observable nodes in the system based on PMU placement and measurement availability relative to the power system network model. This analysis, which occurs in near real-time, can include "islanded" or disconnected portions of the system. It should be capable of providing real-time estimations for multiple islands or disconnected systems.As the topology of the system changes in real-time, a real-time observability analysis is required to correlate the PMU measurements with the topology, so that the LSE can identify observable areas of the system. It is suggested that each of the suspected measurements is systematically checked and eliminated in step-by-step manner.

iv. **Topology detection:** Topology processor should be capable of operating independently across multiple islands in the system. Changes to topology are detected in real-time for each observable island, and new connectivity matrices are constructed to correctly estimate the new state of the system. The network topology processor determines the present topology of the network from the telemetered status of circuit breakers.

v. **Sampling rate:** Three-phase linear state estimation at sampling rate (25 or 50 s/s for 50 Hz system): It should operate at the PMU sampling rate. Visualization of higher frequency sub-synchronous oscillation and resonance

vi. **Single-Line diagrams:** It should include a robust real-time visualization with the capability of displaying one-line diagrams with PMU and LSE data overlaid and updated in real-time. The visualization tools should the capability to create new one-line diagrams and import existing ones.

vii. **Scalability:** It should be highly scalable to accommodate the increase of PMUs and end users to the system.

viii. **Expanded observability:** The PMUs are not required to be placed at all the ends of the elements in the system, since it will result in large data handling by PDCs and super PDCs. Also, it will introduce the large latencies. The concept of expanded observability where the locations at which PMUs are not installed can be made observable through the PMU measurements at other ends. Through this the Islands formed in the system can be bridged and the complete system becomes observable.

6.2 Following new applications are recommended for deployment in URTDSM-II

a) Real time automated event detection and notification dashboard

The application should use high resolution and time synchronized data for:

i. Event Detection - line trips, generation trips, load trips, load loss, islanding, complete loss of supply at a station and other events

ii. Event characteristics - LG fault, LL fault, auto-reclosure and others

iii. Automated report generation and email

The application should be capable of indicating probably event location. The dashboard should provide link to geographical display to reach to reach the nearest PMU location on the grid map. A library of events shall be maintained. The application should have the capability of automated event mining to scan through large amounts of data (weeks, months, years) to assess grid performance by identifying and classifying events. Data and event mining include identification of the type of event, location, severity and duration. and it should provide prompt the operator with quick information about similar event (s) in the past. (The application may use AI, machine learning, big data analytics to deliver such a solution).

b) Early warning system

The application should detect contingencies and slow trends in PMU measurements (such as angular separation, voltage, power flows etc).and generate alarms to draw the attention of the operator. The application should assist system operators in

i. Identifying stress levels in both apparatus and system by detecting dynamic events linked to phase angle separations and other dynamic metrics
ii. By providing guidance towards meaningful real time contingency selection and analysis
iii. Early indicators of potential equipment failure (CTs, PTs, CCVTs etc.,) and device malfunctions
iv. Provide easy summary reports for case study preparation, post event analysis and archival purposes.

(The application may use AI, machine learning, big data analytics to deliver such a solution).

c) Voltage Stability analytics (VSA)

Synchro phasor data enables high-resolution monitoring of actual system voltages, which can be used for advanced real-time visualization of current operating conditions and voltage stability limits to assess the power system's proximity to system collapse. The application shall use LSE based power flow case to perform VSA and identify active and reactive power margins and limiting contingencies in real time operation.

d) WAMS based contingency analysis and security assessment

Static security assessment tool improves operator assist feature of grid monitoring and makes it adaptive and interactive. This tool is meant to provide and perform what-if simulations and integrate power of data mining with intuition and insights of operators. Application shall This will help in improving grid operation efficacy. The output of the LSE should be available for static and dynamic security assessment applications.

e) Islanding detection

The application should be capable of automatically detect islanding events in the grid and identify locations (PMUs) that are in the islanded region. The islanding detection algorithm could use a combination of frequency and phase angle difference signals to detect islands and shows key metrics to the operators. The heatmap/contouring feature should allow users to visualize the islanding event on the geographic map. Islanding Detection Methods should include:

i. Frequency based island detection: If the difference in frequencies is getting larger than a certain limit, then an island state is detected.

ii. ROCOF based island detection: If the rate of change of frequency (ROCOF) between at least two neighbouring values is getting larger than a certain limit, then an island state is possibly present or is in the process of arising.

iii. Phase angle-based island detection: Phase Angle differences between voltage phasors from different PMU locations are used to detect out-of-step/islanding conditions.

f) Real time Inertia Estimation and monitoring

This application should be capable of providing an estimate of system inertia. The application shall provide features for monitoring and trending system MVA/MW capacity on bar/off-bar and the real-time kinetic energy of the system.

g) Post-mortem analytics

This application should provide offline data meta tools to facilitate post-mortem event/disturbance analysis to answer commonly asked questions related to event – When, Where, What and Why?. The application shall have following facilities

i. Disturbance analysis and root cause assessment - Quick and detailed analysis of power system events like generation trips, line trips, generation-load imbalances, and other dynamic events.

ii. Baseline daily performance and establish safe operating ranges - Examine Daily System Performance and establish reliable ranges for voltage, frequency, and other system metrics for real time monitoring systems.

iii. Establish alarm limits for use in operations - Calculate key alarm event detection parameter for different real-time applications and establish after investigating multiple events of same type
iv. Rate of Change of Frequency calculation over variable window.
v. Generator Frequency Response Analysis – Calculation of Primary/Inertial Frequency Response, frequency response characteristics of a system following a generation loss.
vi. Measurement Validation - Verify & Validate SCADA & State Estimation results with phasor data to identify differences & deviations.
vii. Stability Assessment - Identify & Locate substations approaching instability issues and quantify sensitivity limits for real time monitoring

h) Generator Model Validation

The application should have the capability to validate generator models and provide validation reports in real-time to provide the most relevant event information:

i. Automated system to perform model validation after significant events
ii. Validates multiple events
iii. Validates multiple generators
iv. Identifies good vs questionable model parameters (programmatically not visually)

i) Wide Area Control Systems

i. **WAMS based automatic load shedding (AUFLS and df/dt):** The AUFLS and df/dt based automatic load shedding schemes could be effective, if the measurements and control is based on the logic at a central location. This would identify the area/locations where load shedding, if carried out, could be effective in relieving the stress in the system and taking a calibrated decision. e.g. Load shedding will be effective in the States/regions who are importing power if the trigger frequency of the Stages in AUFLS is reached and disabling the Load shedding relays of the States/regions who are exporting power to other States/regions in real time.

ii. **Control of HVDC, PSS and STATCOM for damping system oscillations:** This is the usage of WAMS measurements for actual automatic control applications. This was one of the original thoughts behind going for WAMS installation. The power system oscillations that originate in a post fault event or spontaneous oscillations can be damped quickly using controllers of HVDC and FACTS (like

STATCON) devices. It improves the overall transfer capacity of a power corridor. Lot of actual projects are now under operation in the USA and China. India must take up such projects for capacity building for the future.

The above applications may have to be developed in consultation with the utilities and other stakeholders. Pilots may be taken up for gaining experience on these applications before deployment.

6.3 Following improvements in system infrastructure are recommended

Recommended improvement in the system utilization and its performance

i. 16 digital slots are currently available in each PMU where only 5 are used rest can be utilized for isolator points of line, bus, and line reactors etc.

ii. Each PMU can monitor 2 elements, spare slot available can be used to integrate new lines / ICT from same substation (Non- SAS SUBSTATIONS)

iii. Logic/tool must be developed to detect Voltage discrepancy in phase measurement errors and generate alarms. Utilities need to test/check PMUs during the routine calibration of VTs/SEMs.

iv. Adopting main and standby philosophy in data communication between PMU & PDC and between PDC & PDC to avoid any data loss.

v. Strengthening of time reference / GPS source and stringent daily monitoring by substation on daily basis for time synchronization.

vi. It needs to be ensured that loss of PPS (Pulse per second) should not occur due to the disturbance of PPS cable during maintenance activities.

vii. Dead band defined in PMU data for frequency, voltage and df/dt, should not cause discrepancy in values.

viii. Data storage and Historian: Data storage should be configured to store and retain data at least up to one year. Since the population of PMUs is expected to increase manifold in the coming years, the standards / best practices need to be established for Indian power system. A separate sub-committee may be constituted to formulate a criteria for data archival and retention. For the time being data beyond one year shall be stored and made easily accessible for real-time and off-line applications depending upon the space utilization. Access to historian data through a separate software interface is required to be included. The interface should follow well established industry open standards that support both Windows and Linux operating systems to avoid any shortcomings in applications due to lack of inter-connectivity between applications of different vendors. API shall be provided to enable development of user defined applications.

ix. **PMU Testing:** PMU standards conformance tests shall be performed to verify whether the PMU meets the requirements of IEC/IEEE 60255-118-1 under steady-state, transient, and dynamic power system conditions, and the associated data transfer requirements as given in IEEE Std C37.118.2 or communication requirements given in IEC 61850. PMU field commissioning tests shall include routine visual inspection, insulation test, wiring check, basic functionality check, etc., as required by the relevant standards. In addition, a PMU field commissioning test shall verify correct phase sequence verification. Correct phasor magnitude measurement verification, Correct CT polarity, Correct indication of time, Data and control frames sending/receiving verification. System integration tests shall verify the following: expected phase angles relative to the phase angles from other locations, proper sending/receiving data/control frames to/from PDCs, Proper logging of PMU activities, such as on-line/off-line time, setting changes, etc., PMU status monitoring and trouble reporting, communications channel speed (packets per second)

x. **PDC Latency in multiple streams:** A PDC can thus create a time-aligned, system-wide measurement set. In the hierarchy mode of operation, a local PDC aggregates, time-aligns data from multiple PMUs and feeds it to local applications, and to a control center PDC. The control center PDC collects data from multiple local PDCs, may conduct data quality checks, and feed the data to a regional PDC. A regional PDC may operate in a similar manner, exchanging data with several control center PDCs. PDC latency can be affected by the number of phasors and number of input data streams. If a PDC belongs to a system with multiple PDCs then the latency of the entire network must be considered. PDC must be able to handle off nominal conditions such as high rates of incoming data, incorrect timestamps, and unsupported protocols. PDC must be able to achieve the availability and reliability target levels consistent with the application.

xi. **Sampling rate:** Installation of PMU with high sampling rate is recommended at a few locations to monitor sub-synchronous resonance, very low frequency governor modes and control modes. PDC should have capabilities to store data of higher sample rate PMU apart from existing 25 Hz.

xii. Redundant and reliable high speed communication system is vital for PMU based Wide Area monitoring system. Fiber Optic connectivity between the substation identified for placement of PMU and control center is strongly recommended.

6.4 PMU placement strategy:

a) Placement of PMUs Criterion:

The PMU placement should be based on the analytics/application being developed and put into use.

b) Limiting constraints for Placement of PMUs.

The limiting constraints in installation of additional PMUs include

i. The hardware requirement of the PDCs & Master PDCs as the current PDCs may not have enough memory to process the additional data from the PMUs.

ii. Hardware and communication requirements will also be required to be changed and upgraded.

Communication link issues cannot be entirely eliminated, but suitable measures may be taken for mitigating them. The failure modes are often related to the quality of equipment and installation. Effective measures like planning to reduce failures by employing redundancy techniques shall be taken. As more PMUs are connected to a PDC, the possibility for more latency become more frequent. PDC requirements shall be matching with PMU data requirements and appropriate matching capabilities shall be ensured in advance.

c) Type of PMUs

There are two different type of PMUs defined in IEEE standard C37.118-1. M type (Measurements) PMU is slower i.e., have higher PMU reporting and measurement latency and it is immune to errors caused by out of band frequency oscillations. P type (Protection) PMU is comparatively faster, but it does not filter out out-of-band frequency component, hence it is slightly inaccurate (only when such oscillations are present which is the case when saturation of the core.

Further, the connection of CT and CVTs to PMU input channels is a permanent choice that cannot be changed, or it takes lots of effort and time and money to change. Hence it is important to decide in the beginning of the project whether to connect PMUs to metering cores of CT and CVTs or to protection cores.

Since the PMUs in Phase-I are M type PMUs and are connected to metering core of CT/CVTs, the committee recommends that under Phase-II, M-type PMUs are to be procured and connected to the metering core. The placement of PMUs where it is expected that high fault current would be observed shall take the measurement from protection core. Using measurement core of the CT can lead to issues like saturation while measuring high fault current. Therefore, it is recommended that **few P-type PMUs shall be deployed on pilot basis (say 5 to 10 PMUs in each region).**

d) Minimum criteria of PMU locations:

Based on the above limiting constraints and proposed applications, the following locations should have PMUs (Minimum Criteria)

i. **At one end of all 400 kV and above transmission lines**
ii. **At the HV side of all ICTs connected to 220 kV and above**
iii. **On HV side of coupling transformer of SVC/STATCOM for measurement of HV Bus voltage and current of coupling transformer**
iv. **At one end of line wherever FSC/ TCSC are installed.**
v. **On HV side of converter transformers for measuring HVAC bus voltage and current of converter transformer on each converter station.**
vi. **On both ends of Inter-regional and trans-national tie lines and on boundary buses for such lines.**
vii. **At the Generating Transformers (GTs) at LV side (having HV side of 220kV and above) of the Generating units with capacity above 200 MW for Thermal units, 50 MW for Hydro units and 50 MW for Gas units.**
viii. **On all 220kV substations for measuring voltage of 220 kV bus and current of two lines/transformer catering to load centers.**
ix. **All 132 kV and above ISTS lines in NER & Sikkim and important load centers.**
x. **At RE developer end of the evacuating line connecting the Renewable Energy Pooling Stations (PS) to point of interconnection with the grid of 50MW and above.**
xi. **Islanding, Separating & Restoration Points- At one end of line which is connected to black start stations along with circuit breaker status via synchro phasors.**

xii. **Fiber Optic should be covered under Phase – II for all the above locations of the URTDSM project.**

xiii. **At all ICTs, Bus reactors, Switchable line reactors of critical substations.**

e) Future Considerations & integration of State PMUs

Following locations may also be considered for installation of PMUs under Phase-II, for future projects:

i. **Requirement of PMUs under Phase-II, as per above philosophy, be framed for the planned system up to 2024. Thereafter CTUIL may include the provisioning of PMUs in the scope of planned projects as per the above philosophy.**

ii. **The placement of PMUs for special cases such as Islanding, Separating & Restoration Points and ICTs, Bus reactors, Switchable line reactors of critical substations, load centres of NER shall be suggested by POSOCO in consultation with RPCs & CTU.**

iii. **Existing PMUs & PMUs planned in future by States should be integrated with the URTDSM Project.**

iv. **PMUs in the future projects should be made part of the system with improvements in the PDCs capabilities incorporated in the new Project.**

v. **PMU & PDC consoles at CTUIL, RPCs and CEA- Since CTUIL is entrusted with planning ISTS system, it is recommended that PMU & PDC consoles along with redundant, dedicated & secure communication link up to CTUIL premises be provided for CTUIL.**

The Power flow, Voltage, Angle data of PMU shall be integrated with CTUIL Planning system software for System studies, System planning of ISTS system, in consumable form, through standard protocols along with visualization.

Similar facilities should be made available at all RPCs and CEA if the same is not covered under Phase I. The console for CEA is supplied but could not be installed due to non-availability of dedicated secure communication link.

vi. **The up gradation of PDCs and control centre equipments be reviewed once in two (2) years, so that they can handle the data due to incremental PMU population in the system.**

vii. **PGCIL was of the view that 5 out of 6 analytics developed in Phase-I would not work, due to adoption of the above PMU placement philosophy (in all these 5 analytics PMU is required at both ends). The analytics viz Line parameter estimation, CT/CVT calibration are complementary to each other, where, in one analytic the CT/CVTs are assumed to be accurate and in the other the line parameters are assumed to be accurate (the reference used for one analytic is dependent on the other) and therefore the result of this analytics are not found to be much of use. The Online Vulnerability analysis and Supervised Zone-3 distance protection are protection class analytics as explained in the previous chapters and the results needs validation through DRs. The Zone-3 power swing blocking setting is available in all the relays and has been reported to be implemented by all the utilities as per recommendation of the Committee on the blackout of 2012. Further, the Load encroachment tripping in Zone-3 can be addressed through proper setting of Zone-3 in the relay, which has also been reported to be complied by all the Utilities as per the recommendation of the Committee on the blackout of 2012. Control System for improving system security analytic and the above four analytics, however, shall to be used wherever PMUs are available at both ends and the results be validated.**

viii. **The relevant orders of Ministry of Power, Government of India and CEA/CERC regulations for cyber security compliance should be followed. The directives of CERT-In for time synchronisation of PMUs should be followed in view of cyber security.**

ix. **Training module should be incorporated in Phase-II of URTDSM project for the State Utilities, CTU, POSOCO, CEA and RPCs.**

Annexure B.4

भारतसरकार
Government of India
केंद्रीय विद्युत् प्राधिकरण
Central Electricity Authority
पश्चिम क्षेत्रीय विद्युत् समिति
Western Regional Power Committee
एफ-3,एमआईडीसीक्षेत्र, अंधेरी (पूर्व), मुंबई- 400 093
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No.:WRPC/Comml-I/NPC/2023/

दिनांक: 30.06.2023

To,

The Member Secretary, NPC

Central Electricity Authority

New Delhi – 110066

विषय: "पावर-सिस्टम स्टेबलाइजर (PSS) ट्यूनिंग के संबंध में सामान्य प्रक्रिया को अंतिम रूप देने के लिए उप-समूह" की रिपोर्ट - के संबंध में|

Subject: Report of the "of Sub-Group to finalize common procedure for Power System Stabilizer (PSS) Tuning – regarding

Ref: NPC Division letter no. 4/MTGS/NPC/CEA/2021/71-81 dated 08.02.2021

Please find enclosed herewith the final report of thr Sub-Group constituted to finalize common procedure for Power System Stabilizer (PSS) Tuning, constituted by NPC vide letter under reference.

Submitted for needful please.

भवदीय /Yours faithfully

Enclosed: As above.

(P. D. Lone)
(सदस्य संयोजक/Member Convener)

Copy to: All members as per list.

PROCEDURE FOR PSS TUNING IN INDIAN POWER SYSTEM

Detailed Guide for PSS Tuning in Indian Power Sector

The Report at a Glance

NPC in the 9th Meeting formed the following group to standardize the PSS Tuning procedure. Meetings of the group were held on 15.04.2021 (involving experts from IIT Bombay) and 30.03.2023(involving experts from OEM BHEL) and the report was finalized.

It is a well-known fact that slow moving oscillations are observed in power systems occasionally affecting power and voltage. Such oscillations appear spontaneously under some operating conditions and are experienced by power utilities worldwide. Research literature as well as standard textbooks have analyzed this phenomenon. The PSS (or the slip-stabilizer as it was known in older machines) is a controller which when set properly provides adequate damping to mitigate the problem and is a very elegant and economical solution, instead of restricting power transfer.

The literature on PSS Tuning is however very vast over the years and amongst the standard textbooks the ones by K.R Padiyar or Prabha Kundur discusses these problems. While this report briefly touches on the various aspects of the literature as well shares our experiences of PSS Tuning, a serious reader is encouraged to go through the above textbooks to have a clearer understanding on the subject.

In case one feels overwhelmed we present a quick but limited glance of the objectives and approaches to PSS tuning.

Objectives of PSS Tuning

The PSS should be tuned in such a way that the following objectives are achieved:

Objective 1. The PSS shall not interfere with the primary function of the AVR which is to maintain the excitation especially under stressed conditions.

Objective 2. The PSS shall not worsen the synchronizing Torque (T_s) at any rotor swing frequency.

Objective 3. The intra-plant modes of generator are stable to begin with (by design). The PSS shall not destabilize such intra-plant modes.

Objective 4. Subject to objective (1), (2) and (3) compulsorily satisfied, the PSS may add a moderate phase lead so as to improve the Damping torque(T_d). By adding such a phase lead particularly during inter-area and local-area swing frequencies the small signal stability is enhanced. The PSS compensates for the lag introduced by AVR during small signal stability conditions. This is the primary scope and duty of PSS. A well tuned PSS also enhances transient stability to some extent.

Approach and Testing for achieving the Objectives

Objective-1:-

1. In order to achieve objective (1), the output limits of the PSS signal shall be restricted to maximum ±10% of AVR reference.

   Some literature papers recommended these limits should be +10% & -5% as the limits of PSS influenced on AVR due to first swing stability consideration. So we feel that +10% and -5% limits are desirable but in any case do not exceed beyond the ±10% guideline without strong justifications.

Objective-2 :-

2. In order to achieve objective (2), the frequency response of PSS and other transfer function such as GEP(jω) must be available prior to field trials.

   A software taking inputs from load flow and dynamic data was developed by IIT-B in MATLAB which gave frequency response and was used in WR during PSS tuning exercise. It is strongly recommended that at bare minimum this information must be available to the PSS tuner, and same information may be obtained through this platform or similar platforms.
3. Due to advancement in technology, better ways of estimating the transfer function of the generator using very low input test signal are currently available. It is encouraged to explore them.
4. Attempting to set PSS by only the step response of AVR (without frequency response information available from 2 above) has the hidden danger of possibly destabilizing synchronizing Torque (T_S).

   For some excitation system such as brushless excitation, the step responses of AVR with & without PSS are nearly identical and that is alright. Because step change excites only intra-plant modes, the field step test may not show an appreciable improvement in damping.

   But, when inter-area or local area frequencies are induced by the power system, the same settings of PSS will indicate much better response in simulation. Because of this, we recommended the PSS should be tuned keeping the theoretical frequency response from software and test step response of AVR in field. In short, do not set the PSS only on the basis of step response of AVR.

Objective-3:-

5. In order to achieve objective (3), the step response with and without PSS is the proof. This response should clearly show that the PSS tuning has not spoilt the damping. For a few cases as mentioned earlier, it may appear that there is no improvement in damping. But, it is alright if the PSS tuning is done in alignment with the frequency response and simulation confirms the same. In most cases appreciable damping improvement is seen.
6. Summary: -

Objective	**Tests**
Objective 1	PSS output limits set to ±10% (preferably +10% and -5%)
Objective 2	Tuning as guided by the theoretical frequency response 0 Hz to 3 Hz.
Objective 3	Step test of AVR with and without PSS.

7. Keeping the above approaches as a guideline and suitably blending it with other advances in technology and literature, PSS tuning in field may be adopted. If any doubts on interpretation of settings arises in field, enable the PSS only after removal of such doubts.
8. PSS Tuning done by a group of engineers from the excitation areas of Owner, OEM, RPC/RLDC/CTU and preferably with an academic expertise along with the required software generally blends well. Data of observed oscillations if any, can be shared with the group for better PSS Tuning experience.

Procedure For PSS Tuning in Indian Power System

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1. Regulatory Provision on PSS and its Tuning

1.1 CEA (Technical standards for connectivity to the Grid) Regulation, 2007[1]:

- Power System stabilizer means controlling equipment which receives input signal of speed, frequency and power to control the excitation via the voltage regulator for damping power oscillation of a synchronous machine".

  The PSS need to be Multi-Input PSS (input signal from speed, frequency, and power of generating unit) rather than single input for better performance and stability.
- For New generating Units (part II. 1. C): The AVR of generator of 100 MW and above shall include Power system stabilizer (PSS)

  For Old Units: (part II. 2. 2): For thermal generating units of having rated capacity of 200 MW and above and Hydro Units having rated capacity of 100 MW and above, following facility should be provided at the time of renovation and modernization: Every generating unit of capacity having rated capacity higher than 100 MW shall have PSS.
- **6.g:** The requester and user shall cooperate with RPC and appropriate Load dispatch center in respect of matter listed below, but not limited to: Cooperate with RPC for tuning of PSS provided in the excitation system of generating Unit.

1.2 CEA Technical Standard for Construction of Electrical Plants and Electric Lines (Published in 2010)[2]:

- For Coal or lignite based Thermal Generating Stations (10.2. g.i:), Gas turbine based Thermal generating stations (18), Internal Combustion(IC) engine based Thermal generating station (27) : Suitable Excitation System, as well as Automatic voltage regulator (AVR), shall be provided with the generator as per CEA (Technical standards for connectivity to the Grid) Regulation, 2007. Power System Stabilizer (PSS) shall be provided in AVR for generator of 100 MW and above rating.

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[1] https://cea.nic.in/wp-content/uploads/2020/02/grid_connect_reg.pdf
[2] https://cea.nic.in/wp-content/uploads/2020/02/tech_std_reg.pdf

- For Hydro power Plan (37.3.e): All the performance requirements of AVR, PSS shall be in accordance shall be in accordance with CEA (Technical standards for connectivity to the Grid) Regulation, 2007 and CEA (Grid standard) regulation as and when they come into force.

1.3 Standard technical features of BTG system for supercritical 660/ 800 MW thermal units, CEA, July 2013[3]

1. (16.2.4.iii.d.5) Power system stabilizer (PSS): The excitation system shall be provided with power system stabilizer for achieving the dynamic stability of the system under most stringent conditions of operation in the phase of disturbance created by short circuits conditions, load rejections, switching on/ off of transmission lines as per manufacturer's practice
2. (16.2.5) Stability studies: The detailed computer studies shall be carried out by the supplier considering single machine with infinite bus to confirm the suitability of the turbine generator and its excitation system in the grid for maintaining the power system stability under dynamic and transient conditions and tune the PSS parameters at site for all the machines. The details of simulation technique and method proposed to be used for this purpose shall be furnished.

1.4 Standard technical specification for main plant package of sub-critical thermal power project 2 X (500 MW or above), CEA, Sept 2008:[4]

3. (5.2.4.iv) Power system stabilizer (PSS):

a) The excitation system shall be provided with power system stabilizer for achieving the dynamic stability of the system under most stringent conditions of operation in the phase of disturbance created by short circuits conditions, load rejections, switching on/ off of transmission lines.

b) The power system stabilizer should have adoptable settings, which should automatically adjust to system reactance. In other words, the system should

[3] https://cea.nic.in/wp-content/uploads/2020/04/supercritical.pdf
[4] https://cea.nic.in/wp-content/uploads/2020/04/standard_tech_spec.pdf

provide automatic and continuous measurement of system reactance and power system stabilizer setting must continually adjust itself for any changes in the system reactance to provide required dynamic stability margins.

4. (5.2.4.i.b) Stability studies, both dynamic (long duration, transient) and steady state, shall be carried out to evaluate various parameters of the excitation system, e.g., response time, response ratio, ceiling voltage, loop gains, power system stabilizer (PSS) parameters etc., so as to meet the operational requirements of the grid particularly on loading side as the power station is connected to the grid by long transmission lines. The purchaser will furnish all information/ data necessary to carry out the stability studies to the contractor at detail engineering stage.

1.5 **IEGC 5.2.k[5]:** All generating units shall normally have their automatic voltage regulators (AVRs) in operation. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be got properly tuned by the respective generating unit owner as per a plan prepared for the purpose by the CTU/RPC from time to time. CTU /RPC will be allowed to carry out checking of PSS and further tuning it, wherever considered necessary.

1.6 **Report of the Task Force on Power System Analysis under Contingencies[6]:** Power System Stabilizers (PSS) as part of the generators installed in the network are also critical for damping the local area oscillations and imparting stability to the networks. Optimal tuning of PSS also enhances effectiveness of other HVDC and FACTs controllers in supporting overall/ inter-area stability. Necessary exercise to retune PSS should be undertaken at interval of 3-4 years or even earlier depending on network additions in vicinity of specific generators.

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[5] https://cercind.gov.in/2016/regulation/9.pdf
[6] http://erpc.gov.in/wp-content/uploads/2016/10/Ramkrishna-report_power_system_analysis.pdf q

1.7 Report of the Expert Group: Review of Indian Electricity Grid Code[7]

All generating units shall have their automatic voltage regulators (AVRs) in operation and tuned. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. AVR, Power System Stabilizers (PSS) of synchronous generating units, voltage or reactive power controller of wind, solar generating unit or ESS shall be properly tuned by the respective owner. The above tuning, including for low and high voltage ride through capability of wind and solar generators shall be carried out – at least once every five (5) years, – based on operational feedback provided by the RLDC after analysis of a grid event or disturbance and in case of a major change in excitation system or major network changes/fault level changes near to generating plant as reported by NLDC, RLDC. In order to provide basic requirement of PSS tuning for system security, the PSS tuning procedure shall be prepared by NLDC. The generating stations shall submit the detailed list of proposed tuning of AVR/PSS or reactive power controllers to RPC prior to 31st December for the next financial year. RPC shall compile a list before 31st March and share with all users and RLDC. After completing the PSS tuning, the report shall be submitted by the generating station. The report shall comprise of requisite power system mapping, simulation study and field testing, and report shall be submitted to RPC. RPC may carry out field checking of AVR, Power System Stabilizers (PSS) or voltage or reactive power controller of wind, solar generating unit or ESS, whenever considered necessary. Behaviour of the generating station during actual system event would also be recorded and retuning advised by RPC, if necessary.

[7] https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

2. PSS Tuning: Sharing of the experience of WR by Sh. S. Satyanarayan

2.1 Introduction and Motivation:

PSS Tuning exercise was attempted in the Western Region of India and 23 generating units were taken up for tuning. While the individual testing and reports were made available to the concerned generating stations immediately, a combined report of the full exercise after completion could not be produced. This was partly because of the fact that as the project moved into the next phase, newer situations were emerging and took the focus.

At present an attempt is made to compile all the information from memory about the testing and sharing of the experience gained by the PSS Tuning exercise. So, this report is more like sharing of the experiences of PSS Tuning exercise in WR, from an **individual perspective**.

PSS field tuning began in WR in 2003. During the field trials of PSS Tuning exercise in WR, Dr A.M. Kulkarni, IIT-B (consultant) and Shri Parthasarathy, Manager, BHEL and Shri Satyanarayan S., S.E., WRPC were associated in the PSS tuning field trials at all the station in WR. The generation station excitation team gave all the support and made the tuning a great success. In the initial stages, all utility engineers would participate in the tuning exercise. Two training sessions were organized in IIT-B, Electrical Engg. Dept, by Dr A.M. Kulkarni and their team, for familiarization with all the issues involved. The progress of PSS Tuning exercise was regularly reported in the WREB/WRPC meetings.

After the grid disturbance of 2012, the role and importance of tuning PSS on generators, tuning TCSC damping controllers, HVDC damping controllers has been increasingly felt. While these controllers can positively influence the stability **when done correctly** they can, equally harm, if not correctly tuned or be not efficacious if they are ill-tuned. Hence the tuning of these complex controllers, should be done systematically and properly and with a scientific approach.

a) **Scope of PSS Tuning:** PSS Tuning can be done to improve the poor damping observed in the inter-area modes of oscillations or local mode oscillations without destabilizing the synchronous torque or interfering into the scope of the functions of the AVR. Further PSS comes into action only when there are changes that originate from the grid side. Manual changes in generation ***usually*** bypass the PSS controller by design for power input PSS. Similarly, PSS can be set to be bypassed for very low load levels of generation. Such a well-tuned PSS can stabilize the oscillations and also improve the power transfer accordingly.

b) **Benefits of PSS Tuning:** The PSS is a standard circuitry that is found invariably shipped even in the early machines (late 60s –early 70s). it is also known as the slip stabilizer. And therefore, would be certainly available in newer machines. By properly tuning it, damping of poorly observed modes can be done. The cost of tuning is negligible compared to other modes of enhancing stability, and so the PSS Tuning is a very cost-effective solution to the oscillatory stability issue. The PSS Tuning exercise in WR also enhanced the academic-industry interaction. It also improved the general understanding of the stability issues of the operation of the grid.

c) **Wrongly tuned PSS:** If the PSS is set keeping the above scope in mind, it usually results in a smooth operation. However, it set randomly or erroneously (not as per the scope), it ***does have*** the potential to destabilize a stable operation. In the past, prior to the PSS Tuning exercise, PSS were enabled at some generating units to enhance stability. The PSS Tuning exercise undertaken in WR is the first one to study the tuning problem from a regional perspective. It is also known that individual attempts in the past, to switch on the PSS has been partly successful and partly failure and if unstable operation is observed in the generator, usually such a PSS would be switched off in the field. Such a sorry situation can occur, if either the gains or limits are set incorrectly. Ambitiously trying to improve the step response with the PSS in field trials, can also lead to problems, as one can lose sight of the inter-area oscillatory problems in field testing. Hence the frequency response approach helps in the tuning. It is also known that PSS requires retuning when there are major changes in the grid.

d) **Approach of PSS Tuning in WR:** In the present approach, initially two worst case grid scenarios of high MW and high MVAR dispatches were initially given. Linear analysis of the same was done by IIT-B and analytically modes of oscillations and their damping were quantized. The frequency response of the generators was simulated. Then during field trails, an apt value of the gains was chosen such that the conditions mentioned in the scope are satisfied. By plotting the frequency response curves as a function of the gains, the possible behaviour of the machine during such oscillations was predictable. Finally transient response was done to check that the settings were indeed acceptable. The theory of the method is given in K.R. Padiyar's book in details and the interested reader can pursue the same.

We conclude the introduction and motivation with a brief outline of the exercise.

2.2 A brief outline of the exercise of PSS Tuning in WR:

a) The Vijoy Kumar Committee in April and May 1994 twin grid disturbances in WR had then recommended that the possibility of tuning of PSS on generating machines to enhance stability should be explored.

b) WREB (now WRPC) then handed over the studies to CPRI to examine this aspect. CPRI completed the exercise of carrying out system studies and in 1998-99 had recommended that by tuning PSS on all 210 MW and 500 MW units the stability is enhanced, as seen for the cases of the grid disturbances of April and May 1995 (under the Vijoy Kumar Committee).

c) It has to be remembered that in those days (around 1997-98), the Windows version of power system stability studies packages were not available. CPRI had performed the studies on SIMPOW package of ABB. Since at that time the simulation had modelled all distance relays for the grid, this was probably the first attempt then to simulate the situation and see what the distance relays were seeing and was novel in that aspect.

d) So as per the recommendations of CPRI studies, the task of tuning the PSS on 210 MW and 500 MW units were decided to be undertaken. A search for vendors who could do that task was then explored. There were many discussions and foreign vendors was sought for PSS Tuning work. However, it could not materialize. At about the same time (around 1999-2000) Northern Region had undertaken PSS Tuning of 4 machines with the help of PTI, USA. But before WR could finalize some sort of agreement the same could go through to the final stage. It was also clear that involving a foreign consultant would be expensive from the project cost point of view. The confidence from the discussions that was emerging in WR at that time, was WR could attempt the PSS Tuning exercise using our own engineers and taking academic support from IIT-B.

e) In WR, it was finally decided in the 114th WREB meeting in November 2000, that this exercise can be undertaken with academic support from IIT-B and so the exercise of doing the PSS Tuning was entrusted to IIT-B.

f) Almost two years went in getting data from the generating units. This led to a large gestation period during which the data had to be literally mined and checked. System studies were done again as per the revised grid conditions, and the pilot project to tune 4 generating stations was proposed by IIT-B. It was then decided by WREB to carry out the pilot project at twelve units in the first phase involving two generating units from Gujarat, MP, Maharashtra, Chhattisgarh, RPL and NTPC.

g) In the first phase, the two units chosen were from Wanakbori (Gujarat), Nasik (Maharashtra), Satpura (MP), Korba-W (Chhattisgarh), Dahanu (RPL) and Korba (NTPC). All these units incidentally had BHEL as the manufacturer and all were 200/210/250 MW units.

h) In the initial stage of field exercise itself it became clear that the manufacturer's representative is needed while doing the field test. So BHEL was involved during the field PSS Tuning.

i) The first phase of field testing was completed at all the stations successfully as shown in the table below:

Table 2.2.1

Station	Units	Dates	Excitation	Remarks
NTPC Korba	2,3 (200 MW)	28.06.03-30.06.03	Static DVR	Testing done for fixed gain PSS successfully. But since the DVR had adaptive PSS, the fixed PSS settings could not be used. The DVR's adaptive PSS was however enabled.
Wanakbori Gujarat	4, 5 (210 MW)	14.06.04-16.06.04	Static AVR	Successfully tested and PSS enabled.
Nasik Maharashtra	3, 5 (210 MW)	18.06.04-20.06.04	Static AVR	Successfully tested and PSS enabled.
Dahanu –RPL	1,2 (250 MW)	09.12.04	Static AVR	Successfully tested and PSS enabled.
Korba West – Chhattisgarh	1, 3 (210 MW)	21.07.05-22.07.05	Static AVR	Successfully tested and PSS enabled.

Satpura-MP	8.9 (210 MW)	12.09.06-13.09.06)	Static AVR	Successfully tested and PSS enabled.

*** Please note that the PSS were enabled and continued for some time. Since these were analog old units, at most places, they were also planning retrofitting with Digital version of AVRs.**

j) The success of the first phase led to the second phase of PSS Tuning in WR. The second phase planned for PSS Tuning at 29 units. In addition, with new DVRs coming and DVRs usually (depending on the manufacturer) provide for a default PSS enabled and at that time 11 units were proposed for status checking. This meant to study whether the PSS settings were optimal. The PSS Testing exercise was also extended to 500 MW tuning in this phase. The units planned were divided in two parts.

Table 2.2.2

Station	**Units**	**Dates**	**Excitation**	**Remarks**
NTPC Korba	4,5, 6 (500 MW)	Sept 06 22.08.08	Static DVR	Cards Checked. PSS Tuned.
MSEB Parli	3 units (210 MW)	12.12.06	Static AVR	Successfully tested and PSS enabled.
SGTPS-MP	4 units (210 MW)		Static AVR	Successfully tested and PSS enabled.
Korba West – Chhattisgarh	4 (210 MW)		Static AVR	Successfully tested and PSS enabled.
Gandhinagar–Gujarat	3 units			Could not undertake this PSS Tuning.

Thus 11 units were tuned in the second phase. A total of 23 units were tuned in this project.

k) Eastern region also adopted the same methodology and IIT-B was associated. It is understood that ER had completed at least 8 units at that time.

l) The exercise finished at Part-I of the Second Phase. The status verification proposed earlier could not be done.

m) So, to conclude the brief history, the PSS Tuning exercise in WR was largely successful. It had given excellent academic-industry interaction. Both sides benefitted from the exercise. During the first phase the testing / excitation group of generators were involved from all states in each PSS Tuning. One or two training sessions were also arranged at IIT-B. The approach followed in the PSS Tuning is what is already explained in papers and today is also available in standard post-graduate textbook levels.

2.3 Knowing the PSS and AVR – its role and scope

2.3.1 AVR:

The modern generators have high performance excitation systems. This is essential for steady state operation and also for transient stability. It provides fast control of terminal voltage. However, the fast-acting exciters with high gain AVR can contribute to oscillatory instability. This type of instability is low frequency oscillations (0.2 Hz to 2 Hz) which can appear / persist for no apparent reason. By tuning a PSS, we can get a good stable response.

2.3.2 What is the PSS?

PSS or Power System Stabilizer is a controller in the Voltage Regulator (AVR or DVR). Its input signals are either

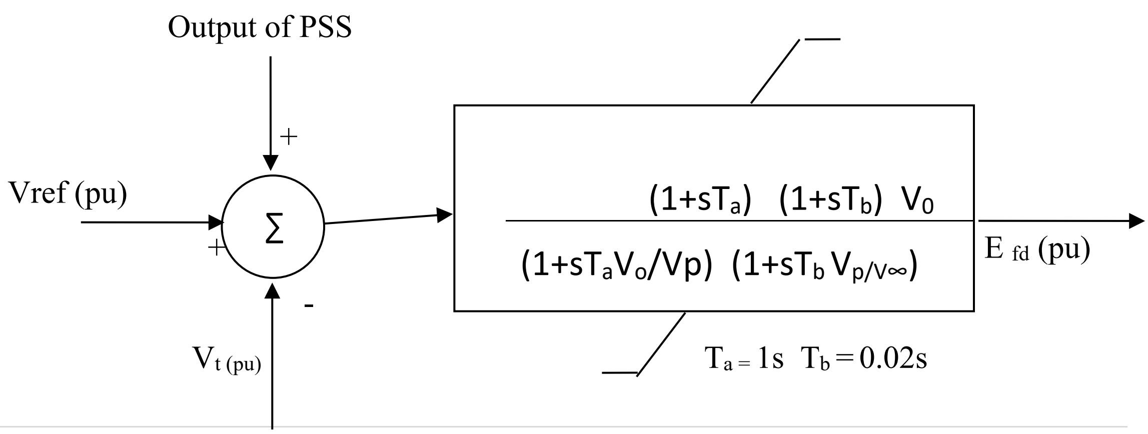
(a) Power

(b) Frequency or speed

(c) A combination of both

(d) A combination of other signals (newer delta-P omega type)

Its output is a voltage signal. This signal is added into the AVR reference voltage. Thus, a PSS modulates the AVR reference voltage. Fig 2.1 gives the AVR block diagram at a 210 MW plant.



$V_{o\,=}$ 200 $V_{p=}$ 5 5 V_{∞} = 80

Fig 2.3.1 AVR Block Diagram

The structure of the PSS is shown in Fig 2.3.2. This is the transfer function version.

Structure of PSS

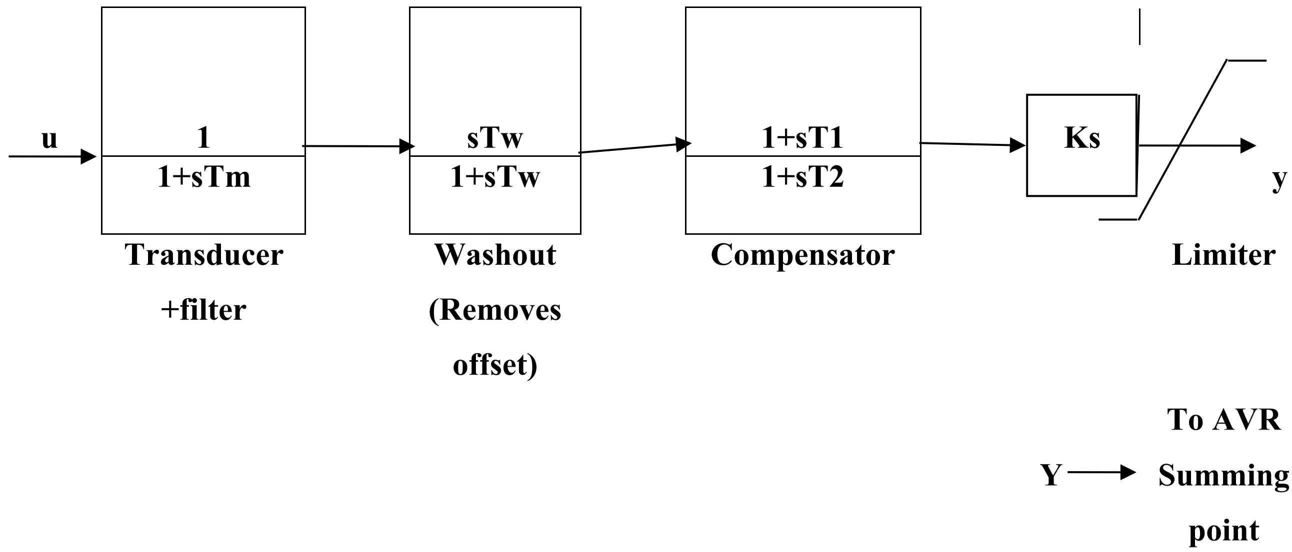


Fig 2.3.2 Structure of PSS

It contains

a) **Transducer or filter:** The input transducer or filter. The input signal u is applied to the PSS.

b) **Washout:** The block removes any dc offset. In other words, it allows changes to be passed. It is because of this the PSS does not respond to steady state. For example, if the input signal is Power, and if the value of P is constant, the output is zero. It is mathematically a practical differentiator.

c) **The main compensator:** At the heart of it, the PSS is a lead compensator. It lifts the lag or compensates for the AVR lag response. This improves the stability in small signal stability conditions. The above controller with one input shown say P.

Let us look at the PSS card (Fig 2.3.3)

Prop. Amplifier

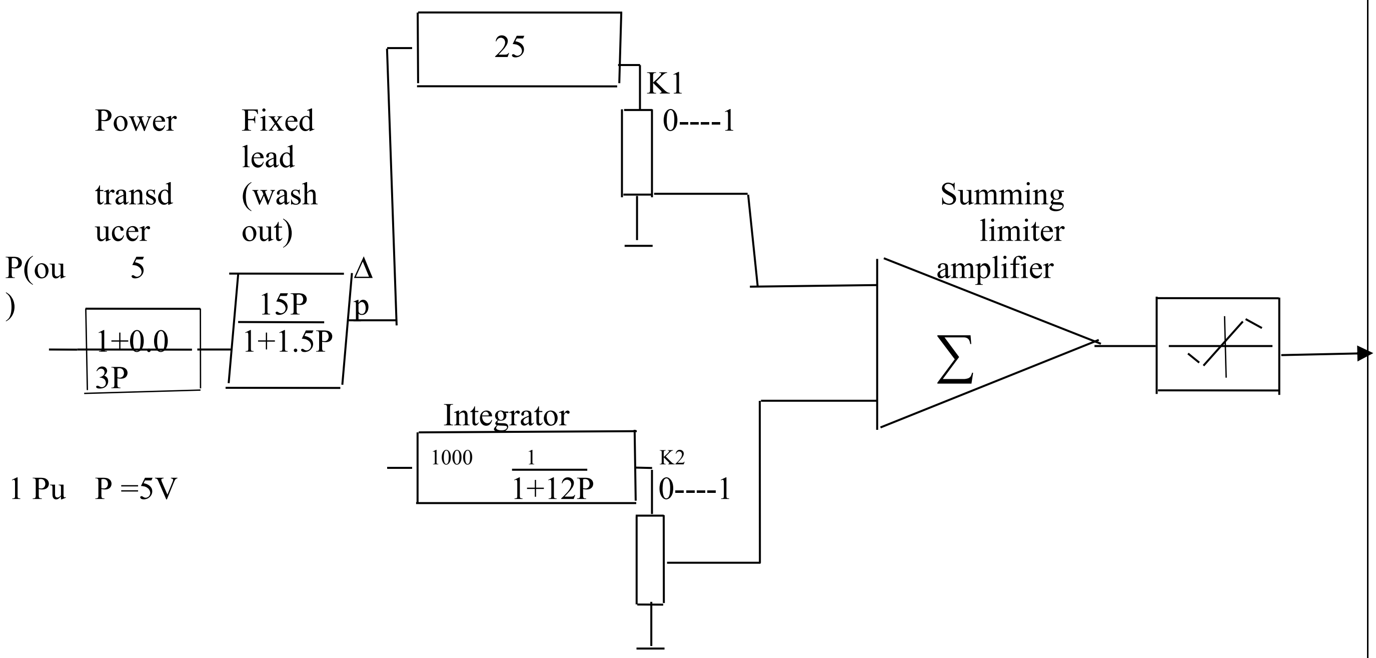


Fig 2.3.3 PSS Card transfer function

We can reduce the same as

$$\frac{\Delta V_{PSS}(s)}{\Delta P(s)} = -\ 25_{k1} - \frac{1000_{k2}}{1 + 12s}$$

$$= -\ \frac{(25_{k1} + 1000_{k2}) + 300_{k1s}}{1+12\ s} = -\ K\ \frac{(1+ sT)}{1+12s}$$

$$T = \frac{300_{k1}}{25_{k1} - 1000_{k2}}$$

$$K = 25_{k1} + 1000_{k2}$$

By changing the ratio of K1/K2 we can change the response of ΔV_{PSS} /ΔP.

4. **Limiter:** The output of ΔV_{PSS} can be limited V_{REF} of AVR. Typically, this is set to +0.1 or -0.05 of $V_{REF.}$ **This is done to prevent / control the PSS excessively modulating $V_{REF.}$**

2.4 Will the PSS act always?

The PSS is supposed to act only when there are changes in the input signal.

However, the PSS is deliberately made ineffective under the following conditions:

a) Manual changes made by operator. For e.g., a power input PSS will not respond to changes in power done from the operator’s desk through say the speeder gear. As the changes were done manually, design control logic exists to pass these changes to PSS.

b) PSS can also be disabled if power of the machine is below a certain percentage of the unit rating. This is settable. Usually, 40% or below Power setting. Refer manual for details.

Except such restrictions, PSS will always act if the changes of power are passed to the PSS controller.

2.5 Logic of PSS Tuning:

The Fig 2.3 shows the logic of PSS Tuning. The ratio of K1/K2 controls the phase of the voltage injected into the AVR. As we can see the PSS is some form of a lead compensation that if added to the pure AVR frequency response, will left the AVR response upwards.

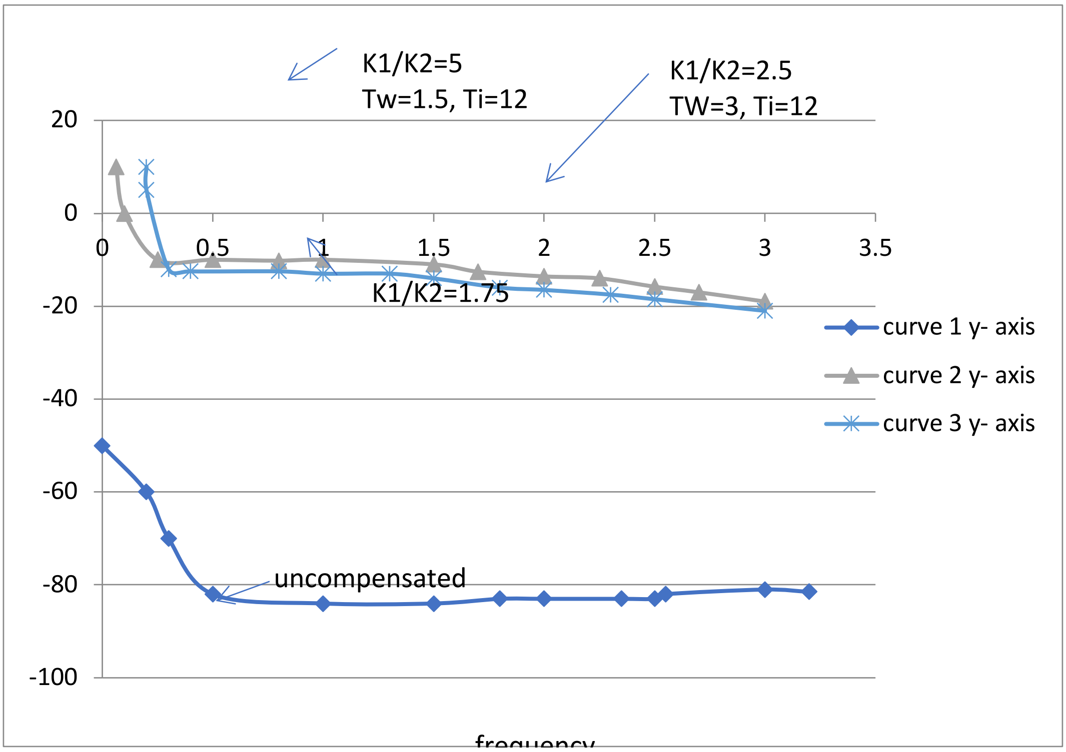


Fig 2.5 Logic of PSS Tuning

The compensated final curve will be above the AVR response which is shown for various values of K1/K2. Settings around 1.75 nicely lifts the curve **and more importantly keeps the compensated curve in first quadrant only**. This ensures Ts (synchronizing torque) is not made negative which is another important factor. For example the light blue coloured curve for k1/k2 = 5 is to be avoided, as for frequencies below 1 Hz, it makes Ts negative. At frequencies around 2 to 2.5 Hz this is very nice. The step response of AVR may show a very good damping. But

This is bad for inter-area modes as Ts is negative. Hence the plotting of frequency response curve helps in choosing PSS gains.

Fixed Gain vs Adaptive PSS: Fixed gain PSS are equally adequate in their role for providing damping requirements. If we have an adaptive PSS then the mechanism of adaptation must be known to comment on the same. Excepting one machine, all PSS tuned in this project were fixed gain PSS.

DVR vs AVR: DVR is the digital version of the AVR. It is easy to know the parameters easily. In AVR the parameters have to be read from the link positions on the card. Apart from that there is no major difference.

Getting Frequency response curves:

This is achieved by a proprietary program developed by IIT-B on the lines of theory given in Padiyar's book. It is beyond the scope of this little report to explain the logic of the same.

3. Effect of Excitation System on Power System Behavior

3.1 Introduction

Instability in Power system crop up due to the fundamental nature of oscillations of the machines. We can understand the basics of excitation system effect through a Single Machine Infinite Bus (SMIB) System. The generator is modelled as a voltage source behind transient reactance - this model is known as the classical model. The internal voltage angle is related to the position of the rotor and described by following equation.

$$M\frac{d^2\delta}{dt^2} = T_m - T_e$$

Where *M is the combined moment of Inertia of generator rotor and turbine in kg.m^2*

δ is the angular position of the rotor with respect to a stationary axis in (rad)

T_m is the mechanical torque supplied by the prime mover in N-m

T_e is the electrical torque output of the alternator in N-m

The SMIB System is as given below:

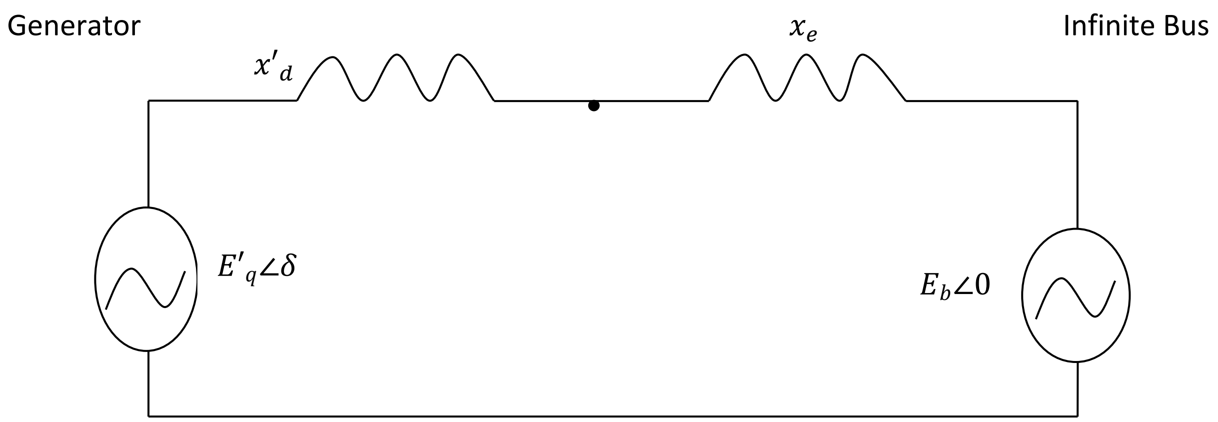


Fig. 3.1.1

When a disturbance is applied to the above system, the deviation is a monotonic increasing deviation from the point of equilibrium. This is because the torque is no longer restoring in nature, but it enhances the deviation. The equilibrium point is called as monotonically unstable and is not a viable operating point. Further to help understand the dynamic behavior of the system, the qualitative behavior is inferred by a familiar dynamic system analogy – the spring mass system.

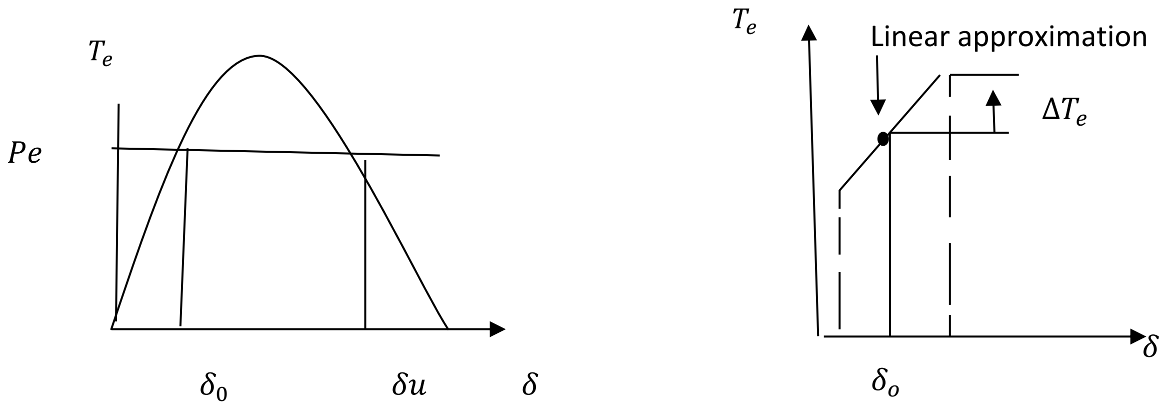


Fig. 3.1.2

The response of the spring mass system is well known as an oscillatory behavior to a disturbance. The SMIB system also has oscillatory behavior of rotor (swings). The frequency of oscillations of the system will depend on the M in the swing equation. If M is larger, the frequency of oscillations will lower and vice-versa.
In such situations if there is no damping present, there is a sustained oscillation of the rotor following the disturbance. However, if the friction is present, then the oscillations will eventually die done. Friction usually implies that there is some kind of a retarding torque proportional to the angular speed.

3.2 SMIB model with field winding equation[i]

For the classical model, it is assumed that field flux remains constant during a disturbance. This is equivalent to say that "E_q" which is proportional to field flux is constant. Following a disturbance, flux seen by the winding does not change immediately, but responds according to Faradays law of Electromagnetism.

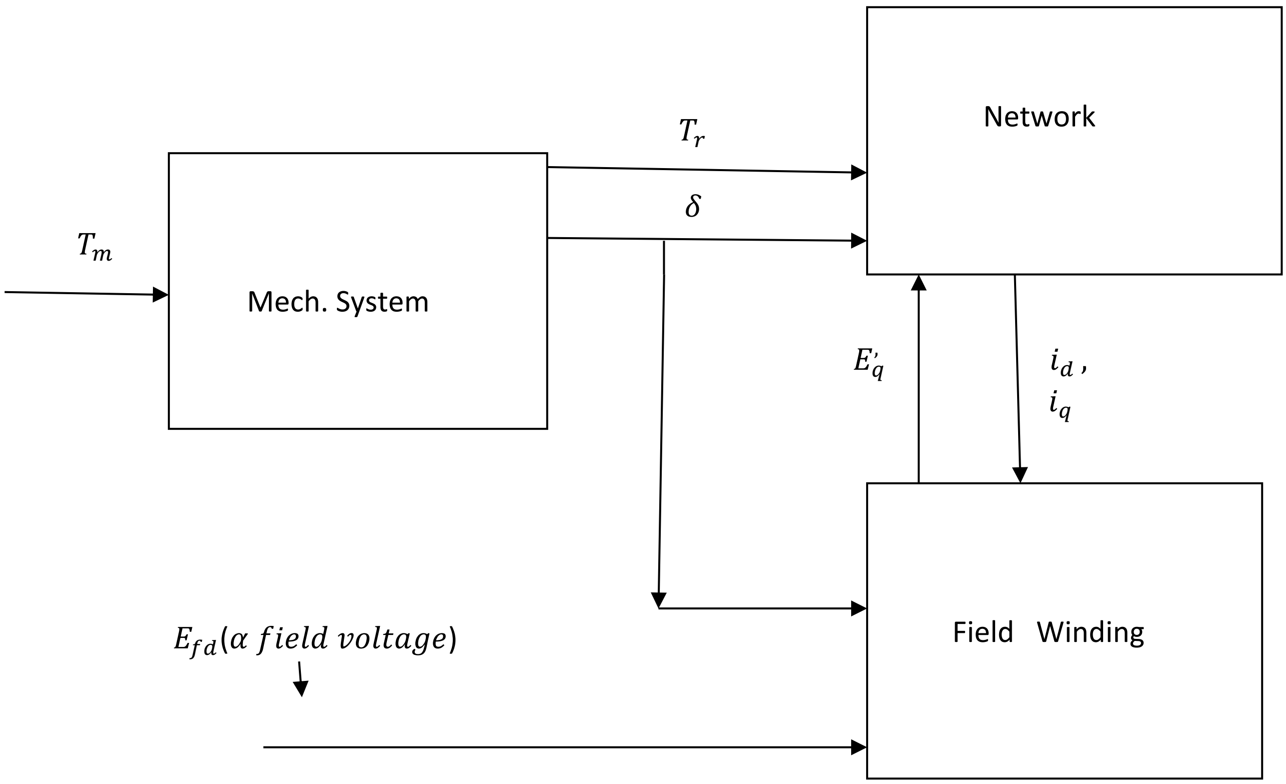


Fig. 3.2.1

The above figure shows a system with field winding. The electrical torque is dependent on both Angle and E_q (the state proportional to field flux). If the angle is oscillating sinusoidally, the response of the field winding flux state is also of oscillatory nature. However, the phase and magnitude of the oscillation is determined by the transfer function. E_{fd} is zero for manual excitation control.

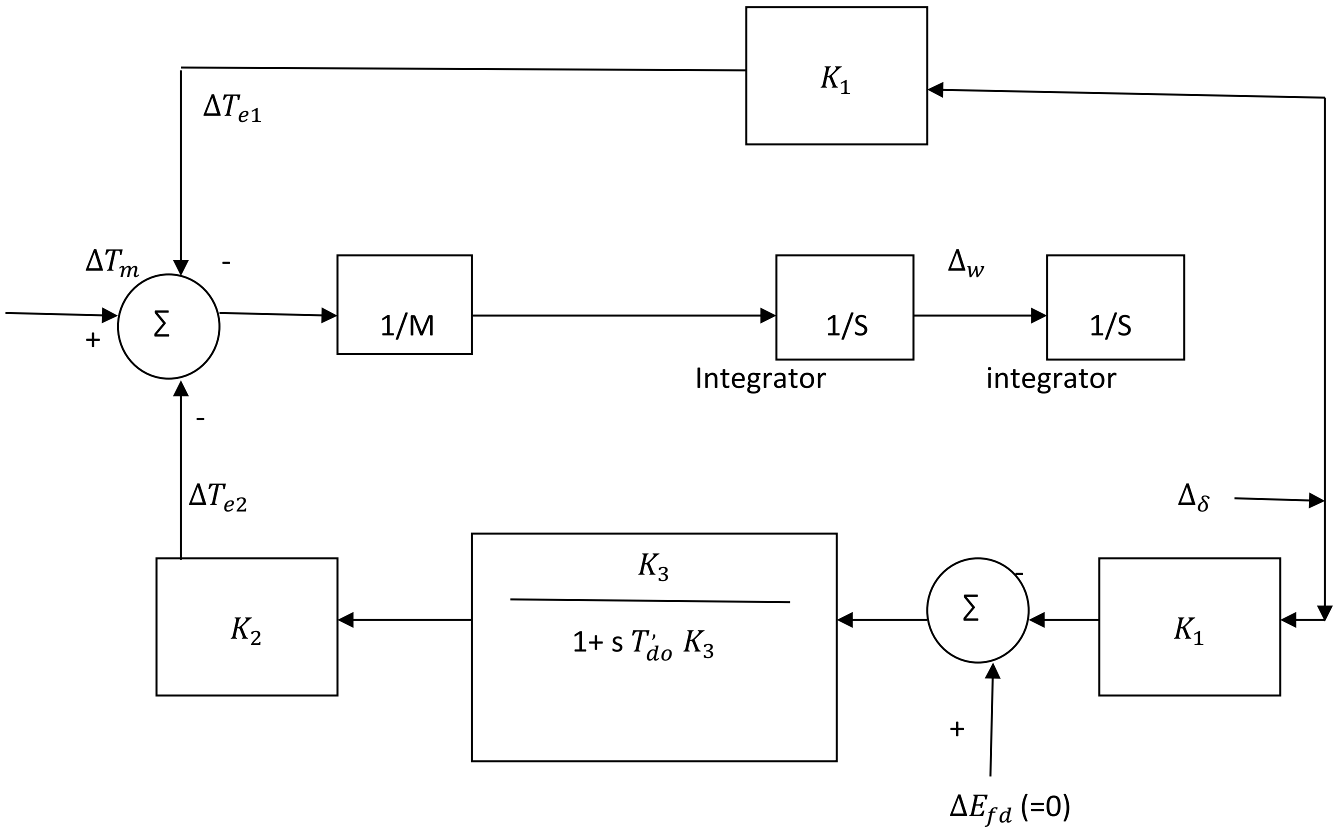


Fig. 3.2.2

The above block diagram represents the transfer function Block Diagram (with effect of field winding). For normal system operation the constant K_1 to K_4 are positive. Thus, if the angle is oscillating sinusoidally, the total electrical torque (forced response) at this oscillation frequency is such that it has a positive component in phase and also a positive component 90° leading the angular oscillations (i.e., in phase with speed oscillations). Consequently, the system is stable because the damping and synchronizing torques are positive.

3.3 Effect of Automatic Voltage Regulator

An AVR is used to regulate the generator terminal voltage by controlling the field current of the excitor. Without AVRs modern turbogenerators cannot operate at full rated power, as their synchronous reactance's are around 2.0pu. Also, the transient stability is improved by fast acting excitors with high gain AVR. V_g is the machine terminal voltage and V_s is output from PSS.

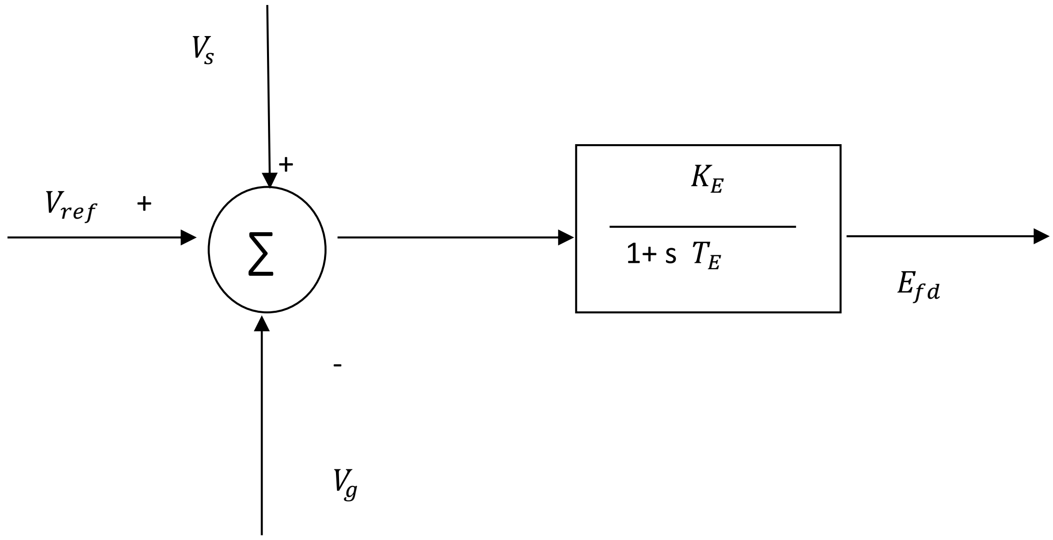


Fig 3.3.1 - Schematic diagram of Static Excitation System

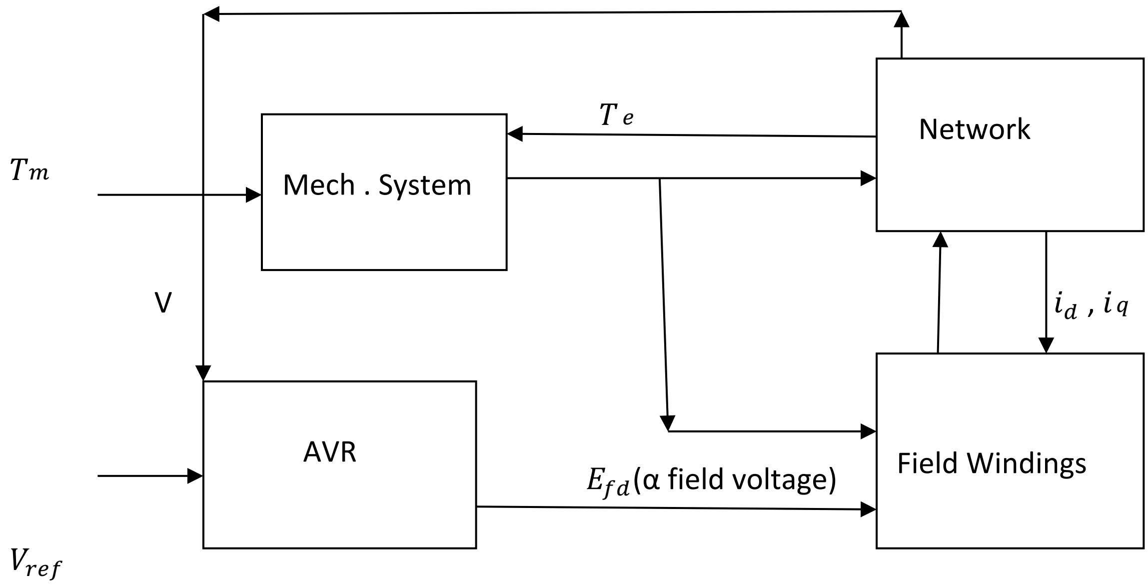


Fig. 3.3.2 - Block Diagram including the static excitation system

4. Power System Stabilizer & Power System Dynamics

4.1 Introduction

The PSS are designed mainly to stabilize local and inter area modes. However, care must be taken to avoid unfavorable interaction with intra-plant modes or introduce new modes which can become unstable.

Depending on the system configuration, the objective of PSS can differ. In general, the PSS is used to damp inter-area modes without jeopardizing the stability of local modes. Many a times local area modes are of major concern. In general, however PSS must be designed to damp both types of modes.

If the local mode of oscillation is of major concern (particularly for the case of a generating station transmitting power over long distances to a load center) the analysis of the problem, can be simplified by considering the model of a single machine (the generating stations is represented by an equivalent machine) connected to an infinite bus (SMIB).

Typically, only a few of the oscillatory swing modes are unstable. The procedure then is to identify the critical mode and the machines which have significant participation in these critical modes. PSS can be tuned on the participating machines.

4.2 Controlling Oscillations

One of the essential of controlling the oscillations and providing the damping is to modulate some controllable quantities which will directly or indirectly cause damping.

The necessary conditions for doing this are

a) The oscillation should be seen in the quantity which is used as the modulation signal. Some obvious quantities which can be used are speed of the generator and power output from the generator.
b) Variation of the controllable quantity should be able to cause an adequate variation in the torque. One possibility is to control the input mechanical torque itself. However, this is not practically feasible due to slow response of the turbine control system. Another option is to control the voltage reference of the AVR or references of the HVDC and SVC controllers in the system.

c) The controller should modulate the controllable quantity appropriately using the modulating signal, so that damping torque is produced at the rotor oscillation frequency.

The most widely accepted and inexpensive way of achieving a stabilizer is to modulate the voltage reference of the AVR using speed/power/bus frequency signals. Note that the controller in each case will be different since these oscillations are not in phase with each other. The feedback signal can be synthesized using a combination of several signals.

4.3 Control Signals for the AVR Voltage Reference:

The following signals have been in use and the controller in each case will be different.

a) **Speed**: This is the most natural choice for the feedback signal. However, the speed signal can aggravate (Sub-Synchronous Resonance) SSR problems and therefore a torsional filter is necessary.

b) **Frequency**: Frequency signal is similar to a speed signal. If frequency at a common (HV) bus for a plant with identical generators is taken, then intra-plant oscillations may be absent in the signal. However, frequency signal is susceptible to noise from nearby loads like arc-furnaces.

c) **Power**: Speed is proportional to the integral of the difference between mechanical and electrical power. Sometimes electrical power alone is used as a signal. However, during power ramping or load changes, the PSS using power signal causes transient variations in the terminal voltage.

d) **Acceleration power**: The acceleration power signal is obtained from the difference of filtered mechanical power (which is synthesized from the speed and electrical power signals) and the electrical power.

e) **Synthesized speed (Delta P - Omega)**: This signal is derived from power and speed signals and is almost like the speed signal in the frequency range of interest but is not prone to causing problems at SSR frequencies.

4.4 Power System Stabilizer

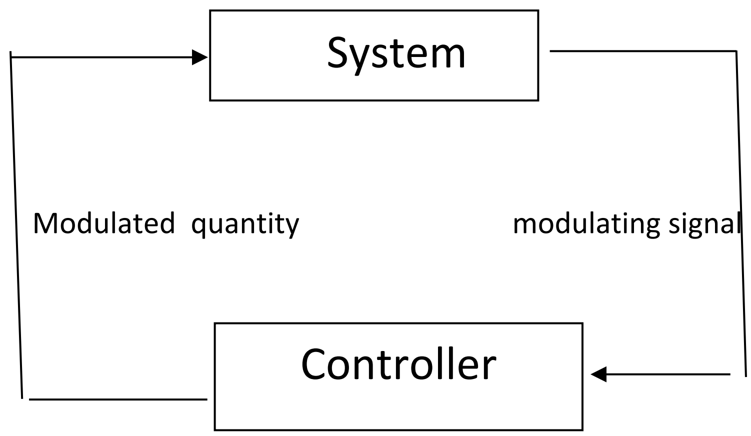


Fig. 4.4.1

4.4.1 Structure of PSS

The structure of PSS and its blocks is discussed in the subsequent sections. It consists of a washout circuit, dynamic compensator, torsional filter, and limiter. The main objective of providing PSS is to increase the power transfer in the network, which would otherwise be limited by oscillatory instability as discussed above.

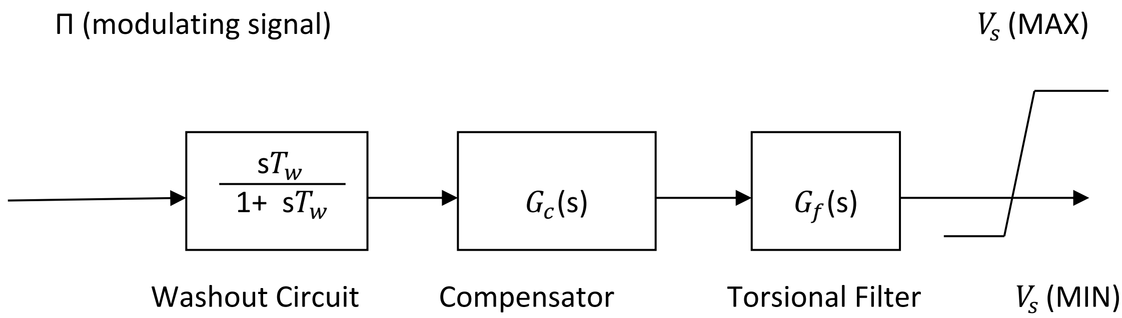


Fig. 4.4.2

4.4.2 Washout Circuit

Washout circuit is provided to eliminate steady state bias in the output of PSS which will modify the generator terminal voltage. The PSS is expected to respond only to transient variations in the input signal and not to the dc offsets in the signal. This is achieved by subtracting it the low frequency components of the signal obtained by passing the signal through a low pass filter.

$$G_w(s) = \frac{sT_w}{1 + sT_w} = 1 - \frac{1}{1 + sT_w} = 1 - G_{ip}(s)$$

4.4.3 Dynamic Compensator

Compensator modulates the controllable quantity appropriately using the modulating signal, so that damping torque is produced at the rotor oscillation frequency. The dynamic compensator used in industry is made up of two lead-lag stages. With static exciters, only on lead-lag stage may be adequate. For design purposes the PSS transfer function is approximated to T(s), the transfer function of the dynamic compensator.

$$T(s) = \frac{K_s N(s)}{D(s)}$$

where,

$N(s)=1+a_1s+a_2s^2 \ldots\ldots a_ps^p$

$D(s)= 1+b_1s+b_2s^2 \ldots\ldots b_ps^p$

4.4.4 Torsional Filter

Torsional filter is essentially a band reject filter to attenuate the first torsional mode frequency. For stabilizers derived from accelerating power, torsional filter can have a simple configuration of a low pass filer independent of the frequency of the torsional mode to be filtered out. Torsional filter is necessitated by the adverse interaction of PSS with the torsional oscillations. This can lead to shaft damage, particularly at light generated loads when the inherent mechanical damping is small. Even if shaft damage does not occur, stabilizer output can go into saturation making it ineffective.

4.4.5 Limiter

The output of PSS must be limited to prevent the PSS acting to counter the action of AVR. For example, when load rejection takes place, the AVR acts to reduce the terminal voltage when PSS action calls for higher value of the terminal voltage. It may be even desirable to trip PSS in case of load rejection.

The negative limit of PSS output is of importance during the back swing of the rotor (after initial acceleration is over). The AVR action is required to maintain the voltage (and prevent loss of synchronism) after the angular separation has increased. PSS action in the negative direction must be curtailed more than in the positive direction. On the other hand, a Higher negative limit can impair first swing stability.

4.5 Uncompensated PSS Open Loop Transfer Function ($GEP_{(s)}$):

The Uncompensated PSS Open Loop Transfer Function ($GEP_{(s)}$) is a system representing the characteristics of a generator, exciter, and power system.

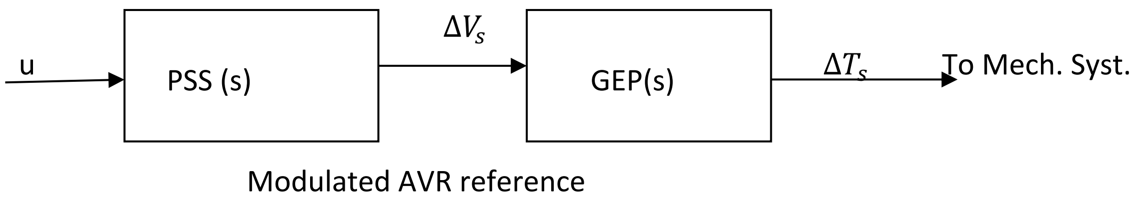


Fig. 4.5.1

The transfer function of the whole assembly is given as where GEP is the

$$\frac{\mathbf{\Delta T_{ep}}}{\mathbf{\Delta \omega_G}} = \mathbf{PSS_{\omega}(s)GEP(s)\ \underline{\Delta}P(s)}$$

During the system study, the aim is to find the suitable Gain and time constant for the PSS. This is to ensure that how much gain the system can be supplied with before it touches instability. The above process is subdivided into three parts as described below:

a. Checking how much phase lag is there with the help of frequency domain analysis between the generator speed and its electrical torque under various operating condition. Basically, it yields uncompensated PSS open loop transfer function (GEP(s)).

b. Checking the AVR response with PSS under operating various scenarios and comparing with a. above, to find the best suitable PSS parameters for suitable phase compensation.

c. Checking the PSS gain Margin to obtain suitable PSS gain having no adverse impact under various operating scenarios. Also, check the PSS gain with root locus method to obtain suitable gain constant so that system is stable even if the gain is increased to three times.

The steps a and b, as described during PSS parameters tuning can be described by the frequency domain analysis of the transfer function generator, exciter, and power system (GEP(s)) and Power system stabilizer compensation (PSS(s)).

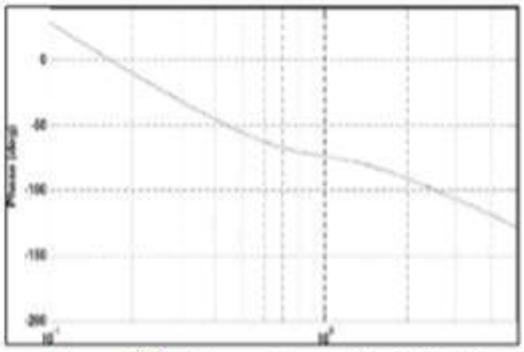


Figure (a) Phase of function GEP(s)

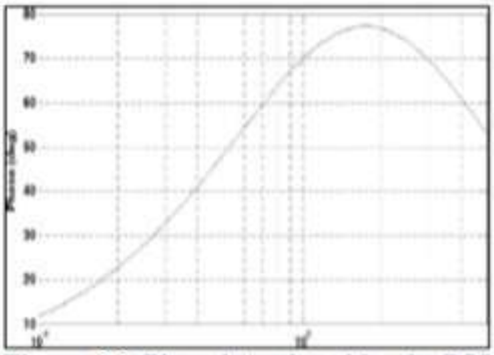


Figure (b) Phase introduced by the PSS lead-lag filters

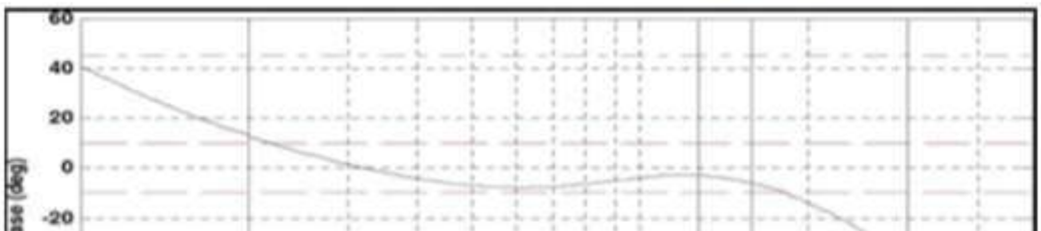


Figure (c) Global phase compensation (After Tuning of PSS with Phase compensation)

Fig. 4.5.2

The PSS transfer function should compensate the phase characteristics of the generator, exciter, and power (GEP) system transfer function so the compensated transfer function ((PSS(s) * GEP(s)) has a phase characteristic of ± 30 degrees in the frequency range of 0.1 Hz to 3 Hz. This is illustrated with the help of figure (a), (b) and (c). The GEP(s) transfer function is a theoretical transfer function, and its phase characteristic cannot be directly measured during field tests (only via simulation). Thus, the Requirement recognizes the practical approach of measuring the frequency response between voltage reference set point and terminal voltage (E_{term} /V_{ref}) and using the phase characteristic of such frequency response as being the phase characteristic of GEP(s). The phase characteristic of E_{term} /V_{ref}) is a better approximation to the phase characteristic of GEP(s) when the frequency response E_{term} /V_{ref}) is obtained with the generator synchronized to the grid at its minimum stable power output.

In order find the suitable PSS time constants, the above parameter estimation must be done for a wide range of external network reactance i.e., from 0.15 p.u. to 0.5 p.u.

After determining the suitable phase margin, the step c., is to find a suitable gain constant for the PSS. Based on literature available, the gain margin can be best computed using frequency domain analysis with the help of root locus method (Eigenvalue analysis/small signal stability studies). As the simulated model can be either a two-area system (Machine with infinite bus) or small area system with nearby buses, so the small signal stability analysis of the system will yield the Eigenvalue and the respective local and control modes. The gain value must be selected such that it is significantly away from the instability. This must be calculated again for a wide range of external network reactance varying from 0.15 p.u. to 0.5 p.u.

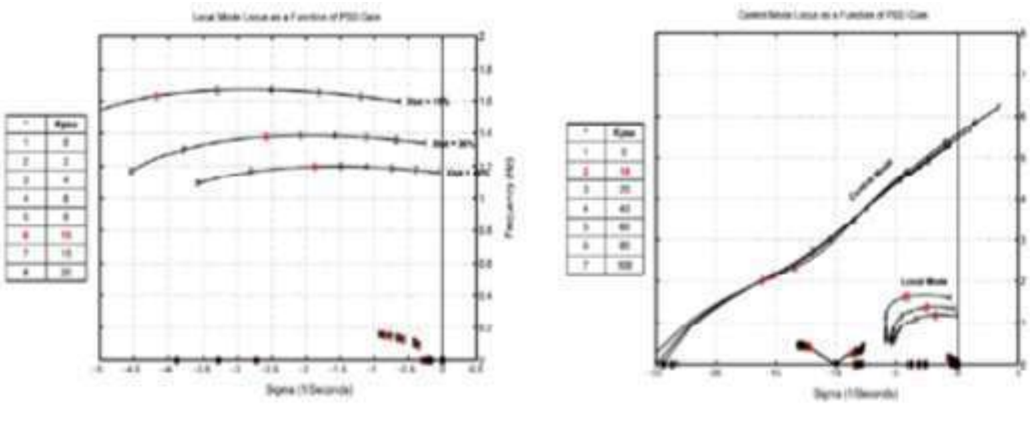


Figure (d) Root Locus of Local mode for different system strength [Ref]

Figure (e) Root Locus of Control Mode for different system strength [Ref]

Fig. 4.5.3

Figure (d) and (e) shows the local and control mode oscillation root locus plot with a variation of gain constant at three different system impedances. During selection of gain margin, it should be verified that the selected gain margin when multiplied by three times then also system should be stable. With this, one gain value can be chosen for one set of external system reactance and similarly for others.

During the selection of gain margin, it is highly desirable to compute the local mode of oscillation for the generators. This local mode of oscillation frequency helps in validating the parameters of the generator during the testing to be done at the field. This oscillation frequency is obtained during gain constant determination from root locus method when the external network impedance used is in proximity of actual system. The obtained gain constant at this frequency is more suitable during actual implementation at site however it may vary depending on the testing carried out at the site.

4.6 Eigen value analysis of a SMIB System:

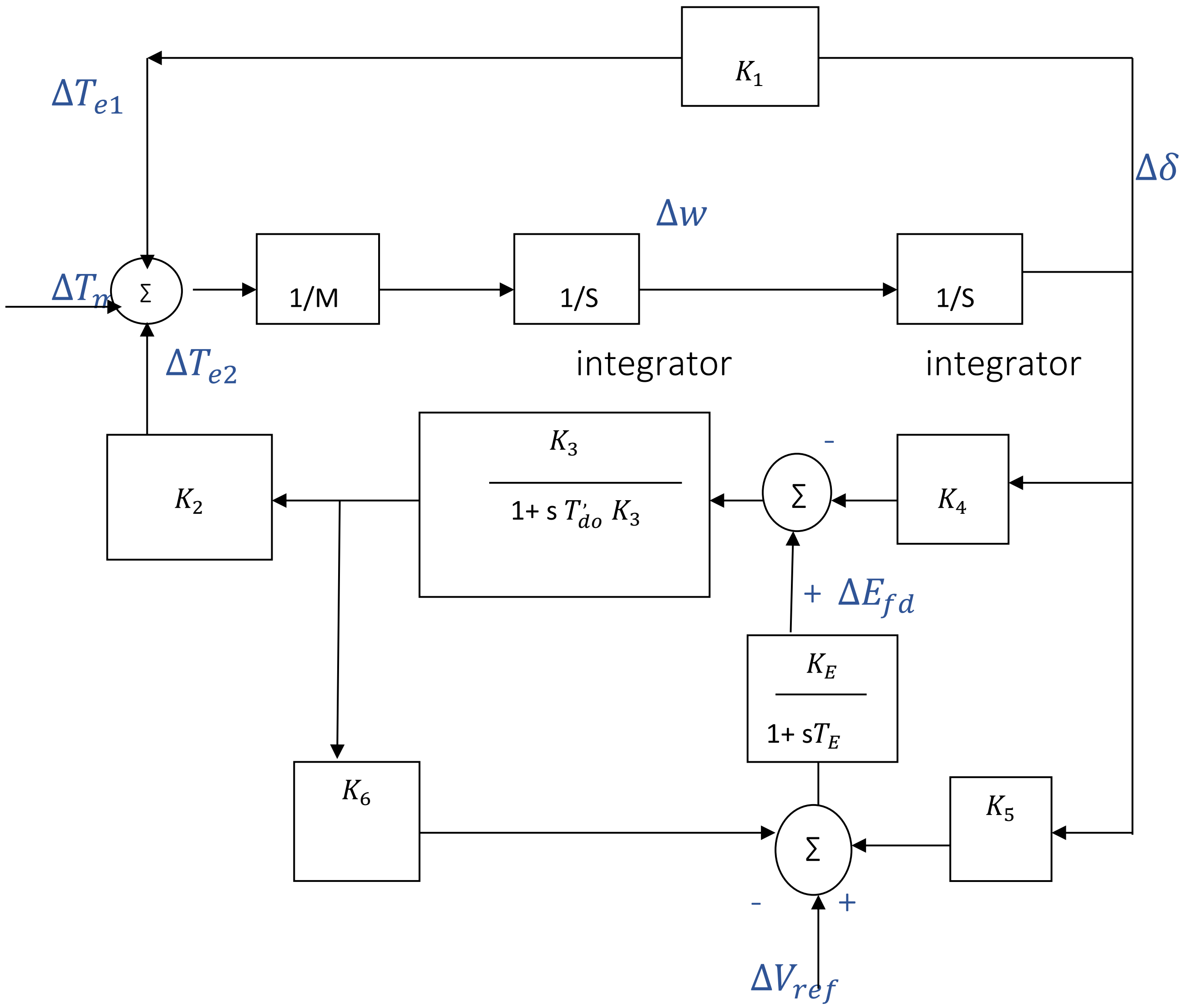


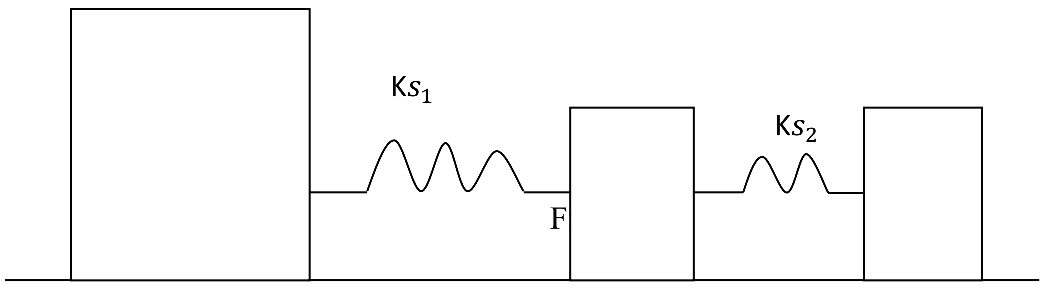
Fig. 4.6.1 - Transfer function Block Diagram including Excitation System.

The mathematical derivation of Eigen value Analysis of a SMIB system and the extent to which a mode is excited (depends on the initial disturbance) is placed at Annexure C.

4.7 Multimachine System

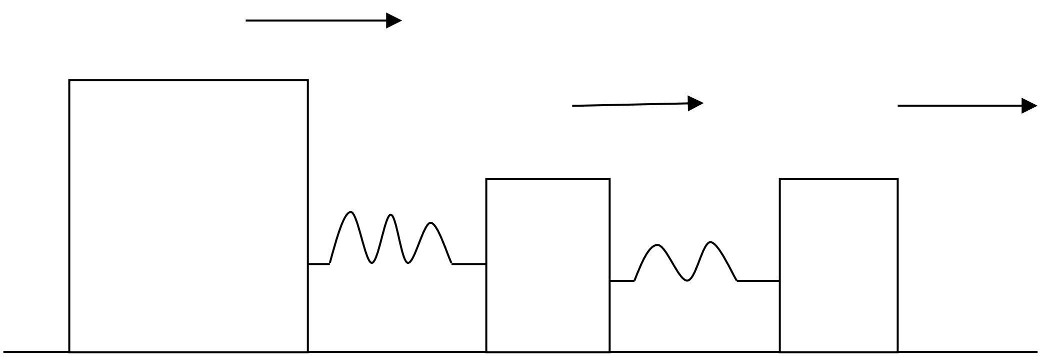
In realistic situation there is no infinite bus, moreover there are many machines connected to each other and the loads by transmission lines. Therefore, a systematic analysis of multimachine systems is required. Let us consider a multi mass, multi spring system.

$Ks_1 << Ks_2$



4.7.1 Two Masses connected together analogy:

There are 2 small masses connected by a very stiff spring which in turn are connected to a relatively larger mass via much less stiff spring. Without explicitly solving the equations of options, we can easily imagine that their response is a combination of serval modes .out of the three modes of which 2 are oscillatory and one which is associated with all the masses moving together. This oscillatory mode of lower frequency involves the two smaller masses moving together against the larger mass. The higher frequency mode involves the two smaller masses oscillating against each other with lesser involvement of the larger mass.
Another point which needs to be addresses is the extent to which each mode is excited. This is determined by initial conditions & disturbances. If a disturbance results in a common initial velocity and displacement for all the masses, then only the non-oscillatory mode is excited.



All masses move together

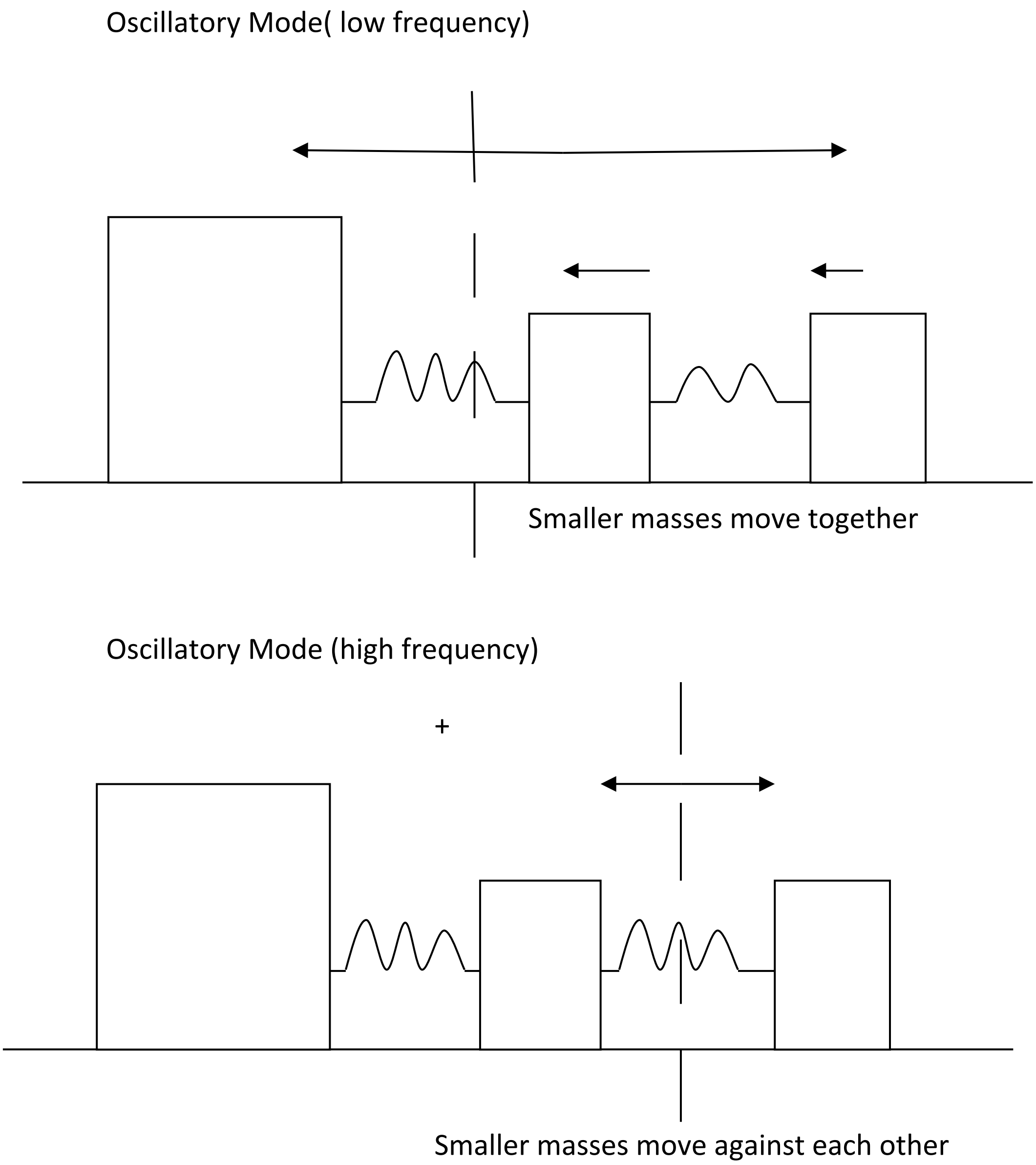


Fig. 4.7.2

4.7.2 Characterization of Swing Modes

For a generator system, there are n — 1 swing (oscillatory) modes associated with the rotor swings. Each of these modes is characterized by a frequency of oscillation. The frequencies are obtained as square root of the non-zero and real eigenvalues of the matrix $[M]^{-1}[K]$.

Not all the generators are 'involved' in all the modes. Typically, each mode is associated with a group of generators swinging against another group. This information can be obtained by doing eigenvalue analysis. There is also a mode associated with the movement of the 'center of inertia' which corresponds to the dynamics of the average frequency. If there is no mechanical damping present and loads are of constant power type, this is manifested as a pair of zero eigenvalues.

In a practical system, the various modes (of oscillation) can be grouped into 3 broad categories

A. Intra-plant modes in which only the generators in a power plant participate. The oscillation frequencies are generally high in the range of 1.5 to 3.0 Hz.

B. Local modes in which several generators in an area participate. The frequencies of oscillations are in the range of 0.8 to 1.8 Hz.

C. Inter-area modes in which generators over an extensive area participate. The oscillation frequencies are low and in the range of 0.2 to 0.5 Hz.

The above categorization can be illustrated with the help of a system consisting of two areas connected by a weak AC tie.

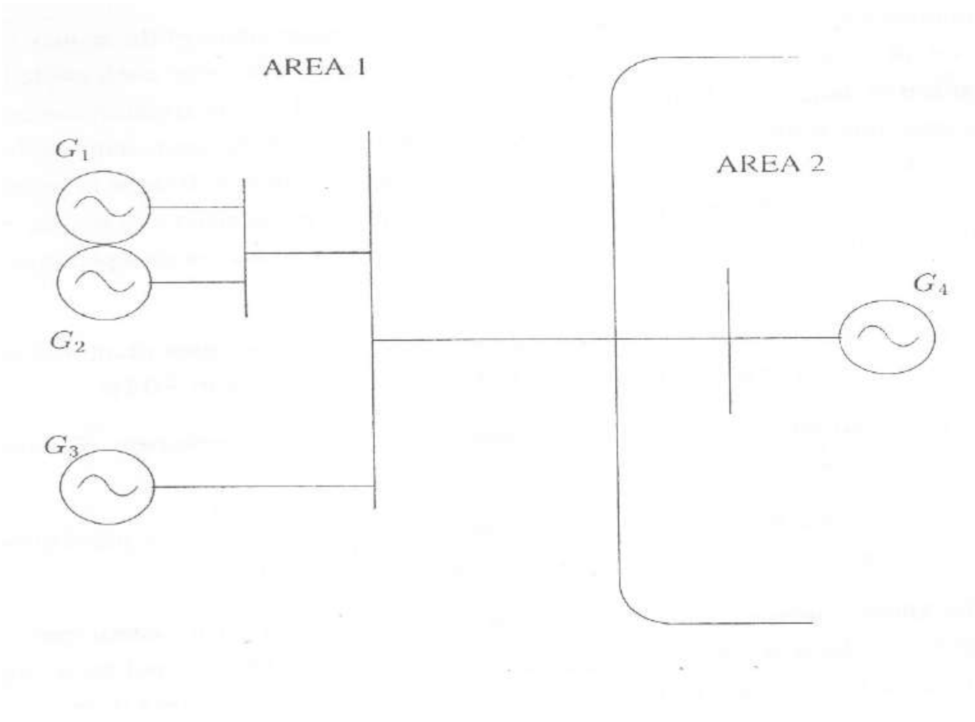


Fig. 4.7.3

Area 2 is represented by a single generator G4. The Area 1 contains 3 generators G1, G2, and G3. The generators G1 and G2 are connected in parallel and participate in the intra-plant oscillations which have higher frequency due to the lower reactance between the two machines and smaller inertias. During the local mode oscillation, G1 & G2 swing together against G3. During oscillations due to inter-area mode, all generators G1 to G4 participate and have the lowest frequency.

It is to be noted that the distinction between local modes and inter-area modes applies mainly for those systems which can be divided into distinct areas which are separated by long distances. For systems in which the generating stations are distributed uniformly over a geographic area, it would be difficult to distinguish between local and inter-area modes from physical considerations. However, a common observation is that the inter-area modes have the lowest frequency and highest participation from the generators in the system spread over a wide geographic area.

4.7.3 Participation of Machine to oscillation mode

The participation of the machines to a particular oscillation mode can be estimated and the mathematical derivation is placed at Annexure D.

5. PSS Tuning Approach

The basic intent of adding a Power System Stabilizer (PSS) is to enhance damping to extend power transfer limits. The very nature of a PSS limits its effectiveness to small excursions about a steady state operating point. The small excursions about an operating point are typically the result of an electrical system that is lightly damped which can cause spontaneous growing oscillations, known as system modes of oscillation. Enhanced damping is required when a weak transmission condition exists along with a heavy transfer of load. A PSS works in conjunction with the excitation system of a synchronous machine to modify the torque angle of the shaft to increase damping. The performance of the excitation system is critical in the overall capability of a PSS. Tuning of a PSS shall only be accomplished after the excitation system has been tuned and calibrated. On new equipment, PSS may be software incorporated in digital automatic voltage regulators. AVR terminal voltage and current measurements are used to compute accelerating power and synthetic speed (integral of accelerating power). PSS cost can be low if PSS is required in competitive power plant procurement specifications. Procurement specifications should include requirement for tuning during commissioning and a requirement for stability program model and data.

5.1 PSS Tuning points to be considered

PSS typically utilizes phase compensation and adjusting phase compensation is the main task in PSS tuning. Phase compensation is accomplished by adjusting the PSS to compensate for phase lags through the generator, excitation system, and power system such that PSS provides torque changes in phase with speed changes. Tuning should be performed when system configurations and operating conditions result in the least damping

Some areas of concern of PSS are:

a) PSSs are manufactured as both analog and digital types. Testing methods may not be identical with both types of PSSs.
b) PSS modification of torque angles by varying excitation can excite turbine generator shaft torsional where shaft torsional are less than 20 hertz. This is especially true for PSSs that utilize speed as input. Typically, torsional filters are used to remove the torsional contribution to the input to the PSS.

c) PSS output can interfere with transient response of excitation systems. Therefore, output limits are usually incorporated in the PSS scheme.
d) PSS can interact with under excitation limiters. Thus, the limiters must be tuned to work in conjunction with the PSS.
e) Rapid load changes can result in large VAR swings from PSS response that utilize electric power. Upgrading to type 2 PSS input (integral of accelerating power) may solve this problem.
f) Another major concern is that PSS response should be checked with UEl limits as many times UEL can result in PSS to be made off which can result in negative damping in the system with a high load angle scenario. In one plant when the UEL limit got hit has led to PSS being switched off causing LFO.

5.2 Experience of PSS tuning in Indian Power System

Some of the experiences of PSS tuning in Indian Power sector has showed following observations

5.2.1 Model validation

Model validation is one important aspect that needs to be carried out during the PSS tuning exercise as the first step. This ensures the study results and actual site tests are matching and the calculated PSS setting can be directly implemented for further PSS testing and fine- tuning. This can be done by validation of the local mode of frequency during the step test. Among all vendors referred in table 1, only vendor V1 performs the model validation during actual PSS tuning.

5.2.2 Measurement devices

One of the major issues observed during the field testing is the lack of a high sample rate (>10 Hz) and high-resolution recording (up to 2 decimal places) devices for important parameters. In the absence of good data, validating the response and deciding whether the system is adequately damped becomes difficult. One such example is shown in figure 1 corresponding to vendor V2 where accessing the damping is not quite visible due to low- resolution data.

5.2.3 Reference voltage step change

During tuning it was observed that a voltage step of 5 % is good for analyzing the PSS response on active power damping. In many cases, vendors have utilized smaller voltage steps of 1%-3% which were found to be inadequate for analyzing the response.

5.2.4 Disturbance test:

Overall plant response can only be determined by a disturbance test. It is one of the most effective tests to ensure the actual performance of PSS during an actual event. The disturbance test is done by either switching of transmission lines/ shunt compensation or creating any artificial fault on any of the transmission lines evacuating from the generating plant. The precursor to this test is that first the PSS in all units for the plant is tuned with step response. While performing this test, first the PSS of all units is made off and then disturbance is applied. Again, the same sequence is performed by keeping PSS on for all units. In case there are different capacity units, then the first PSS of the same capacity units to be tested one by one and then overall plant testing can be completed and compared in the sequence as described above.

5.2.5 Generation level for PSS tuning

PSS damping effect is more pronounced when the unit is generating on the higher side. Therefore, PSS tuning is recommended to be conducted at the generation level of 80-100 % of the rated capacity. During field testing, it was observed that PSS has cutoff criteria due to which below a certain constrained generation level, it gets bypassed. It was observed that in the thermal power plant that it is bypassed below the technical minimum level and for hydro its generally 0-10 % of the unit capacity. So, while performing step test on one unit, the generation level of other unit is also to be known so that its PSS on/off status is known. In addition to this, all the PSS tuning test at the generators must be done at the same generation level so that results/output can be easily compared.

5.2.6 Governor status

In India, restricted governor mode of operation (RGMO) has been implemented on governor control in line with IEGC. To get appropriate results by creating an ideal condition for PSS tuning, generator primary frequency response control must be switched off as due to frequency variation the generation point keeps on varying, and thus comparison among various test results becomes difficult.

5.2.7 PSS gain

During testing, it was observed that utilities are conservative on increasing PSS gain even though sufficient margin is available for better PSS performance. Thus, to resolve this issue, PSS study was carried out to provide them with sufficient input on how higher gain improves PSS performance on damping without compromising on the security aspects. One example of a PSS response with higher PSS gain is shown in figure 2.

5.3 Simulation Studies to be carried out before PSS Tuning

1. Inputs from plant to be taken as per the data format at Annexure E and preparation of the Base Case
2. List of Assumptions and the Details of different local/inter-area modes from PMU data to be taken for the base case.
3. Damping Indices such as Damping Ratio, Gain Margin, Phase Margin and Settling Time. There are two ways for damping calculation. One is based on successive peak reduction methods while the other is measurement techniques like Prony, Matrix pencil, etc. which utilizes exponential decaying sinusoidal representation of the power system signal. Practical indices are given below. Range is in line with IEEE 421.2 Standard.

Table 5.3

Damping Index	**Range**
Gain margin	2-20 dB
Phase margin	20 to 80 degrees
Mp	1 to 4 (0-12 dB)
Bandwidth	0.3-5 Hz

Overshoot	0% to 40%
Rise Time	0.025s-2.5s
Settling Time	0.2s-10s
Damping Ratio (cos phi)	0.25-1

4. Constructing GEP(s) and the Procedure for finding Local Mode and the standard software for root locus as per 3.3 in the previous chapter. The tuning of GEP to be done as per the requirement.
5. Selecting Parameters and Tuning PSS(s), using standard software for bode plots, such that compensated phase = +/-30 degrees at 0.1Hz - 4Hz Preferably achieve low gain and phase lag at noted modes
6. Gain test (3x) using root locus, Running the model for different simulated tests using standard transient stability program, Step test & Disturbance Test
7. Simulation Report Template for handing over to Plant

5.4 Modeling of Power Plant during Study[8]

Any Generating power plant where PSS tuning is to be carried out may not have the details of complete Indian power system for dynamic study. However, they have the details of the transmission system evacuating from their substation. So, a detailed modeling of the generator with adjacent nodes needs to be done during PSS tuning. Further in a large integrated system like all India Grid, it is difficult to carry out simulation studies. It is therefore desirable to have following approaches

1. Single Machine Infinite Bus (SMIB) System – In this approach an equivalent infinite bus to be represented by the rest of the grid is required to made available to the generator company, based on which generator can carry out simulation studies adopting the optimal PSS & Settings (for more details see chapter 1)
2. Plant bus with Incidental Buses are modeled in detail & rest of the grid with equivalent generators at remote buses – in this approach, up to 3rd buses from the plant are modeled in detail and at the 3rd bus equivalent generator representing the rest of the system is required to be modeled. All the details are required to made available to the Generator for carrying out simulation studies

[8] Designing a stabilizer for satisfactory operation with an external system reactance ranging from 20% to 80% on the unit rating will ensure robust performance (Ref: Vitthal Bandal, Student Member, IEEE, B. Bandyopadhyay, Member, IEEE, and A. M. Kulkarni “Design of Power System Stabilizer using Power Rate Reaching Law based Sliding Mode Control Technique”

for adopting the optimal PSS settings (for more details see Multi Machine model in Chapter 2)

Out of the above two choices the first choice seems to be a simplistic approach and easily implementable.

During the Study, the generating power station is connected to Infinite Bus such as the system becomes a SMIB system which means constant voltage and constant frequency at the Infinite Bus (as already discussed in Chapter 1). An estimated total external grid reactance varying from (including main transformer reactance) 0.2 to 0.8 pu (on Generator MVA base) connecting the generator to the infinite grid need to be used for simulation. This will enable to check the AVR response and PSS output during varying network topologies ranging from strong to week system.

To validate the models, the AVR step test, which is implemented to give the small step voltage into the summing junction of the AVR reference, is simulated in terms of both armature voltage, V_t, and generator field voltage, E_{fd}. The response of the excitation system to a 5% step change of AVR needs to be plotted.

5.4.1 Phase Compensator tuning

Following points should be considered while identifying phase compensations

a) Identify inter-area modes of oscillation. Measure generator and excitation system response without PSS.
b) Time constants of two lead-lag blocks should be optimally determine for this purpose. Normally, in the range of low frequency oscillations ranging from 0.1 to 2 Hz, time constants of the PSS should be selected to compensate for the phase lags of the system by linear analysis. The time constants for the phase compensation for T1, T2, T3 & T4 can be 0.25, 0.025, 0.25 & 0.025 respectively.
c) PSS should be tuned to provide as close to 0 degrees of phase shift as possible at the inter-area frequency or frequencies. The destabilization of intra-plant modes with higher frequencies should be avoided.
d) If local stability concerns require PSS settings resulting in an inter-area phase shift other than zero, the setting shall in no case result in a phase

shift more than 40 degrees at inter-area modes. The compensated phase lag at local mode frequency should be below 100^o, preferable near 2Hz.

e) The PSS provides substantial phase shift so that the electrical torque provided by the generator is approximately in phase with speed. The goal is to eliminate phase lag as best as possible throughout a wide range of frequencies of interest, then adjust gain.

5.4.2 Washout

To eliminate the steady sate bias output of PSS, washout is required. There is an interrelationship between the phase compensation and the washout time constant as already discussed in chapter 2. Short washout time constants provide additional phase compensation in frequency-based PSS at the lower frequencies while dramatically reducing the gain. A washout time constant of 10 seconds or less is recommended to quickly remove low frequency components (below 0.1 Hz) from the PSS output. The smaller time constant will reduce the influence on the system voltage from the PSS during any sustained/extended frequency deviation (i.e., loss of generation), especially if the PSS has a high gain setting.

5.4.3 Gain Selection

Gain Selection has already been discussed in detail in Chapter 2 GEP section. For the gain tuning of PSS, eigenvalue analysis is used to determine a range of the gain instead of a single gain value. It had to be determined, not only from analytical methods, but also from field testing, to obtain the gain that could provide the best possible damping of the selected modes while keeping the noises from the PSS at an acceptable level. The control mode of the system became unstable while the local mode of oscillations is stabilized as the system gain, Ks, increased. At approximately 25 p.u. of the system gain, the control mode became un-stabilized. Therefore, the tentative range of the gain can be selected near a third of the un-stabilized gain value at which the local mode has been stabilized. The maximum gain is supposed to be in the range of 7 to 8 p.u.

5.4.4 Time – Domain Simulation

After tuning of the PSS parameters, the effect of the tuned PSS should be simulated in the time-domain by transient stability programs, such as PSS/E or TSAT, among others. A 2% AVR step response and a three-phase fault test simulated in the time-domain for this purpose will show a greater degree of damping to the oscillations compared to a system without the PSS.

5.4.5 Commissioning Tests:

a. Perform an impulse response by injecting a large signal into the AVR (5-10%) and identify local mode damping. Verify local mode oscillation damping has improved, or, at a minimum, has not been degraded.
b. Additionally, non-take over type under excitation limiters (UEL) must be coordinated with the PSS to ensure stable performance during limiter operation. After the gain is set, under excite the machine until the UEL becomes active and perform a step and/or an impulse response test while monitoring the output power (MW). Ensure that the UEL is not interacting with the PSS in such a way that the damping level is reduced, or instability is observed (since the PSS reduces the gain margin in the UEL control and vice versa).
c. If instability is observed, retuning of the UEL or PSS is required. Coordination should be performed with all appropriate limiters in the AVR.

5.5 The varying operating conditions are:

a) External Network Reactance: By Varying External Network reactance from 0.15 p.u. to 0.5 p.u. in step of 0.05- and 0.1 p.u.
b) Generator Reactive Power: keeping reactive power to Maximum, Minimum and Zero with maximum real power output.

5.6 The various perturbations applied are:

a) Step Response: The perturbation consists in voltage reference steps increase as well as a decrease of 2 % and 5 % magnitude.

b) 3 phase Fault on Transmission line connecting the generator and its tripping: 100 ms three phase fault on the mid-way of the line with connecting the generator with the grid followed by its tripping. This is to be done for all the lines if the generator is connected to multiple substations (Only if detailed modeling is done)

c) 3 phase faults on the HV side of main generating transformer: 100 ms three phase fault on the generating transformer.

5.7 Performance Verification in Field tests

5.7.1 AVR Step response test with open circuited Generator

This test is carried out to establish the internal DC voltage of the AVR and to get the behavior of the excitation system of the generator. It also confirms the validation of the excitation models used in offline simulation of PSS tuning. A 3% AVR step signal may be injected into the summing point of the AVR at 3600 turbine speeds (rpm), with the main circuit breaker open. The results obtained are to be matched with the models used in the simulation to establish that the excitation models are validated.

5.7.2 AVR Step response test with Full Load (Before Tuning)

In this test, the validation of the existing PSS parameters set by the manufacturer can be checked by a 2% AVR step test (e.g., If the time constant for phase compensation is set at 0.5 sec. and the gain is set approximately 7 p.u., a high-frequency oscillation appears in the outputs. This should be ascertained through off-line simulation, the control mode of the system seems unstable because of the inappropriate parameters of the PSS, including time constants for phase compensation and system gain).

5.7.3 PSS Gain Margin Test

After setting the tuned parameters in the PSS, the gain margin test should be performed by increasing the gain step-by- step, without applying step signal until one of the output signals was hunted. (e.g., for a typical system suppose at approximately 20 p.u. of the gain, the MW and field voltage is found to be hunting then, the maximum gain should tentatively be considered as 7 p.u.). The final value of gain should be selected after checking the response in the next test.

5.7.4 AVR Step Response Test with Full Load (After Tuning)

In this test, the damping effects at each gain are observed in accordance with an increase in the gain, up to the tentative value set in the previous gain margin test. (e.g., the final value of PSS gain is set at 7 p.u. after an analysis of the damping of power oscillations, number and amplitude of swings, and field voltage variation. Compared with the results without PSS (gain=0), the damping of low-frequency oscillation is significantly enhanced for the tuned PSS (gain=7)). This establishes that the parameters of PSS were successfully tuned so that the performance of PSS was finally verified in the field test.

5.7.5 Impulse test

As the actual disturbance cannot be applied to units during PSS tuning at the site, so to check unit the response for the various disturbance, an impulse test can be carried out. That's why it is a complimentary test to the disturbance test. As demonstrated like the frequency response test, random noises as done for frequency response test, low magnitude Impulse type signal can be superimposed over the generator terminal voltage reference for a step-change in impulse input, the response of generator and exciter parameters can be checked with and without PSS.

5.7.6 OEL/UEL test

After the PSS gain is set, it is important to ensure that under excitation limiter (UEL) & over excitation limiter (OEL) is not interacting with the PSS in such a way that the damping level is reduced or instability is observed. For this, the machine is under and overexcited until the UEL/OEL becomes active and then step/impulse response test is performed. If any instability is observed in active power, then retuning of the UEL/OEL or PSS is required.

5.7.7 Frequency response test

Frequency response testing consists of applying a known driving signal to the system (or a portion of the system) and measuring the output (or an intermediate point) concerning to the input. Several methods are used to measure frequency response, including methods that apply either sinusoidal or noise signals. Frequency response testing has the advantage that the transfer function of the element under test is often immediately evident. For this reason, the frequency response method is recommended for determining the small-signal transfer functions of excitation system components.

5.7.8 Disturbance test

This is the most effective way to check PSS performance by creating an actual disturbance like the opening of transmission lines/switching of reactors after consultation with the system operator. This ensures the conformance of the PSS tuning impact in real-time. During this test, all units at the plant should have their PSS out service followed by all units with their PSS in service.

5.7.9 Governor test

The interaction of the PSS with changes in Active Power should also need to be tested by application of a +0.5 Hz frequency injection to the governor while the Generating Unit is selected to Frequency Sensitive Mode. This ensures PSS performance during frequency events.

5.8 Additional test which can also be performed by the generator to ascertain the PSS response under other varying condition.

5.8.1 Active Power Response Test:

The interaction of the PSS with changes in Active Power should also be tested by application of a +0.5 Hz frequency injection to the governor while the Generating Unit is selected to Frequency Sensitive Mode.

5.8.2 Actual Disturbance Test (if Possible)

The PSS performance also to be tested with creating actual disturbance like the opening of transmission lines/Switching of Reactors/Other after consultation with RPC and RLDC. This ensures the conformance of PSS tuning impact in real time.

5.9 Care to be taken while performing the PSS tuning.

a) The test should be stopped when the large deviation is observed in simulated and actual response.
b) Any Test should be immediately stopped when growing/sustained oscillation is observed in the parameters of the generator.

c) When performing a frequency response test on a generator connected to the grid, caution should be exercised when injecting frequencies that are close to the resonant frequencies of the machine (e.g., local mode, inter-area mode, intra-plant mode) or neighboring machines.

d) Extreme care should be taken when injecting frequencies higher than 3 Hz, as these may correspond to the lowest shaft torsional frequencies of turbogenerator sets. The turbine manufacturer should be consulted to obtain a torsional profile of the rotor turbine shaft prior to proceeding with testing.

5.10 **PSS Tuning Report**

The PSS Tuning Report should be able to demonstrate the following and should include:

A. Improved damping following a step change in voltage from 1% -5%.

B. Improved damping of frequencies in the band 0.02 Hz – 4 Hz.

C. Any oscillations getting damp out within 2 cycles.

D. No appreciable instability at 3 times proposed gain.

E. Improved Damping under variable system operating condition (Real and Reactive Power and Terminal voltage) and network topologies by varying the system impedance (15 % < X system impedance < 50 %).

F. Improved Damping after the short circuit as for a duration defined in CEA transmission planning Criteria 2013 on the directly connected lines from the generating station.

G. Should not have negative interaction or any adverse impact on the torsional mode of the generator (Applicable for Large Steam Turbine generating unit on single shaft units)

H. Procedure adopted for simulation model validation after PSS Tuning.

I. Changes made on filed during the PSS tuning Activity.

J. Proposed changes / suggestions for the simulation model.

K. Proposed changes / suggestions for the PSS

5.11 **Frequency of PSS field testing**

A. Regular Interval of five years.

B. After large network change near to the generating station.

C. As per operational feedback by system operator.
D. Use simulation outputs.
E. Preferable loading of 80-100% MCR.
F. Before tuning of PSS, the AVR needs to be properly tuned using standard tests as per IEEE Std 421.2-2014.
G. After any abnormal PMU signatures / less-damped oscillations observed.

5.12 **Timelines for PSS Tuning Activity**

Table 5.12

S. No.	Activity	Nodal Agency	Format No.	Due date
1	Advance intimation and simulation data submission by plant to RPC, CTU, RLDC	Power Plant	PSS-F1 (Coal, Gas, Hydro)	31st Dec before the start of due FY.
2	Annual PSS Testing/Tuning plan	RPC	List	31st Mar
3	Share SMIB grid data to plants	RLDC/NLDC	Format PSS-F2	30th Apr
4	Conduct SMIB simulations and provide report with findings to RPC, CTU and RLDC. Submit the PSS tuning planned date for concurrence in OCCM.	Power Plant (with OEM)	Report and model (raw, dyr) along with test date.	30 days before test
5	Feedback from RLDC to plant	RLDC / NLDC	Report	15 days before test
6	Field Testing, PSS tuning, model validation and submission of report to RPC, CTU and RLDC	Power Plant (with OEM)	Report and validated model (raw, dyr)	60 days after test
7	Acceptance and feedback to plant/RPC/CTU	RPC	Report	45 days after report submission
8	Initiate retesting/re-tuning, if needed within 5 years	RPC	List	As required

5.13 **Keeping PSS ON during real-time**

Sometimes the operators at generating plant forget to put ON the PSS after synchronizing of unit (no automatic switching of PSS in/out is available at many plants due to which the plants are manually maintaining the PSS ON/OFF, whenever there is low generation/start-up of unit). As a result, oscillations were observed for longer time with high peak to peak amplitude during N-1 contingency from generating plant. So, compliance monitoring must be there (Ref: WECC Standard VAR-STD-2b-1 – Power System Stabilizer) and suitable actions must be taken for compliance by the generating plant. Code must be taken from RLDC/SLDC to make PSS ON/OFF like RGMO/FGMO.

6. Conclusions

6.1 Block design criteria and choice of parameters:

The tuning of the PSS shall be carried out once in two years or whenever there is significant change in the network nearby the generator. The choice of various parameters of the PSS each of the component block in short is as given below**:**

6.1.1 Washout Circuit

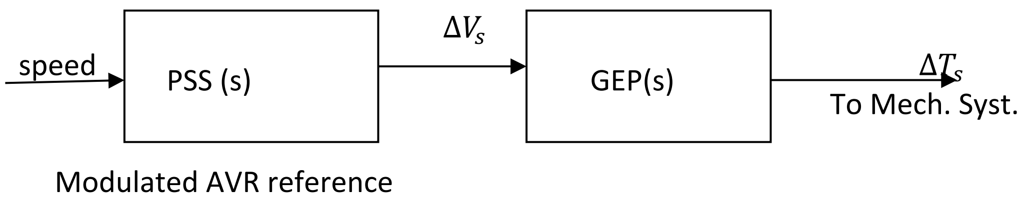
If only the oscillations of frequency around 2 Hz are of interest, the time constant Tw can be chosen in the range of 1 to 2. However, if low frequency modes are also to be damped, then Tw must be chosen in the range of 10 to 20 Sec.

6.1.2 Dynamic Compensator

PSS settings would be set to dampen mode with oscillations within the range of 0.2 Hz to 2 Hz.

The time constants, T1 to T4 are to be chosen from the requirements of the phase compensation to achieve damping torque.

The gain of PSS is to be chosen to provide adequate damping of all critical modes under various operating conditions. It is to be noted that PSS is tuned at a particular operating condition (full load conditions with strong or weak AC system) which is most critical. The critical modes include not only local and inter-area modes, but other modes (termed as control or exciter modes) introduced by exciter and/or torsional filter.



System Block Diagram showing the effect of PSS on Electric Torque

Fig. 6.1.1

The basis for the choice of the time constants of the dynamic compensator can be explained with reference to the block diagram of the Single machine system when PSS is included as shown in the above block diagram. Note that ΔVs is the modulated AVR reference, while Te3 is the component of electrical torque caused by modulating the AVR reference.

The transfer function PSS(s) is obtained from the above figure for speed as the input u. If u, is not speed, but some other signal like electrical power, then PSS(s) should also include the effect of the transfer function between speed and the input. If PSS is to provide pure damping torque at all frequencies, ideally the phase characteristics of PSS must balance the phase characteristics of GEP at all frequencies. As this is not practical, the following criteria are chosen to design the phase compensation for PSS.

The compensated phase lag (phase of P(s) = GEP(s) PSS (s)) should pass through 90o at frequency around 3.5 Hz (For frequency input signal this can be reduced to 2.0 Hz).

The compensated phase lag at local mode frequency should be below 45°, preferably near 20^{o}

The gain of the compensator at high frequencies (this is proportional to TI T3/T2T4) should be minimized.

The first criterion is important to avoid destabilization of intra-plant modes with higher frequencies. It is also preferable to have the compensated phase to be lagging at inter area modes so that PSS provides some synchronizing torque at these frequencies. The time constant of the washout circuit can also affect the compensated phase lag. The third criterion is required to minimize the noise amplification through PSS.

To set the gain of the PSS, root locus analysis is performed. The optimal PSS gain is chosen for the tuning condition as the gain that results in the maximum damping of the least damped mode. The optimum gain (Kopt) is related to the value of the gain (KI) that results in instability. For speed input stabilizers Kopt = 1/3 KI for frequency input stabilizers Kopt = 2/3KI. For power input stabilizers Kopt = 1/8KI.

These thumb rules are useful while implementing PSS in the field without having to do root locus studies.

To summarize, the tuning procedure for the dynamic compensator is as follows:

Identify the plant GEP(s)

Choose the time constants from the phase compensation technique described earlier and from the knowledge of GEP(s).

Select the PSS gain such that it is a fraction of the gain corresponding to instability. This can be determined from root loci.

6.1.3 Torsional Filter

The torsional filter in the PSS is essentially a band reject filter to attenuate the first torsional mode frequency. The transfer function of the filter can be expressed as

$$FILT(s)=\frac{w_n^2}{w_n^2+2\xi w_n s+w_n^2}$$

For stabilizers derived from accelerating power, torsional filter can have a simple configuration of a low pass filter independent of the frequency of the torsional mode to be filtered out. Torsional oscillations are a concern mainly for speed input stabilizers. In PSSs which use power, Delta P- Omega, or acceleration power input torsional filters may not be used.

6.1.4 Limiter

Ontario Hydro (in the WECC report) uses a -0.05 p.u as the lower limit and 0.1 to 0.2as the higher limit. Recent studies have shown that higher negative limit can impair first swing stability.

6.2 Data for carrying out PSS tuning studies and responsibilities of utilities

The Generating Power Plant where the PSS tuning has to be carried out will submit the Generating Unit Data for PSS tuning Study along with the PSS tuning Study Report to CEA/POSOCO/CTU/STU. These details need to be provided prior to the actual tuning of the generating plant in advance (at least 2 months) for validation by CEA/POSOCO/CTU/STU.

6.2.1 The details of Generator Data Submission

A. Generator Dynamic and Short Circuit Data (Standard IEEE Dynamic Model as per PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU)
B. Combined Generator-Turbine inertia of the Unit (in Sec)
C. Generator Transformer Details (R, X, R0, X0, Voltage Ratio, Rating)
D. Generator Excitation Characteristic Details (Type, Make etc.)
E. Curves to be submitted: Generator PQ Capability Curve, VEE Curve, Open and short circuit saturation curve.
F. IEEE Standard Model/ Transfer Function Block Diagram of AVR and PSS and their variation range (As per the PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU)
G. IEEE Standard Model/Transfer Function Block Diagram of Generator Governor and their parameter (As per the PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU) h. Rotor and Stator Current limits.
H. Over excitation and Under Excitation Limit of AVR.
I. Any other details required for Studies.
J. Whenever the Generator Components Models (Generator / AVR / PSS / Governor/ Limiters) are not as per standard IEEE models, the onus will be on generating station to submit a verified generic model in PSS/E format to CEA/ POSOCO/ SLDC/ CTU/STU. The new model submitted should capture the input/output relationship appropriately in the simulation. Further, the Curves submitted should be easily readable. In case it is not readable, then the generator plant should submit at least a set of suitably spaced 10-20 data points to enable reconstruction of the manufacturer curves
K. Formats for RLDC data sharing to Plants is enclosed as Annexure E.
L. Detailed formats for the First time Charging (FTC) may be as per available on the GRID-INDIA website as amended from time to time.

6.2.2 Data from POSOCO

A. Low frequency Oscillation Range for Inter-Area observed in the grid based on analysis of Oscillation monitoring system history of last six months.
B. Inter plant oscillations captured during small perturbations and during faults near the generating units through WAMS system should be periodically shared in the Protection sub-Committee of RPCs to decide the review of PSS Tuning of the nearby Generators.
C. Minimum and Maximum Fault level of the Generator Bus and Adjacent Bus without the contribution of generating unit where PSS has to be commissioned and tuned.

6.3 Operational Planning for PSS testing/tuning of units under commercial operation

Generating units shall submit the testing plan to OCCM. In the test plan, the following details must necessarily be shared.

- Indicated date and test duration
- Generation level at which the test has to be done.
- Transmission switching if required
- Unit synchronization / de-synchronization

On the day of the test, code shall be exchanged with the RLDCs for conducting the test. After concurrence from OCCM, the final plan shall be confirmed to RLDC on D-3 basis (D is the date of scheduled PSS testing).

In case of unit tripping during PSS tuning, the DC of the generators shall be revised by the power plant from the 7th time blocks. Schedules of the beneficiaries would be revised accordingly. Beneficiaries shall treat the unit under PSS tuning as a credible contingency and should be ready with matching reserve within the state control area to avoid deviations. As PSS tuning is a compliance requirement by the power plant, tripping of the unit during testing shall be treated only as a business risk.

During PSS tuning field-test, the desired injection schedule for conducting the test shall be ensured by the beneficiaries. Power plant shall coordinate with the beneficiaries for the same. It is observed that PSS of thermal plant is bypassed (many times automatically) when the generation is below technical minimum.

6.4 Field Tuning Procedure & steps to be followed

1. Briefing to power plant personnel about the PSS tuning activity.
2. Confirm AVR/PSS block diagram and PSS parameter ranges.
3. Actual values of AVR parameter settings to be confirmed (from documentation or visual inspection of settings)
4. If values are different from those used in analytical studies, the design is redone
5. Excitation System Engineer (Manufacturer's representative) shall check the AVR and PSS hardware.
6. To confirm the machine parameters used for design, check whether for a step change in AVR reference, the reactive power response is a good approximation of the simulated response.
7. For step response of AVR reference (2%), obtain the response of generator output power (without PSS)
8. Now include the PSS as follows:
    - Keep output limits at a small range (+I- 0.01).
    - Set the time constants as per analytical studies as follows: Increase the gains in small steps according to a proportion dictated by analytical studies. The values may be increased to slightly more than this value (just to ensure that adequate stability margin exists) and then reverted. If spontaneous instability is detected in field voltage during this process, reduce the gains.
    - Increase limits range to about +/- 0.1 pu.
9. Carry out tests at 4.3 to establish/ensure that the PSS is tuned properly. Tests at 4.4 and Active Power Response Test & Actual Disturbance Test may be carried out if feasible.
10. A report on the tuning activity shall be prepared with all details at 4.9.
11. Monitor PSS and generator as the operating conditions change. The response for close in line faults and tripping be recorded for future analysis.

6.5 PSS Typical Testing Procedure

The following procedure may be followed by generators for the PSS tuning tests and its performance

Table 6.5

Test	Method	Remarks
A	**Frequency Response Test, Step Response Test, Impulse Test without PSS**	
	Synchronous Generator Switched running rated MW, unity pf, PSS OFF	
	1. Record steady state for 10 seconds 2. Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Record steady state for 10 seconds 2. Inject 3% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Inject band limited (0.2- 4Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. 2. Remove noise injection.	
	1. Inject Limited Magnitude Impulse signal (Recommendation of OEM) into voltage reference and measure frequency spectrum of Real Power. In between change the magnitude of Impulse to inject the disturbance. 2. Remove Impulse Injection.	

B	**Gain Margin Test, Frequency Response Test, Step Response Test, Impulse Test without PSS, Active power response test.**	
	Synchronous Generator running rated MW, unity pf, PSS Switched ON	
	1. Increase PSS gain at 30 second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3– x4 2. Return PSS gain to initial setting	
	1. Record steady state for 10 seconds 2. Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Record steady state for 10 seconds 2. Inject +3% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. 2. Remove noise injection.	
	1. Select the governor for Frequency Sensitive Mode (FSM) 2. Inject +0.5 Hz step into the governor. 3. Hold until generator MW output is stabilised 4. Remove step	
C	**Under-excitation limiter Interaction test**	

	Synchronous generator running rated MW at unity power factor. Under-excitation limit temporarily moved close to the operating point of the generator	
	1. PSS on. 2. Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	Under-excitation limit moved to the normal position. Synchronous generator running at rated MW and at leading MVAr close to Under-excitation limit.	
	1. PSS on. 2. Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
D	**Over-excitation limiter Interaction test**	
	Synchronous Generator running rated MW and maximum lagging MVAr. Over-excitation Limit temporarily set close to this operating point. PSS on	
	1. Inject positive voltage step into AVR voltage reference and hold. 2. Wait till Over-excitation Limiter operates after sufficient time delay to bring back the excitation back to the limit. 3. Remove step returning AVR Voltage Reference to nominal	
	Over-excitation Limit restored to its normal operating value. PSS on	

References

1. CEA (Technical standards for connectivity to the Grid) Regulation, 2007 and CEA Technical Standard for Construction of Electrical Plants and Electric Lines.
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4. Standard technical specification for main plant package of sub- critical thermal power project 2 x (500 MW or above), CEA, Sept 2008.
5. CERC, Indian Electricity Grid Code 2010
6. CEA Transmission Planning Criteria 2013
7. Report of the Task Force on Power System Analysis under Contingencies, August 2013, New Delhi.
8. PSS Tuning Study and Implementation finalized by ERLDC & ERPC in 171st OCC.

Annexure A

(Extracts from WECC Report)[ii]

Simplified Power System Stabilizer Tuning Procedure for Hydro Units with Static Exciters

This procedure assumes that the unit in test will remain stable when the Power System Stabilizer is removed from service.

1. Attach equipment. Disconnect the Power System Stabilizer (PSS) from the Automatic Voltage Regulator (AVR) summing junction. Perform a frequency response of the terminal voltage (Vt) vs. V signal with the unit at full load.
2. From the V-t frequency plot, establish the phase delay of the exciter and generator (for example 154 o at 0.4Hz).
3. Tune the Washout and PSS to provide phase lead in the frequency range of 0.1Hz to 1.0Hz equal the phase lag of Vt. The phase lead angle is equal to 90 +180 -- 26 =296 or – 64. 90 is derived from Pe lagging the terminal voltage by 90. The 180 is to be compensated for the – 1 of the PSS.
4. Turn the gain of the PSS to near 0. Synchronize the unit. Ensure that the PSS output is not connected to the AVR summing junction (test switch 2 is open).
5. Perform a frequency response of Pe vs. V-signal. This will indicate the frequency of the local mode oscillation. However, this will not indicate the inter-area oscillations, as they are very difficult to excite with a single machine connected to a very strong bus.
6. Now that the local mode phase and frequency are known with the help of pole-zero placement techniques, the PSS settings can be calculated.
7. Use a modeling program or equivalent mathematical program to verify PSS settings are going to result in the proper phase in the inter-area (0.1Hz to 1.0Hz) and provide indication of the local mode damping.
8. Apply settings to PSS with gain turned down. Ensuring test switch 2 is open. Connect test equipment to the PSS, replacing the Watt Transducer output (PSS input) with V-signal.
9. Compare the frequency response of the model and actual equipment to ensure correct operation of the PSS.
10. Reconnect the watt transducer to the PSS. With the machine on-line at a reasonable loading, connect the PSS (test switch 2).

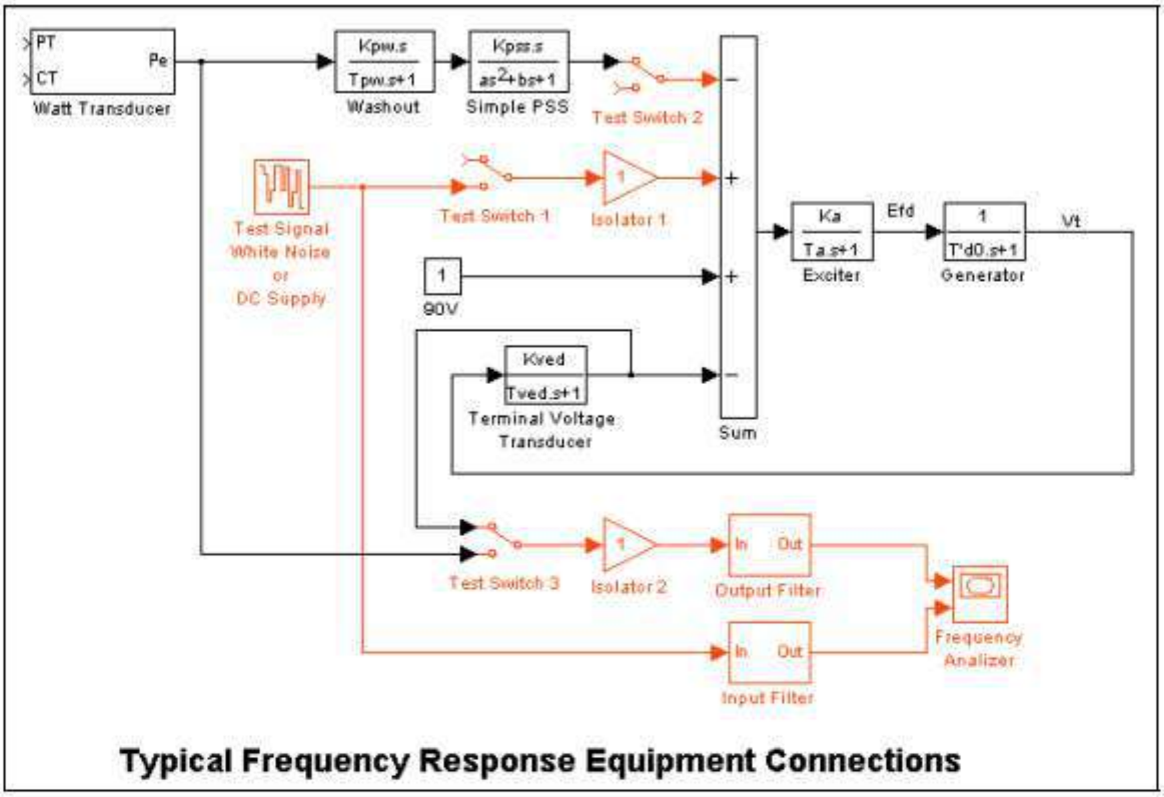

Figure 1

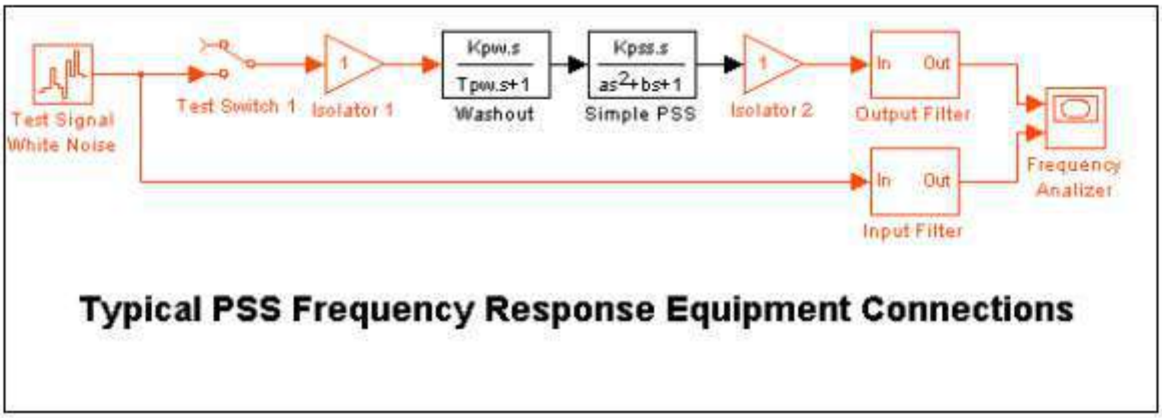

Figure 2

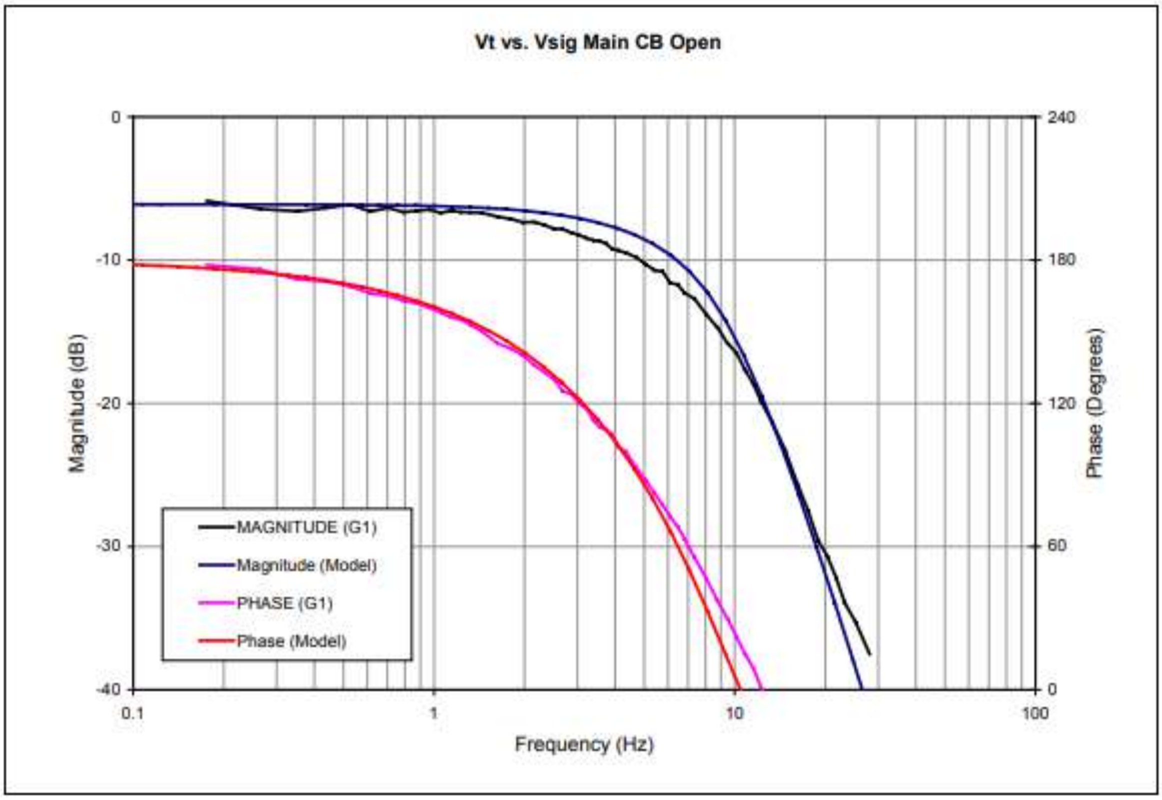

Figure 3

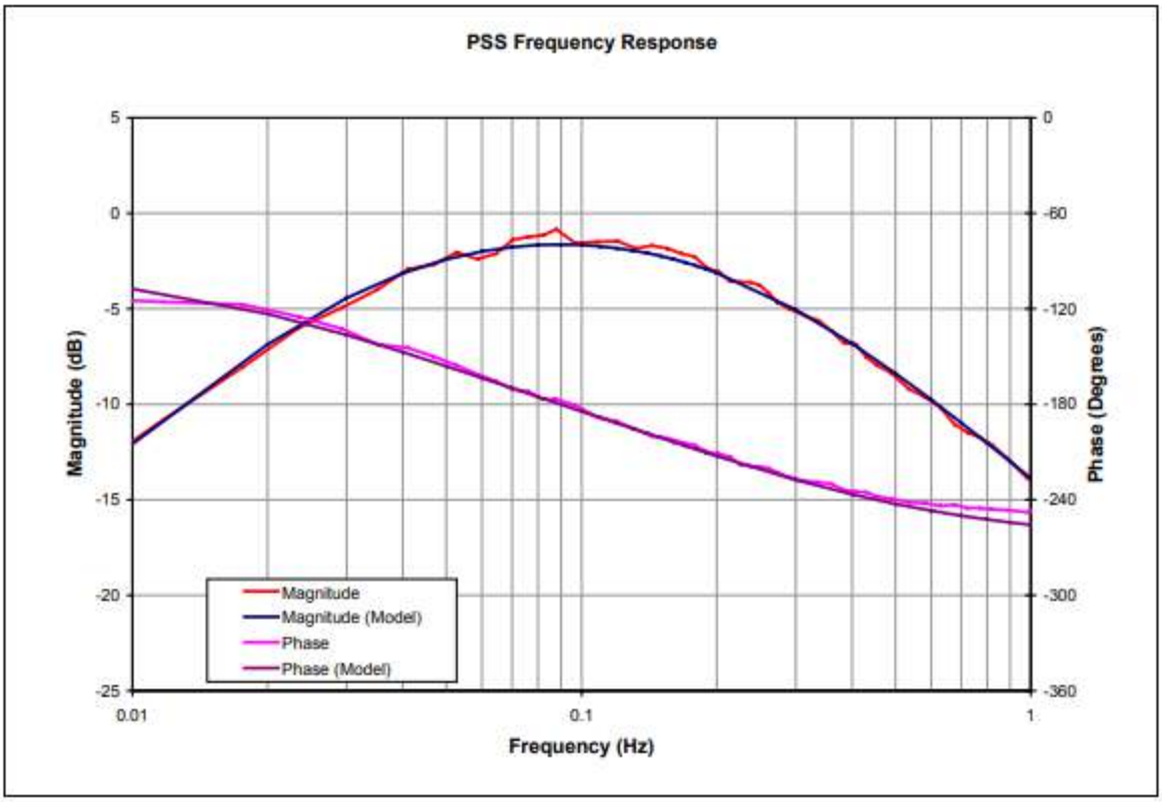

Figure 4

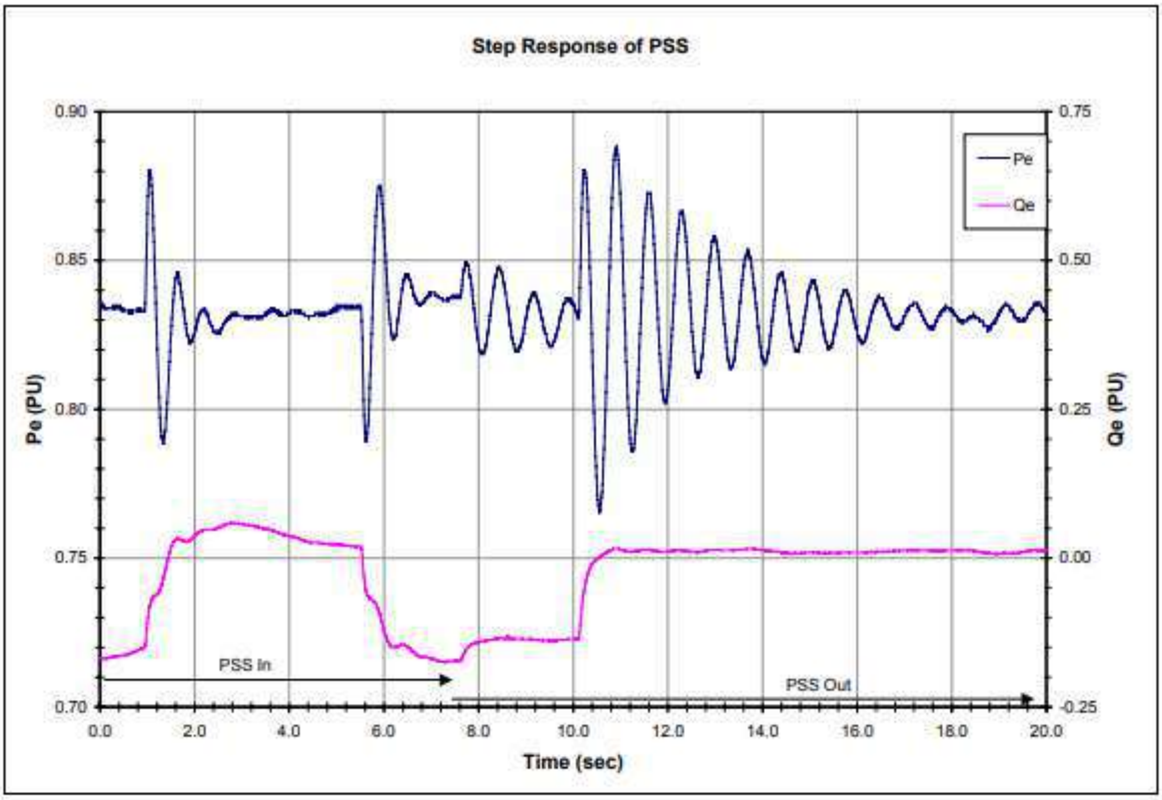

Figure 5

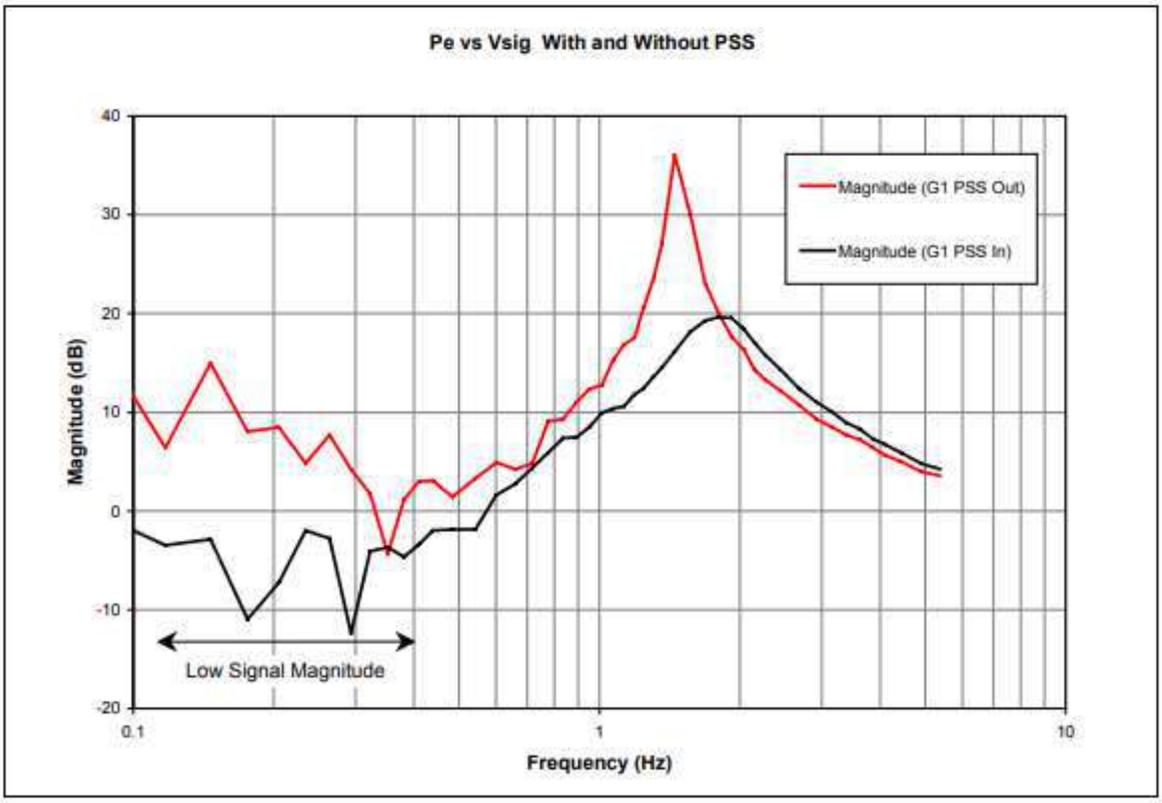

Figure 6

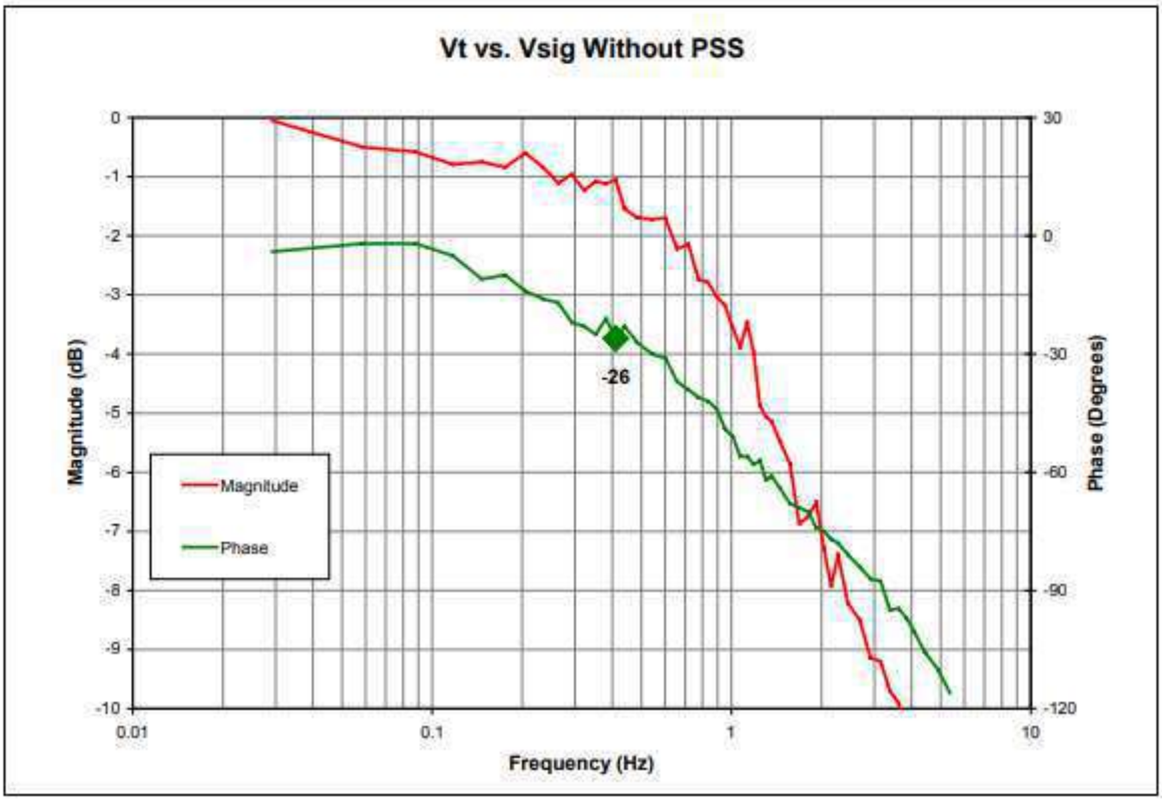

Figure 7

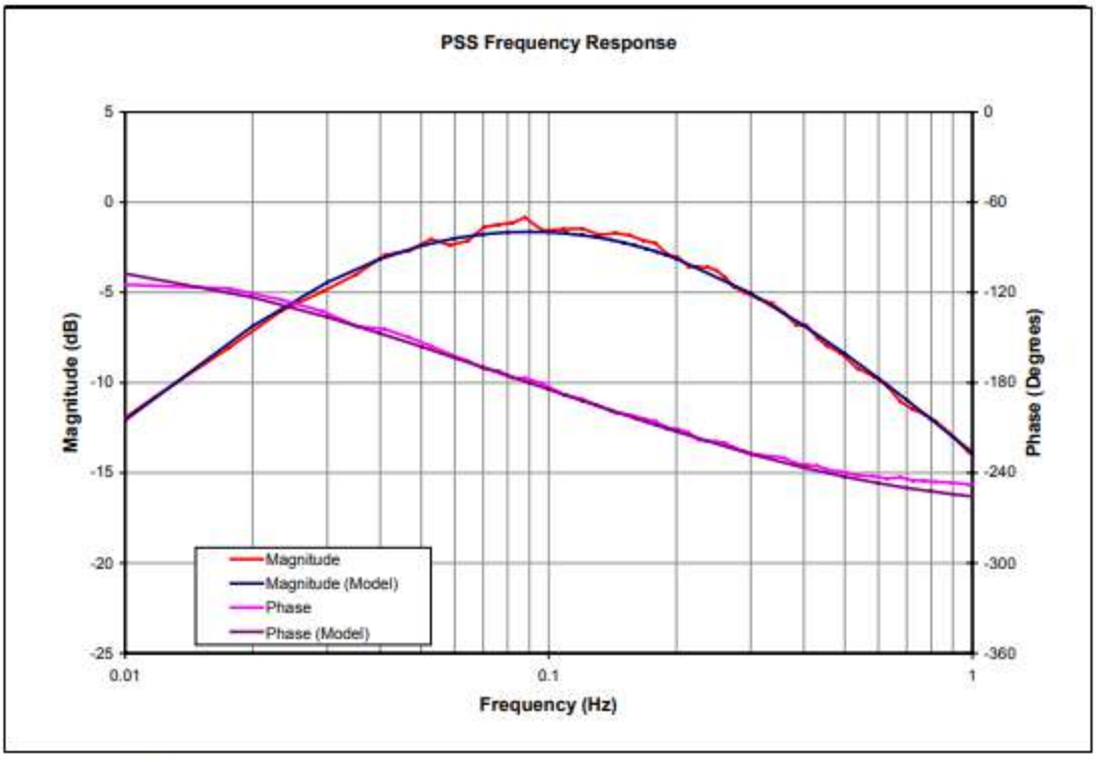

Figure 8 Model Verifcation

IEEEST Model

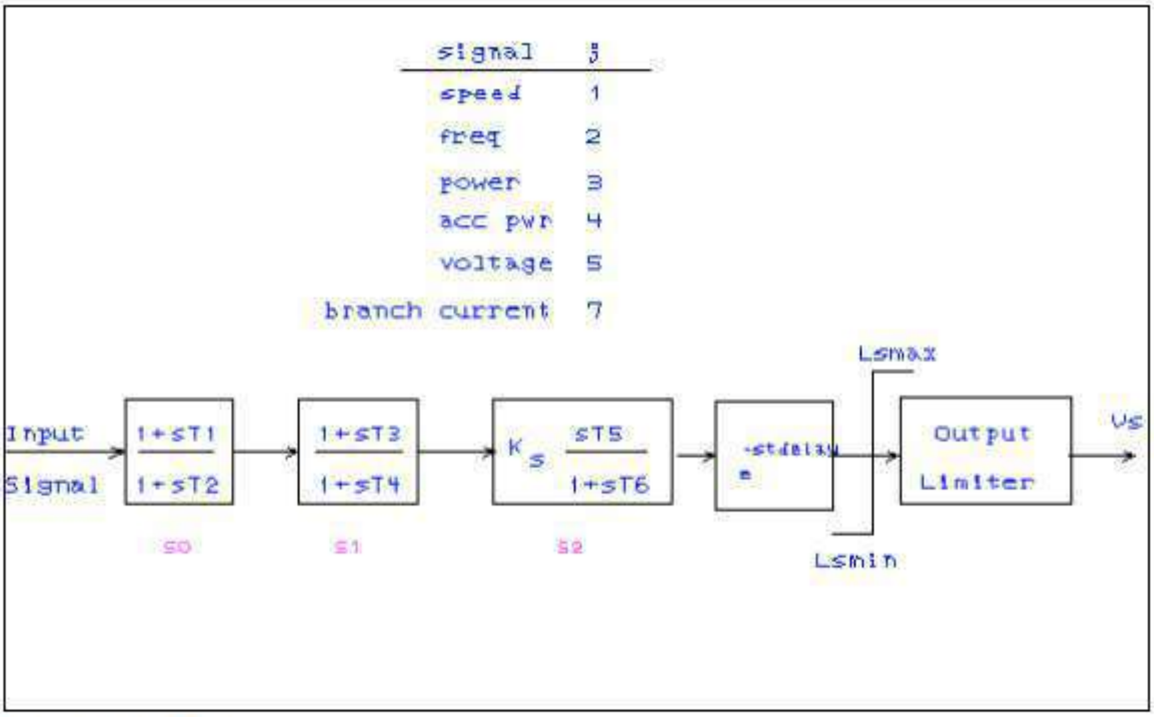

Figure 9 IEEEST Model

Bus No.	Bus Name	PSS/E MODEL	ID	T1	T2	T3	T4	T5	T6	Ks	Lsmax	Lsmin	Tdelay
6021	KCL G1 13.8	IEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6022	KCL G2 13.8	IEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6023	KCL G3 13.8	IEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6024	KCL G4 13.8	IEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00

Figure 10 Model Parameters

Annexure B

Commonly Used PSS as Per IEEE Standard

1. PSS1 A: Generalized form of a PSS with a single input. Some common stabilizer input signals are speed, frequency, and power. Typical design parameter for power system stabilizers with frequency or speed input is given in the table 1 and 2 respectively.

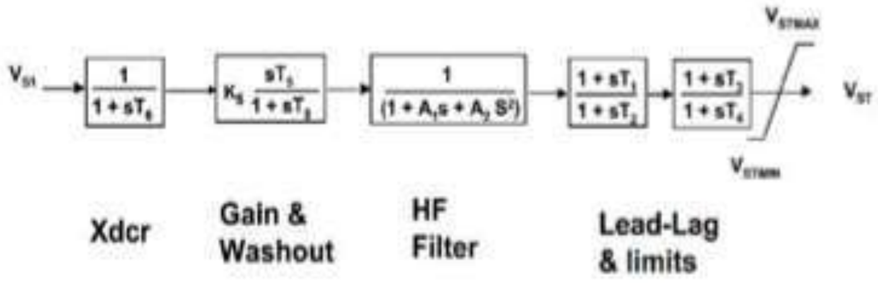

Figure.1

PSS1A Table 1: Range of typical design parameters for power system stabilizers with frequency or speed input

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_5	0.5 s to 50 s	Washout (reset) time constant
T_1, T_3	0.03 s to 2.0 s	Lead (zero) time constant
T_2, T_4	0.01 s to 10 s	Lag (pole) time constant
K_S	0.10 pu to 10 pu	Stabilizer gain
V_{STMIN}, V_{STMAX}	±0.02 pu to ±0.10 pu	Stabilizer output signal limits

Table 2: Range of typical design parameters for power system stabilizers with power input

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_5	0.5 s to 50 s	Washout (reset) time constant
T_1, T_3	0.1 s to 2.0 s	Lead (zero) time constant
T_2, T_4	0.01 s to 0.20 s or 10 s to 20 s	Lag (pole) time constant
K_S	±0.10 pu to 10 pu	Stabilizer gain (sign depends upon choice of input signal)
V_{STMIN}, V_{STMAX}	±0.02 pu to ±0.10 pu	Stabilizer output signal limits

2. PSS2A/2B: This stabilizer model is designed to represent a variety of dual-input stabilizers, which normally use combinations of power and speed or frequency to the stabilizing signal.

This model can be used to represent two distinct types of dual-input stabilizer implementations as described as follows:

A. Stabilizers that, in the frequency range of system oscillations, act as electrical power input stabilizers. These use the speed or frequency input for the generation of an equivalent mechanical power signal, to make the total signal insensitive to mechanical power change.

B. Stabilizers that use a combination of speed (or frequency) and electrical power. These systems usually use the speed directly (i.e., without phase-lead compensation) and add a signal proportional to electrical power to achieve the desired stabilizing signal shaping.

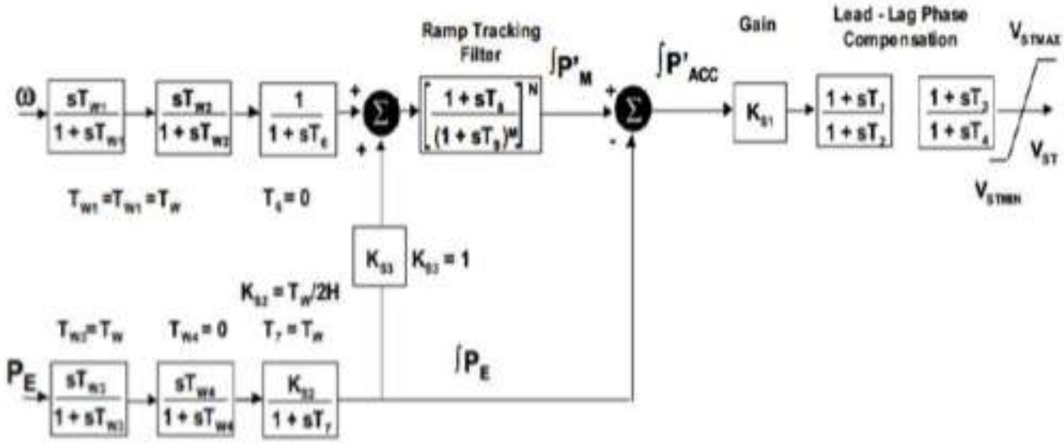

Figure 2: PSS2A

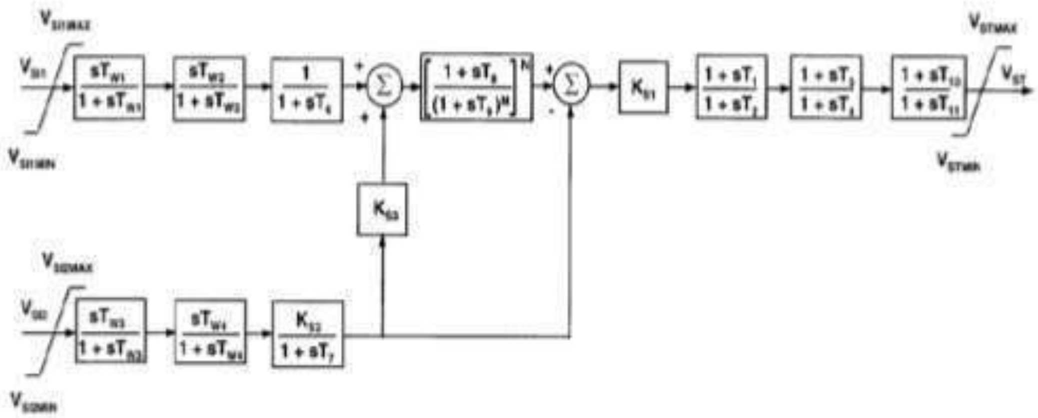

Figure 3: PSS2B

Table 3 : Range of typical design parameters for dual input power system stabilizers (PSS2A/2B)

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_{W1} through T_{W4}	0 s to 20 s	Washout (reset) time constants[a]
K_{S2}	0 pu to 10 pu	Mixing gain
K_{S3}	1	Mixing gain[b]
T_8, T_9, N, M	$T_8 = 0.5$ s; $T_9 = 0.1$ s; $N = 1$; $M = 5$ or $T_8 = 0.3$; $T_9 = 0.15$; $N = 4$; $M = 2$	Selected to minimize voltage change during mechanical power changes[c]
T_7	0 s to 20 s	Low pass filter time constant[b]
T_1, T_3, T_{10}	0.01 s to 6.0 s	Lead (zero) time constant
T_2, T_4, T_{11}	0.01 s to 6.0 s	Lag (pole) time constant
K_{S1}	0.10 pu to 50 pu	Stabilizer gain[d]
V_{STMIN}, V_{STMAX}	±0.02 pu to ±0.10 pu	Stabilizer output signal limits[d]

[a] A value of 0 indicates a bypassed block.
[b] When the PSS2A or PSS2B structure is used to represent integral-of-accelerating-power-based PSS units $K_{S3} = 1$, $T_7 = T_{W2}$, $T_{W4} = 0$, $K_{S2} = T_7/(2 \times \text{inertia})$.
[c] Some special circumstances may require alternative selection of T_8, T_9, N, and M.
[d] V_{STMAX} and K_{S1} typical values assume V_{REF} summation point PSS.

3. PSS 3B: The PSS model PSS3B has dual inputs of electrical power (VSI1) and rotor angular frequency deviation (VSI2). The signals are used to derive an equivalent mechanical power signal. By combining this signal with electrical power, a signal proportional to accelerating power is produced. The time constants T 1 and T 2 represent the transducer time constants, and the time constants T W1 to T W3 represent the washout time constants for electric power, rotor angular speed, and derived mechanical power, respectively. In this model, the stabilizing signal V ST results from the vector summation of processed signals for electrical power and angular frequency deviation.

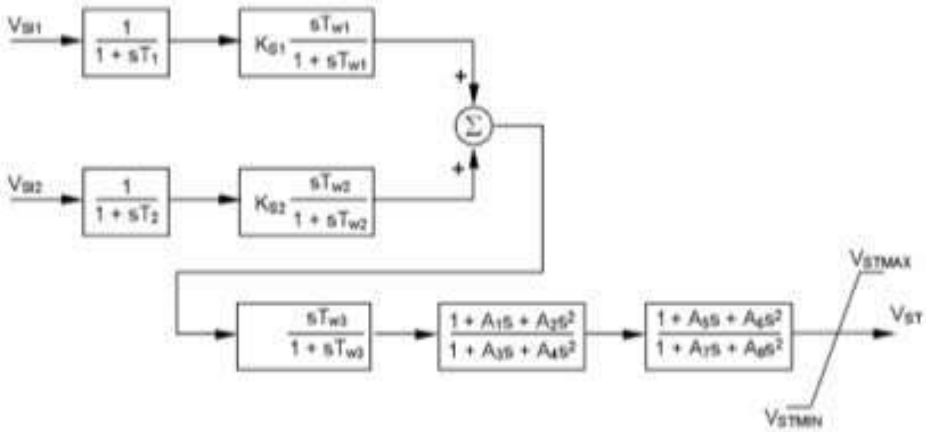

Figure 4: PSS3B

4. PSS4B: The PSS4B model represents a structure based on multiple working frequency bands. Three separate bands, respectively dedicated to the low-, intermediate- and high-frequency modes of oscillations, are used in this delta-omega (speed input) PSS. The low band is typically associated with the power system global mode, the intermediate with the inter-area modes, and the high with the local modes. Each of the three bands is composed of a differential

filter, a gain, and a limiter. Their outputs are summed and passed through a final limiter V STMIN /V STMAX resulting in PSS output VST

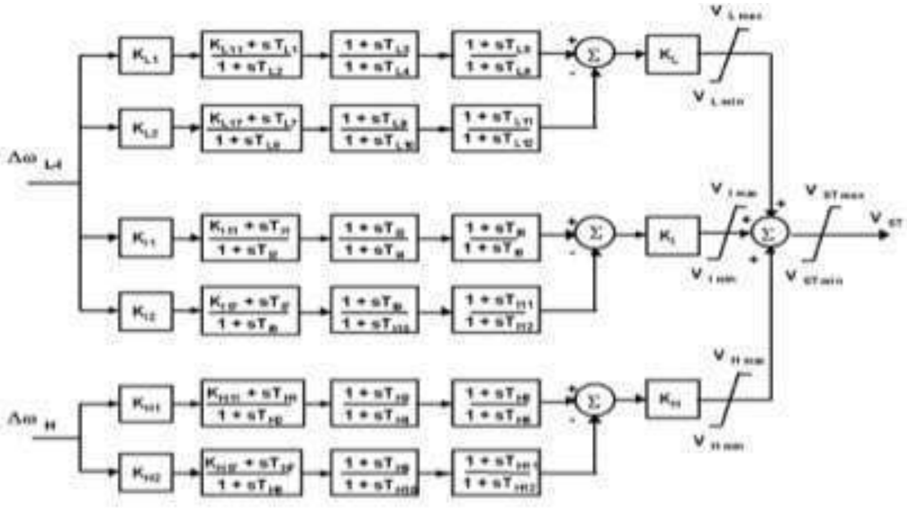

Figure 5: PSS4B

Table 4 Range of typical design parameters for multi-band power system stabilizers

Symbol	Typical range	Definition
F_L	0 Hz to 0.3 Hz	Low band central frequency
F_I	0.3 Hz to 2 Hz	Intermediate central frequency
F_H	2 Hz to 10 Hz	High band central frequency
K_L	0 pu to 10 pu	Low band gain
K_I	0 pu to 50 pu	Intermediate band gain
K_H	0 pu to 100 pu	High band gain
VL_{MIN}, VL_{MAX}	0 pu to 1.0 pu	Low band output signal limits
VI_{MIN}, VI_{MAX}	0 to 1.0 pu	Intermediate band output signal limits
VH_{MIN}, VH_{MAX}	0 to 1.0 pu	High band output signal limits
V_{STMIN}, V_{STMAX}	0 to 0.1 pu	Stabilizer output signal limits

Annexure C

Eigen Value Analysis of SMIB System

Consider the system:

$$\dot{x} = f\,(x\,,u\,)$$

The stability of an equilibrium point can be judged by the solution of the linearized system at the equilibrium point x_o Letting

$$x = x_o + \Delta\, x$$

and $\Delta\, u$ = 0, we obtain:

$$\dot{x} = \dot{x_o} + \Delta\, x = f(x_o, u\,) + \left[\frac{\partial\, f(x,u)}{\partial x}\right] \Delta\, x|_{x=x_o}$$

Therefore

$$\Delta\, \dot{x} = [A(x_o, u)]\, \Delta\, x$$

where A is a nxn matrix whose elements are functions of x_o and u. The ijth element of [A] is given by

$$A_{ij}(x_o, u) = \frac{\partial f_i}{\partial x_j}(x_o, u)$$

For a given x_o, and u, the matrix A is constant. The solution of the linearized state equation is given by

$$\Delta\, x(t) = e\verb|^|A(t - to)\;\; \Delta\, x(to)$$

$$= C_1 e^{\lambda_1 t} v_1 + C_2 e^{\lambda_2 t} v_2 + \cdots \ldots \ldots .. + C_n e^{\lambda_n t} v_n$$

where $C_1, C_2 \ldots .. C_n$ are constants depending on the initial conditions. . λ_i and v_i are the ith eigenvalue and the corresponding eigenvector of matrix [A]. It is assumed that all eigenvalues are distinct. If the number of first order differential equations is n, then there are n eigenvalues It can be seen that if Re[λ_i] < 0 for all λ_i, then for all sufficiently small perturbations from the equilibrium point x_o, the trajectories tend to x_o as $t \longrightarrow \infty$. Hence, x_o is asymptotically stable. If Re[λ_i] > 0 for all λ_i then any perturbation leads to the trajectory leaving the neighborhood of x_o. Hence x_o is unstable. If there exists i and j such that Re[λ_i] < 0 and Re[λ_j > 0] then x_o, is called a saddle point and the system is unstable.

Complex eigenvalues are associated with oscillatory behavior. In this context it is useful to note that:

$$\cos(wt) + j\sin(wt) = e^{j\omega t}$$

$$\cos(wt) - j\sin(wt) = e^{-j\omega t}$$

The extent of a particular mode in the response is dependent on the nature of the disturbance. Some mode (λ_i) may be 'visible' in some states in greater proportion compared to other states. This is determined by the individual components of the 'eigenvector (ν_i) corresponding to that mode. Also, the extent to which a mode is excited depends on the initial disturbance ($\Delta\, x(0)$).

The swing equation for SMIB system is

$$M\frac{d^2\delta}{dt^2} + D\frac{d\delta}{dt} = T_m - T_{max}\sin\delta$$

Where,

$$T_{max} = \frac{E_g E_b}{(x_g + x_o)}$$

The state space form is given by

$$\frac{dx_1}{dt} = x_2$$

$$\frac{dx_2}{dt} = -\frac{D}{M}x_2 - \frac{T_{max}}{M}\sin x_1 + \frac{T_m}{M}$$

Where,

$$x_1 = \delta, x_2 = \frac{d\delta}{dt}$$

The equilibrium points are given by

$$x_2 = 0$$

$$x_1 = \sin^{-1}\frac{T_m}{T_{max}}$$

From the power angle curve shown in Fig. 1.2, it can be seen that there are two values of δ corresponding to a specified value of T_m, (when T_m, < T_{max}) when the range of δ is confined to -180^o < δ < 180^o.

$$x_o^1 = x_s = (\delta_s, 0)$$

$$x_o^2 = x_u = (\delta_u, 0)$$

Let $y_1 = \Delta\, x_1, y_2 = \Delta\, x_2$,

Then,

$$\begin{bmatrix}\dot{y}_1\\ \dot{y}_2\end{bmatrix} = \begin{bmatrix}0 & 1\\ -\frac{K}{M} & -\frac{D}{M}\end{bmatrix}\begin{bmatrix}y_1\\ y_2\end{bmatrix}$$

Where,

$$K = T_{max}\cos\delta_e$$

δ_e is the angle at equilibrium $\delta_s \; or \; \delta_u$

The eigenvalues of the linearized system are given by

$$\lambda = \frac{-D \pm \sqrt{D^2 - 4KM}}{4M^2}$$

If K is positive, then eigen values have negative real parts. If K is negative one of the eigenvalues is positive real. This is true when $\delta_e = \delta_u$ Hence the system is small signal unstable at δ_u. For small D, and K > 0 eigenvalues are complex given by

$$\lambda = -\sigma \pm jw$$

Where,

$$\sigma = \frac{D}{2M}, \qquad w = \sqrt{\frac{K}{M} - \frac{D^2}{4M^2}}$$

Annexure D

Participation factors

In SMIB system it was determined that the response of various states of the system was a combination of several patterns or modes:

$$\Delta x(t) = e^{\wedge}A(t - to) \ \Delta x(to)$$
$$= C_1 e^{\lambda_1 t} v_1 + C_2 e^{\lambda_2 t} v_2 + \cdots \ldots \ldots + C_n e^{\lambda_n t} v_n$$

where c1 c2, c_n, are constants depending on the initial conditions. λ_i and $v_i$are the eigenvalue and the corresponding right eigenvector of matrix [A]. It is assumed that all eigenvalues are distinct.

The extent of a mode being excited is determined by the vector product $c_i = u_i^T \Delta x(0))$ where $\Delta x(0)$ is the initial deviation from the equilibrium point. The vector u_i is called the left eigen vector corresponding to eigenvalue λ_i at and is related to the right eigenvectors v_i as follows:

$$u_i^T v_j = 0 \ i \neq j$$
$$1 \ i = j$$

To characterize the involvement of individual states in the various modes (eigenvalues), we use a measure called 'participation factor': The participation of a particular state j in a mode i is given by,

$$p_i(j) = v_i(j) u_i(j)$$

For certain class of systems, magnitude of $v_i(j)$ and $u_i(j)$ are identical. Then $v_i(j)$ itself is a measure of the participation. The multi-mass multi-spring system is an example of such a system.

The multi-mass multi-spring system is analogous to a multimachine system with I) the machines represented by the classical model, 2) loads being constant power 3) Transmission system being lossless.

In this case, the linearized system equations can be written as

$$[M]p^2 \Delta \delta = -[K] \Delta \delta$$

where $[M]$ is diagonal matrix with $M_{ij} = \frac{2H_j}{w_B}$ (H_j is the inertia constant of j[th] synchronous machine). $K_{ij} = \partial P_{ei} / \partial \delta_j$ where P_{ei} is the power output of i[th] machine, δ_j is the rotor-angle of j[th] machine referred to a rotating reference frame (with the operating speed w_0). If the network can be reduced by retaining only the internal buses of the generators and the losses in the reduced network can be neglected,

$$K_{ij} = -\frac{E_i E_j}{X_{ij}} \cos\left(\delta_i - \delta_j\right) \simeq \frac{1}{X_{ij}}$$

where X_{ij} is the reactance of the element connecting the generator buses i and j. E_i and E_j are the generator voltages?. Assume that the voltages are around 1.0 p.u. and the bus angle difference (in steady state) are small. The matrix [K] is singular and has rank ≤ (m — 1) where m is the size of K (also equal to the number of generators). This enables the reduction of the number-of angle variables by one by treating relative angles (with respect to a reference machine which can be chosen as the first machine) as state variables.

The solution of equation can, in general, be expressed as

$$\vartriangle \delta^R = \sum_{j=1}^{m-1} v_j (c_i \cos w_i t + d_j \sin w_j t)$$

where $\vartriangle \delta^R$ $[\Delta\delta_{21}\ \Delta\delta_{31} \quad \Delta\delta_{m1}]^t$ is the vector of relative angles $(\Delta\delta_{i1} = \Delta\delta_i - \Delta\delta_1)$ $c_i \ldots., c_{m-1}, d_1, d_2, \ldots., d_{m-1}$ are scalars depending on the initial conditions, v_i, v_{m-1} are vectors. The structure of a vector v_j depicts the participation of various machines in the oscillation mode whose frequency is w_j.

Annexure E

Details to Plant for PSS Tuning

1. Lowest possible oscillation frequency: …………………..… Hz
2. Inter-area oscillation frequency: …………………………. Hz (Range is 0.2-0.8 Hz)
3. Local area oscillation frequency: …………………………..…Hz (Range is 1 - 3 Hz)
4. Highest possible Oscillation. Frequency: …………………... Hz
5. Three Phase Short Circuit Level (Fault Level) at step-up transformer HV side (minimum value): ………………………… [MVA]
6. Three Phase Short Circuit Level (Fault Level) at step-up transformer HV side (maximum value): ………………………. [MVA]
7. Assumptions made for calculating short circuit level:

[i] Power System Stabilizers a short course under Continuing Education Program – Department of Electrical Engineering, IIT Bombay, Powai Mumbai
[ii] WECC Power System stabilizer Tuning Guidelines.

सत्यमेव जयते

भारत सरकार/**Government of India**

विद्युत मंत्रालय/**Ministry of Power**

केन्द्रीय विद्युत प्राधिकरण/**Central Electricity Authority**

एन.पी.सी. प्रभाग/**National Power Committee Division**

Ist Floor, Wing-5 ,West Block-II, RK Puram, New Delhi-66, e-mail:rishika@nic.in

No. 4/MTGS/NPC/CEA/2020/ 71—81 Date: 8th February, 2020

To,
(As per distribution list)

Subject: Constitution of "Sub-group to finalize a common procedure for Power System Stabilizers (PSS) Tuning"-reg.

In the 9th meeting of NPC, it was decided that a Sub-group may be constituted comprising of representatives of Protection Sub-Committee (PSC) of respective RPCs, NPC, NLDC, CTU, NTPC and NHPC, to finalize a common procedure for Power System Stabilizers (PSS) Tuning. NPC Secretariat vide letter No. 4/MTGS/NPC/CEA/2020/07-14 dated 01.01.2021 had asked for nominations from all the RPCs, NLDC, CTU, NTPC and NHPC. Based on the receipt of nominations, the composition of the Sub-group has been formed as follow:

S. No.	Designation	Organisation	Name	Constitution of the Committee
1	Member Secretary	WRPC	Sh. Satyanarayan S.	Chairman
2	Member Secretary	NPC	Smt. Rishika Sharan	Member
3	Superintending Engineer	WRPC	Sh. P. D.Lone	Member Convener
4	Executive Engineer	NERPC	Sh. S. Mukherjee	Member
5	Executive Engineer	NRPC	Sh. Ratnesh Kumar,	Member
7	Executive Engineer	ERPC	Sh. Pranaya Piyusha Jena	Member
6	Assistant Executive Engineer	SRPC	Sh. Sriharsha Mundluri	Member
8	Sr. General Manager	CTU	Sh. Partha Sarathi Das	Member
9	General Manager	NHPC	Sh. Umesh Kumar Nand	Member
10	General Manager	NLDC	Sh. Vivek Pandey	Member
11	Chief Manager	NLDC	Sh Phanishankar	Member
11	AGM (OS-SIIS)	NTPC	Sh. Sanjeev Kumar Singh	Member

Term of Reference (TOR) of the Sub-group:

1. To examine the present procedure of Power System Stabilizer (PSS) tuning of generating units in all the five regions of Indian Power System.
2. To study the PSS tuning exercise in the past and to finalize a common procedure for PSS Tuning at all India Level.

Sub-Group may Co-opt/associate any other expert in the field, as they feel necessary.

Yours faithfully,

8/12/2021

(ऋषिका शरण/Rishika Sharan)
मुख्य अभियन्ता एवं सदस्य सचिव,रा.वि.स /
Chief Engineer & Member Secretary, NPC

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Copy for kind information to:

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2. Member (GO&D), CEA

Annexure B.4.1

Grid Controller of India Limited

(formerly Power System Operation Corporation Limited)

National Load Despatch Centre (NLDC)

Procedure

for

Power System Stabilizer(PSS) Testing

Prepared in Compliance

to

Clause 40(2)(c) & 40(3) of Central Electricity Regulatory Commission
Indian Electricity Grid Code
Regulations, 2023

July 2023

Contents

1. Background

This procedure lays down the guidelines for data submission and testing of the Power system stabilisers (PSS).

2. Scope

The procedure shall apply to all generating stations, State Load Despatch Centres (SLDCs), Regional Load Despatch Centres (RLDCs), National Load Despatch Centre (NLDC).

3. Definitions

Words and expressions used in this procedure are defined in the Act or any other regulations specified by the Central Commission or Central Electricity Authority shall, unless the context otherwise requires, have the meanings assigned to them under the Act or other regulations specified by the Central Commission, as the case may be.

4. Regulatory provisions as per IEGC 2023

Quote ''

Regulation 29(6)

All generating units shall have their automatic voltage regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers (Power Plant Controller) and any other requirements in operation, as per the CEA Technical Standards for Connectivity. If a generating unit with a capacity higher than 100 (hundred) MW is required to be operated without its AVR or voltage controller in service, the generating station shall immediately inform the concerned RLDC of the reasons thereof and the likely duration of such operation and obtain its permission.

Regulation 29(8)

Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the concerned RPC. In case the tuning is not complied with as per the plan and procedure, the concerned RLDC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the concerned RLDC may approach the Commission under Section 29 of the Act.

'' Unquote

5. Responsibilities for Conducting Primary Response Testing:-

As per clause 40 (2) of IEGC 2023,

- The owner of the power system element shall be responsible for carrying out tests as specified in these regulations and for submitting reports to NLDC, RLDCs, CEA and CTU for all elements and to STUs and SLDCs for intra-State elements.
- All equipment owners shall submit a testing plan for the next year to the concerned RPC by 31st October to ensure proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform the concerned RPC in advance.
- The tests shall be performed once every five (5) years or whenever major retrofitting is done. If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so advised by SLDC or RLDC or NLDC or RPC, as the case may be

6. Modelling of power plant before performing PSS Testing

- The SMIB approach may be used for modelling and conducting the studies of PSS along-with the Excitation system in a RMS Simulation software.
- To account for varying network conditions at the generator bus, the equivalent reactance of the transmission line to the infinite bus to be varied and checked.
- The Developed Generator+ Excitation system + PSS Model needs to be validated, before using the tuning results from the model
- Inputs from plant to be taken as per the data format at Annexure-1 and Single Machine Infinite Bus Model(The SMIB is to be developed using IEEE Models, if User Defined Model(UDM) are considered, source code of UDM to be shared) is to be prepared and suitable tests shall be carried out on this model
- Model Validation may be done by validation of the local mode of frequency during the step test.

7. Tests to be performed in the site

Before performing the actual PSS testing on the generator at any given loading, the already existing PSS set parameters of the generator shall be verified with the simulated parameters as mentioned in previous section. If there is huge variation of the parameters, then it is suggested to tune the parameters accordingly with the simulated parameters. Once the initial set of tuned parameters are incorporated in to the actual PSS settings, a preliminary ± 2% AVR step test may be performed on the generator. After conforming the non-existence of the abnormal behavior of the generator, the parameters shall be finalized in to the PSS for performing the suggested tests as mentioned in the procedure

During the PSS Testing, it is recommended to record the following signals

a. Real Power
b. Field Current
c. PSS Output
d. Field Voltage
e. Reactive current
f. Generator Voltage

In case of non-availability of the 6 channel recorder the following 4 signals (can be recorder if a 4 channel recorder is used) have been prioritized and the same to be presented for test results

a. Real Power
b. Field Current
c. PSS Output
d. Field Voltage

A graphical comparison of the P_{Out} with the PSS OUT and PSS IN shall be attached as per the Annexure-2 for both the channels.

A. PSS Gain Margin Test

After setting the tuned parameters in the PSS, the gain margin test should be performed by increasing the gain step-by- step gradually, without applying step signal until one of the output signals(Real becomes osciallatory hunted. (e.g., for a typical system suppose at approximately 20 p.u. of the gain, the MW and field voltage is found to be hunting then, the maximum gain should tentatively be considered as 7 p.u.). The final value of gain should be selected after checking the response in the next test.

B. **AVR Step response test with Partial and Full Load (After Tuning):** The step change is given to Vref of AVR and the machines performance (Real Power Oscillation time duration & Magnitude) with PSS in-service against PSS out-service is to be checked.

<table>
<tr><td rowspan="8">Step Response Test</td><td rowspan="4">Channel 1 &2</td><td rowspan="4">± 2-3% Step</td><td>PSS-ON</td><td rowspan="2">Around Technical Minimum Load</td></tr>
<tr><td>PSS-OFF</td></tr>
<tr><td>PSS-ON</td><td rowspan="2">80 % - MCR Loading</td></tr>
<tr><td>PSS-OFF</td></tr>
<tr><td rowspan="4">Channel 1 &2</td><td rowspan="4">± 5% Step</td><td>PSS-ON</td><td rowspan="2">Around Technical Minimum Load</td></tr>
<tr><td>PSS-OFF</td></tr>
<tr><td>PSS-ON</td><td rowspan="2">80 % - MCR Loading</td></tr>
<tr><td>PSS-OFF</td></tr>
</table>

C. Actual Disturbance test

This is the most effective way to check PSS performance by creating an actual disturbance like the opening of transmission lines/switching of reactors after consultation with the system operator. This ensures the conformance of the PSS tuning impact in real-time. During this test, the PSS of all other units shall be made OFF by keeping the PSS ON for the actual unit which is being tested.

Brushless Excitation System: PSS performance of brushless exciters is not evident when compared to the PSS performance of static excitation system and there was no discernible improvement observed with PSS On against PSS Off. Thus in general the following test may be done for all Machines

i. The Tripping of any transmission line connected to the generating station may be done to simulate the effect of change in Vref.

ii. The above test would provide the disturbance in the stator side and the PSS response would be checked rather than the change in Vref by imbibing the step change in Field voltage.

iii. During this test, if possible the PSS at other machines (if any) also may be kept off.

D. Impulse Test

Complimentary to the Disturbance Test, the impulse test is to be done this test is analogous to the various disturbances the machine experiences. A low magnitude impulse signal super-imposed over the AVR reference set-point needs to be given for the generator and machine behavior to be checked with and without PSS

E. **Validation of PSS Performance during Under-Excitation/Over-Excitation**: The Step Response Test needs to be done at MCR with maximum leading/lagging reactive power output as per the capability curve and machine is excited until the Over Excitation Limiter/ Under Excitation Limiter becomes active. This is to be checked for the inter-action of the PSS with OEL/UEL.

8. Precautions to be taken while performing the PSS tuning

- The test should be stopped when the large deviation is observed in simulated and actual response.
- Any Test should be immediately stopped when growing/sustained oscillation is observed in the parameters of the generator.
- Both Step Up and Step Down tests needs to be carried out.
- Step up to be followed by Step down with a time gap of 20 sec, if taken up, simultaneously.

9. Periodicity of the PSS Tuning

A. At least once every five (5) years
B. Based on operational feedback provided by the RLDC after analysis of a grid event or disturbance
C. In case of major network changes or fault level changes near the generating station as reported by NLDC or RLDC(s), as the case may be
D. In case of a major change in the excitation system of the generating station

10. Contents of the PSS Tuning Report

The PSS Tuning Report should be able to demonstrate the following and should include:

- Improved damping for
    a. Step change in voltage from 2% -5%.
    b. Tuned for Frequency band 0.02 Hz – 4 Hz.
    c. Reduction in No. of Cycles of Oscillation
- No appreciable instability at 3 times proposed gain.
- Improved Damping under variable system operating condition (Real and Reactive Power and Terminal voltage) and network.
- Procedure adopted for simulation model validation after PSS Tuning.
- Changes made on filed during the PSS tuning Activity.
- Proposed changes / suggestions for the PSS
- Static details of the generator like OCC, SCC characteristics, P-Q capability curves, datasheets of the turbine and governor.
- Damping torque calculation shall be submitted as per the procedure shown in the Annexure-3.
- Make, Model, transfer function - IEEE equivalent models along-with the final Implemented settings of
    i. Generator
    ii. Excitation system
    iii. PSS
    iv. Governor

Annexure B.5

October 2022

Report of the Committee on Automatic Under frequency Load shedding

National Power Committee
CEA

Table of Contents

Abbreviations and Symbols

AC	Alternating Current
D	Load Frequency Dependence MW/Hz
DC	Direct Current
COI	Centre of Inertia
F	Frequency
FFR	Fast Frequency Response
GW	Gigawatt
GWh	Gigawatt-hour
GW•s	Gigawatt-second
H	Inertia
IBR	Inverter-Based Resource
kW	Kilowatt
kWh	Kilowatt-hour
LR	Load Response
MW	Megawatt
MWh	Megawatt-hour
MW•s	Megawatt-second
NLDC	National Load Dispatch Centre
PMU	Phasor Measurement Unit
PV	Photovoltaics
RLDC	Regional Load Dispatch Centre
RE	Renewable Energy
RoCoF	Rate of change of frequency also known as df/dt
SCADA	Supervisory Control and Data Acquisition
UFLS	Under-frequency Load Shedding

Definitions

'Area Control Error' or 'ACE'	means the instantaneous difference between a control area's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction of meter error. Mathematically, it is equivalent to: ACE = Deviation (ΔP) + (Frequency Bias) (K) * (Deviation from nominal frequency) (Δf) + meter error;
'Automatic Generation Control' or 'AGC'	means a mechanism that automatically adjusts the generation of a control area to maintain its Interchange Schedule Plus its share of frequency response;
'Demand'	means the demand of active power in MW;
'Demand Response'	means variation in electricity usage by end customers/control area manually or automatically, as per system requirement identified by concerned load despatch centre;
'Frequency Response Characteristics' or 'FRC'	means automatic, sustained change in the power consumption by load or output of the generators that occurs immediately after a change in the control area's load-generation balance, and which is in a direction to oppose a change in interconnection's frequency. Mathematically it is equivalent to FRC = Change in Power (ΔP) / Change in Frequency (Δf)
'Governor Droop'	in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from zero to full load;
'Inertia'	means the contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is coupled with the power system and synchronized to the frequency of the power system;
'Nadir Frequency'	means minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss;
'Reference contingency'	means the maximum positive power deviation occurring instantaneously between generation and demand and considered for dimensioning of reserves;
'Tertiary Reserve'	means the quantum of power which can be activated, in order to restore an adequate secondary reserve. Fast Tertiary Reserve Response shall come into service starting from five (5) minutes and shall sustain up to thirty (30) minutes. Slow Tertiary Reserve Response shall come into service starting from fifteen (15) minutes and shall sustain up to sixty (60) minutes;

1. Executive Summary

1. In the 2^{nd} NPC meeting dated 16-July-2013, AUFLS scheme was adopted at a national level and comprised four stages of UFLS at 49.2 Hz, 49.0 Hz, 48.8 Hz and 48.6 Hz. Prior to that, each region adopted a three-stage plan for flat UFLS, with similar settings.
2. The above calculation of load relief was based on the methodology adopted by Zalte Committee recommendations, formed in WR, after the July 2012 blackout. Zalte committee was formed to review the defense mechanism for WR after the July 2012 blackout. Zalte Committee while formulating the AUFLS plan considered the factors such as frequency dependence of loads, voltage dependence of loads and seasonal variations of the loads.
3. NPC regularly reviewed the quantum of load to be shed in each region, based on the increasing demand. In the 9^{th} NPC meeting, it was informed that the loads expected to be shed were on the much higher side. Accordingly, it was decided to form a group to examine the same.
4. In Jan 2021, a committee under Member Secretary, WRPC was formed to examine the AUFLS scheme for All India Grid and give recommendations. Also, the Committee was to examine the df/dt setting for different regions and suggest a suitable approach for effective working of the same.
5. Although governors were enabled before 2012, the response observed was not satisfactory. After the 2012 blackout, the Indian Power system implemented many reforms and Regulations, notably the DSM from 2014. Many efforts to bring transient response of governors as an aid to intercept the runaway frequency were taken by the Hon'ble CERC. Today RGMO/FGMO is widely implemented also many States have Automatic Demand Management System (ADMS) in place.
6. In a conventional large grid, due to sufficient number of synchronous machines and hence rotating mass, lack of adequate system inertia has largely not been of a concern. Global experience suggests that RE integration driven displacement of conventional synchronous generators has an impact on the rotating mass (inertia) in the system, particularly during higher penetration of renewable. Considering a significant growth in RE, and ambitious RE integration targets for Indian power system, the AUFLS and df/dt schemes may require periodic reviews.
7. Though the system is now integrated and strong, however it is desired that various frequency control actions are able to restore the frequency to its target value. These

frequency controls (primary, secondary, and tertiary) operating in continuum shall act in respective time domains to maintain frequency at or nearby its target value i.e., 50 Hz.

8. The safe, secure, and reliable operation of grid requires that the nadir frequency should be at least 0.2 Hz above the first stage of under frequency load shedding scheme under different system loading conditions. This implies that the nadir frequency shall be above or 49.4Hz, if the first stage trigger frequency adopted is 49.2Hz. System Operator, accordingly, may estimate and maintain the reserves
9. The nadir frequency is a function of the system inertia & primary response and in real time the system inertia varies and depends on the rotating masses running in the system. Therefore $\frac{df}{dt}$ AFLS scheme would be the appropriate choice to address the inertia response and the first stage of the AUFLS is required to be set by considering, where the final system frequency would settle, which depends on the primary response.
10. Many important capital city islanding schemes are being designed as per the direction of ministry. Islanding should occur below the last stage of AUFLS scheme with sufficient margin of 0.3-0.4 Hz below the last stage, as there is no further defense mechanism. At present last stage is at 48.8Hz. The present Committee recommended last stage is 48.6Hz which is above the Island trigger frequency of 48.0/47.9Hz generally adopted by more than 0.6Hz. The last Stage-II trigger frequency setting recommended is 48.0Hz. Though it overlaps with the pre-Islanding Load Shedding plan, it will not affect the performance of formation of Island, since it is certain that at these system frequencies, the system has disintegrated into two or more parts/Islands.
11. Under presence of governor action in normal frequency range, and more so with the hysteresis controller characteristic of the RGMO, care should be taken to not over-shed and raise the frequency to alarming levels in the initial stages of load relief. All the generators are expected to operate in FGMO for frequency going above 50 Hz, therefore any increase in frequency above 50 Hz is expected to be counter acted by FGMO.
12. As long as the system is integrated, the benefits of the large inertia and governor are definitely seen. However, parts of a system can isolate, suddenly bringing down the inertia and heavy falls in frequency can be seen. Inertia falls have been seen recently in cases of Mumbai blackout in Oct 2020 and Feb 2022. The only way to implement this using additional load shedding below 48.6 Hz.

13. The Committee, assuming a very conservative response of RGMO/FGMO, adopted the estimation methodology of Load Shedding quantum, based on the regulation of generators and the frequency dependence of load.
14. The Committee also reviewed various international practices being followed and tried to arrive suitable plan for the Indian Power Grid.
15. Two Approaches towards the design of AUFLS was discussed and it was decided to stick with Approach A, which is a traditional AUFLS plan with load shedding quantum as a percentage of the peak demand. The Approach B was also discussed, and it was decided that this can be adopted in future, when the communication system up to the load centers and the Wide Area monitoring becomes mature.
16. **Approach A**

    The committee proposed the following two tier AUFLS scheme:

    a. When system is integrated – Stage I-A to I-E.

       A demand disconnection of 20% is envisaged in this stage with trigger frequency for disconnection starting from 49.2 Hz to 48.6 Hz for I-A and I-E respectively.

       The feeders on which the Stage I-A to E relays have been installed should be excluded from all type of load shedding schemes such as ADMS, SPS, any other planned Load Shedding Scheme, LTS, Island Loads, preparatory Island loads identified for shedding or any other emergency load shedding schemes etc.

    b. When system has split into more sub-systems – Stage II-F to II-H.

       A demand disconnection of 18% is envisaged in this stage with trigger frequency for disconnection starting from 48.4 Hz to 48.0 Hz for Stage II-F & Stage II-H respectively.

       The loads wired under this scheme shall not include any loads as given under (a) above. No planned preparatory islanding scheme loads that are wired up for Load shedding shall be covered in this stage. The feeders identified for implementation under Stage II-F to H, preferably, shall be feeders emanating from EHV stations.

17. The Stage-IE recommended by this committee is on 48.6Hz and the Stage-II-H is recommended at 48Hz. A desperate measure load shedding under Stages-II F to H in three stages will come into play when the system has separated, and unplanned Islands have been formed. Islanding schemes are proposed to be done at 48.1 /48.0

Hz (which is in general implemented for all the Islanding scheme design). So, Islanding schemes philosophy requires to be suitably accommodative to this.

18. The last part of the report is with respect to ROCOF relays also known as df/dt relays. With the integration of the grid, the earlier severe contingencies like loss of the largest station in the grid, generally does not trigger the df/dt relays on a system wide scale during the high and moderate system loading conditions. The df/dt rates for credible and less severe contingencies (3-5% of loss of generation) during the off-peak period and high RE generation may touch 0.1Hz/sec. Now a days, the settings available in numerical relays is 0.01Hz/sec. However, during light loading conditions and high RE generation (wind & Solar), the df/dt rates of 0.1Hz/sec and higher could be seen in the system for severe contingencies. A philosophy as to how this could be addressed and the df/dt could be implemented is discussed under this part. Introduction of wide area controls would make df/dt based load shedding a comprehensive tool to tackle the severe contingencies during operation of grid with low system inertia.

2. Introduction and background

1. Synchronous generators in India operate around a nominal 50 Hz frequency, and frequency reflects the balance of generation and load. The change in frequency allows a continuous balance of generation and load at all times. UFLS is a critical safety net designed to stabilize the balance between generation and load when an imbalance between generation and load causes frequency to fall rapidly (e.g., during large generation loss or an islanded operation). Automatic disconnection of loads, typically through tripping of pre-designated load feeders, is intended to help recover frequency back to acceptable levels so that generation can rebalance, and frequency can stabilize to within reasonable levels.
2. UFLS operations serve to prevent large-scale outages from occurring, however, the system is planned, designed, and operated in such a way that these types of safety nets only occur as a last resort for extreme or unexpected disturbances. The concept of UFLS and other safety nets is that controlled tripping of portions of the system loads may mitigate the potential for a larger and more widespread blackout. UFLS schemes are designed to disconnect pre-determined loads automatically if frequency falls below specified thresholds. All UFLS frequency thresholds are set below the expected largest contingency event in each Interconnection to avoid spurious load disconnection, and they are set to coordinate with generator under frequency protection to avoid the tripping of generators when they are required the most.
3. The Indian Power system, initially comprised of four independent synchronous grids (North, West, South and East with North-East grids), had deployed AUFLS comprising of flat under frequency load shedding scheme (UFLS) as well as df/dt (ROCOF) load shedding scheme to disconnect the loads in the event of contingencies of generation loss. The integration of the regional grids took place in a planned manner. A major twin blackout happened on 30th and 31st July 2012 when the NEW grid (North+East+North-East+West grids) were already synchronized and at that time Southern grid was an independent synchronous system. With the integration of the Southern grid in Dec 2013. the All-India Power system has since then been one synchronous grid.
4. In the 30th and 31st July 2012 blackout, the Western and Southern grids survived on both occasions. East and Northeast survived on the first day only. The Northern region collapsed in both the blackouts.

5. Subsequent to the blackout of July 2012, the Zalte Committee was appointed in the Western region. The committee revised the loads that should be tripped in the WR, in the AUFLS plans.
6. In the second meeting of NPC held on 16th July 2013, NPC decided to adopt recommendations in Zalte committee report for determination of quantum of load for AUFLS in all the regions. NPC decided to implement AUFLS scheme with 4 stages of frequency viz. 49.2, 49.0, 48.8 & 48.6 Hz in all the regions and upgrade the tripping frequency setting. (Zalte Committee had 3 stages 48.8 Hz, 48.6 Hz and 48.2 Hz).
7. In the 8th meeting of NPC held on 30th Nov 2018, it was decided to modify the existing AUFLS scheme by raising the frequency by 0.2 Hz for four stages of AUFLS i.e., 49.4, 49.2, 49 and 48.8 Hz.
8. In the 9th meeting of NPC held on 22nd Nov 2020, it was pointed out that the quantum of loads to be shed were much higher than the Zalte Committee calculations. It was decided to constitute a Sub-committee under the chairmanship of Member-Secretary-WRPC with representatives from POSOCO and RPCs to study the AUFLS scheme and submit its report to NPC. NPC Secretariat vide letter No. 4/MTGS/NPC/CEA/2020/01-06 dated 1st Jan 2021 had asked for nomination from all the RPCs. Based on the receipt of nominations from all the RPCs, the Sub-Committee was formed vide CE, NPC letter dated 19th Jan 2021. The copy of letter is enclosed as *Annexe-1*.

Designation & Organization	**Name of Member**	**Constitution of the Committee**
Member Secretary, WRPC	Sh. Satyanarayan S.	Chairman
Member Secretary, NPC	Smt. Rishika Sharan	Member
Sr. General Manager, NLDC	Sh. Rajiv Porwal	Member
Superintending Engineer(P), WRPC	Sh. P.D. Lone (Shri J.K. Rathod is transferred on deputation)	Member Convener
Superintending Engineer, NERPC	Sh. B. Lyngkhoi	Member
Executive Engineer, SRPC	Ms. N.S. Malini	Member
Executive Engineer, ERPC	Sh. P.P. Jena	Member

Executive Engineer, NRPC	Sh. Reetu Raj Pandey EE (Sh. Ratnesh Kumar EE transferred)	Member

Terms of Reference (TOR) of the Sub-Committee:

a) To examine the AUFLS scheme for all Indian Grid currently deployed and suggest any revision for the same

b) To examine the df/dt settings in different regions for all India grid and suggest a suitable approach for effective working of the same

Proceedings of the sub-Committee:

a) The Committee met on 7th Apr 2021, 7th Dec 2021, 06th Sept 2022 and 12th Oct 2022 through online meetings. The Committee took time to formulate the design steps. Several changes had taken place in the grid after the Zalte Committee report was first published in 2012. Notably the DSM regulations were introduced since 2014 and are in place with amendments. Also, regulations on governor action also bore fruit and the RGMO/FGMO response is being monitored rigorously, since then. The earlier settings, as discussed in the Zalte Committee report, did not have a large number of generators providing governor response in 2012 in the normal frequency range. Also, the first load relief settings were lower starting at 48.8 Hz, which got progressively increased, yet keeping the same one Hz load relief. So, there was a need to study the impact on each setting carefully, on the frequency correction post load shedding, due to RGMO/FGMO. Another problem was the df/dt relays as a scheme would not operate as earlier desired due to non achievement of triggering criteria, because of the increase of inertia due to integrated operation of the entire grid; newer challenges of wind and solar generation and their loss would still give the df/dt relays a role to provide local relief.

b) The power number observed for the recent events using PMU data is around 10000 MW/Hz. It is considered that a contingency involving tripping of largest generation plant (reference contingency) of around 5000 MW may cause frequency fall to 49.50 Hz from 50 Hz. Frequency response characteristics indicate that frequency in this case would recover to 49.70 Hz (considering FRC of around 15000 MW/Hz).

c) The last challenge was seen from isolated incidents at Mumbai in 12th Oct 2020 and 27th Feb 2022 blackouts, where a small part would separate due to loss of synchronism or contingencies driven causes respectively. Now the designer has to plan on saving the grid from losing integrity and at the same time has to make provisions in case the integrated operation is lost, and the grid breaks up in two or more parts due to voltage collapse or rotor angle instability. To put all these aspects together takes time.

d) The major reason of the increase in load shedding targets was the adoption of load shed quantum on the basis of observed power number (MW/Hz), at some point of time in NPC meetings, instead of the load frequency dependency number D (confusingly has same units of MW/Hz). As already mentioned above at the time of the Zalte Committee the RGMO/FGMO was not significant. So, there is a need to revisit the Zalte Committee design considerations and adopt the same to the newer challenges mentioned. The Zalte Committee report is included in Annex-2.

e) International practices also indicates that Indian Power System should go for more stages and shed more load. Earlier the individual grids were isolated in India, like WR, NR, SR, ER + NER. With integration, no doubt the advantages in terms of increased observed power number have come. But the designer has to be aware that in case of disintegration, the inertia would suddenly reduce, and this disturbance of generation loss can become a higher disturbance (percentage wise) in the deficit system. Hence more stages are required. These stages would not at all operate in integrated case, but in separation may be a lifesaver.

We now proceed to mention the AUFLS scheme design considerations.

3. Theoretical aspects of important factors in the design considerations of AUFLS:

Following factors must be understood before proceeding to design of AUFLS.

1. Load frequency Dependence D (MW/Hz):

Observed Power Number ƛ(MW/Hz):

Frequency influence of generators in normal frequency and emergency range:

System Inertia H:

Because there is some confusion in the minds of working engineers, we now proceed to discuss each factor in detail, giving examples and finally proceed to form the design specifications and the scope of the problem.

a) Load frequency Dependence D (MW/Hz):

Let us assume that all generators in an ac system are operating at constant MW load on the machines. Also assume that the frequency is steady at rated frequency of 50.0 Hz. Now when a generator trips, the frequency drops sharply and continues to do so for time. After some time, the frequency has steadied down and settled to a steady state value. Why did the frequency reach and stayed at the steady state value?

Let us assume that the generation loss has caused a one Hz drop in the frequency.

(**Remember**: No governors actions so far is assumed)

The answer to the above can be found in load frequency dependence D. D signifies that when the system frequency drops, the net load value comes down.

Load frequency dependency D = 1.5 % means that if frequency falls by 1% the load demand falls by 1.5 %. For a 50 Hz system, as in India, if frequency falls by 2%, then the load demand has fallen by 3%. But 2% frequency drop means 1 Hz frequency drop. (50 Hz= 1 p.u.= 100%).

So, in this example, after generation was lost, the frequency steadied at 49 Hz. That is 2% change in frequency. It implies that D=1.5%. In other words, the demand drop is 3% of the load.

So, all the following statements are identical:

2. D=1.5%

Demand drop = 3%

A demand drop of 3% in AUFLS will bring the frequency up by 1Hz. (The load shedding problem)

All the above is true assuming no generation rise due to drop in frequency. That is governor action in this frequency range is not there.

The Zalte Committee, by assuming D=1.5%, essentially designed a 3% demand relief per stage, to raise the frequency up by one Hz. But due to various reasons (of voltage, frequency, and seasonal variations) it multiplied the demand requirement of 3% by a factor of 1.7, the reasons being demand itself changes (due to voltage and frequency change), so that by shedding (3%*1.7 ≈5%) of demand, you end up raising the frequency by one Hz. The number 1.7 used is purely heuristic.

The assessment of value of D at the time of tripping is discussed in subsequent sections.

b) What is the value of D?

Since D is very important, it is also of interest to know, what should be the value of D, to be assumed while solving the AUFLS problem?

It is clear that loads are frequency dependent. Each load, like air conditioner, induction motors, etc., is frequency dependent. It is very easy to take such loads in the laboratory and measure the frequency dependence D. Such a work done by EPRI, is given in reference book of Prabha Kundur (1).

But **nobody** can tell what the exact amount of frequency dependent loads like air conditioners or induction motors, for example, are on, in the grid at any point of time. Efforts to estimate them are largely in the research area as that would require wide-scale measurements.

In other words, the value of D is not constant and estimate of D has to be made in advance, so that the AUFLS quantum and stages can be decided. That will require a huge number of measurements. Therefore, while designing the AUFLS scheme, the estimate of different loading scenarios and the impact of D on the Nadir frequency and final settling frequency is required to be assessed based on past events and experiences. Unfortunately, since D is a variable, each 500 MW trip of generation does not give the same drop in frequency.

No doubt, historically and empirically, value of D has been assumed as 1.5%. ***This was even before the days of the Zalte Committee when the Regional Protection Committees assumed the value as 1.5%. Frequency dependency of loads has reduced significantly with the introduction of power electronics-based drive load, VFD drives,***

etc. hence value of D needs to be revisited once. With integration of inverter-based resources in the grid this load frequency dependence needs to be revisited in future. The expected reduction in inertia value due to integration of RE based resources may require periodic revision of this aspect.

Suppose that the average D was 3%, instead of the assumed 1.5%, at the time a generator trips. This would result in higher settling in frequency. Hence by conservatively designing the UFLS scheme D=1.5%, we can still have favorable results, if D is higher at the moment of the trip. However, if D was only 1% average, the frequency rise would be there, but resulting settling frequency would be less than the target value one Hz. But it is okay, as now the load dispatcher can manually control.

The main idea of flat UFLS is to ensure that the system survives, first automatically and then manually the load dispatcher would correct. Unfortunately, under the control actions of RGMO (which does not allow generation drop as frequency is rising up to 50.0 Hz) and/or if D is higher than assumed, there is a strong danger of over-correcting. Hence initial stage targets are kept lower than lower stage targets. A pure linear FGMO does not suffer from this problem. Draft IEGC and IEGC 2010 mandate the linear FGMO operation above 50 Hz. However, the same has not been implemented completely. Even in case of a low frequency prevailing before a credible or severe contingency, the frequency should not be ideally below 49.7Hz on a continual basis and these low frequency operations have been seen to be for a shorter period. Also, low frequency operation of the grid is unviable to the States who are overdrawing from the grid. In addition to DSM penalties, ADMS shall come into play to address this. This makes the problem of stage wise load relief design a little complex. To appreciate this problem let us first discuss other related issues beginning with the observed power number.

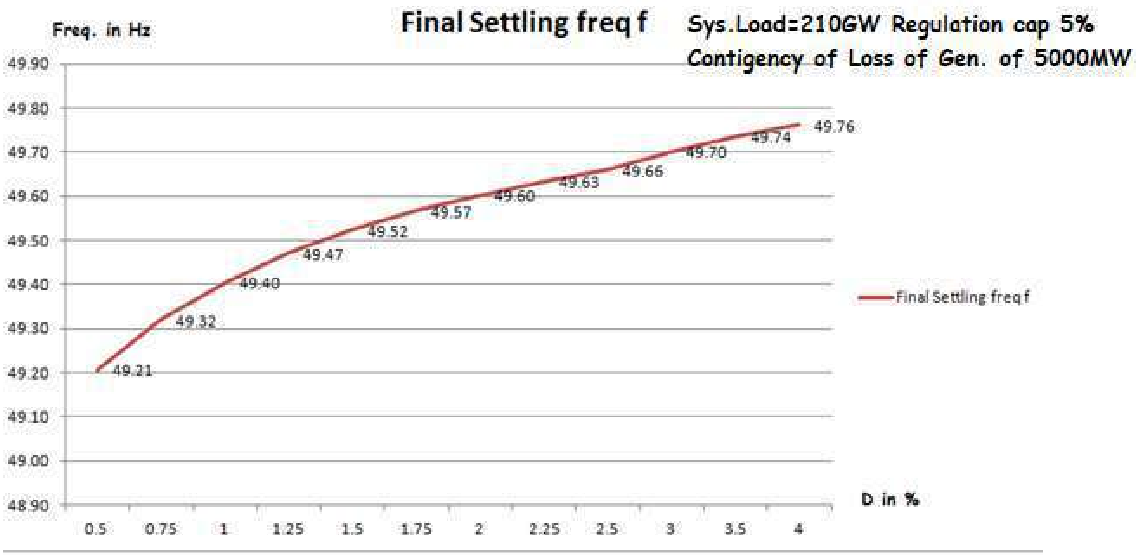


Figure 3.1

c) Observed Power Number ƛ(MW/Hz):

Power Number or power system stiffness ƛ(MW/Hz) means the MW needed to be lost/(gained) to raise/(lower) frequency by one Hz. Measurement of the power number is done by power system engineers worldwide. Upon loss of a generation or load throw off, the ratio of Generation Lost/Frequency difference is the power stiffness.

This number, no doubt, gives some idea of the average frequency drop to be anticipated when the generation is lost.

When governor action in the normal frequency range was not enabled, the observed power number essentially is the same as the load frequency damping D. This figure formed the basis of AUFLS load quantum determination in the earlier days.

However, when generators start changing the generation (by enabling governors or RGMO), the situation is different. Suppose a 2000 MW generation trip results in 0.2 Hz frequency change, the observed power number is 10,000 MW/Hz as per above definition. However, all the governors if they gave support of 500 MW transiently, the above formula would give (1500/0.2) 7500 MW/Hz. Since we have factored out change in generation, if system size is 200000 MW, 7500 MW is 3.75% of demand and D therefore is 1.875% in this case. That way D can be estimated. Using observed power number, the same system has 10000 MW loss and D appears to be 2.5%, while it is only 1.875%.

Unfortunately, the rise in generation pickup due to governor pick up is not readily available, but in principle one could co-relate if one has the required data.

The more important point in this example is we should shed 7500 MW per stage to raise the frequency up by one Hz and not 10,000 MW. Therefore, while revisiting the stage wise anticipated load relief, this point has to be kept at the back of the calculations.

d) Frequency influence of generators in normal frequency and emergency range: Turbo Generators are equipped with a non-by passable mechanical governor that saves it during over speed conditions or emergency control area. It is a mechanical governor with a frequency droop of about 5%. It is also equipped with electronic governors to a CMC. Frequency influence characteristics can also be introduced in the CMC and can be used to. RGMO is an example of the frequency influence that can be used to increase the generation by a maximum amount of 5% of MCR. In RGMO when the frequency starts rising, the generation raised by RGMO is not reduced till frequency crosses a higher value. This means that when load is shed, frequency rises. But the generation of RGMO that had picked up would remain till frequency goes higher and the frequency reaches 50Hz. In the present problem, it means that earlier stages should not over shed, and raise the frequency to the extent of correcting the frequency to the fringe ranges of emergency control (usually 51.8 to 55 Hz), which is a remote possibility.

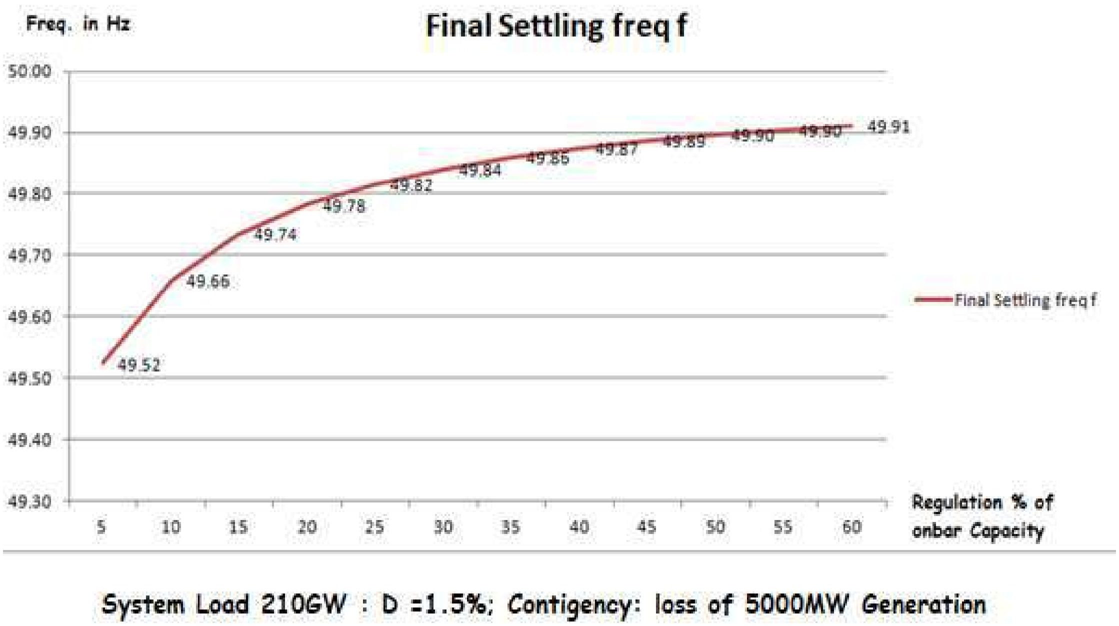


Figure 3.2

e) Role of System Inertia H:

System inertia H has increased, due to interconnections of the grid. This has two noticeable impacts.

a) The initial rate of change of frequency, df/dt, reduces.
b) It makes the disturbance appear smaller, as compared to independent regional operations of earlier days. A 5000 MW generation loss, in earlier days of an average regional size 50000 MW is a 10% disturbance. In a 200000 MW grid, it is only 2.5%

It may also be cleared that the settling frequency is in NO way related to H. It depends only on D. However, when governor action is there, the regulation through governor improves the settling frequency.

From our perspective, as long as the Indian Power System is integrated, the first five stages can handle generation losses and maintain integrated system. A few examples of generation loss are given by POSOCO and are given in Annexure I. It is seen that the grid is able to manage with RGMO and D such that the first stage frequency is not reached.

It would be a nightmare if opposite of (b) above happens and triggers any of the Stage I-A to E and system disintegrates immediately after the triggering of the AUFLS stages. Under such conditions, the importing regions (just before the separation) will experience it as a large disturbance resulting in rapid drop in frequency, whereas the exporting region will experience a different kind of disturbance with loads already shed under AUFLS and an over rich generation region, resulting in rapid rise in frequency. This rapid rise of frequency in the exporting region can only be addressed through the FGMO action of generators. At present the generators have not switched over completely from RGMO to FGMO. However high frequency droop governor correction, as a mechanical back, is always there in every generator.

Also, in earlier days, when regional grids were isolated. So even in the extreme case of total regional blackout, other regions could always assist in start-up power. But with integration of grids to an All-India grid, this situation is dreadful to imagine. The Black start alone may not be sufficient considering a worst dark blackout.

Restoration could take up much longer times. The good part is in a system split, there would be an over and a under generated island. But a relay engineer now is

forced and needs to add additional stages as followed by international community.

It cannot be over emphasized that All-India targets must be met. If one is reaping the rewards of integration of the grids. The AUFLS now must be very strictly implemented by all stake holders, and when the relays operate the requisite quantum of load MUST be shed.

f) Role of Voltage and Frequency dependence

The Zalte Committee also discussed voltage dependence factors. It may be noted that when it was designed, the first stage was already at 48.8 Hz. Further drop in frequency can also cause voltage problems and so more load was required to be shed. Currently the first stage is at 49.4 Hz and voltages overall are on the higher side, so this calculation can be dropped for the initial stages. Frequency dependence is D and is already elaborated above.

g) Role of Seasonal factors

In Zalte Committee seasonal factors is mentioned. Broadly seasonal load variations in demand are known. The Zalte Committee added an ad-hoc factor, so that if you want to disconnect 2% load plan for at least 4% or so of connected loads, so that one eventually ends up at 2% actually, handling for various other factors like Planned load shedding, emergency load shedding, reduced load on feeder etc.

In WR, for where the Zalte report was primarily written, Gujarat has almost all feeders connected to UFLS. They always met the regional target, as they had wired a huge quantum of loads in UFLS. They reaped huge benefits in 1990s to 2000s as they more or less survived the regional blackouts in WR in spite of the fact of being physically located as tail ends of the grid.

While the above approach was a regional adjustment for WR, as an All-India approach, there is a need to state clearly that all regions have to contribute their targets. If a region plans to connect 4% of connected demand internally, so that it can meet the agreed or specified target of 2%, it is okay. States and regions, have to finalize the internal workings. At an All-India level, the specified targets MUST be met. India being a diversified entity in its underlying unity, the targets must be met by each State/Region. **How to achieve this is no doubt left for regional RPCs to decide/plan, but All-India targets in this report must be met.**

h) Reasons for failure of AUFLS schemes WRPC Inspection:

Inspection of AUFLS done by RPC Secretariats, in the past have revealed following abnormalities.

a) UFLS feeder is already in planned or emergency load shedding.
b) Substation authorities do not have power to change feeder in case the feeder is already under planned or unplanned load shedding.
c) Feeders are coming in the area of high frequency during split. Load shedding is not distributed amongst the grid and in particular to load importing areas,
d) Very few load shedding is done in primarily importing areas of the state.

The above are just a few observations. Hence in this revision, there is demarcation of AUFLS at national level, up to 48.6Hz. socializing cannot be acceptable for system frequency below 48.6Hz.

Before discussing our recommendations, there is a need to look at international experience, in particular the Continent of Europe.

4. International Practices of AUFLS

POSOCO representative shared the various international practices to give the quantum of load shedding at each stage of under-frequency in terms of percentage of total load. This makes interesting reading. **Annexure II gives details.**

a) Continental Europe:

Important points from Continental Europe experience are:

Cumulative demand disconnected is 45 % of total load at Continental Europe level. In Great Britain system, the value is 50% of national load.

It is important to note that there is a gap of 1Hz from 50 Hz for initiation of UFLS at 49 Hz. However, there are stringent regulations to control the frequency and all constituents adhere to maintain interchange for controlling frequency. The final stage of demand disconnection is 48 Hz mostly. Almost 50% of the load is to be shed.

Frequency quality defining parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1 000 mHz	1 000 mHz
maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
frequency recovery range	not used	± 500 mHz	± 500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

Frequency quality target parameters referred to in Article 127:

Table 2

Frequency quality target parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
maximum number of minutes outside the standard frequency range	15 000	15 000	15 000	15 000

Table 4.1

Automatic low frequency demand disconnection scheme characteristics:

Parameter	Values SA Continental Europe	Values SA Nordic	Values SA Great Britain	Values SA Ireland	Measuring Unit
Demand disconnection starting mandatory level: Frequency	49	48,7 – 48,8	48,8	48,85	Hz
Demand disconnection starting mandatory level: Demand to be disconnected	5	5	5	6	% of the Total Load at national level
Demand disconnection final mandatory level: Frequency	48	48	48	48,5	Hz
Demand disconnection final mandatory level: Cumulative Demand to be disconnected	45	30	50	60	% of the Total Load at national level
Implementation range	± 7	± 10	± 10	± 7	% of the Total Load at national level, for a given Frequency
Minimum number of steps to reach the final mandatory level	6	2	4	6	Number of steps
Maximum Demand disconnection for each step	10	15	10	12	% of the Total Load at national level, for a given step

Table 4.2

b) NERC:

North American Electric Reliability Corporation (NERC) standard PRC-006-2 stipulates that Automatic Underfrequency Load Shedding shall handle an imbalance of up to 25%.

c) New Zealand

AUFLS technical requirements report incorporated by reference into the Electricity Industry Participation Code 2010 on 21 December 2021 by the Electricity Industry Participation Code Amendment (Automatic Under-Frequency Load Shedding Systems) 2021, mentions a net demand disconnection of 32% in various stages.

d) Powertech Consultant:

In line with recommendation of consultant appointed by *"Taskforce on Power System Analysis under Contingencies*" in December 2012 as a follow up of the recommendations of Enquiry Committee under Chairperson, Central Electricity Authority (CEA) on Grid Disturbances of 2012 in Indian Grid. The number of steps and quantum of load shedding at each step is in line with recommendations of consultant Powertech labs. Section 3.2 of Task-III report of POWERTECH Labs Inc indicates that UFLS relays are generally designed for load-generation mismatch of up to 25%. The same has been recommended for Indian grid based on summation of regional variations of demand.

5. Scope and Formulation of AUFLS Plan for Indian Power system

Scope:

While formulating the AUFLS it is required to try and predict whether the system is integrated or a part of the system has separated, from the past experiences. It is likely that the system remains integrated, if the frequency is well above 49.4 Hz, for most of the times. It can be safely assumed that in today's integrated Indian grid (200 GW), if the frequency drops below 48.~~8~~ 6 Hz, then there is a high probability that a part of the system is disintegrated. (Example Mumbai Blackout dated 12-10-2020)

There are always two parts in a split grid problem, an over-generated island and an under-generated island. Usually, as backed by numerous experiences, over-generated islands have a greater probability of survival. The under-generated islands must do urgent and quick load shedding. In WR, Gujarat state had always wired maximum loads for UFLS, and **not** surprisingly they have always survived as a state power system. Hence sticking to a load shedding plan always pays in the long run.

In this design proposal, we may assume any frequency drop below 48.8 Hz as a case of system separation. So that gives the designer two windows.

(i) Above 48.6Hz, and (ii) Below 48.6 Hz.

Once a part of the system is below 48.6Hz, we expect a maximum seriousness and a desired to shed loads, almost mercilessly. **This is much better than losing the entire part-system and starting from black-start. Hence Socializing is not allowed in this part. In the first part requisite quantum is to be shed.** For below 48.6Hz, it is clear that if we do not shed the loads, this system is going to go dark, in all probability and eventually, so better to shed the loads and survive. Maybe the probability of such occurrences is very rare, once in ten or twenty years. Still a load shed at this stage, is the best option available.

Not only that, **this is our only insurance in an under-generated island.**

6. Theoretical aspects

It is necessary to understand the concept of dynamic frequency response during normal and severe contingency, so that an approach towards formulation of the AUFLS and df/dt based Load Shedding schemes can be decided. The simplified/elementary mathematical model and interpretation of these mathematical equations is described below for better understanding and deciding the approach.

Let us try to understand as to how the system behaves initially when a generation loss or demand increase takes place, step by step:

(i) A simple linear model of primary Automatic Load Frequency Control (ALFC) is considered for understanding the dynamics of the system.

(ii) The system is originally running in its normal state with complete power balance, that is, $P_G^0 = P_D^0$ + losses. The frequency is at normal value f^0. Where P_G^0 & P_D^0 is the steady state generation and load of the system before any disturbance (disturbance is increase in load/loss of generation). All rotating equipment represents a total kinetic energy of "W^0_{kin}" MW sec.

(iii) By connecting additional step load, load demand increases by ΔP_D which we shall refer to as "new" load which is also synchronous to generation loss. (If load demand is decreased then new load is negative). The generation immediately increases by ΔP_G to match the new load, that is $\Delta P_G = \Delta P_D$.

(iv) It will take some time for the control valve in the speed governing system to act and increase the turbine power. Until the next steady state is reached, the increase in turbine power will not be equal to ΔP_G. Thus, there will be power imbalance in the area that equals ΔP_T - ΔP_G i.e., $\Delta P_T - \Delta P_D$. As a result, the speed and frequency change. This change will be assumed uniform throughout the area. The above said power imbalance gets absorbed in two ways. 1) By the change in the total kinetic K.E. 2) By the change in the load, due to change in frequency. Since the K.E. is proportional to the square of the speed, the area K.E. is

$$W_{kin} = W^0{}_{kin} \left(\frac{f}{f^0}\right)^2 \quad \text{MW sec}$$

The "old" load is a function of voltage magnitude and frequency. Frequency dependency of load can be written as

$$D = \frac{\partial P_D}{\partial f} \text{ MW/Hz}$$

Thus, $\Delta P_T - \Delta P_D = \frac{d}{dt}(W_{kin}) + D\Delta f$

Since $f = f^0 + \Delta f$

$$W_{kin} = W^0{}_{kin}\left(\frac{f^0+\Delta f}{f^0}\right)^2 = W^0{}_{kin}\left[1+2\frac{\Delta f}{f^0}+\left(\frac{\Delta f}{f^0}\right)^2\right]$$

$$\approx W^0{}_{kin}\left(1+2\frac{\Delta f}{f^0}\right)$$

$$\frac{d}{dt}(W_{kin}) = 2\left(\frac{W^0{}_{kin}}{f^0}\right)*\frac{d}{dt}(\Delta f)$$

Substituting the above in eq. (1)

$\Delta P_T - \Delta P_D = 2\left(\frac{W^0{}_{kin}}{f^0}\right)*\frac{d}{dt}(\Delta f) + D\Delta\mathrm{f}$ MW

dividing this equation by the generator rating P_r and by introducing per unit inertia constant

$H = \frac{W^0{}_{kin}}{P_r}$ MW sec/MW (or sec)

$\therefore \Delta P_T - \Delta P_D = \left(\frac{2H}{f^0}\right)*\frac{d}{dt}(\Delta f) + D\Delta\mathrm{f}$ pu MW

The ΔP' s are now measured in per unit (on base P_r) and D in p.u. MW per Hz. Typical H values lie in the range 2 – 8 sec. Laplace transformation of the above equation yields

$$\Delta P_T(s) - \Delta P_D(s) = \left(\frac{2H}{f^0}\right)s\,\Delta f(s) + D\Delta\mathrm{f}(s)$$

$$= \left(\left(\frac{2H}{f^0}\right)s + D\right)\Delta f(s)$$

i.e., $\Delta f(s) = \frac{1}{\left(\frac{2H}{f^0}\right)s+D}*\big(\Delta P_T(s) - \Delta P_D(s)\big)$

$\Delta f(s) = G_p(s)[\Delta P_T(s) - \Delta P_D(s)]$

Where $G_p(s) = \frac{1}{\left(\frac{2H}{f^0}\right)s+D} = \frac{\left(\frac{1}{D}\right)}{(1+s*\frac{2H}{f^0*D})} = \frac{K_p}{1+sT_p}$

Where $K_p = \frac{1}{D}$ & $T_p = \frac{2H}{f^0*D}$

The dynamic response, by making a reasonable assumption that the action of speed governor plus turbine generator is instantaneous compared with rest of the power system and the effect of the same is introduced in the following equation.

$$\Delta f(s) = -(\Delta\, Load\ increase\ or\ \Delta Gen\ loss)*\left(\frac{RK_p}{R+K_p}\right)*\left(\frac{1}{s}-\frac{1}{s+\frac{R+K_p}{RT_p}}\right) \dots (2)$$

Where "R" is the regulation of the governor.

$$\Delta f(t) = -(\Delta\, Load\ increase\ or\ \Delta Gen\ loss)*\left(\frac{RK_p}{R+K_p}\right)*\left(1-e^{-\left(\frac{R+K_p}{RT_p}\right)t}\right)$$

$$\Delta f(t) = -(\Delta\, Load\ increase\ or\ \Delta Gen\ loss) * \alpha * \left(1 - e^{-\beta t}\right) \ldots\ldots\ldots (3)$$

Where $\alpha = \left(\frac{RK_p}{R+K_p}\right)$ & $\beta = \left(\frac{R+K_p}{RT_p}\right)$

Interpretation:

When the load/generation is suddenly increased / decreased by say 2%, certainly it must have come from somewhere as the load increase of 2% (step load if considered) has been met instantaneously.

In the milliseconds following the closure of the switch (of a step load), the frequency has not changed a measurable amount, speed governor would not have acted and hence turbine power would not have increased. In those first instants the total additional load demand of 2% is obtained from the stored kinetic energy, which therefore will decrease at an initial rate of 2% MW. Release of KE will result in speed and frequency reduction. As seen in eq. (3) above,

Initially, frequency changes (reduces) at the rate of (Δ Load increase or ΔGen. loss) * α * β Hz / sec. As the time "*t*" increases governor regulation "R" comes into play and the frequency reduction causes the steam valve to open and result in increased turbine power. Further, the "old" load decreases at the rate of D MW / Hz.

In conclusion, the contribution to the load increase of 2% is made up of three components: (a). Rate of decrease of kinetic energy from the rotating system, (b). Increased turbine power and (c) "Released" old customer load.

Initially the components (b) and (c) are zero. After that, component (a) keeps decreasing and components (b) and (c) keeps on increasing. Finally, the frequency and hence the KE settle at a lower value and the component (a) becomes zero.

As t->0, the rate of fall of freq is highest and the rate of fall reduces. The df/dt relay therefore will come into play during the initial period. The higher the severity of contingency and lower the inertia, the rate of fall would be high. This factor will decide the development of the plan of df/dt. After the frequency reaches the frequency Nadir, the governor will respond and pull back the frequency and subsequently the frequency would settle at a higher value than the frequency Nadir and frequency will settle at that point. This settling of frequency would be useful in deciding the design plan for the flat frequency load shedding scheme (AUFLS). Keeping this background in mind, the plan for selection of frequency for stages, df/dt rates and quantum of load shedding of the AUFLS and df/dt has been described in the following sections.

7. Selection criterion for trigger frequency for lower end and upper end Stage:

The selection of trigger frequency for the lowest Stage and the highest stage depends on number of factors as has been discussed above in the previous sections. The factors affecting the trigger frequency is required to be analysed in depth and the same is given in this section.

There was a disagreement amongst the members regarding the frequency setting for the Stage-A of AUFLS. POSOCO was of the view that the Stage-A frequency setting can be kept at 49.4Hz and subsequent stage frequencies could be 0.2Hz lower for a five stage AUFLS, for following reasons;

(i) Under the credible contingency of loss of largest generating station, the frequency falls to around 49.5 Hz, therefore the trigger frequency for Stage-A should be 0.1Hz below the Nadir frequency which comes out to be 49.40 Hz and subsequent stages can be triggered with a 0.2Hz difference.

(ii) The Thermal/Hydro/Gas and specially the RE generator low frequency trip setting needs to be obtained and frequency setting for the last stage should be above the trip setting of these generators, so that the generators should not trip before the last stage AUFLS trigger frequency. In the recent past when the frequency dipped below 49.5Hz, RE generators (wind units) tripping was reported in SR.

(iii) The inertia of the system would come down due to huge RE penetration and convertor/inverter applications in the drive loads, this aspect also requires to be considered while deciding the Stage-A AUFLS, trigger frequency.

The above observations of POSOCO were deliberated at length and the following views were expressed as counter argument to above.

(i) Thermal/Hydro generators low frequency trip setting generally in the range 47.5 Hz

(ii) For RE generators especially Wind:

- For RE generators, CEA standard operating range is 49.5 to 50.2 Hz
  This was discussed thoroughly in view of the penetration of wind generation of @ 22000 MW and any tripping of these units before frequency reaching the 1st stage is not desirable.
- CEA standards have defined the normal operating frequency range of 49.5 to 50.2 Hz for rated output. However, it remained silent on the performance of Wind generators at frequencies other than the operating range of 49.5-50.2Hz.

It should be ensured that the generators shall not trip, if the frequency falls below the operating frequency range. However, it is possible that at lower frequencies, the output of the generating unit may fall, if governors are not enabled. Therefore it is also recommended that the governors on the wind generators be enabled and accordingly this enabling provision be included in the CEA regulations.

(iii) The effect of variable "D" under various operating points is discussed under this para and the following table gives the final settling frequency for a system of 210GW having only 5% capacity under RGMO/FGMO (this being very conservative approach) with a droop of 5% for different values of D. In all probabilities the value of D would be 1-3.5% for various real time scenarios. The settling frequency for D=1% is 49.4Hz, where the load dependence on frequency is linear. Therefore, the variable D in worst case could settle the frequency to 49.4Hz, for a credible contingency of 5000MW. The estimation of final settling frequency has been done as per the approach given under "B)-a)" section below. D therefore in worst case will have an effect of 0.1 to 0.15Hz on the final settling frequency (compared with assumed value of 1.5%). **Therefore, even if it is assumed to be around 1.5%, it can turn out to be a good assumption for all practical purposes.**

Effect of variation of D on the final settling frequency for a contingency of 5000MW

Stage	freq (a)	Gen (b)	Load (c) =(b)	Gen Loss (d)	D in % (e)	D Pu MW/HZ (f)=((e*c/(a/100))/c	Gen (reg) 5% gen respond (g)=b*5/100	R reg (h)	R Hz/p.u. MW (i)=2.5*b/g	FRC β (j)=f+1/i	**Δ fo (k)=(d/b)/j**	**Final Settling freq f (l)=a-k**	Gen increase through Gov (m)=g/i	**Load drop due to freq dependence (n)=(e*b)/(0.01*a)*k**	**LS reqd.= Load-Gen (o)**
A	50.00	210000	210000	5000	0.5%	0.01	10500	5%	50	0.03	0.79	49.21	210	1667	**4642**
A	50.00	210000	210000	5000	0.75 %	0.015	10500	5%	50	0.04	0.68	49.32	210	2143	**3937**
A	50.00	210000	210000	5000	1.00 %	0.02	10500	5%	50	0.04	0.60	49.40	210	2500	**3408**
A	50.00	210000	210000	5000	1.25 %	0.025	10500	5%	50	0.05	0.53	49.47	210	2778	**2996**
A	50.00	210000	210000	5000	1.50 %	0.03	10500	5%	50	0.05	0.48	49.52	210	3000	**2666**
A	50.00	210000	210000	5000	1.75 %	0.035	10500	5%	50	0.06	0.43	49.57	210	3182	**2396**

A	50.00	210000	210000	5000	2.00 %	0.04	105 00	5%	50	0.06	0.40	49.60	210	3333	**2170**
A	50.00	210000	210000	5000	2.25 %	0.045	105 00	5%	50	0.07	0.37	49.63	210	3462	**1980**
A	50.00	210000	210000	5000	2.50 %	0.05	105 00	5%	50	0.07	0.34	49.66	210	3571	**1816**
A	50.00	210000	210000	5000	3.00 %	0.06	105 00	5%	50	0.08	0.30	49.70	210	3750	**1551**
A	50.00	210000	210000	5000	3.50 %	0.07	105 00	5%	50	0.09	0.26	49.74	210	3889	**1344**
A	50.00	210000	210000	5000	4.00 %	0.08	105 00	5%	50	0.1	0.24	49.76	210	4000	**1178**

Table 7.1

(iv) A credible contingency of 5000 MW (for a 210000MW system , 2.4% of total generation) in the grid due to loss of generation or rise of load is considered in the estimation sheet with Frequency dependence load factor 'D' of 1.5% and governor droop of 5% (with only 5% of generation capacity expected to respond under RGMO/FGMO). With this contingency, new operating frequency would settle at 49.52 Hz from the initial frequency of 50 Hz. However, there is a considerable reduction in D due to introduction of VFDs, power electronic based drive loads, RE generation etc. in the system. The fall of frequency could be steep, and the Nadir frequency would be around 49.4 Hz, but the frequency, finally, would settle to 49.52Hz. **In conclusion, for a credible contingency of loss of highest generating station in the system of @5000MW, would settle the system frequency at 49.52, with Nadir frequency would certainly touch 49.4Hz, even during the system inertia is high**. It appears from the estimates that at off peak load conditions and when RE generation (wind & solar) is high the Nadir frequency could easily fall below 49.4Hz. The calculations based on the approach explained in B) below for a system of 210GW, having regulation capability of 5% of total capacity on bar, D of 1.5%, the settling frequency for a credible contingency of 5000MW would be 49.52Hz.

Credible contigency of 5000MW on the final settling frequency

Stage	freq	Gen	Load	Change in load/ Gen Δ "G/L" ***	Pu Δ "G/L"	D in %	D freq dependance	D MW/ Hz	D Pu MW/ HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	**Δ fo**	**Final Settling freq f**	Gen increase through Gov	**Load drop due to freq depence**	**LS reqd.= Load-Gen**	**With 20% safety margin for stage-A to C LS reqd & 40% for Stage-D & E**	**% of total load**
A	50.00	210000	210000	5000	0.02	1.5%	0.015	5000	0.03	10500	5%	50	0.05	0.48	49.52	210	2381	3584	4301	2.05%

Table 7.2

(v) It requires to note that all the regions in their OCC meetings, are reviewing the primary response of the generators in their regions. The primary response of the generators have increased and therefore the kind of steep fall in the frequency which was being experienced in the past have now been flattened.

(vi) The primary function of AUFLS is to respond as a defense protection mechanism, if the settling frequency is equal to or lowers than the trigger frequency of the respective Stages and not to respond to the rate of change of frequency. df/dt is the primary defense protection mechanism which shall respond for the rate of change of frequency.

(vii) If the Stage-IA frequency of 49.4Hz, is adopted, the Stage-A AUFLS may get triggered, when the system inertia is low, even for credible contingency & contingencies of less severity, resulting in unnecessary load shedding even though the final settling frequency would be higher than the trigger frequency of 1st Stage. **It is also pertinent to note that the load connection to system is not automatic and is manual, though the load shedding is automatic. Once the load is shed through AUFLS, it is difficult to bring back the load into system immediately and it takes hours to bring back the load, since the loads that have been shed are remote loads (in case of WR load shedding feeders are at 33kV and below level feeders which are at remote locations and it is required to communicate with the switching S/Stns for restoration of loads).**

Therefore, the first stage (Stage-IA) trigger frequency can safely be adopted at 49.2Hz. The last stage (Stage-IE) trigger frequency can safely be adopted at 48.6Hz, in view of the above observations. The Stage I is further divided into 5 substages and the trigger frequencies for these Stages can be Stage-IA=49.2Hz, Stage-IB=49.0Hz, Stage-IC=48.8Hz, Stage-ID=48.7Hz and Stage-IE=48.6Hz. The trigger frequency difference for the last 3 stages is 0.1Hz,

since it is very likely that the system would be under severe stress below 48.8Hz and quick action is required to restore the frequency back to around 50Hz. Even after this, if the frequency falls further it is fair to assume that the system has disintegrated, and Islands have already been formed. Under such system conditions desperate measures are required to be taken and therefore Stage-II is being proposed. The trigger frequencies for Stage-II would be Stage-IIF=48.4Hz with 6% of Load shed; Stage-IIG=48.2Hz with 6% of Load shed & Stage-IIH=48.0Hz with 6% of Load shed.

8. The AUFLS stage wise quantum and their distribution among regions can be decided based on the following two alternative methods / philosophies:

a) Approach-A:

The estimate of Load shedding required under Stage-I-A, B, C, D & E, is made as per the calculation methodology adopted under alternative Approach-B

The combined effect of frequency dependence of load factor “D” and the regulation response of the generators “R” with following assumptions can be used to see the frequency settling point and load required to shed.

1. For simplicity assume a loss less system i.e., generation = load. This can be fairly a good assumption, since the system prior to disturbance is in steady state and system losses are approximately proportional to the loads. Further a Generation Loss has been considered which is similar to Load increase in Δ "G" Empirically the “frequency dependence of load” can be seen in the range of 1.5%. As has been seen in the previous sections ‘D’ in worst case scenario has little influence in the final settling frequency. So, it is fair to assume the “frequency dependence of load” as 1.5% in the peak period. Therefore, at a peak demand of 210000MW, the “frequency dependence of load” factor D if assumed to 1.5% the fall/decrease in load would be 6300MW/Hz for 1 Hz fall of frequency.

   The generators are assumed to be running to their full capacity and therefore can provide 5% governor response through RGMO/FGMO as stipulated in IEGC. There could be some generators which may be running below the full load capacity and can provide more response also. However, on bar generators can provide 5% governor response through RGMO/FGMO during the above load scenario. This is a very conservative approach. For example, this translates to a regulation factor “R” of 50 Hz/p.u. MW on the new MW base of 10500MW (Old MW base being 210000MW) for the Stage-I-A.

   In the calculations, it has been tried to establish, at what generation drop/load increase the frequency would settle to 49.2, 49.0, 48.8, 48.7 & 48.6 Hz respectively, as these being the Stages for Stage-I, identified for load shedding. The initial frequency is assumed to be at 50 Hz. If the frequency falls to 49.2 Hz due to either generation loss or demand rise, even after primary reserves respond, the AUFLS 1st stage (i.e., Stage-I-A) will give relief. To estimate the Generation Loss/Demand Increase quantum (Generation loss has been estimated for estimating LS), with the Load dependence of frequency (D) and regulation factor (R), the system frequency settling at 49.2Hz what would be the "generation loss quantum" that would settle the frequency to 49.2 Hz. There will be a generator RGMO/FGMO response and load loss (due to frequency dependence) due to fall of frequency from 50Hz to 49.2 Hz. Now after the Stage-I A load shedding is triggered and gives load relief, the frequency will rise above 49.2Hz but will not reach 50Hz, since with the increase of frequency again the Loads will increase due to "D". This increase in load is also required to be shed so that the frequency is restored to 50Hz. The steps involved are as given below.

(i) Generation and loads assumed to be 210000MW

(ii) Frequency drops to 49.2Hz from 50Hz

(iii) Calculate D in p.u. MW/Hz,

(iv) Calculate R in Hz/p.u. MW

(v) Calculate change(drop) in load due to fall of freq from 50Hz to 49.2Hz (0.8Hz)

(vi) Calculate β (FRC)=D+ 1/R

(vii) Find f_o = (loss of gen)/ β

(viii) Find the settling freq. by adjusting the generation loss till f_o become 49.2Hz.

(ix) The new load and generation due to freq drop is calculated as follows.

New Load (NL_1) =Initial Load (NL_0)- Load Drop (LD_0) due to freq. fall. -- (1)

New Generation (NG_1) = Initial Gen. (NG_0)-Gen Loss + RGMO/FGMO. --(2)

RGMO/FGMO response has been assumed to be very low.

Now to establish the Load generation balance (LGB) (so that frequency can be raised to 50 Hz), the Load Shedding (LS_1) quantum required can be estimated by comparing the new loads with the new generation. The difference between new load and new generation would be the load shedding quantum to raise the frequency above 49.2 Hz.

(LS_{11}) =(NL_1) - (NG_1) --(3)

(x) With the LS_1 Load is shed, the Load-Generation balance is established, so the frequency will try to reach 50Hz. However again due to frequency rise from

49.2Hz to 50Hz, the load will increase because of load dependence on the frequency. With the assumed D and NL, the rise in load say NL_{11} is estimated. Now if this Load is added to LS_{12}, a perfect load generation balance will be achieved. Therefore, the load shedding quantum for Stage IA will be

Load Shedding quantum in Stage-A (LS_1) = LS_{11} + LS_{12}. ---------------(4)

(xi) The LS quantum arrived at to raise the frequency to 50Hz from 49.2Hz was estimated for Stage-I-A. Even after Load Shedding (LS_1) under Stage-A as above, if suppose the frequency does not improve and keeps falling further to 49 Hz, the Stage-B of AUFLS would trigger.

Now for Stage-B, the Initial frequency assumed to be at 50Hz with a NL_2 & NG_2 to be same.

$NL_2 = NL_1 – LS_1$ and $NG_2 = NL_2$

Now the steps (1) to (4) are repeated.

(xii) The above steps are followed to arrive the LS quantum for each stage. It is assumed that at the start of every stage the initial frequency is 50Hz.

The quantum of load increase/ Generation loss is iteratively achieved so that the new system frequency settles at 49.2 Hz. The load shedding quantum required to establish load and generation balance is computed by carrying out load loss (due to 'D') due to frequency falling to 49.2 Hz and this increase due to raising the frequency to 50 Hz, the very negligible governor action and load loss due to AUFLS at 49.2 Hz. This approach has been extended to see where this frequency settles at 49.0, 48.8, 48.6 and 48.5 Hz and the adjusted load shedding quantum required to be wired up for AUFLS. Therefore, even if Stage-I A, B, C & D does not raise the frequency to 50Hz, the last Stage-E is capable to increase the frequency from 48.5Hz to 50 Hz, if the loads are shed is estimated for Stage-IE. This is even true for all the Stages-I B, C &D. So, each stage, independently, is capable to raise the frequency from the stage trigger frequency to 50Hz.

The calculations were done with the above assumptions, and it is observed that during the peak demand scenario (210000MW), a sudden 3% of demand rise or 3% generation loss of (6300MW) will lead to frequency falling to 49.43 Hz.

(xiii) Stage-A (49.2 Hz) and Stage-B 49.0 Hz: The calculations done for a 210 GW system with initial frequency of 50 Hz is as given in the table below.

(xiv) The final calculations done are as follows for Stage-I-A to E.

D in %	1.5%		R reg	5%																
Load	210000												Effect of both D & R						Load Shedding	
Stage	freq	Gen	Load	Change in load/ Gen Δ "G/L" ***	Pu Δ "G/L"	D in %	D freq dependance	D MW/ Hz	D Pu MW/ HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	**Δ fo**	**Final Settling freq f**	Gen increase through Gov	**Load drop due to freq dependence**	**LS reqd.= Load-Gen**	**With 20% safety margin for stage-A to C LS reqd & 40% for Stage-D & E**	**% of total load**
		C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	W	X
A	50.00	210000	210000	8400	0.04	1.5%	0.015	6300	0.03	10500	5%	50	0.05	0.80	49.20	210	5040	**4681**	**5617**	**2.7%**
B	49.20	201810	201810	10100	0.05	1.5%	0.015	6153	0.03	10091	5%	50	0.05	1.00	49.00	202	6159	**5550**	**6660**	**3.2%**
C	49.00	191912	191912	11500	0.06	1.5%	0.015	5875	0.03	9596	5%	50	0.05	1.20	48.80	192	7041	**6325**	**7590**	**3.6%**
D	48.80	180604	180604	11780	0.07	1.5%	0.015	5551	0.03	9030	5%	50	0.05	1.30	48.70	181	7242	**6455**	**9037**	**4.3%**
E	48.70	169004	169004	11850	0.07	1.5%	0.015	5206	0.03	8450	5%	50	0.05	1.40	48.60	169	7300	**6484**	**9078**	**4.3%**
																Stage A-C		**16555**	**19867**	**9.5%**
																Stage D-E		**12939**	**18114**	**8.6%**
																Grand Total		**29494**	**37981**	**18.1%**

Table 8.1

The calculations were done with the above assumptions, and it is observed that during the peak demand scenario (210000MW), a sudden 4% of demand rise or 4% generation loss of (8400MW) will lead to frequency falling to 49.20 Hz in Stage-A.

The above estimates were done based on the assumed values of D, R and with a demand of 210000MW. The same was repeated for 150000MW system and the estimates are as follows.

D in %	**1.5%**		**R reg**	**5%**													
Load	**150000**									**Effect of both D & R**							
Stage	freq	Gen	Load	Change in load/Gen Δ "G/L" ***	D in %	D Pu MW/HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	Δ fo	**Final Settling freq f**	Gen increase through Gov	**Load drop due to freq dependence**	**LS reqd.= Load-Gen**	**With 20% safety margin for stage-A to C LS reqd & 40% for Stage- D & E**	**% of total load**
		C	D	E	G	J	K	L	M	N	O	P	Q	R	S	T	X
A	50.00	150000	150000	6000	1.5%	0.03	7500	5%	50	0.05	0.80	49.20	150	3600	**3343**	**4012**	**2.7%**
B	49.20	144150	144150	7200	1.5%	0.03	7208	5%	50	0.05	1.00	49.00	144	4390	**3956**	**4747**	**3.2%**
C	49.00	137094	137094	8200	1.5%	0.03	6855	5%	50	0.05	1.20	48.80	137	5020	**4510**	**5412**	**3.6%**
D	48.80	129031	129031	8400	1.5%	0.03	6452	5%	50	0.05	1.30	48.70	129	5164	**4603**	**6444**	**4.3%**
E	48.70	120760	120760	8470	1.5%	0.03	6038	5%	50	0.05	1.40	48.60	121	5218	**4635**	**6489**	**4.3%**
													Stage A-C		**11809**		**9.4%**
													Stage D-E		**9238**		**8.6%**
													Grand Total		**21047**		**18.1%**

Table 8.2

From the above tables, it is seen that the % Load shedding quantum remains the same for 210000MW and 150000MW operating point of the system. Further it is required to consider that in real time the load shedding feeders could be under forced outage or unavailable due to other reasons and therefore an approximate safety factor assumptions can be made and the final AUFLS quantums for Stage-I-A to E can be recommended as given below.

S. No.	Stage	Frequency	Demand disconnection	
1	I-A	49.2 Hz	3.5%	
2	I-B	49.0 Hz	3.5%	
3	I-C	48.8 Hz	4%	
4	I-D	48.7 Hz	4.5%	
5	IE	48.6 Hz	4.5%	20%
Desperate measures- Load Shedding				
6	II-F	48.4 Hz	6%	
7	II-G	48.2 Hz	6%	
8	II-H	48.0 Hz	6%	18%
	Total			36%

Table 8.3

I) Stage I-A to E:

(i) It is the responsibility of the State to shed loads that would trip the above quantum of demand as specified.

(ii) State is free to shed loads anywhere in Stage I-A to E as per its convenience

(iii) The feeders on which the Stage I-A to E relays have been installed should be excluded from all type of load shedding schemes such as ADMS, SPS, any other planned Load Shedding Scheme, LTS or any other emergency load shedding schemes etc.

(iv) The figures are with respect to the maximum demand catered in the past.

(v) When demand drops the connected feeders remain the same, so that overall, the demand will be commensurate with the expected targets.

II) Stage II-F to H:

(i) The Stages II-F to H shall be connected to all load centers. In particular States shall connect loads where the load centers are importing from stations away from the load centers.

(ii) It is strongly recommended that the distribution of loads under these stages be done uniformly throughout the State as far as possible.

(iii) Depending on regional power flow, ensure that all importing loads are well covered.

(iv) No planned preparatory islanding scheme loads that are wired up for Load shedding are covered in the above.

(v) Feeders other than those covered under b)-(iii) and c)-(iv) should be wired up for implementation of Stages II-F to H.

(vi) The feeders identified for implementation under Stage II-F to H, preferably, shall be feeders emanating from EHV stations, since under this stage it is assumed that the system has entered in emergency state and a reliable load disconnection is required under this stage.

b) Approach-B

The system may separate or remain integrated if the frequency touches any of the five stages of AUFLS i.e., 49.2,49.0,48.8,48.7 & 48.6Hz. Therefore, in this approach, the total load shedding quantum decided based on the calculation table is given below, for the current year (FY 2022-2023 or calendar year 2022), has been allotted LS quantum to each region based on the import/export of the Region during the last years (FY

2021-22 or calendar year 2021) all India peak demand. This is done for the 1st two stages of frequency 49.2 & 49 Hz, since during these two stages the import/export of the Regions needs to be controlled based on the internal generation available in that region. The tie line flows will ease out and the chances of Low Frequency Oscillations (LFOs) will be the least or controllable. In the 2012 blackout the frequency did not fall below 49.2 Hz initially, still the system got separated. Only after separation, the frequency in the importing regions fell below 49.2 Hz and those in exporting regions it increased above 50Hz. As brought out by the Enquiry Committee the quantum of LS operated, at that time, in import regions was not sufficient (AUFLS mal functions /in-operations).

While adopting this approach, there are two ways in which it can be implemented. In the first, the AUFLS quantum for importing & exporting regions can be kept fixed in a ratio decided (say 60:40 or 70:30 …) based on the import/export during all India peak demand of last year. The all-India peak for last year has been considered, since during the peak period, the system is operated under stressed condition, and it is the most difficult period when series of unforeseen contingencies occur. At other than peak loading conditions of the system, there is a cushion available in the form of spinning reserves and other avenues to mitigate the series of contingencies. However, this cannot be expected to be true all the times.

Another way to address the variability of the Import/export of regions in real time, Wide area measurement systems (WAMS) using PMUs (PhasorMeasurement Unit) is the best tool for monitoring and controlling. Under this, the inter-regional flow of power between regions would be monitored in real time and based on the imports of a region, the UFR's of importing region will automatically enabled and the UFRs in the export region would automatically be disabled based on the import/export quantum plus the power generation at the largest station of the region. When the frequency reaches the 1st stage, the load shedding relays would operate to give designated relief in those regions accordingly. There exists a possibility of selecting UFR relays and therefore the quantum automatically through a wide control system if the UFRs at the sub-transmission level having communication facility.

This approach was discussed and it was felt that this is a futuristic approach which can be implemented when the automation and communication becomes mature at transmission/distribution level. Also members felt that in the real time, the inter-regional power flow is not uni-directional, but changes season to season and even day *to day. The bidirectional exchange between regions has been observed and in case of some regions like SR, there are diurnal variations in exchange of power. The settings implemented would have to be dynamic during the day/season. When an integrated power system splits into sub-systems following cascaded outages, the sub-systems or islands are created in an unplanned way. The frequency, at which such splitting would occur, cannot be predicted. Therefore, it's not possible to design any post splitting UFLS to ensure survival of the islands. However, UFRs once installed, would operate whenever the threshold frequency is reached.*

Therefore, the group felt that this approach may be thought of in future for implementation after ascertaining the fulfilment of communication requirements. But establishing proper communication to AUFLS feeders in far remote areas is also the most difficult and challenging task.

The detail of this approach B is given at Annexure-III

Comprehensive study on stage wise load shedding under AUFLS quantum with system load of 210 GW and 150 GW with D=1.5% and R=5% is given below:

For 210000 MW System load: The calculation table given in Table 8.4 below.

New Gen	New Load	Change in load Δ "L" due to freq rise from 49.2Hz to 50Hz	Pu Δ "L"	D in %	D freq dependance	D MW/Hz	D Pu MW/HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	Δ fo	Δ Increase in load due to increase in freq	New Gen after freq increase	New Load after freq increase
AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ
U6	V6	AC6-AB6	AD6/AC6			AG6*AC6/(0.01*B6)	((1.5/100)*AC6/(50/100))/AB6	AB6*5/(100*M6)		2.5*AB6/AJ6	AI6+1/AL6	AE6/AM6	AC6*AG6*0.8	AB6	AC6+AO6
201810	204960	3150	0.0154	1.5%	0.015	6149	0.030468	202	5%	2500	0.031	0.498	1531	201810	206491
191912	195651	3740	0.0191	1.5%	0.015	5965	0.030585	192	5%	2500	0.031	0.617	1810		
180604	184871	4267	0.0231	1.5%	0.015	5659	0.030709	181	5%	2500	0.031	0.742	2058		
169004	173362	4358	0.0251	1.5%	0.015	5329	0.030774	169	5%	2500	0.031	0.806	2097		
157323	161704	4381	0.0271	1.5%	0.015	4981	0.030835	157	5%	2500	0.031	0.867	2104		

Table 8.4 cont_

													Effect of both D & R									Load Shedding apportionment				
Stage	freq	Gen	Load	Change in load/Gen Δ "G/L" ***	Pu Δ "G/L"	D in %	D freq dependance	D MW/Hz	D Pu MW/HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	Δ fo	Final Settling freq f	Gen increase through Gov	Load drop due to freq dependence	LS reqd.= Load-Gen	With 20% safety margin for stage-A to C LS reqd & 40% for Stage- D & E	New Gen after gen loss+ regulation	New load after loss of load due to freq dependence	With 20% safety margin for stage-A to C LS reqd & 40% for Stage- D & E	% of total load	Importing Region	Exporting Region	Ratio of LS sharing
		C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
					E6/D6			H6*D6/(0.01*B6)	((15/100)*D6/(50/100))/C6	C6*5/100		2.5*C6/K6	J6+1/M6	F6/N6	B6-O6	K6/M6	I6*O6	V6-U6+A06	S6*1.2	C6-E6+Q6	D6-R6	T6	W6/D6	W6*0.6	W6*0.4	
A	50.00	210000	210000	8400	0.04	1.5%	0.015	6300	0.03	10500	5%	50	0.05	0.80	49.20	210	5040	4681	5617	201810	204960	5617	3%	3370	2247	60:40
B	49.20	201810	201810	10100	0.05	1.5%	0.015	6153	0.03	10091	5%	50	0.05	1.00	49.00	202	6159	5550	6660	191912	195651	6660	3%	3996	2664	60:40
C	49.00	191912	191912	11500	0.0599	1.5%	0.015	5875	0.03	9596	5%	50	0.05	1.20	48.80	192	7041	6325	7590	180604	184871	7590	4%	5313	2277	70:30
D	48.80	180604	180604	11780	0.0652	1.5%	0.015	5551	0.03	9030	5%	50	0.05	1.30	48.70	181	7242	6455	9037	169004	173362	9037	4%	proportional to the peak demands		
E	48.70	169004	169004	11850	0.0701	1.5%	0.015	5206	0.03	8450	5%	50	0.05	1.40	48.60	169	7300	6484	9078	157323	161704	9078	4%	proportional to the peak demands		
																Stage A-C		16555				19867	9%			
																Stage D-E		12939				18114	9%			
																Grand Total		29494				37981	18%			

Table 8.4 210 GW system

For 150 GW system load: The calculation Table 8.5 given below.

New Gen	New Load	Change in load Δ "L" due to freq rise from 49.2Hz to 50Hz	Pu Δ "L"	D in %	D freq dependance	D MW/Hz	D Pu MW/HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	**Δ fo**	**Δ Increase in load due to increase in freq**	New Gen after freq increase	New Load after freq increase
AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ
U6	V6	AC6-AB6	AD6/AC6			AG6*AC6/(0.01*B6)	((1.5/100)*AC6/(50/100))/AB6	AB6*5/(100*M6)		2.5*AB6/AJ6	AI6+1/AL6	AE6/AM6	AC6*AG6*0.8	AB6	AC6+AO6
144150	146400	2250	0.015369	1.5%	0.015	4392	0.030468	144	5%	2500	0.031	0.498	1093	144150	147493
137094	139760	2666	0.019073	1.5%	0.015	4261	0.030583	137	5%	2500	0.031	0.616	1291		
129031	132074	3043	0.023037	1.5%	0.015	4043	0.030707	129	5%	2500	0.031	0.741	1467		
120760	123868	3107	0.025087	1.5%	0.015	3807	0.030772	121	5%	2500	0.031	0.805	1495		
112411	115542	3131	0.027101	1.5%	0.015	3559	0.030836	112	5%	2500	0.031	0.868	1504		

Table 8.5 cont-

													Effect of both D & R									Load Shedding apportionment				
Stage	freq	Gen	Load	Change in load/Gen Δ "G/L" ***	Pu Δ "G/L"	D in %	D freq dependance	D MW/Hz	D Pu MW/HZ	Gen (reg) 5% gen respond	R reg	R Hz/pu MW	FRC β	Δ fo	Final Settling freq f	Gen increase through Gov	Load drop due to freq depence	LS reqd.= Load-Gen	With 20% safety margin for stage-A to C LS reqd & 40% for Stage- D & E	New Gen after gen loss+ regulation	New load after loss of load due to freq dependence	With 20% safety margin for stage-A to C LS reqd & 40% for Stage- D & E	% of total load	Importing Region	Exporting Region	Ratio of LS sharing
		C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
					E6/D6			H6*D6/(0.01*B6)	((1.5/100)*D6/(50/100))/C6	C6*5/100		2.5*C6/K6	J6+1/M6	F6/N6	B6-O6	K6/M6	I6*O6	V6-U6+AO6	S6*1.2	C6-E6+Q6	D6-R6	T6	W6/D6	W6*0.6	W6*0.4	
A	50.00	150000	150000	6000	0.04	1.5%	0.015	4500	0.03	7500	5%	50	0.05	0.80	49.20	150	3600	3343	4012	144150	146400	4012	3%	2407	1605	60:40
B	49.20	144150	144150	7200	0.049948	1.5%	0.015	4395	0.03	7208	5%	50	0.05	1.00	49.00	144	4390	3956	4747	137094	139760	4747	3%	2848	1899	60:40
C	49.00	137094	137094	8200	0.059813	1.5%	0.015	4197	0.03	6855	5%	50	0.05	1.20	48.80	137	5020	4510	5412	129031	132074	5412	4%	3788	1624	70:30
D	48.80	129031	129031	8400	0.065101	1.5%	0.015	3966	0.03	6452	5%	50	0.05	1.30	48.70	129	5164	4603	6444	120760	123868	6444	4%	proportional to the peak demands		
E	48.70	120760	120760	8470	0.070139	1.5%	0.015	3720	0.03	6038	5%	50	0.05	1.40	48.60	121	5218	4635	6489	112411	115542	6489	4%	proportional to the peak demands		
																Stage A-C		11809				14171	9%			
																Stage D-E		9238				12933	9%			
																Grand Total		21047				27104	18%			

Table 8.5 150GW system

9. The problem of df/dt schemes:

Due to integration, df/dt schemes have following known issues:

1) The smallest df/dt rate measurable/settable by a relay is usually 0.05 Hz/sec and such relays are available.
2) As per an earlier study on df/dt in 2007, when ER and WR were integrated, is the reduction in df/dt below measurable levels. See Annexure.
3) The df/dt at the point of the separation is the highest. Relays must have a minimum of 6 cycles to detect this to prevent a mal-operation. Now a day a 3cycle sliding window validation of df/dt is available. Lower the number of cycles, the faster is the response, however the low cycle sliding window have an issue of mal-operations.
4) Hence reliability of df/dt as a regional scheme is not so good, though it can provide reliefs under certain scenario.
5) However, df/dt in region where a generation loss ~~has~~ takes place, tends to operate as the df/dt is relatively higher at loads which are electrically in proximity to such generators than those loads which are electrically far from the disturbance centre.

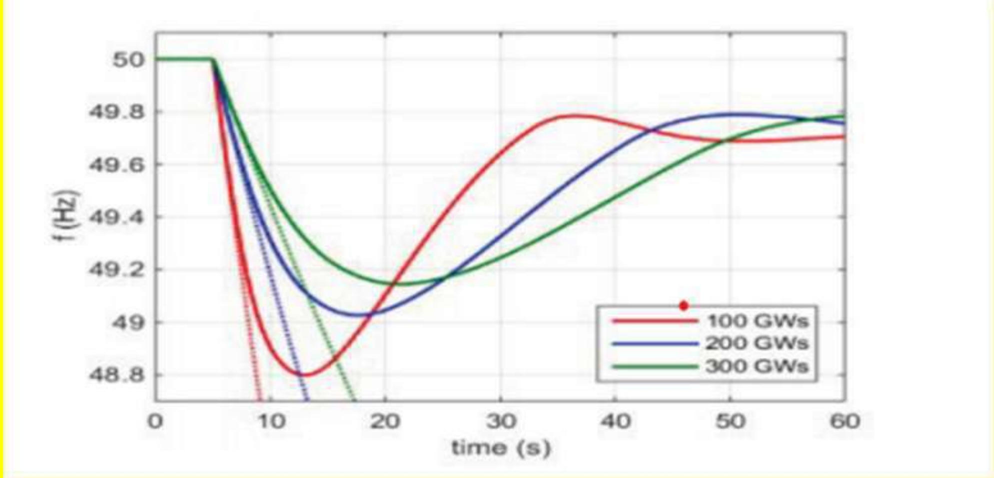
It is because of the above disadvantages, that this Committee emphasizes on flat AUFLS.

Reduced Inertia and role of df/dt:

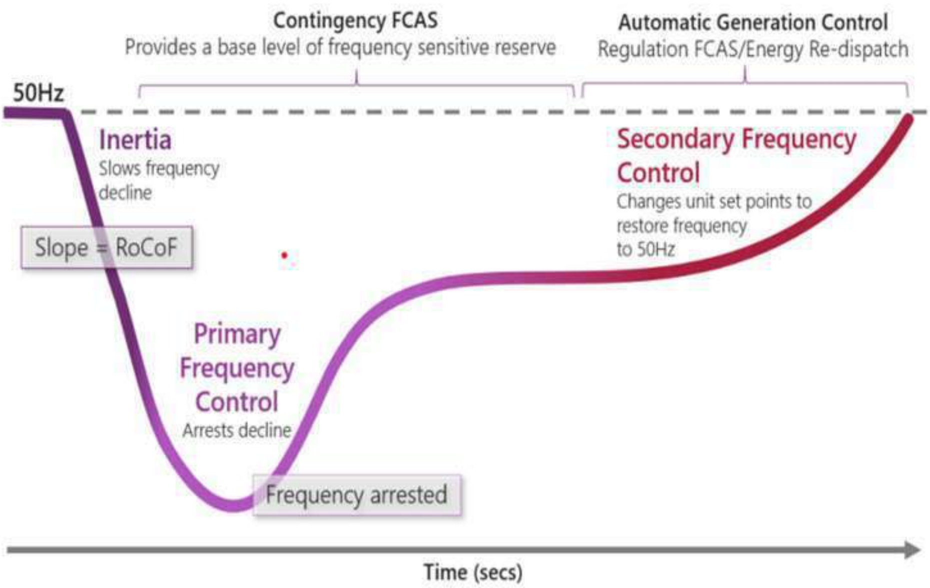
The Indian Electricity Grid Code mandates operation of power system within a narrow frequency band of 49.90 to 50.05 Hz, which is expected to be narrowed down further to 49.95-50.05 Hz, in the future. A frequency excursion is restricted by the combined response of system inertia, load response, primary frequency response of generators, initially. The wind and solar penetration is variable therefore during high penetration, the synchronous rotating inertia of the system reduces and during low penetration, it increases. Therefore, it is difficult to analyze and estimate the correct value of rotating inertia. This diminishing inertia has high impact on df/dt during credible/severe contingency.

Out of total installed capacity of 404.4 GW, RE amounts to 114.4 GW (as per CEA data July 2022). With the target of integrating 175 GW of RE installed capacity by 2022, the Indian grid is likely to experience relatively low inertia scenarios in the future. Reduced inertia will result in steep fall of frequency during severe contingency in the system.

Typical impact of decreasing inertia is shown below.



1) The system frequency response to a severe contingency shown below.



Within short time of contingency, the rate of fall of frequency is high, if the system inertia is not sufficiently large. Therefore, Kinetic energy stored in the rotating masses is unable to provide adequate damping to the change in frequency and the frequency is likely to fall sharply with high df/dt.

2) The rate of fall of frequency is also tightly coupled with electrical proximity of the loads where the contingency happens.

3) These two factors namely inertia of the system and proximity of loads to the contingency decides the rate of fall of frequency electrically nearby area where generation loss occurs.

Keeping in view the above theoretical aspect and the operation of the system at present and in near future, the following setting philosophy is proposed for df/dt.

Guiding principles for implementation of df/dt relays:

a) Enabling frequency for df/dt:

- The df/dt relays have 2 set of settings to be set, 1st is the enabling frequency, and the 2nd is the rate of fall of frequency. Once the enabling frequency is reached the relay is ready to operate and operates once the 2nd set i.e., rate of fall is detected.
- Assuming that a contingency may happen at any frequency. Therefore, enabling frequency of df/dt can be set below 50 Hz but should not be below 49.9 Hz as stipulated in IEGC. Enabling frequency should be set at 49.9 Hz. i.e., the relay should always be enabled when the system frequency is below 49.9Hz.
- Now a days with numerical protections relays commercially available are having a minimum settable rate of fall of frequency of 0.01Hz/sec. Further the validation cycle of the rate sensing available is from 1 cycle minimum with sliding window validation.
- For a large integrated system having high inertia, the rates of 0.05Hz/sec with a validation of 6 cycles is a better choice (relays may mal operate if they are set below 0.05Hz/sec. in a high inertia system and becomes too sensitive, since these relays are sensitive to the electrical proximity of disturbance from the relay location). The sliding window validation of 5-8 cycles will also tend to increase the reliability of these relays, rather than going for validation cycle below 6 cycles.

b) Df/dt relay setting philosophy:

Considering the theoretical aspects and the system inertia, the df/dt relay settings can be decided on the following principles.

Severe contingency of largest station generation loss, major corridor loss RE (wind and solar) generation penetration at that point of time in the region will have an impact on deciding initial and subsequent stages of df/dt.

- 1st Stage:
  - Quantum: Largest generating station in the region or peak imports by the Region whichever is higher. The quantum shall be 30 % of the higher.
  - Rate for RE rich region: Setting of df/dt shall be 0.1 Hz/sec for high RE generation system region when RE installed capacity > ¼ of total installed capacity.
  - Rate for low RE region: Setting of df/dt shall be 0.05 Hz/sec when RE installed capacity < ¼ of total installed capacity.

- 2nd Stage:
  - Quantum: Largest generating station in the region or peak import by the system whichever is higher. The quantum shall be 40 % of the higher.
  - Rate for RE rich region: Setting of df/dt shall be 0.15 Hz/sec

    For high RE generation region, when RE installed capacity > ¼ of total installed capacity.
  - Rate for low RE region: Setting of df/dt shall be 0.1Hz/sec, when RE installed capacity < ¼ of total installed capacity

- 3rd Stage:
  a. Quantum: Largest generating stations in the region or peak import by the system whichever is higher. The quantum shall be 50 % of the higher.
  b. Rate for RE rich region: Setting of df/dt shall be 0.2 Hz/sec

     For high RE generation region, when RE installed capacity > ¼ of total installed capacity.
  c. Rate for low RE region: Setting of df/dt shall be 0.25 Hz/sec, when RE installed capacity < ¼ of total installed capacity

Suppose if grid splits into several small areas, then df/dt at the point of separation is the highest and therefore provision of additional stages of df/dt based load shedding at the initial stage of credible contingency is required to be introduced in future to countermeasure diminishing inertia due to RE penetration. A system study to evaluate the value of diminishing inertia due to RE penetration is required to be estimated accurately at National level.

As brought out above the df/dt trigger frequencies given above would be experienced in the split grid operations. Therefore, the above df/dt scheme of arrangement can further be discussed at the regional level and RPCs in consultation with stake holders can decide the quantum of Load shedding required to be wired up.

Adaptive load shedding with df /dt is the most viable solution to arrest steep fall in frequency at initial stage of disturbance and a PMU based WAMS supervised system can be considered for implementation of df/dt, in future.

10. Conclusion

1) **AUFLS setting**: The AUFLS is divided in two groups i.e., Stage-I and Stage -II with %age of quantum of load shedding is given below:

Sr. No.	***Stage***	***Frequency***	***Demand Disconnection***	***Total Quantum of LS***
Stage-I Defense plan- Load Shedding				
1	I-A	49.2 Hz	3.50%	
2	I-B	49.0 Hz	3.50%	
3	I-C	48.8 Hz	4.00%	
4	I-D	48.7 Hz	4.50%	
5	I-E	48.6 Hz	4.50%	**20%**
Stage-II Desperate plan- Load Shedding				
6	II-F	48.4 Hz	6.00%	
7	II-G	48.2 Hz	6.00%	
8	II-H	48.0 Hz	6.00%	**18%**
Grand Total (Stage-I + II)				**36%**

Table 10.1

2) **df/dt setting: The Stage-II feeders of AUFLS can be wired up for the df/dt relays also.**

df/dt setting for high penetration RE region and low penetration RE region philosophy recommended is as follows.

Following terminology is used while deriving the quantum of load shedding.

RE rich: RE installed capacity >1/4 of Total installed capacity

RE low: RE installed capacity <1/4 of Total installed capacity

Sr. No	***Stage***	***'X' in MW = Largest generating station or peak import in the region whichever is higher***			
		Enabling Frequency 'Hz'	***df/dt setting 'Hz/sec'***		***Quantum of Load Shedding 'MW'***
			RE rich	***RE low***	
1	***Stage 1***	***49.9***	***0.1***	***0.05***	***30% of 'X'***
2	***Stage 2***	***49.9***	***0.15***	***0.1***	***40% of 'X'***
3	***Stage 3***	***49.9***	***0.2***	***0.25***	***50% of 'X'***

a) The validation shall be 6 cycles for 0.05 Hz/sec setting and 5-7 cycles for setting of 0.1Hz/sec and above on a sliding window basis.
b) The quantum is for a region as whole, and the RPCs shall decide how to further distribute the quantum amongst the States.

Table 10.2

3) The quantum of load shedding required in above AUFLS Stages (Stage I & II) shall be decided on the basis of Regional Peak Loading conditions during the last year. The quantum shall be reviewed/revised by NPC accordingly and informed to RPCs by 1st of November. If the peak demand is lower than the last year peak demand, the settings will remain unchanged.
4) AUFLS should be distributed within the region by the RPCs by 1st December, in consultation with the stakeholders after receipt of the allocated load shedding quantum from NPC.
5) AUFLS relays under Stage-I should be implemented preferably on downstream network at 11/22/33 kV level.
6) AUFLS relays under Stage-II should be implemented on upstream network at EHV (66/110/132 kV) level so that load relief obtained is fast and reliable as it is a desperate measure for areas that have disintegrated.
7) As far as possible, the df/dt relays shall be installed on feeders electrically in proximity to Largest Generating Stations in the States or State Loads being fed through Import of power from ISTS network.
8) Feeders to be wired under AUFLS Stage-I, Stage-II and df/dt shall be connected to serving loads and shall not be under Planned/distress load shedding, SPS, ADMS, feeders etc. The AUFLS shall not include the preparatory LS for Islanding Schemes if any.
9) The feeders selected for AUFLS and df/dt shall not have RE generation or any other distributed generator connected to these feeders. In such cases instead of tripping the feeder, the relays can be installed to shed loads on the feeders. However, if this is not possible the low RE generation or distributed generation feeders shall be selected by proper ranking.
10) The df/dt load shedding is specific to regions and therefore, the quantum of load shedding required to be wired up under the df/dt scheme be discussed at regional levels in the RPCs. The RPCs in consultation with the stakeholders can decide on the quantum of Load shedding required to be wired up in Stage-1, 2 & 3 of the df/dt schemes. The trigger criteria can also be reviewed by the RPCs, based on the

observed df/dt rates in the regions, if it feels so. The quantum indicated in above df/dt Table 10.2 is for reference only.

Testing of AUFLS and df/dt:

1) Wherever relays are installed at 110 / 132 kV level and above S/s: The periodicity of testing shall be **Twice in a year.**
2) Wherever relays are installed at 66 kV level and below S/s: The periodicity of testing shall be **Once in a year.**
3) SLDCs shall in consultation with the Utilities responsible for testing should chalk out a plan of relays testing schedule before 1st of December and submit the same to RPC/RLDC.
4) Test shall be carried out by the State testing teams and report of the test carried out should be submitted to SLDC. SLDC shall submit a compiled progressive report of the same to RPC/RLDC every month. The format for testing of AUFLS is enclosed at Annexure-IV
5) SLDC should monitor the periodicity of test and ensure that the relays are tested as per the schedule. Deviation if any shall be intimated to RPC/RLDC with proper justification.
6) If possible, relays through test up to breakers may be carried out. If this is not possible the continuity of trip circuit of UFR up to the trip coil of breaker should be checked during the testing.
7) SLDC's shall ensure that at least 10% of the total relay testing be witnessed/carried out by other Circle Testing Engineer/RLDC/RPC.

PROTECTION CODE

- Protection Protocol
- Protection Settings
- Protection Audit Plan
- System Protection Scheme (SPS)
- Recording Instruments

Effective from 01.10.2023

PROTECTION PROTOCOL

- **Uniform Protection Protocol**
  - For proper **Co-ordination** of protection system
  - To have a **repository of protection system, settings and events at regional level**
  - Specifying **timelines** for submission of data
  - To ensure **healthiness of recording instruments** including triggering criteria and time synchronization
  - To provide for **periodic audit** of protection system

- All the users shall provide and maintain effective protection system having reliability, selectivity, speed, and sensitivity. Back up protection system shall be provided.
- The protection protocol should comply with relevant CEA (Central Electricity Authority) Technical Standards and Regulations.
- **RPC (Regional Power Committee)** is responsible for developing and revising the protection protocol in consultation with stakeholders.
- Changes in the protection protocol require deliberation and approval from the **concerned RPC**.
- Violation of the protocol of the region shall be brought to the notice of **concerned RPC by the concerned RLDC or SLDC**, as the case may be

PROTECTION SETTINGS

- **RPCs**
  - **Review of protection settings**, from time to time and **at least once a year**. Data including base case to be provided by **RLDC and CTU.**
  - **Maintain centralized database** of relay settings for elements connected at 220 kV and above (132 kV and above in NER)and update periodically. **RLDCs shall also maintain such database.**
  - **Carry out detailed system studies, once a year**, for protection settings. Required **data** to be provided **by RLDCs and CTU.**
  - Provide database access to CTU/NLDC/RLDC/SLDC/STU and to all users of respective region.
  - **Changes in the network and protection settings** of grid elements connected to 220 kV and above (132 kV and above in NER) shall be **informed to RPCs by CTU and STUs**, as the case may be. Elements of network below 66 kV and radial in nature which do not impact national grid may be excluded as finalized by the respective RPC.

- **Users**
  - Furnish implemented protection settings for each element to RPC
  - **Obtain RPC's approval for any changes** in setting or implementation of new protection system
  - **Intimate RPC** about implemented changes **within a fortnight**
  - Ensure correct and appropriate setting with proper co-ordination

PROTECTION AUDIT PLAN

All users → Role

132 kV and above

Conduct Internal Protection Audit — Once in a year

Report and shortcomings identified shall be rectified and informed to RPC

Conduct Third Party Protection Audit — Once in 5 years/ as per RPC

Protection Audit Recommended by RPC → (3 Months) → Conduct Third Party Protection Audit → (1 Month) → Submission of Audit Report along with action plan for rectification to respective RPC and RLDC or SLDC → The necessary compliance to such protection audit report shall be followed up regularly in the respective RPC.

- ensure correct and appropriate settings
- ensure proper coordinated protection settings
- Annual audit plan for the next financial year shall be submitted by the users to their respective RPC by 31st October.
- shall adhere to the annual audit plan and report compliance of the same to their respective RPC.
- Format prescribed for third party audit report

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PROTECTION AUDIT PLAN

Protection Performance Indices

a) The Dependability Index defined as D=Nc/(Nc+Nf)

where,

Nc is the number of correct operations at internal power system faults and

Nf is the number of failures to operate at internal power system faults.

(b) The Security Index defined as S=Nc/(Nc+Nu)

Where,

Nc is the number of correct operations at internal power system faults

Nu is the number of unwanted operations.

(c) The Reliability Index defined as R=Nc/(Nc+Ni)

Where,

- Nc is the number of correct operations at internal power system faults
- Ni is the number of incorrect operations and is the sum of Nf and Nu

- **Users** shall submit protection performance indices of previous month to their respective RPC and RLDC on monthly basis, which shall be reviewed by RPC.
- Each User shall also submit the reasons for performance indices less than unity of individual element to RPC and action plan for corrective measures. The action plan will be followed up regularly in the **respective RPC**.
- If any user fails to comply with protection protocol or fails to undertake remedial action identified by RPC within specified timelines, **concerned RPC may approach the Commission** for suitable directions.

SYSTEM PROTECTION SCHEME

- SPS for identified systems should have redundancies in measurement of input signals and communication paths involved up to the last mile to ensure security and dependability.

- For the operational SPS,
  - **RLDC or NLDC**, as the case may be, in consultation with the concerned RPC(s) shall perform regular load flow and dynamic studies and mock testing for reviewing SPS parameters & functions, at least **once in a year**.
  - **RLDC or NLDC** shall share the report of such studies and mock testing including any short comings to respective RPC(s).
  - The data for such studies shall be provided **by CTU** to the concerned RPC, RLDC and NLDC.

- **Users/SLDCs** shall report about the operation of SPS immediately and detailed report shall be submitted within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs

- The performance of SPS shall be assessed as per the protection performance indices specified in these Regulations. In case, the SPS fails to operate, the concerned **User** shall take corrective actions and submit a detailed report on the corrective actions taken to the concerned RPC **within a fortnight**.

RECORDING INSTRUMENTS

- **Users** shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.
- Disturbance recorders to have time synchronization and a standard format for recording analogue and digital signals which shall be included in the **guidelines issued by the respective RPCs**.
- The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers **by the respective RLDC**.
- Disturbance recorders which are non- compliant shall be listed out for discussion at RPC.

REPORT SUBMISSION TIMELINE(AS PER OPERATING CODE)

Sr. No.	Grid Event^ (Classification)	Flash report submission deadline (users/ SLDC)	Disturbance record and station event log submission deadline (users/ SLDC)	Detailed report and data submission deadline (users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
1	GI-1/GI-2	8 hours	24 hours	+7 days	+7 days	+60 days
2	Near miss **event**	8 hours	24 hours	+7 days	+7 days	+60 days
3	GD-1	8 hours	24 hours	+7 days	+7 days	+60 days
4	GD-2/GD-3	8 hours	24 hours	+7 days	+21 days	+60 days
5	GD-4/GD-5	8 hours	24 hours	+7 days	+30 days	+60 days

ग्रिड-इंडिया
GRID-INDIA

THANK YOU

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Minutes of the 44th Meeting of Forum of Load Despatchers (FOLD)
held on 20th March, 2023 through Online

1. The 44th meeting cum workshop of the Forum of Load Despatchers (FOLD) was held on 20th March 2023. Officials from SLDCs, RLDCs, NLDC participated in the meeting. The NLDC, RLDCs and SLDCs were connected through Team/VC. More than 120 officials from GRID-INDIA and SLDCs have participated the meeting.

2. **The Agenda of the meeting are :**

   Presentation on

   I. Managing and Leading Team - **presented by Ms. Bindiya Jain , Chief Manager (HRD)**.

   II. Knowledge Sharing by Tamil Nadu SLDC on two shift operation of Thermal Power Plant - **presented by TN SLDC.**

   III. Final Report Sharing by FOLD Working Group - Disturbance recorder (DR) parameter standardization - **presented by members of the working group.**

   IV. Director (MO), GRID-India chaired the meeting. Director (MO) welcomed all the Load Despatchers to the 44th meeting of Forum of Load Despatchers (FOLD) and congratulating them for their 24X7 efforts to manage the integrated grid functioning with Reliability, Economy and Sustainability.

   - Director (MO), GRID-INDIA expressed his concern about the high power demand phase and steps that are being taken up to tide over the phase in a planned and effective way.
   - He talked about gas generation of 5000 MW by NTPC and 4000 MW tender by NVBN for gas generation from private generating stations to mitigate the high demand period through increased power generation.
   - Director (MO) stated that imported coal based generators and gas based generators were unable to bid in day ahead market due to the price cap of Rs. 12.
   - Further Director (MO) discussed about the upcoming Basic PSO exam for the System Operators scheduled on 26 March 2023. He congratulated the FOLD secretariat for organising the training program for SLDCs and Grid-India employees to apprise them with the Basic PSO exam syllabus. He motivated the participants to utilise the training

program in getting acquainted with the syllabus of the exam and refresh their knowledge to get certified in the exam.

3. Ms. Bindiya Jain has given a presentation on Leading & Managing Team. She has shared various research done by Google, Mckinsey, Gallup on manging teams. She had share factors that click the team like Psychological safety, dependability, structure & clarity, meaning and impact. The participants appreciated the presentation and have suggested more of such session in a formal way, which can be included as part of the training program.

4. Shri S. Kajamoideen, Chief Engineer, TTPS and Shri A. Ravichandran, Executive Engineer, Technical Service, Tuticorin Thermal Power Station (TTPS) has shared best practice about two shift operation in Tuticorin Thermal Power Station. TTPS officials have share various benefit owing to tow shift operation. Some of the benefit are complete accommodation of RE like solar and wind into the TNEB grid, less coal consumption and reduction of emission Carbon, SOX and SO2 are some of the benefit of two shift operation. Further, TTPS officials has also share the adverse effect like increased in oil consumption due to frequent shutdown and startup operation, increased DM water consumption, increased in auxiliary power consumption and variable cost etc. The participants across SLDCs have appreciated the best practice of TNEB.

5. Member from FOLD working group on Cyber Security, Sh. Amit Prasad Gupta, DGM, NERLDC presented the progress of activity of the group. Shri Gupta has shared that in phase –I, as on date, the SOPs for the following domain areas have been prepared :

- Active Directory Installation in Its and OTs Network
- Network Architect of IT & OT
- Physical security controls
- SOP for peripheral security devices - firewall

Further, the group has plan to publish the SOPs in the Phase –II report by the end of April, 2023 on the following:

- Log Management, policy and procedures
- Website application security
- Remote access management
- Disaster recovery and backup

6. FOLD working group on resource adequacy and reserve estimation presented their progress on the report. The report will be finalized by end of this month. The development on the working group as shared by the members are:

i. As sample study carried out for Karnataka system.

ii. Study was carried out using GAMS. Explored open source software like NREL PRAS and GridPath. But lacked flexibility. That's why GAMS unit commitment module was used.
iii. For creating Monte Carlo simulation of forced outage scenarios RAND function is used.
iv. Requirement of speed improvement of GAMS UC module is there for more accommodating more number of Monte Carlo simulation output i.e. more scenarios.
v. Also the team is exploring modelling of merchant power plants in the context of state RA studies.
vi. Calculation of capacity credits using same GAMS module is under consideration as well.

7. Member of **FOLD** working group on ***Disturbance recorder (DR) parameter standardisation***, Sh Bimal Swargiary, Chief Manager, NERLDC presented the final report and recommendation of the working group. The final report is attached as annexure-I D.

8. Director (MO), GRID-INDIA appreciated the presentations shared by all the respected members of SLDCs/GRID-INDIA.

9. The meeting concluded with the vote of thanks to all.

DISTURBANCE RECORDER (DR) PARAMETER STANDARDIZATION

REPORT OF FOLD WORKING GROUP - 3

ACKNOWLEDGEMENT

The members of the Working Group-3 would like to extend gratitude to the FOLD management for being given the opportunity to be involved with this initiative. We would like to acknowledge the participation of each utility and organization (TRANSCOs, GENCOs, SLDCs, NLDC and RLDCs) for sharing valuable information, engaging in fruitful discussions, collection and improvisation of ideas related to different protection and operational philosophies and procedures which formed the basic building blocks for drafting the report on "Standardization of Disturbance Recorder Parameters".

Table of Contents

ACRONYMS

DR ………………………………………...Disturbance Recorder

DRPC………………………… …………DR Personal Computer

EL………...……………………………...Event Logger

ROT...Relay Operating Time

GPS………………………..……………Global Positioning Satellite

IDMT……………………………………Inverse Minimum Definite Time

TOR…………………..............................Terms of Reference

BCU……………………………………..Bay Control Unit

SAS……………………………………...Substation Automation System

HMI……………………………..……Human Machine Interface

DCDB…………………………………....Direct Current Distribution Board

ACDB……………………………………Alternating Current Distribution Board

IED………………………………………Intelligent Electronic Device

NGR……………………………………..Neutral Grounding Reactor

CB………………………………………..Circuit Breaker

CEA…..Central Electricity Authority of India

CERC……………………………………Central Electricity Regulatory Commission

IEGC……………………………….........Indian Electricity Grid Code

RTU……………………………………..Remote Terminal Unit

PREFACE

As per the discussion in 41st FOLD Meeting, a Working Group was constituted to streamline the Disturbance Recorder (DR) Parameter Standardization. According, a detailed study of the philosophies adapted by the power utilities in India and abroad was carried out. This report may be used by the power utilities as a guide for effective and optimal Disturbance Recorder Parameter Settings/Configuration in order to enable effective post-fault analysis for finding the root cause of an eventand suggest remedial measures. The present day modern IED's are IEC 61850 complaint and provide all standard features of DR configuration. The same can be utilized by the power utilities to incorporate all the necessary field level data (protection functions, switchgear status, and auxiliary device status) to provide valuable information to the event analysis group.

The **Terms of Reference (TOR)** of this group was to survey and compile prevailing national and international practices and standard regarding DR configuration, health monitoring and DR reader application software. Accordingly Working Group shall submit recommendations on the following aspects:

1. Triggering criteria of DR (Criteria for start of recording)
2. Sampling rate to be adapted for DR to enable verification of system models and to capture harmonics related to transient conditions
3. Recording window to cover pre-trigger, trigger (fault) and post-fault duration
4. Data format for raw data files of DR
5. Power supply arrangement for DR and associated equipment like GPS Receive/Clock, the SCADA/EMS RTU, modems and any other equipment supplying signals to the DR
6. Protocol for monitoring healthiness of DR including loss of supply, time synchronization

The group was mandated to prepare a report and submit within 3 months from the date of constitution of the Working Group.

MEMBERS OF FOLD WORKING GROUP

SN	NAME OF MEMBERS	DESIGNATION	CONTANCT NO.	AFFILIATION
1	Sh. Bimal Swargiary	Chief Manager	9435499779	NERLDC
2	Sh. Shashank Tyagi	Chief Manager	9599441243	NRLDC
3	Sh. Mohit Kumar Gupta	Manager	9650430505	NLDC
4	Sh. Akash Modi	Manager	8584072082	ERLDC
5	Sh. Vamshi Ballikonda	Manager	9480811828	SRLDC
6	Sh. Selvamani Prabaharan M	Deputy Manager	9629125521	WRLDC
7	Sh. Rupanka Kumar Goswami	AGM	9613146565	AEGCL, Assam
8	Ms. Barsha Kashyap	Deputy Manager	9706692773	AEGCL, Assam
9	Sh. Abhishek Kalita	Deputy Manager	8486213068	AEGCL, Assam
10	Sh. Nishanta Baruah	Asst. Manager	8473036988	AEGCL, Assam
11	Ms. Laishram Ritu	DGM	7008178772	SLDC, Manipur
12	Ms. Steffi Okram	Manager	8974724715	SLDC, Manipur
13	Ms. Jayela Wahengbam	DM	9856875084	SLDC, Manipur
14	Sh. B. M. Shah	EE	9925212836	SLDC, Gujarat
15	Sh. Shikhar Nema	AE	9425805299	SLDC, MP
16	Sh. Madhav Pande	Executive Engr.	9833608212	SLDC, Maharashtra
17	Ms. Smita Aparajita Pattanaik	Asst. Manager	9438908321	SLDC, Orissa
18	Sh. P. Balaji	Executive Engr.	9492129949	APTRANSCO
19	Sh. Sandeep Yadav	SE	9310404372	SLDC, Haryana
20	Sh. Munish Satija	Executive Engr.	9315016211	SLDC, Haryana

CHAPTER 1

INTRODUCTION

The Electricity Grid serves as one of the most important contributors for country's economic growth and emergency services. However, power system is prone to various types of faults and disturbances which can range from transient faults on transmission lines and switchyard equipments to system-wide disturbances. Investigation and root cause analysis of each grid disturbance is utmost necessary and critical for optimizing the performance of protection system and increasing reliability of the grid network.

Disturbance Recording devices have been in use since many decades. With advancement in technology and introduction of numerical relays, the capability of the Disturbance Recorder function in the relay has increased manifold. Standalone DR systems were used when internal DR recording facility for relays and BCUs were not available. For systems which still function with external DR recording devices may also incorporate the parameter standards proposed in this report accordingly (subjected to the features available in standalone DR or EL recording system). Recording of analog inputs with high sampling frequency, monitoring the status of internal protection functions, switchgear elements and auxiliary devices are available in modern IEDs. The tools required to perform post-incident analysis include extracted Disturbance Recorder files (Oscillographic Fault Records which include the analog values of currents and voltages, digital status of switchyard equipments and auxiliary relays and status of protection signals with accurate time stamps) and Event Logger files which can capture pre-event, event and post-event system conditions with high degree of accuracy and precise GPS based time stamping.

In the view of the critical importance of DR and EL data for event analysis, IEGC mandates submission of DR and SOE outputs by various entities/utilities for post-event analysis within 24 hours with RLDC. Each grid connected entity has a distinct configuration for DR parameter settings, which pose a challenge while analyzing events involving multiple entities or wide area disturbances. A standard philosophy and set of guidelines for DR parameter settings, analog and digital channel configuration is therefore utmost necessary which can be incorporated by the various utilities for achieving maximum benefit and conclusive results from the DR equipment.

CHAPTER 2

PURPOSE

Post-Despatch Analysis forms an integral part for ensuring system security and reliability. Disturbance Recorder (DR) output from Numerical Relays is an important tool for event analysis, which helps in classifying the cause of fault based on signature patterns and protection event logs. The DR data collected from the IEDs of affected elements along with pre and post fault information of the interconnected grid elements helps in proper root cause analysis to prevent occurrence of such events in future. Submission of DR and EL output is also mandated as per various provisions of CERC (Indian Electricity Grid Code) Regulations, 2010 and CEA (Grid Standards) Regulations, 2010 for quick analysis of the Grid Events. The following regulations can be summarized in brief as below:

As per clause no 5.2 (r) of CERC IEGC, all the users, STU/SLDC and CTU shall send information/data including DR/EL output to RLDC within 24 hours.

As per section clause No. 4.6.3 of IEGC (System Recording Instruments), recording instruments such as Data Acquisition System/DR/EL/FL/Time Synch. Devices shall be provided by all users, STUs and CTUs and shall always be kept in working condition for recording dynamic performance of the system.

As per clause no 12(1) of CEA Grid Standard Regulation, any tripping of generating unit or transmission element shall be promptly reported by the respective Entity (along with relay indications), to the appropriate Load Despatch Centre in prescribed reporting formats.

As per clause no 15(3) of CEA Grid Standard Regulation, all operational data, including disturbance recorder and event logger reports, for analyzing the grid incidents and grid disturbances and any other data which in its view can be useful for analyzing grid incident or grid disturbance shall be furnished by all the Entities within twenty-four hours to the Regional Load Despatch Centre and concerned Regional Power Committee.

However, it has been observed that post-despatch analysis is not effective at times in finding out the root cause of the event due to non-standardization of DR output.

The purpose of this report is to provide a general understanding of the considerations required for standardization of Disturbance Recording output so that uniformity is maintained by the utilities during DR submission.

CHAPTER 3

TRIGGERING CRITERIA FOR DR

Triggers cause a Disturbance Recorder or Micro-processor based relay to capture waveforms for specific power system conditions. Recording events may be triggered by changes in measured analog values, calculated analog values, internal logical statements, operation of protection elements or by change in state of an external input.

The triggering criteria for DR generation should be "**Start of Any Protection Function and Trip Event**" as per the following observation:

During grid disturbances which results in cascade tripping events, studyingbehaviour pattern of various upstream and downstream relays is of utmost importance. The most general cause of underreaching/overreaching and maloperation of unit/non-unit protections are due toimproper grading of individual operating times resulting in inadequate time discrimination among different protections functions (TMS, preset time delay), impedance reach, external discrepancies, internal logical errors and deviation from standard setting guidelines.

If "Start of Any Protection Function and Trip Event" is set in the IEDs as triggering criteria for DR generation, the DR and EL files can be extracted from upstream/downstream and associated elements during a large-scale grid disturbance, a thorough study can be carried out to pinpoint the actual cause of maloperation of the protection scheme. The absence of "Any Start" signal as the triggering criteria will miss out DR generation at crucial places which might lead to a non-conclusive post event analysis.

The internal storage capacity of memory in IEDs may vary for different manufacturers. However, the memory clearing function follows the FIFO(First-In-First-Out) method when the storage memory gets filled up. It should be a practice to extract the DR files immediately after occurrence of a grid disturbance event and transfer the relevant files to a secondary storage device (DRPC or dedicated workstations). This would nullify the chances of overwriting of memory and loss of actual disturbance recorder files.

Recommendation: Triggering Criteria for DR should be "Start of Any Protection Function and Trip Event"

CHAPTER 4

SAMPLING RATE TO BE ADOPTED FOR DR TO ENABLE VERIFICATION OF SYSTEM MODELS AND TO CAPTURE HARMONICS RELATED TO TRANSIENT CONDITIONS

Sampling Frequency can be defined as the number of analog values samples collected per second by the IED. The Sampling Frequency is mostly inbuilt in the relays and is dependent on manufacturer and model number of IED. The same cannot be changed by the user (e.g. ABB, Siemens, MiCOM and ERL the sampling frequency is predefined). However, for GE make relays, the sampling frequency is selectable from a drop-down menu.

SN	Relay Make	Sampling Frequency (fs)
1.	ABB	1000 Hz
2.	SIEMENS	1000 Hz
3.	MICOM	Dependent on model No: P442: 1200 Hz P443: 2400 Hz
4.	GE	3200 Hz (Default) *Selectable
5.	ERL	4800 Hz
6.	ZIVERCOM	1600 Hz

TABLE 1: SAMPLING FREQUENCY VALUESFOR DIFFERENT RELAYS

Note: With increase in value of Sampling Frequency, the number of samples (Data for analog values) recorded or calculated per second increases and digital channels are more frequently time stamped which in turn increases the Data size of the DR file (.dat file)

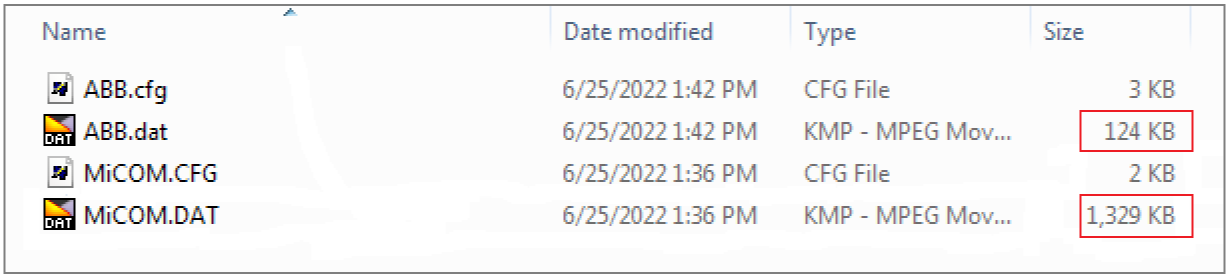


FIG 1: FILE SIZE COMPARISON OF GENERATED DR FILES BY DIFFERENT MAKE RELAYS FOR SAME EVENT

The above figure depicts the DR files generated for a 220kV Line with ABB make Main 1 relay and Alstom MiCOM make Main 2 relay (Difference in size of .dat file can be observed due to different sampling frequency). A comparison of data collected in the DR outputs for fs = 1000 Hz and fs = 2400 Hz for the same recording window, has been carried out with respect to root cause analysis.

Relay Make	**Model**	**Sampling Frequency (fs)**	**Data file size**	**Interval between successive samples**	**Fundamental and lower order harmonic values**
ABB	REL650	1000 Hz	124 KB	1ms apart	Approximately Same
MICOM	P443	2400 Hz	1329 KB	0.417ms apart	Approximately Same

TABLE 2: COMPARISON OF DATA DERIVED FROM DIFFERENT SAMPLING FREQUENCY

i) As per root cause analysis from recorded DR files, it can be observed that adopting a higher sampling frequency of 2400Hz does provide us more frequently collected fault data per interval but from a macroscopic point of view, a sampling frequency of 1000 Hz does not provide any less information for performing necessary observations and study.

ii) DR analysis particularly deals with observation of the sinusoidal trends of current and voltage waveforms (values of voltage, current, phase angle, harmonics etc.) along with the status of protection functions and various switchgear and auxiliary relays. A Sampling Frequency of >= 1000 Hz would be acceptable as each sample can be viewed in the DR at an interval of 1ms apart

iii) Relay Operating Time for Unit Protection functions are instantaneous (<30ms) whereas for backup protection functions it may vary from 50ms to >1 second (e.g. IDMT curve settings, definite time delays). Hence, sampling at 1ms interval is sufficient for analysis of the sequence of events (start and trip of protection functions and analyzing the sinusoidal values of voltages and currents) for root cause analysis.

Recommendation: Sampling Rate to be adopted should be greater than or equal to 1000 Hz

CHAPTER 5

PARAMETER SETTINGS FOR RECORDING WINDOW TO COVER PRE-TRIGGER, TRIGGER (FAULT) AND POST-FAULT DURATION EFFECTIVELY

Power system protection is basically divided into two parts:

i) Unit Protection
ii) Non-Unit Protection

The unit protections (Differential protection of transformers, line feeders, busbar, and inherent protection of transformers) should separate the faulty section instantaneously with higher accuracy of selectivity and reliability. Whereas the non-unit protections (IDMT overcurrent and earth fault, definite time delayed protections, delayed zones of distance protection) provide as a backup for the main protections in case of its non-operation or underreaching conditions.

The DR recording window should provide sufficient information for capturing the response of the above mentioned protection philosophies along with details about pre-fault scenario and post fault clearance scenario of the grid elements for thorough in-depth analysis.

The pre-fault recording window is an important aspect for DR analog and digital channels due to the following reasons:

i) The direction of power flow and loading prior to the fault
ii) Observing the trends of current and voltage waveforms in the pre-fault state
iii) The status of digital signals prior to the fault (e.g. Carrier Healthy status, CB ready status, VT fuse fail status are vital points for failure of Distance Protection schemes)

A recording window of 500ms to cover the pre-fault scenario may be considered adequate and sufficient for this purpose.

The post-fault time set for DR recording window should have ample recording time to capture the operation of non-unit protections and delayed operation of unit protections from their pickup time. Considering the Auto-reclose dead time of 1s/1.5s, Relay Operating Time for E/F and O/C as a backup for Zone 2/Zone 3 protections), it can be derived that a minimum of 2.5 seconds of post – fault recording time should be considered to record all the power system events during any generalized fault scenario.

Recommendation:

SN	Description	Settings
1.	Pre-fault Capture Time	500ms
2.	Post-fault Capture Time	2500ms
3.	Total time of DR Window	3000ms

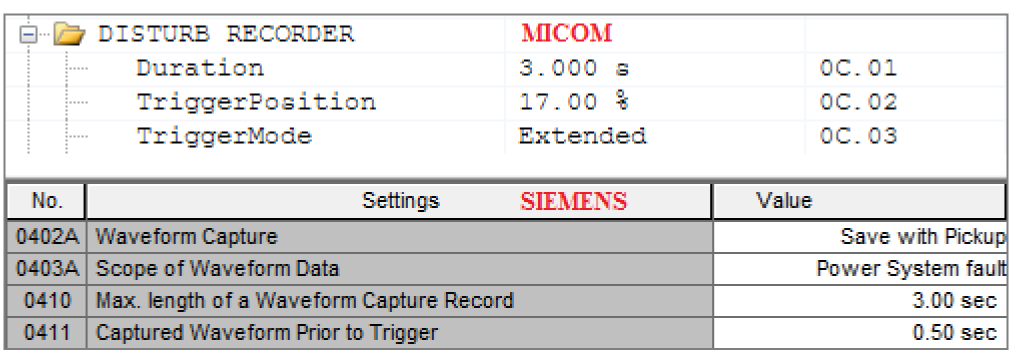
TABLE 3: ALLOTTED TIME FOR CAPTURE TIME OF DR WINDOW

Note:

i) The basic minimum length of DR window to be set is as per the above table. However, utilities may increase the Recording Time if required.

ii) The above setting of "time window parameters" may vary with respect to relay models and manufacturers. E.g. MiCOM relay provide setting field for "Total DR Window Time" and "Trigger Position" in percentage value. The above philosophy can likewise be implemented with respect to different relays.

iii) DR Recording features like "Trigger Mode: Extended" for MICOM relays "Scope of Waveform data: Power System Fault" can be utilized to record the overall sequence of events into a single DR file.



DISTURB RECORDER	MICOM	
Duration	3.000 s	0C.01
TriggerPosition	17.00 %	0C.02
TriggerMode	Extended	0C.03

No.	Settings SIEMENS	Value
0402A	Waveform Capture	Save with Pickup
0403A	Scope of Waveform Data	Power System fault
0410	Max. length of a Waveform Capture Record	3.00 sec
0411	Captured Waveform Prior to Trigger	0.50 sec

FIG 2: DR PARAMETER SETTINGS EXAMPLE FOR MICOM AND SIEMENS RELAY

CHAPTER 6

DATA FORMAT FOR RAW DATA FILES OF DR

The recorded DR files should comply with the Comtrade Standard IEC 60255-24, IEEE C37.111-2013

Recorded COMTRADE files are basically divided into three parts:

i) .hdr (Header File)
ii) .cfg (Configuration File)
iii) .dat (Data File)

Files with extension .inf and. rioare also present for some manufacturers. (These files store information about the trip events in the relay)

The **.dat file** contains the values measured for each of the input channels defined in the DR configuration for each sample in the record. It also contains the sequence number and time stamp each set of samples. The **.cfg** file contains the information required to interpret the .dat file. The DRs are viewed in third party softwares e.g. Wavewin by ABB, Siemens SIGRA etc.

Recommendation:

i) .cfg and .dat files are sufficient for DR viewing purpose
ii) Other files generated by relays of different manufacturers can be used for other purposes (e.g. Comtrade playback with relay test kit via .rio file).
iii) The .cfg file and .dat file can be edited to alter the Disturbance Recorder viewable information. E.g. the name of digital channels, analog channels can be changed via .cfg file whereas the values of analog quantities can be altered by editing the .dat file using third party softwares (e.g. notepad++). However, the permission to mask and secure the data records of DR files is solely based on relay manufacturers. E.g. ABB masks the .dat file in non-readable format.

CHAPTER 7

POWER SUPPLY ARRANGEMENT FOR DR AND ASSOCIATED EQUIPMENTS LIKE GPS RECEIVER/CLOCK, THE SCADA/EMS RTU, MODEMS AND ANY OTHER EQUIPMENT SUPPLYING SIGNALS TO THE DR

The DR function is inbuilt in the IED which is powered by a DC source. The IED's are connected in a LAN configuration which is further extended to a centralized DRPC. The communication network is established with the help of Ethernet switches which are generally powered by DC source. Fibre Optic Cables, LAN cables, Light Interfacing Units etc. are used for establishing the Ethernet network. The GPS Receiver/Clock unit mostly has provisions for both AC and DC supply. Hence, it is utmost necessary to maintain two independent DC sources at the substation for redundancy.

Recommendation for redundancy in DC supply:

i) Two numbers of separate Battery Banks, Battery Chargers and DCDBs should be maintained
ii) Use of DC changeover relays in the C&R panel to ensure continuous DC supply for the IEDs, Ethernet switches, RTU's, GPS Units etc.

AC Supply is used by SAS Computers, Centralized DRPC, Metering PC and Gateway PCs. For SAS based substations, SAS HMIs plays a vital role in control and monitoring operations. The absence of AC supply can jeopardize the systematic and secure operations during time of emergency. Redundancy in AC supply is hence required to be maintained in the substation.

Recommendation for redundancy in AC supply:

i) Use of Inverters/UPS units (with immediate uninterrupted changeover) which bypasses the station AC supply to the equipments during healthy condition and inverts the DC supply from Battery banks during power supply failure

ii) Two separate set of inverters/UPS units should be used with the following configuration (if applicable) to promote redundancy:

Inverter 1: SAS-1, Gateway-1, DRPC

Inverter 2: SAS-2, Gateway-2, Metering PC etc.

Life contact/Watchdog contact can be utilized if available in case of *Standalone DR/EL system* to monitor its **healthiness** via *annunciator board*.

CHAPTER 8

PROTOCOL FOR MONITORING HEALTHINESS OF DR INCLUDING LOSS OF SUPPLY AND TIME SYNCHRONIZATION

A. Healthiness of IED:

Disturbance Recorder and Event Logger functions are inbuilt in the IEDs. Protection functions may depend on intra-IED Ethernet network link established in the substation (for GOOSE communication) based on adapted scheme. Hence, for monitoring the healthiness of the DR, it is mandatory to monitor the power supply to the IEDs and the healthiness of the Local Area Network.

IEDs come with self-supervision feature. Due to any internal hardware or firmware error, the IED automatically activates the "Error Mode" which can be observed by the 'Error LED' in front HMI or in the 'Event List' in the HMI. IEDs also comprise a "Watchdog/Self-supervision/Internal Fail potential free normally open (NO) contact which is latched in case of power supply failure or IED being in error mode. Such Watchdog contacts are also present in Ethernet switches and RTUs.

The healthiness of one relay can be monitored by the other relay by establishing a hard wiring between the watchdog contacts of the concerned relays with a Binary Input (Opto Input) of the other nearby relays. The same Binary Input can be linked with the DR digital channels.

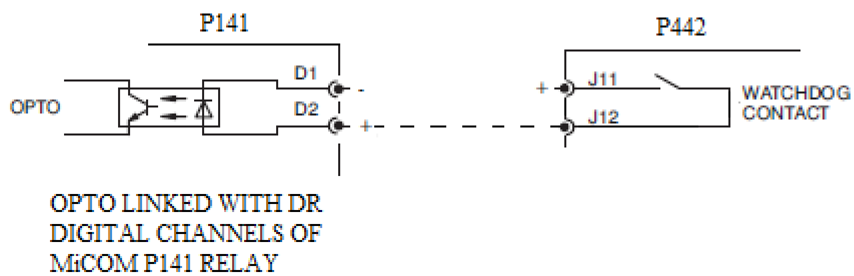


FIG 3: INTRA-IED HEALTHINESS MONITORING SCHEME WITH WATCHDOG CONTACT

E.g. For 132kV Lines, the protection scheme is based on Main Distance Protection relay and a backup Overcurrent and Earth fault relay. A case may arise when the Distance protection relay (say P442) failed to respond to a fault. In that case, if the healthiness of the P442 relay is monitored by the backup OC and EF relay (say P141), we may find from the extracted DR from P141 relay that, Dir. OC and EF protection had picked up for the fault along with a prevalent “Main relay Unhealthy” status. This would indicate the unhealthiness of the P442 relay during the instant of the fault and the doubt of discrepancy in relay settings can be left out.

Modern IEDs (IEC 61850 complaint) such a MiCOMP442 (in the above example) has inbuilt ‘Logical Devices’ viz. Control, Measurement, Protection, Records, Systems’. Each Logical Device has a ‘Logical Node’ called “LPHD” to monitor its health status. E.g. **Protection/LPHD1.ST.PhyHealth.stVal** can be used to monitor the healthiness of the Protection functions in the relay. However, these are suitable for tagging of SAS based alarms. For the purpose of DR channel configuration, fail proof Watchdog contacts should be utilized.

B. Healthiness of Time Synchronization:

The IEDs are in time synchronization with the GPS unit by IRIG-B (Inter-Range Instrument Group Time Code Format B) or SNTP (Simple Network Time Protocol)

For proper and in-depth analysis of power system faults (Sequence of Events, pickup and drop-off of protection functions), it is essential for relays at local and remote ends to be tie synched with the local standard time.

Basic Architecture of GPS time synchronization for IEDs in a substation

i) The GPS Receiver unit is present in the same Ethernet network as the IEDs. The GPS Antennae and the Time Display Unit is connected to the GPS Receiver
ii) The configuration for accessing the time through SNTP is present in the IED. E.g. ABB

SNTP: 1					
ServerIP-Add		172.16.0.140			
RedServIP-Add		0.0.0.0			

FIG 4: TIME SYNCHRONIZATION SETTINGS FOR ABB RELAY

In order to monitor the healthiness of the Time Synchronization, the following procedure can be followed. ABB, Siemens and MiCOM make relays are considered for the description:

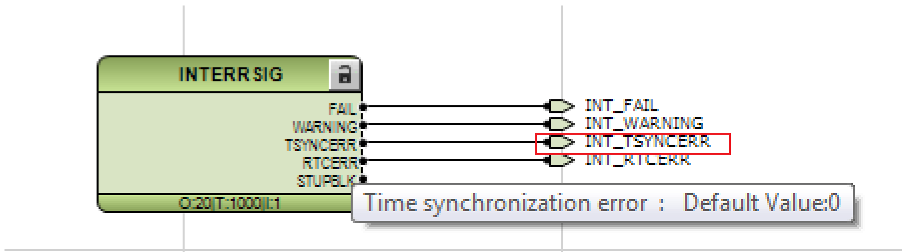


FIG 5: TIME SYNCHRONIZATION MONITORING FOR ABB MAKE RELAYS

The signal "TSYNCERR = Time Synchronization Error" form the functional block "INTERRSIG: Internal Error Signals" can be used. The annunciation and recording of Time Synch error can be achieved by:

i) The signal can be mapped to the DR digital channels
ii) The signal can be linked with SAS alarm tags
iii) The signal can be mapped with an LED of the relay
iv) The signal can be used to latch a Binary Output for connection to an external Annunciator Panel (for audible alarm) in case of loss of time synchronization

Information				Source							
Number	Display text	Long text	Type	BI	F	S	C	1	2	3	4
00067	Resume	Resume	OUT								
00068	Clock SyncError	Clock Synchronization Error	OUT								
00069	DayLightSavTime	Daylight Saving Time	OUT								
	SynchClock	Clock Synchronization	IntSP_E								
00070	Settings Calc.	Setting calculation is running	OUT								
00071	Settings Check	Settings Check	OUT								
00072	Level-2 change	Level-2 change	OUT								

FIG 6: TIME SYNCHRONIZATION MONITORING FOR SIEMENS MAKE RELAYS

The "Clock SyncError" signal in the Siemens relay can be mapped to the Disturbance Recorder Configuration; LED's or tagged as SAS alarms.

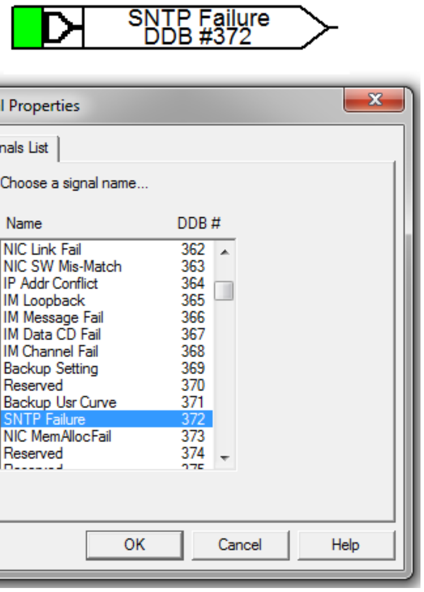


FIG 7: TIME SYNCHRONIZATION MONITORING FOR MICOM MAKE RELAYS

The Internal Input signal “SNTP Failure” can be mapped with the Disturbance Recorder Digital channels, LED’s and SAS alarms.

Recommendations:

i) Use of Watchdog contact in IEDs to monitor its healthiness by establishing an intra-IED hard wired network and assigning the same to the digital channels of IED

ii) Use of internal Time Synchronization error signal in relays as input to the DR digital channel to monitor the time synch status of the relays during fault events.

iii) Integrating time synch error in station SCADA and remote RLDC end also

CHAPTER 9

INTERNATIONAL PRACTICES ADOPTED FOR DR PARAMETER SETTINGS

A. Triggering Criteria for DR

As per "An Examination of possible criteria for triggering swing recording in disturbance recorders" by Leonard Swanson & Jeffrey Pond, USA – a power equipment fault causes an instantaneous increase in current magnitude, decrease in the voltage magnitude, increase in power, local change in frequency, decrease in measured apparent impedance and changes in symmetrical component quantities. It is fairly localized in impact on the system. A criteria based on any one of these impacts can be used to determine the presence of a fault and trigger a fault recording event

- Change in magnitude of analog quantities
- Rate of Change of analog quantities
- Oscillation in frequency
- Change of state of External Inputs
- Relay internal logic (programmed) trigger

The above points refer to start or trip of a protection function, operation of relay logics and change of state of switchgear elements or auxiliary equipments.

As per "Requirements for a Fault Recording system" by Rich Hunt and Jeff Pond" – Triggering of records for protective relays is almost always based on the "**Pickup or operation of a protection function**".

B. Sampling rate to be adopted for DR

As per "Alberta Reliability Standard Disturbance Monitoring and Reporting Requirements PRC-002-AB-2" – Each legal owner of a transmission facility, generating unit and aggregated generating facility must have fault recording data that meets a minimum recording rate of 16 samples per cycle

As per “System Monitoring – Fault Recording” by National Grid Electricity Transmission (UK) (NGET), the sampling frequency of analog channels for fault recording purposes shall be at least 1 kHz. The measurements of analog channels shall have an accuracy of 1% or better.

C. Recording window to cover pre-trigger, trigger (fault) and post-fault duration

As per “An Examination of Possible Criteria for Triggering Swing Recording in Disturbance Recorders” by Leonard Swanson & Jeffrey Pond, USA – Recording of power equipment faults is used to verify the operation of the protection system, which should clear faults in a matter of cycles, so record lengths are typically in the range of 20 cycles to 10 seconds.

D. Data format for raw data files of DR

Data format to be followed should be as per IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for power systems. The recorded DR files should comply with the Comtrade Standard IEC 60255 – 24. DR files with extensions (.hdr, .cfg, .dat) are used for viewing the DR data.

E. Power supply arrangement for DR and associated equipments

As per “System Monitoring – Fault Recording” by National Grid Electricity Transmission (UK) (NGET), the fault record shall be stored in a non-volatile memory storage medium for subsequent retrieval by means of a Personal Computer (PC). The equipment shall be capable of retaining its selected parameterization and settings when its auxiliary energizing supply is removed and subsequent reinstated. Fault recording devices need to be powered via a UPS or other supply that would not be disrupted in the event of a de-energization of user’s connection.

F. Protocol for monitoring healthiness of DR including loss of supply and time synchronization

As per “Requirement for a Fault Recording System” by Rich Hunt and Jeff Pond –the following ideas are stated:

i) Redundancy in DFR
ii) Using a combination of devices to record the same fault
iii) Cross-triggering using contact wiring among IEDs or with intra-relay communication.

As per “Alberta Reliability Standard Disturbance Monitoring Equipment Installation and Data Reporting PRC-018-AB-1”, disturbance monitoring equipment should be equipped with internal clocks synchronized to within two (2) milliseconds or less of the Universal Coordinated time scale.

CHAPTER 10

RECOMMENDED LIST OF DR CHANNELS FOR GRID ELEMENTS

Generalized Protection schemes are considered for the configuration of the channels. The numbers of IEDs used at substation level may vary depending on the implemented scheme and to promote redundancy in protection schemes. The list of DR channels can be established with the segregation of protection functions and number of IEDs used.

Allocation and number of analog and digital channels varies for different manufacturers and models of relay. E.g. ABB (REL650) provides 40 numbers of analog configurable channels and 96 numbers of digital configurable channels. The “Trigger Decision” can be selected per channel.

MiCOM (P444) provides 8 analog channels and 64 digital channels (out of which the decision to trigger the DR can be set for 32 channels whereas the status of remaining 32 channels would be included in the DR when some protection function triggers it). MiCOM (P442) included 32 settable DR digital channels. Similarly, for Siemens relays, the numbers of allotted digital channels vary from 32 to 64+ depending on model used.

Based on study of practical fault scenarios and the DR analog and digital channels required to correctly arrive at a conclusive decision without ambiguity, the following list of DR channels are proposed for implementation. Keeping in view the constraints in number of allotted digital channels (for previous models of particular relays), the priority wise implementation can be carried out. Some relays have specific internal protection signals not common with other relays (e.g. phase selection logic in ABB relays). The same can be implemented in the DR if required. The following list contains the generalized group of signals which are present for all protection functions.

A. The protection scheme generally implemented for 132kV Transmission lines are as follows:

i) Main 1: Distance Protection Relay (with associated functions)

ii) Main 2: Backup Protection relay (with associated functions)

MAIN 1: DISTANCE PROTECTION RELAY

SL NO.	ANALOG CHANNELS	REMARKS
1	RØ VOLTAGE	
2	YØ VOLTAGE	
3	BØ VOLTAGE	
4	NEUTRAL VOLTAGE	
5	V_SYNCH (SYNCHRONIZING VOLTAGE)	WHEN TPAR IS IMPLEMENTED
6	RØ CURRENT	
7	YØ CURRENT	
8	BØ CURRENT	
9	NEUTRAL CURRENT (IN)	
10	MUTUAL COMPENSATION CURRENT (IM)	FOR PARALLEL LINES

TABLE 4:ANALOG CHANNELS FOR DISTANCE RELAY

SL NO.	DIGITAL CHANNELS	REMARKS
1	ZONE 1 PICKUP	
2	ZONE 2 PICKUP	
3	ZONE 3 PICKUP	
4	ZONE 4 (REV) PICKUP	
5	ZONE 1 TRIP	
6	ZONE 2 TRIP	
7	ZONE 3 TRIP	
8	ZONE 4 (REV) TRIP	
9	CARRIER AIDED ZONE TRIP (PUTT/POTT)	
10	AR BLOCK	
11	CB READY (AS PER AR LOGIC)	
12	AR START	
13	AR CLOSE COMMAND	
14	AR UNSUCCESSFUL	
15	AR SWITCH OUT	
16	SOTF INITIATION	
17	SOTF OPERATED	
18	VT FUSE FAIL	
19	BROKEN CONDUCTOR	
20	POWER SWING BLOCK	
21	CARRIER UNHEALTHY/FAIL	
22	CARRIER SWTICH OUT	
23	CARRIER SEND	

SL NO.	DIGITAL CHANNELS	REMARKS
24	CARRIER RECEIVE	
25	DT SEND	
26	DT RECEIVE	
27	CB CLOSE	
28	CB OPEN	
29	86 RELAY OPTD	
30	MAIN2/BACKUP RELAY/BCU FAIL	
31	TIME SYNCHRONIZATION STATUS	
32	LAN NETWORK STATUS	

TABLE 5: DIGITAL CHANNELS FOR DISTANCE RELAY

If the IED has more than 32 configurable digital channels (currently available IEDs provide more than 32 digital channels), these following signals are to be configured:

SL NO.	DIGITAL CHANNELS	REMARKS
1	RELAY 3Ø TRIP	
2	DISTANCE PICKUP (RØ-EARTH)	
3	DISTANCE PICKUP (YØ-EARTH)	
4	DISTANCE PICKUP (BØ-EARTH)	
5	DISTANCE PICKUP (RØ-YØ)	
6	DISTANCE PICKUP (YØ-BØ)	
7	DISTANCE PICKUP (BØ-RØ)	
8	AR IN PROGRESS	
9	AR SUCCESSFUL	
10	96 RELAY OPERATED	

TABLE 6: OTHER IMPORTANT DR DIGITAL CHANNELS

MAIN 2: BACKUP PROTECTION RELAY

SL NO.	ANALOG CHANNELS	REMARKS
1	RØ VOLTAGE	
2	YØ VOLTAGE	
3	BØ VOLTAGE	
4	NEUTRAL VOLTAGE	
6	RØ CURRENT	
7	YØ CURRENT	
8	BØ CURRENT	
9	NEUTRAL CURRENT (IN)	

TABLE 7: OTHER IMPORTANT DR DIGITAL CHANNELS

SL NO.	DIGITAL CHANNELS	REMARKS
1	RELAY 3Ø TRIP	
2	OVERCURRENT R PHASE START	
3	OVERCURRENT Y PHASE START	
4	OVERCURRENT B PHASE START	
5	OVERCURRENT OPEARTED	
6	EARTHFAULT START	
7	EARTHFAULT OPERATED	
8	CB OPEN	
9	CB CLOSE	
10	86 OPEARTED	
11	96 OPERATED	
12	MAIN1 RELAY FAIL	
13	TIME SYNCHRONIZATION STATUS	
14	LAN NETWORK STATUS	

TABLE 8: DIGITAL CHANNELS FOR BACKUP PROTECTION RELAY

OTHER PROTECTION FUNCTIONS

SL NO.	DIGITAL CHANNELS	REMARKS
1	LBB INITIATION	
2	LBB RETRIP	
3	LBB BUS/BACKUP TRIP	
4	CURRENT REVERSAL OPERATED	
5	WEAK INFEED/ECHO OPERATED	
6	UNDERFREQUENCY START	
7	UNDERFREQUENCY OPEARTED	
8	SPECIAL PROTECTION SCHEME OPERATED	

TABLE 9: DIGITAL CHANNELS OF OTHER PROTECITON FUNCTIONS (IF ENABLED)

*With respect to different relay manufacturers (additional internal protection signals e.g. Zone 1 single phase trip, Zone 1 multi-phase trip (Siemens); Phase selection start (indicating fault loop) in case of ABB etc. are present. These signals are a value addition in terms of DR analysis. If additional DR digital channels are present in the relays, the same can be added.

**The status of "CB Open" may also be utilized for triggering DR as per requirement to keep a track for CB operations (planned or spurious).

***If single pole CB is used for 132kV lines, refer **(TABLE 11)** for digital signals for Single phase Auto-reclosure and CB status.

B. The protection schemes and configuration at 220kV and above are as follows:

i) Main 1: Distance Protection (With associated Functions)

ii) Main 2: Distance Protection (With associated Functions)

SL NO.	ANALOG CHANNELS	REMARKS
1	VOLTAGE RØ	
2	VOLTAGE YØ	
3	VOLTAGE BØ	
4	VOLTAGE NEUTRAL	
5	CURRENT RØ	
6	CURRENT YØ	
7	CURRENT BØ	
8	CURRENT NEUTRAL (IN)	
9	MUTUAL COMPENSATION CURRENT (IM)	FOR PARALLEL LINES

TABLE 10: ANALOG CHANNELS FOR MAIN 1 AND MAIN 2 RELAYS FOR 220kV LINE

SL NO.	DIGITAL CHANNELS	REMARKS
1	TRIP RØ	
2	TRIP YØ	
3	TRIP BØ	
4	ZONE 1 PICKUP	
5	ZONE 2 PICKUP	
6	ZONE 3 PICKUP	
7	ZONE 4 (REV) PICKUP	
8	ZONE 1 TRIP	
9	ZONE 2 TRIP	
10	ZONE 3 TRIP	
11	ZONE 4 (REV) TRIP	
12	CARRIER AIDED ZONE TRIP (PUTT/POTT)	
13	AR BLOCK	
14	CB READY (AS PER AR LOGIC)	
15	AR START	
16	AR CLOSE COMMAND	
17	AR UNSUCCESSFUL	
18	AR SWITCH IN/OUT	
19	SOTF INITIATION	
20	SOTF OPERATED	
21	VT FUSE FAIL	
22	BROKEN CONDUCTOR	
23	POWER SWING BLOCK	
24	CARRIER UNHEALTHY/FAIL	
25	CARRIER SWTICH OUT	
26	CARRIER SEND	
27	CARRIER RECEIVE	
28	DT SEND	
29	DT RECEIVE	
30	EARTH FUALT START	

SL NO.	DIGITAL CHANNELS	REMARKS
31	EARTH FAULT OPERATED	
32	CB RØ CLOSE	
33	CB RØ OPEN	
34	CB YØ CLOSE	
35	CB YØ OPEN	
36	CB BØ CLOSE	
37	CB BØ OPEN	
38	86 RELAY OPTD	
39	96 RELAY OPEARTED	
40	MAIN2/MAIN1/BCU FAIL	
41	TIME SYNCHRONIZATION STATUS	
42	LAN NETWORK STATUS	

TABLE 11: DIGITAL CHANNELS FOR MAIN 1 AND MAIN 2 RELAY OF 220kV LINE

FOR 400kV AND ABOVE LINES WITH 1 AND ½ CB SCHEME

SL NO.	ANALOG AND DIGITAL CHANNELS	REMARKS
1	RØ TIE CT CURRENT	**TABLE 10** and **11** are also applicable for 400kV and above lines. **TABLE 12** are the additional signals which should be configured. N.B. **Pole Discrepancy** relay(PDR) is present in the CB Marshalling box, the status of which may be received in the relay and configured as Digital Input if potential free contact is available.
2	YØ TIE CT CURRENT	
3	BØ TIE CT CURRENT	
4	TIE CT NEUTRAL CURRENT	
5	RØ TIE CB OPEN	
6	RØ TIE CB CLOSE	
7	YØ TIE CB OPEN	
8	YØ TIE CB CLOSE	
9	BØ TIE CB OPEN	
10	BØ TIE CB CLOSE	
11	ALL AR DIGITAL SIGNALS FOR TIE CB	
12	WAIT FOR MASTER	FOR AR LOGIC
13	86 OPERATED TIE CB	
14	STUB PROTECTION OPERATED	

TABLE 12: ANALOG AND DIGITAL SIGNALS IN ADDITION TO TABLE-10&11 FOR 400kV AND ABOVE

SL NO.	DIGITAL CHANNELS	REMARKS
1	DISTANCE PICKUP (RØ-EARTH)	
2	DISTANCE PICKUP (YØ-EARTH)	
3	DISTANCE PICKUP (BØ-EARTH)	
4	DISTANCE PICKUP (RØ-YØ)	
5	DISTANCE PICKUP (YØ-BØ)	
6	DISTANCE PICKUP (BØ-RØ)	
7	AR IN PROGRESS	
8	AR SUCCESSFUL	
9	CARRIER UNHEALTHY/FAIL CH-II	
10	CARRIER SWTICH OUT CH-II	
11	CARRIER SEND CH-II	

12	CARRIER RECEIVE CH-II	
13	DT SEND CH-II	
14	DT RECEIVE CH-II	
15	OVERVOLTAGE START	
16	OVERVOLTAGE STAGE-I OPEARTED	
17	OVERVOLTAGE STAGE-II OPEARTED	
18	UNDERFREQUENCY START	
19	UNDERFREQUENCY OPEARTED	
20	SPECIAL PROTECTION SCHEME	If Any
21	LBB INITIATION	
22	LBB RE-TRIP OPERATED	
23	LBB BUSBAR/BACKUP TRIP OPERATED	

TABLE 13: OTHER IMPORTANT DIGITAL CHANNELS

TRANSFORMER PROTECTION

C. The protection functions implemented for Transformers can be summarized as follows:

i) Differential Protection (and associated functions)

ii) HV Backup overcurrent and Earthfault Protection

iii) LV Backup overcurrent and Earthfault Protection

iv) REF Protection*and other protection functions*

SL NO.	ANALOG CHANNELS	REMARKS
1	HV CURRENT RØ	
2	HV CURRENT YØ	
3	HV CURRENT BØ	
4	HV NEUTRAL CURRENT	
5	LV CURRENT RØ	
6	LV CURRENT YØ	
7	LV CURRENT BØ	
8	LV NEUTRAL CURRENT	
9	DIFFERENTIAL CURRENT RØ	
10	DIFFERENTIAL CURRENT YØ	
11	DIFFERENTIAL CURRENT BØ	
12	DIFFERENTIAL BIAS CURRENT	
13	REF DIFFERENTIAL CURRENT	
14	REF BIAS CURRENT	
15	HIGH IMPEDANCE RESULTANT REF CURRENT	

TABLE 14: ANALOG CHANNELS FOR TRANSFORMERS

*Tie CT current channels should also be included in case of 1 and ½ CB scheme

SL NO.	DIGITAL CHANNELS	REMARKS
1	DIFFERENTIAL RØ START	

2	DIFFERENTIAL YØ START	
3	DIFFERENTIAL BØ START	
4	DIFFERENTIAL RØ TRIP	
5	DIFFERENTIAL YØ TRIP	
6	DIFFERENTIAL BØ TRIP	
7	DIFFERENTIAL TRIP (CURVE)	
8	DIFFERENTIAL UNRESTRAINED TRIP (HIGHSET)	
9	2^{ND} HARMONIC BLOCK OPERATED	
10	5^{TH} HARMONIC BLOCK OPERATED	
11	OVERFLUXING ALARM	
12	OVERFLUXING TRIP	DEFINE STAGES
13	OVERFLUXING HIGHSET TRIP	
14	REF START/ALARM	
15	REF TRIP	
16	BUCHHOLZ ALARM	
17	BUCHHOLZ TRIP	
18	MAIN TANK PRV TRIP	
19	OLTC PRV TRIP	
20	OSR TRIP	
21	HV WTI ALARM	
22	HV WTI TRIP	
23	LV WTI ALARM	
24	LV WTI TRIP	
25	OTI ALARM	
26	OTI TRIP	
27	MOG ALARM	
28	AIRCELL FAILURE	
29	86 OPEARTED HV	
30	96 OPERATED HV	
31	86 OPEARTED LV	
32	96 OPEARTED LV	
33	HV CB OPEN	
34	HV CB CLOSE	
35	LV CB OPEN	
36	LV CB CLOSE	
37	FIREFIGHTING ALARMS/TRIPS	
38	MAIN2/BCU FAULTY	
39	TIME SYNCHRONIZATION STATUS	
40	LAN NETWORK STATUS	

TABLE 15: DIGITAL CHANNELS FOR TRANSFORMERS

*Merged alarm/Trip signals of HV/LV WTI, a single “Differential Start” signals rather than differential start status of each phase etc. can be configured if the IED provides only 32 configurable DR digital channels.

SL NO.	DIGITAL CHANNELS	REMAKRS
1	OVERCURRENT RØ START	
2	OVERCURRENT YØ START	
3	OVERCURRENT BØ START	
4	OVERCURRENT RØ TRIP	
5	OVERCURRENT YØ TRIP	
6	OVERCURRENT BØ TRIP	
7	OVERCURRENT LOWSET TRIP	
8	OVERCURRENT HIGHSET TRIP	
9	EARTH FAULT START	
10	EARTH FAULT LOWSET TRIP	
11	EARTH FAULT HIGHSET TRIP	
12	LBB INITIATION	
13	LBB RETRIP AND BACKUP TRIP	
14	86 OPERATED	
15	96 OPERATED	
16	RELAY FAIL (MAIN/BACKUP/BCU)	
17	TIME SYNCHRONIZATION STATUS	
18	LAN NETWORK STATUS	

TABLE 16: OVERCURRENT AND EARTHFAULT PROTECTION FOR TRANSFORMERS

*The analog channels would comprise (V_R, V_Y, V_B, V_N, I_R, I_Y, I_B, I_N) with respect to HV or LV side in case separate OC & EF relay is provided as considered in the table above

REACTOR PROTECTION

D. The protection functions implemented for Reactors can be summarized as:

i) Differential Protection
ii) Restricted Earth fault Protection
iii) Backup Impedance, Overcurrent protection etc.

SL NO.	ANALOG CHANNELS	REMARKS
1	HV CURRENT RØ	
2	HV CURRENT YØ	
3	HV CURRENT BØ	
4	HV NEUTRAL CURRENT	
5	NCT CURRENT RØ	
6	NCT CURRENT YØ	
7	NCT CURRENT BØ	
8	NCT NEUTRAL CURRENT	
9	DIFFERENTIAL CURRENT RØ	
10	DIFFERENTIAL CURRENT YØ	
11	DIFFERENTIAL CURRENT BØ	
12	DIFFERENTIAL BIAS CURRENT	
13	REF DIFFERENTIAL CURRENT	
14	REF BIAS CURRENT	
15	HIGH IMPEDANCE RESULTANT REF CURRENT	

TABLE 17: ANALOG CHANNELS FOR REACTOR DIFFERENTIAL PROTECTION

SL NO.	DIGITAL CHANNELS	REMARKS
1	DIFFERENTIAL RØ START	
2	DIFFERENTIAL YØ START	
3	DIFFERENTIAL BØ START	
4	DIFFERENTIAL RØ TRIP	
5	DIFFERENTIAL YØ TRIP	
6	DIFFERENTIAL BØ TRIP	
7	DIFFERENTIAL TRIP (CURVE)	
8	DIFFERENTIAL UNRESTRAINED TRIP (HIGHSET)	
9	2^{ND} HARMONIC BLOCK OPERATED	
10	5^{TH} HARMONIC BLOCK OPERATED	
11	OVEREXCITATION START	
12	OVEREXCITATION TRIP	ADD STAGES
13	REF START/ALARM	
14	REF TRIP	
15	BUCHHOLZ ALARM	
16	BUCHHOLZ TRIP	
17	MAIN TANK PRV TRIP	
18	OLTC PRV TRIP	
19	OSR TRIP	
20	HV WTI ALARM	
21	HV WTI TRIP	
22	LV WTI ALARM	
23	LV WTI TRIP	
24	OTI ALARM	
25	OTI TRIP	
26	MOG ALARM	
27	AIRCELL FAILURE	
28	FIREFIGHTING ALARMS/TRIPS	
29	NGR BUCHHOLZ ALARM	
30	NGR BUCHHOLZ TRIP	
31	NGR PRV TRIP	
32	NGR OTI ALARM	
33	86 OPEARTED	
34	96 OPERATED	
35	CB OPEN	
36	CB CLOSE	
37	BACKUP_IMP RELAY FAIL	
38	TIME SYNCHRONIZATION STATUS	
39	LAN NETWORK STATUS	

TABLE 18: DIGITAL CHANNELS FOR REACTOR DIFFERENTIAL PROTECTION

*Inherent Protection signals can be utilized with Backup impedance or REF relay if constraint arises for number of configurable digital channels

SL NO.	ANALOG CHANNELS	REMARKS
1	VOLTAGE RØ	
2	VOLTAGE YØ	
3	VOLTAGE BØ	
4	VOLTAGE NEUTRAL	
5	CURRENT RØ	
6	CURRENT YØ	
7	CURRENT BØ	
8	CURRENT NEUTRAL	

TABLE 19: ANALOG CHANNELS FOR REACTOR BACKUP IMPEDANCE PROTECTION

SL NO.	DIGITAL CHANNELS	REMAKRS
1	ZONE START	
2	ZONE TRIP	
3	OVERCURRENT START	
4	OVERCURRENT TRIP	
5	DIFFERENTIAL RELAY FAIL	
6	CB OPEN	
7	CB CLOSE	
8	86 RELAY OPERATED	
9	96 RELAY OPERATED	
10	TIME SYNCHRONIZATION STATUS	
11	LAN NETWORK STATUS	

TABLE 20: DIGITAL CHANNELS FOR REACTOR BACKUP IMPEDANCE PROTECTION

BUSBAR PROTECTION

E. The protection functions available for bus bar relay are:

i) Bus bar protection

ii) LBB protection

SL NO.	ANALOG CHANNELS	REMARKS
1	BAY 01-CURRENT RØ	
2	BAY 01-CURRENT YØ	
3	BAY 01-CURRENT BØ	
4	BAY 02-CURRENT RØ	
5	BAY 02-CURRENT YØ	
6	BAY 02-CURRENT BØ	FOR ALL BAYS 1..2..3..
7	INCOMING RØ CURRENT IN ZONE A	
8	DIFFERENTIAL RØ CURRENT IN ZONE A	
9	INCOMING YØ CURRENT IN ZONE A	
10	DIFFERENTIAL YØ CURRENT IN ZONE A	
11	INCOMING BØ CURRENT IN ZONE A	
12	DIFFERENTIAL BØ CURRENT IN ZONE A	

TABLE 21: DIGITAL CHANNELS FOR REACTOR BACKUP IMPEDANCE PROTECTION

SL NO.	DIGITAL CHANNELS	REMARKS
1	BAY 01 CONNECTED TO BUS A	
2	BAY 01 CONNECTED TO BUS B	
3	BAY 02 CONNECTED TO BUS A	
4	BAY 02 CONNECTED TO BUS B	
5	BAY 03 CONNECTED TO BUS A	
6	BAY 03 CONNECTED TO BUS B	
7	DIFFERENTIAL TRIP OPERATED	
8	ZONE A COMMON TRIP	ZONE A and ZONE B refer to Main Bus 1 and Main Bus 2
9	ZONE A LBB BACKUP/EXTERNAL TRIP	
10	ZONE A OPEN CT ALARM	
11	ZONE A DIFFERENTIAL ALARM	
12	ZONE A INCOMING CURRENT ALARM	
13	ZONE B COMMON TRIP	
14	ZONE B LBB BACKUP/EXTERNAL TRIP	
15	ZONE B OPEN CT ALARM	
16	ZONE B DIFFERENTIAL ALARM	
17	ZONE B INCOMING CURRENT ALARM	
18	CHECKZONE TRIP	
19	ENDZONE PROTECTION OPERATED	
20	MAIN2/BCU ETC. RELAY FAIL (IF ANY)	
21	TIME SYNCHRONIZATION ERROR	
22	LAN NETWORK ERROR	

TABLE 22: DIGITAL CHANNELS FOR BUSBAR DIFFERENTIAL PROTECTION

LINE DIFFERENTIAL PROTECTION

F. Line differential Relay includes the following protection functions:

i) Line Differential Protection
ii) Backup Overcurrent and Earth fault protection
iii) Distance Protection (if Optical Link is in failed state. Function available as per site requirement)

SL NO.	ANALOG CHANNELS	REMARKS
1	CURRENT RØ	
2	CURRENT YØ	
3	CURRENT BØ	
4	CURRENT NEUTRAL	
5	REMOTE END CURRENT RØ	
6	REMOTE END CURRENT YØ	
7	REMOTE END CURRENT BØ	
8	REMOTE END CURRENT NEUTRAL	
9	DIFFERENTIAL CURRENT RØ	
10	DIFFERENTIAL CURRENT YØ	
11	DIFFERENTIAL CURRENT BØ	
12	BIAS CURRENT	

TABLE 23: ANALOG CHANNELS FOR LINE DIFFERENTIAL PROTECTION

SL NO.	DIGITAL CHANNELS	REMARKS
1	DIFFERENTIAL RØ TRIP	
2	DIFFERENTIAL YØ TRIP	
3	DIFFERENTIAL BØ TRIP	
4	DIFFERENTIAL RESTRAINED TRIP	
5	DIFFERENTIAL UNRESTRAINED TRIP	
6	2^{ND} HARMONIC BLOCK OPERATED	
7	5^{TH} HARMONIC BLOCK OPERATED	
8	RECEIVE SIGNAL 01	
9	RECEIVE SIGNAL 02	
10	SEND SIGNAL 01	
11	SEND SIGNAL 02	
12	REMOTE RELAY ERROR	
13	MAIN2/BACKUP RELAY FAIL	
14	CB OPEN	
15	CB CLOSE	
16	86 OPERATED	
17	96 OPERATED	
18	BACKUP RELAY/BCU FAIL	
19	TIME SYNCHRONIZATION ERROR	
20	LAN NETWORK FAIL	

TABLE 24: DIGITAL CHANNELS FOR LINE DIFFERENTIAL PROTECTION

*AR signals, Distance Protection, OC and EF protection signals, single pole CB status to be included as per scheme implemented for the short line.

If separate OC and EF relay is present, the DR list as inTABLE 7 & 8** are also applicable

CHAPTER 11

DISTURBANCE RECORDER PARAMETERS FOR GENERATING STATIONS

The presently implemented Disturbance Recorder channels were collected from the following generating stations: NEEPCO, NHPC, NTPC, ADANI, KMPCL, OPTC and AGTCPP. With respect to the protection functions kept for Generators, the DR channel list was compiled.

The following compilation of DR analog and digital channels is a summarized list of analog and digital channels comprising all available protections kept for generators. The list is to be segregated with respect to the protection functions available at site.

SN	ANALOG CHANNELS	REMARKS
1	RØ VOLTAGE	
2	YØ VOLTAGE	
3	BØ VOLTAGE	
4	NEUTRAL VOLTAGE	
5	RØ CURRENT (LOAD SIDE)	
6	YØ CURRENT (LOAD SIDE)	
7	BØ CURRENT (LOAD SIDE)	
8	NEUTRAL CURRENT	
9	NEUTRAL CURRENT SENSITIVE)	
10	RØ CURRENT (NEUTRAL SIDE)	
11	YØ CURRENT (NEUTRAL SIDE)	
12	BØ CURRENT (NEUTRAL SIDE)	
13	FREQUENCY	
14	EXCITATION TRAFO HV CURRENT	
15	1ST STAGE RESIDUAL OVERVOLTAGE	
16	2ND STAGE RESIDUAL OVERVOLTAGE	
17	100% STATOR EARTH FAULT VOLTAGE	
18	100% STATOR EARTH FAULT CURRENT	
19	OPEN DELTA VOLTAGE	
20	NGT VOLTAGE	
21	REF CURRENT/VOLTAGE	(Depending on HZ or LZ REF implementation)
22	NEGATIVE SEQUENCE CURRENTS	(If Applicable)
23	STATOR FAULT 20HZ INJ. VOLTAGE	
24	STATOR FAULT 20HZ INJ. CURRENT	

TABLE 25: ANALOG CHANNELS FOR GENERATOR PROTECTION

SN	DIGITAL CHANNELS	REMARKS
1	GENERATOR DIFFERENTIAL START	
2	GENERATOR DIFFERENTIAL RØ TRIP	
3	GENERATOR DIFFERENTIAL YØ TRIP	
4	GENERATOR DIFFERENTIAL BØ TRIP	
5	GENERATOR DIFFERNTIAL TRIP	
6	POWER 1 TRIP	
7	POWER 2 TRIP	
8	OVERCURRENT STAGE-I TRIP	
9	OVERCURRENT STAGE-II TRIP	
10	EARTHFAULT TRIP	
11	UNDER EXCITATION START	
12	UNDER EXCITATION OPERATED	DEFINE STAGES
13	OVER EXCITATION START	
14	OVER EXCITATION OPEATED	DEFINE STAGES
15	OVERVOLTAGE START	
16	OVERVOLTAGE TRIP	DEFINE STAGES
17	UNDERVOLTAGE START	
18	UNDERVOLTAGE TRIP	DEFINE STAGES
19	UNDERFREQUENCY ALARM	
20	UNDERFREQUENCY TRIP	DEFINE STAGES
21	OVERFREQUENCY ALARM	
22	OVERFREQUENCY TRIP	DEFINE STAGES
23	TURBINE TRIP	
24	TURBINE EMERGENCY TRIP	
25	GENERATOR ELECTRICAL FAULT	
26	STATOR EARTH FAULT ALARM	
27	STATOR EARTH FAULT TRIP	
28	NEG. PHASE SEQ THERMAL ALARM	
29	NEG. PHASE SEQ THERMAL TRIP	
30	GENERATOR THERMAL OVERLOAD TRIP	
31	UNDER IMPEDANCE PROTECTION OPERATED	DEFINE STAGES
32	NEUTRAL VOLT. DISPLACEMENT PROT. OPERATED	
33	RESIDUAL OVERVOLTAGE TRIP	DEFINE STAGES
34	RØ CB OPEN	DEFINE FOR GENERATOR CB, FIELD CB ETC. (AS PER APPLICABLE SCHEME) AND AS PER (GANG OPERATED OR SINGLE POLE CB)
35	RØ CB CLOSE	
36	YØ CB OPEN	
37	YØ CB CLOSE	
38	BØ CB OPEN	
39	BØ CB CLOSE	
40	FIELD FAIL ALARM	
41	FIELD FAIL-1 TRIP	
42	FIELD FAIL-2 TRIP	
43	VT FUSE FAIL ALARM	
44	REVERSE POWER TRIP (32G)	DEFINE STAGES
45	SENSITIVE EARTH FAULT TRIP	
46	ANY START	
47	ANY TRIP	
48	ROTOR EARTH FAULT START	
49	ROTOR EARTH FAULT TRIP	DEFINE STAGES

SN	DIGITAL CHANNELS	REMARKS
50	STATOR EARTH FAULT START	
51	STATOR EARTH FAULT 95% TRIP	DEFINE STAGES
52	STATOR EARTH FAULT 100% TRIP	
53	STANDBY EARTH FAULT TRIP	
54	OVERCURRENT START	
55	OVERCURRENT TRIP	DEFINE STAGES
56	EXCITER TRIP	
57	POLE SLIPPING OPERATED	
58	DEAD MACHING TRIP	
59	LOW FORWARD POWER PROTECTION OPERATE	
60	OUT OF STEP TRIP	
61	UNBALANCE LOAD CURRENT OPERATED	
62	100% STATOR EARTH FAULT START (3^{RD} HARM.)	
63	100% STATOR EARTH FAULT TRIP (3^{RD} HARM.)	
64	LBB INITIATION	
65	LBB OPERATED	
66	UNIT MANUAL EMERGENCY TRIP	
67	LOSS OF EXCITATION OPERATED (40G)	
68	NEG. SEQ. CURRENT PROTECTION ALARM	
69	NEG. SEQ. CURRENT PROTECTION TRIP (46G)	
70	86 RELAY OPERATED	86X/Y/Z as per scheme
71	POLE SLIP Z1 TRIP	
72	POLE SLIP Z2 TRIP	
73	ACCIDENTAL ENERGIZATION PROTECTION	
74	CO2 RELEASE	
75	AVR FAULTY	
76	TIME SYNCHRONIZATION ERROR	
77	LAN NETWORK ERROR	
78	MAIN 2/BCU FAIL	

TABLE 26: DIGITAL CHANNELS FOR GENERATOR PROTECTION

The above mentioned DR analog and digital channels are summarized in general for thermal, hydro generating plants. The segregation of protection functions for generators among respective IEDs is based on scheme of C&R Panel (Control and Relay panel) followed at site. The DR channels are to be configured as per protection functions implemented in the relays or nos. of relays. The above **TABLE 25 & 26** may be segregated as such.

ANNEXURE – I

Standardization of Disturbance Recorder Channels is also dependent on additional factors such as: Protection Philosophy followed by the Utilities, Substation level C&R Panel architecture, IED communication network, Switchyard Equipment, Station auxiliaries etc.

A field study was carried out with the participating utilities for visualization of the current state of DR parameters and system architectures on a wide area perspective.

The following points were considered for the conducted questionnaire based data collection:

i) Modern IEDs support communication over local area network (Ethernet) via optical fibre/RJ45/LAN cable, time synchronization over SNTP, GOOSE messaging system. Centralized DRPC is present within the same network for monitoring and operations.
ii) Redundancy in power supply for IEDs and station auxiliaries and monitoring the same via recorded DR data
iii) Status of switchyard equipment and tripping relays (inherent protection, master trip etc.)
iv) Carrier Communication Status
v) Triggering criteria adopted by the utilities and the DR recording window parameters.

As per inputs received from utilities, transmission companies and generation companies from North-Eastern, Eastern, Western, Southern Grid viz. AEGCL, AEML-T, AP TRANSCO, HVPNL, MEPTCL, KMTL, MSPCL, TRIPURA TRANSCO, TPCL, MSETCL, DHARIWAL, ESSAR, INDIGRID, JP NIGRIE, KMPCL, DIKCHU, DVC, JORETHAND, JUSNL, WBSETCL, OPTCL, MPPTCL, MPPGCL, NTPC, NEEPCO, NHPC, OTPC, ADANI, KORBA NTPS, VSTPS, AgTCPP the following status were observed for various grid substations.

TABLE 27: FIELD STATUS WITH RESPECT TO TOR POINTS

SL No.	PARTICULARS	STATUS
1	Are the IED's in the Substation connected using fibre optic/LAN cable into a local Ethernet network?	62% are equipped with optical fibre/LAN cable into a local Ethernet network
2	DR downloading facility at the substation a. Centralized DRPC b. Laptop/PC is manually connected using the front port of the relay for DR files extraction only when a grid disturbance has taken place	57% are equipped with Centralized DRPC whereas front port extraction is carried out for others
3	Is there any standard list of DR analog and digital channel configuration followed by the utility?	Standard list available: 52%
4	Are the IED's in the substation time synchronized with the GPS system?	76% are GPS Synchronized
5	Is redundancy maintained for AC supply (in form of inverters) in the substation for AC appliances (SAS PC, DRPC and Metering PC)?	76%
6	Is redundancy maintained for DC supply for IED's, GPS modules, Ethernet switches etc.?	76%
7	Mode of DR trigger available in the IEDs for protection functions a. DR trigger "only with trip" b. DR trigger with both "Start and trip"	76% have adopted "Start and Trip"
8	Is pre-fault time of 500ms and overall DR capturing time window of 3 sec followed?	73% with minor variations in pre-fault and post trigger timings
9	Is the status of the auxiliary tripping relays and switchgear elements included in the DR digital channels? a. Master trip relays (86), LBB Trip relay (96) b. CB Open/Close Status	90%
10	Is the "setting philosophy" followed as per RK setting Guidelines?	85%
11	Is "Time Synch error" recorded in the DR if an IED is out of time synchronization during a fault event?	41%
12	Is "LAN Error" recorded in the DR if an IED is out of LAN during a fault event?	33%
13	Is the status of all the inherent protection of transformers /reactors/NGRs included in the DR digital channels?	72%
14	Are the signals associated with carrier protection schemes implemented in the DR? a. Carrier Healthy b. Carrier Switch In/Out	A: 86% B: 76%
15	Are "Watchdog contacts/Life contacts" of IEDs used for monitoring the healthiness as a digital channel in the DR?	59%

ANNEXURE – II

The most common cases of tripping events for grid elements occur for transmission lines. As transmission lines travel through various terrains (hilly, half/fully submerged, jungle, lightning prone, vegetation growth along the corridor) it may be practically impossible to maintain absolute healthiness of the transmission line equipments and its corridor clearance throughout the year. However, the utmost motive is to restrict the number of disturbances in transmission lines under acceptable limits and to take measures so that such disturbance can be avoided in future.

It has been observed around the world that, the most common cases of transmission line fault is "Single phase to Earth (1Ø-E)" and transient in nature. Auto-reclosure function plays an important role in saving the grid elements from unnecessary outages during transient single phase to earth faults. From Power System Protection field of view, modern IEDs are equipped with programmable logics which greatly enhances the scope of design of important protection philosophies which otherwise has extensive use of hard wirings and auxiliary relays.

The non-operation/failed operation of Auto-reclosure may be due to various reasons (programmed logic is not fulfilled; nature of fault has changed during dead time). To absolutely pin point the reason for the above, it is necessary that the extracted Disturbance Recorder file should comprise of all the Analog values of voltages and current along with the Digital statuses of all equipments and protection functions (PLCC, CB, auxiliary relays etc., relay internal protection signals). This can only be achieved if the DR parameters and channels are configured to its full capability to capture the sequence of events during the faults.

As such, a list of probable grid disturbances that utilities face were drafted in the form of questionnaire and shared with participating TRANSCO's for sharing the ideas and philosophies they adopt for DR configuration to study fault events.

TABLE 28: CASES OF UNSUCCESSFUL AUTO-RECLOSURE OPERATIONS

Sl No.	Case Description	Probable Explanation	DR channels required for analyzing the event
1.	A single pole (RØ pole) trip is issued by the relay and dead time of AR is started. The relay issues a three pole trip during the dead time and AR is unsuccessful	A three pole trip in dead time is issued if there is an evolving fault in the other two healthy phases.	▪ AR Start ▪ AR in progress ▪ AR Unsuccessful ▪ Protection Status of the other healthy phases
2.	The relay issues a three pole trip in spite of the AR functions being kept ON	AR BLOCK logic may be high in the relay. AR Block may be linked with CB healthy status, CB spring charge, Gas pressure, Carrier Faulty etc.	▪ AR Block Status ▪ CB Ready Status ▪ Carrier Healthy
3.	For an 1 and ½ CB scheme, AR is successful in the Main CB but unsuccessful in the Tie CB	AR Block logic may be high in the Tie CB. "Wait for master" setting for Tie CB might be incorrect	▪ Wait for Master in Tie Bay CB ▪ AR Block Status ▪ CB Ready Status
4.	The relay issues a RØ pole trip to the CB. Thereafter, the whole bus is tripped on LBB Operation	Failure of opening or delay opening of RØ pole CB. Trip wirings for R-pole might be linked with Y or B phase pole	▪ LBB Initiation ▪ CB Open/Close status per pole ▪ Analog values of current ▪ 86R status
5.	For 132kV Level, relay issues a three pole trip and AR dead time is started. However, AR operation is not achieved after elapse of the dead time	Synchro check function might have blocked the AR	▪ Vsynch analog channel

TABLE 29: UNDER/OVER REACHING BY DISTANCE RELAY

Sl No.	Case Description	Probable Explanation	DR channels required for analyzing the event
1.	During a single phase to earth fault, the distance protection is not picked at the local end relay, whereas the upstream relay operated in Zone 3	Dir. EF protection might have picked up for the local end relay due to high resistive nature of the fault. If the upstream end relay belongs to a very long line, the Zone 3 reach may be large enough to sense the fault. The EF setting at local end should be revised	▪ Earth fault start ▪ Zone 3 pickup ▪ Zone 3 Optd ▪ VT Fuse Fail ▪ Time Synch Status
2.	The upstream relay trips on IDMT Earth fault before the local end relay which sensed the fault in Zone 3 reach	The EF ROT for upstream relay is not set with respect to Zone 3-time delay. TMS should be verified	▪ Earth fault Start ▪ Earth fault Operated ▪ Zone 3 pickup ▪ Time Synch Status
3.	For a fault in the mid-portion of a transmission line, the relay at local end trips on Zone 1 protection instantaneously. But the remote end relay fails to sense the fault at the inception, whereas later trips on Zone 2 protection.	The local end source is stronger than the remote end source which might be comparatively very weak. Probable implementation of weak infeed with echo can be studied, Zone settings may be revised and Carrier healthiness be verified	▪ Zone 2, Zone 3 pickups ▪ Carrier Healthy ▪ Earth fault Start ▪ Time Synch Status
4.	"Carrier Send" signal was high in the relay during operation of PUTT scheme. However, the remote end relay failed to receive the carrier input and PUTT was not successful	"Carrier Fail" may be persistent in the PLCC link which may be due to faulty "Rx level" or other associated issues	▪ Carrier Healthy ▪ Zone 2 pickup ▪ Time Synch Status
5.	The relay at local end issues a trip on Zone 1 instantaneously. But the upstream CB is tripped on EF at the same time	EF High set may be enabled for the upstream relay. Transmission lines should not have EF High set protection enabled.	▪ Earth Fault Start ▪ Earth Fault Operate ▪ Time Synch Status
6.	During a fault, the line is tripped on Zone 2 protection but the upstream adjacent transformer is also tripped either on Earth fault of Overcurrent protection instantaneously	The EF and OC High set settings of the transformer are to be re-evaluated. High set should be kept based on %Imp with a delay of 50ms	▪ OC and EF Start ▪ OC and EF Trip ▪ OC and EF HS Optd
7.	Frequent loss of the double circuit line in spite of corridor clearance not being an issue	Lightning faults, poor tower footing earthing	▪ Analog values of current and voltages ▪ Mutual compensation current channel ▪ Time Synch Status

Sl No.	Case Description	Probable Explanation	DR channels required for analyzing the event
8.	A relay in a radial of the line issued a Zone 2 or Zone 3 trip during a single phase to earth fault in spite of the fact that no power source is available for a radial feeder to feed the fault	The substation might be a LILO point along a long radial line. The line might trip due to capacitive current effect during phase to earth faults.	▪ Current and voltage channels ▪ Pre-fault duration of 500ms
9.	A transmission line trips and later when it is charged, it is found healthy. The issue is repeated on many instances in spite of no corridor clearance issues.	Insulator Disc Puncture, Disc Crack, Spurious DT receive signal etc.	▪ Pre-fault duration of 500ms ▪ Current and voltage channels ▪ Carrier and DT signal channels
10.	An important 132kV Line is tripped due to a fault. There is subsequent cascading tripping of associated feeders resulting in a partial blackout.	During peak load conditions, (n-1) contingency may not be maintained which resulted in overcurrent operation of other feeders. The overcurrent settings for the feeders are to be re-evaluated.	▪ Pre-fault duration of 500ms ▪ Overcurrent Start ▪ Overcurrent Trip ▪ Zone pickups and trips ▪ Time Synch Status
11.	Spurious SOTF operation when Zone 2 or Zone 3 was picked up in the relay	"Manual CB close contact" may be false latched. "Auto-initiation" settings might be enabled, initial pre-fault loading of the line might be below the "pole open detect settings" of the relay	▪ Pre-fault duration of 500ms ▪ SOTF initiation ▪ Current and voltage phasors
12.	A radial transmission line trips due to fault. On the first and second charging attempt it trips on SOTF. The line is surveyed but no physical fault is found	If the HV and LV CBs of downstream transformers at remote end substation are kept closed, heavy charging current is down during charging of line and relay senses it as an SOTF	▪ Pre-fault duration of 500ms ▪ SOTF initiation ▪ Current and voltage phasors Harmonic Table
13.	Spurious DT signal which led to the tripping of CB at remote end	Issue of hard wiring in the PLCC Panel	▪ DT Send ▪ Carrier Send ▪ Manual CB Trip

TABLE 30: CASES OF TRANSFORMER DIFFERENTIAL TRIPPINGS

Sl No.	Case Description	Probable Explanation	DR channels required for analyzing the event
1.	During an out of zone fault, the differential protection of the transformer is operated	CT saturation, Loose CT connection	▪ Pre-fault data of 500ms ▪ Idiff and Irest current ▪ HV and LV current values
2.	During an out of zone fault, the restricted earth fault protection is operated	NCT Polarity mismatch, loose connection in CT path	▪ Pre-fault data of 500ms ▪ NCT current value ▪ HZREF resultant current/voltage (if applicable)
3.	Spurious operation of PRD, Buchholz relay	Due to moisture ingress during rainy season, mechanical jerk	▪ Inherent protection operate status ▪ All analog channels ▪ Pre-fault data of 500ms
4.	Tripping of the transformer in differential protection during charging operation	2nd harmonic blocking value should be checked along with fault current (if any)	▪ 2nd harmonic blocking ▪ All analog channels
5.	Mal-operation of the NIFPS system	The status inputs of the NIFPS control box might have mal-operated	▪ Inherent protection operate status ▪ 86 relay status ▪ Analog value of current
6.	Transformer has tripped on Over fluxing. When the voltages are near nominal limit, the first attempt of charging is carried out but it trips again on V/f protection	The V/f pickup should be checked. Whether tailor made curve or IEEE curve is followed and the cooling down period set in the relay	▪ V/f pickup ▪ V/f Alarm ▪ V/f trip operated ▪ Pre-fault values ▪ All voltage channels
7.	Buchholz relay operation during an earthquake	Due to mechanical jerk and improper slant of the pipe connecting conservator with main tank	▪ Buchholz operate status ▪ Pre-fault data of 500ms ▪ Time synch status
8.	Differential protection operated during stormy weather	Damaged lightning arrester	▪ Pre-fault data of 500ms ▪ Analog values of current and voltages

TABLE 31: OPERATION OF BUSBAR PROTECTION

Sl No.	Case Description	Probable Explanation	DR channels required for analyzing the event
1.	During a fault in Bus 1, the busbar relay failed to discriminate the faulty bus and the total system (Bus 1 and Bus 2) were tripped	The inputs of bus isolator status, CB status for feeders are not properly reported to the busbar relay	▪ Analog current values of all the bays ▪ Busbar differential current ▪ Busbar restraint current ▪ Isolator and CB status ▪ Busbar operate Zone status ▪ Busbar trip status
2.	Spurious LBB operation from the busbar relay	Spurious initiation of external protection operated to the busbar relay, double DC earth fault leading to false LBB initiation	▪ 86 status of each bay ▪ LBB initiation ▪ LBB trip ▪ Pre-fault data of 500ms
3.	Busbar mal-operation due to external fault	CT saturation, CT loose connection, CT polarity issue	▪ Pre-fault data of 500ms ▪ Analog current values of all the bays ▪ Busbar differential and restraint current ▪ Bus Zone status ▪ Check Zone status (if any) ▪ Busbar Trip status

CHAPTER 12

EXPLORING THE STANDARDS AND POSSIBILITIES FOR DISTURBANCE RECORDER PARAMETERS FOR RENEWABLE ENERGY (RE) GENERATING STATIONS

A REVIEW OF STANDARDS ADOPTED AT RE GENERATION SITE

The Amguri Solar Plant of North Eastern Region has been considered for understanding the protection philosophy followed at RE Generation Plants and likewise the DR standardization Parameters have been forwarded.

The “Amguri Solar Plant” located at the district of Sivasagar, Assam has a generation capacity of 70MWp. The project was executed by M/s Jackson Power Private Limited and commissioned in the year 2022.

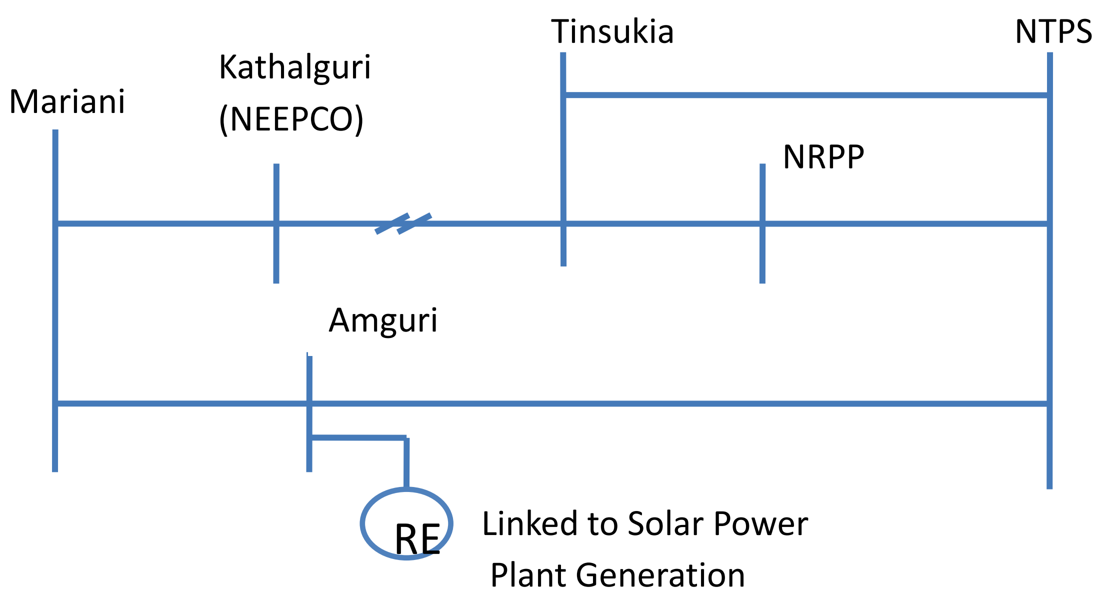


FIG 8: CONNECTIVITY OF AMGURI SOLAR PLANT

The previous 220kV transmission line between 220kV NTPS Grid Substation and 220kV Mariani Grid Substation has been included with 220kV Amguri Power Plant and the new connectivity has been formed as 220kV NTPS – Amguri and 220kV Amguri – Mariani Line.

PROTECTION FUNCTIONS (INVERTERS)

The protection and sustainable operation functions for a RE Generating plant is divided into three categories viz.

A. DC Side Protection
    a. Overvoltage Protection
    b. Overcurrent Protection
    c. Reverse Polarity
    d. Anti PID
    e. Ground Fault Monitoring
    f. Insulation Monitoring
    g. Over heat Protection
    h. Surge Protection
    i. Fan Protection

B. AC Side Protection
    a. Over/Under Voltage Protection
    b. Over Current Protection
    c. Current Balance
    d. Over/Under Frequency Protection
    e. Short Circuit Protection
    f. Surge Protection
    g. Earthfault Protection

C. Grid Support Features
    a. Low Voltage Ride Through (LVRT)
    b. High Voltage Ride Through (HVRT)
    c. Anti-Islanding
    d. Active & Reactive Power Regulation
    e. PF Control
    f. Soft Shutdown

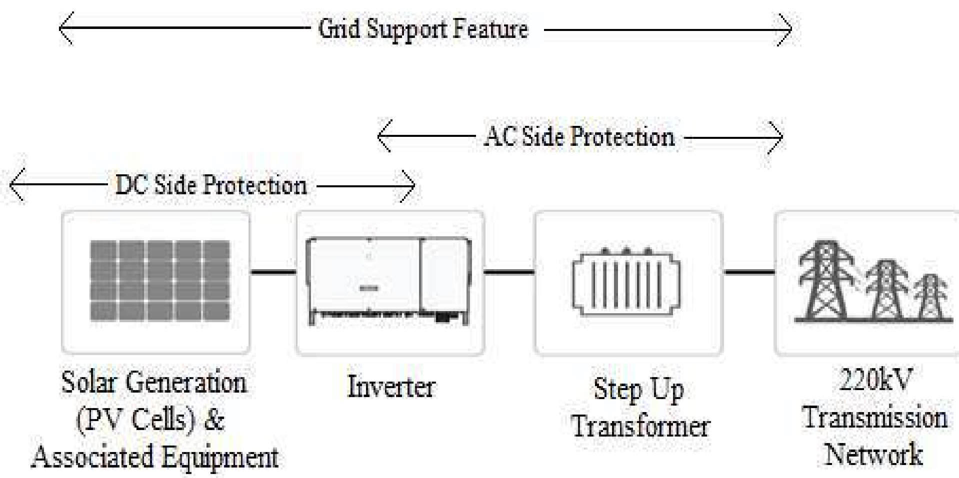


FIG 9: DC SIDE, AC SIDE AND GRID SUPPORT FEATURES IN A RE GENERATION PLANT

The above list has been compiled based on the inputs received from M/s Jackson. As per the inputs received from site, the logics and settings for the above protection functions and Grid Support Features are configured as per CEA Guidelines and IEC 62109, IEC 62116 standards.

CONTROL AND MONITORING SYSTEM

Two different models of PV Grid Connected Inverters are used at Amguri viz. **SG110CX and SG250HZ**

- The PV Grid-Connected String Inverters (Make: Sungrow) communicate with Computers (equipped with monitoring software) using Modbus RTU Protocol. This protocol can read the real-time operating data and fault states of the inverter.
- The analog values of current, voltages, Power, fault states are reported to the monitoring workstation with the help of pre-defined addresses (as per the Inverter Communication Manual) which is linked with the monitoring software.
- All protection functions are inbuilt in the inverter, the status of which is registered in the “event log” present in the inverter which can be extracted using local vendor provided application software. The status of each protection function can be reported to the SCADA system using “Addresses” as per the inverter manual.

No.	Name	Address	Data Type	Unit	Note
22	A-B line voltage/phase A voltage	5019	U16	0.1 V	Output type (address: 5002) is 1: upload phase voltage; 2: upload line voltage
23	B-C line Voltage/phase B Voltage	5020	U16	0.1 V	Output type (address: 5002) is 1: upload phase voltage; 2: upload line voltage
24	C-A line Voltage/phase C Voltage	5021	U16	0.1 V	Output type (address: 5002) is 1: upload phase voltage; 2: upload line voltage
25	Phase A current	5022	U16	0.1 A	
26	Phase B current	5023	U16	0.1 A	
27	Phase C current	5024	U16	0.1 A	
28	Reserved	5025～5026	U32	W	
29	Reserved	5027～5028	U32	W	
30	Reserved	5029～5030	U32	W	
31	Total active power	5031～5032	U32	W	
32	Total reactive power	5033–5034	S32	var	
33	Power factor	5035	S16	0.001	>0 means leading <0 means lagging

FIG 10: SCREENSHOT OF MODBUS ADDRESSES FOR ANALOG VALUES IN INVERTER OPERATION (FROM INVERTER MANUAL)

LCD or APP display (decimal)	Communication send data (hexadecimal)	Description	Classification
011	0x000B	Device abnormal	Fault
012	0x000C	Excessive leakage current	Fault
013	0x000D	Grid abnormal	Fault
014	0x000E	10-minute grid overvoltage	Fault
015	0x000F	Grid high voltage	Fault
016	0x0010	Output overload	Fault
017	0x0011	Grid voltage unbalance	Fault
019	0x0013	Device abnormal	Fault
020	0x0014	Device abnormal	Fault
021	0x0015	Device abnormal	Fault
022	0x0016	Device abnormal	Fault
023	0x0017	PV connection fault	Fault
024	0x0018	Device abnormal	Fault
025	0x0019	Device abnormal	Fault
030	0x001E	Device abnormal	Fault
031	0x001F	Device abnormal	Fault
032	0x0020	Device abnormal	Fault
033	0x0021	Device abnormal	Fault
034	0x0022	Device abnormal	Fault
036	0x0024	Excessively high module temperature	Fault
037	0x0025	Excessively high ambient temperature	Fault
038	0x0026	Device abnormal	Fault

FIG 11: SCRENSHOT OF MODBUS ADDRESSES FOR CONDITION MONITORING OF INVERTER FUNCTIONS (FROM INVERTER MANUAL)

TABLE 32: REMARKS AGAINST TOR POINTS FOR AMGURI RE PLANT

Sl. No	Terms of Reference	Remarks
1	Triggering criteria for DR	At inverter level, the various operations are monitored through the Local SAS HMI. The status of analog and digital values from the inverters is reported to the SAS via Modbus protocol. "Event log" can be viewed from the SAS after any disturbance has occurred. Comtrade DR facility (.cfg, .dat) etc. is not available for the inverter.
2	Sampling rate to be adopted	Not Applicable for Inverters
3	Data format for raw data files of DR	Not Applicable for Inverters
4	Power supply arrangement for DR and associated equipments	2KVA UPS for redundancy in AC supply. Two manually selectable DC sources are present. Automatic DC changeover is absent.
5	Protocol for monitoring healthiness of DR	Not Applicable

Observations and suggestions forwarded by FOLD Working Group 3

1. As per conversation with M/s Jackson, the status of protection functions, grid support features for the inverters etc. are inbuilt within the same inverter module. There is no provision of separate IEDs to monitor the protection functions. Hence, the DR recording facility (in comtrade format as applicable at Generating Stations and Transmission substations) is not applicable to the solar plant inverters at Amguri.
2. The protection at stepped up voltage at 220kV Level at Amguri Plant is as per the protection philosophies followed by other transmission utilities. Hence, the main area of concern is post-fault monitoring of analog values and digital status at inverter level (DC side and AC Side)

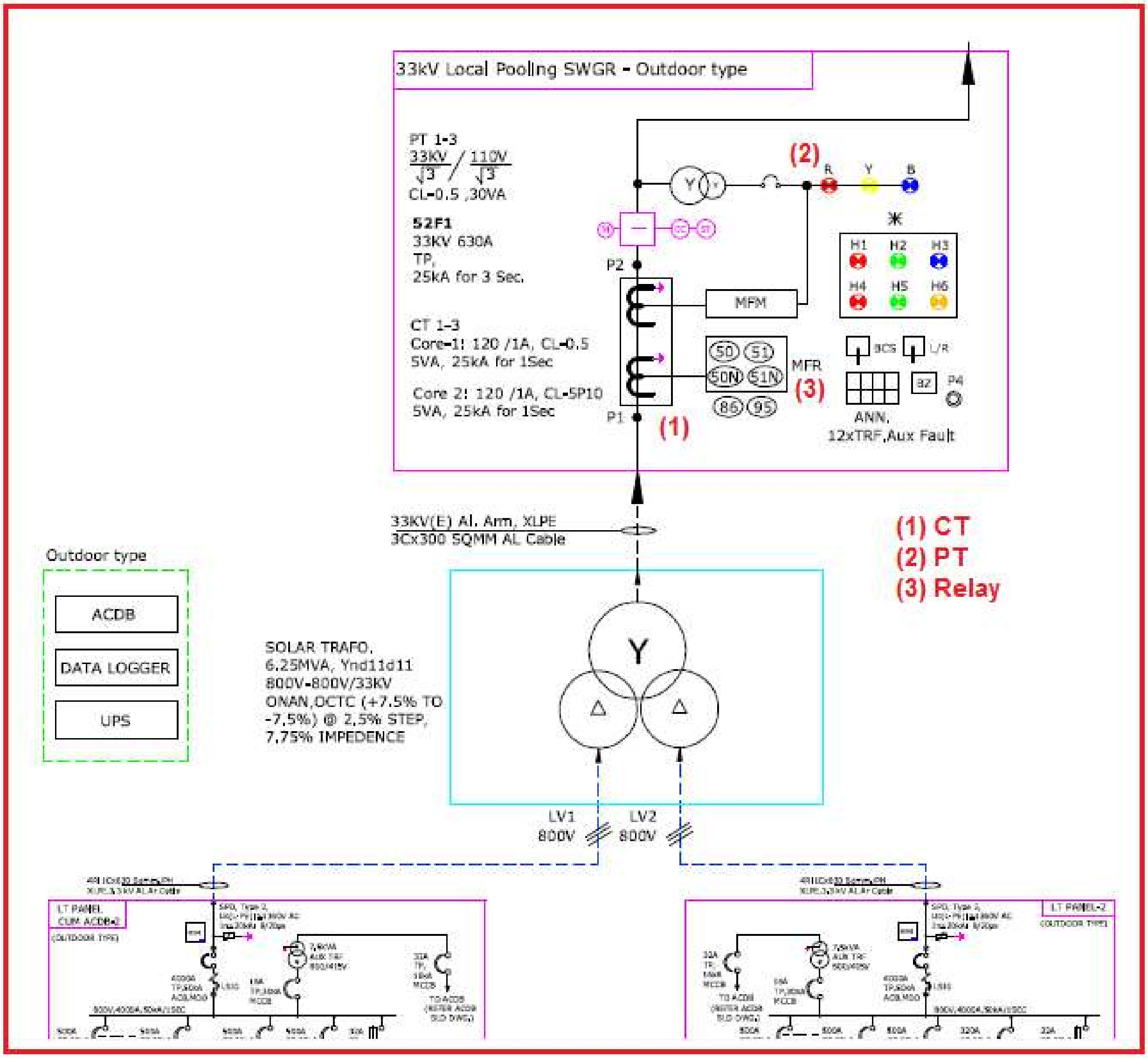


FIG 12: 800V-800V/33kV STEP UP TRANSFORMER CONNECTED TO INVERTER STRINGS

3. The inverters support event logger facility. The status of various protection and control signals can be extracted through the display interface connected to the inverters (The HMI of SAS or via application softwares of the concerned model of inverters.) The status of the inverters is represented by “numerical codes” in the event logger; each code corresponds to a definite status as described in the inverter manual.

4. The polling frequency of inverter data to the SAS at Amguri was reported to be 250ms resolution. The GPS date/time stamp(synchronized to common reference (e.g. Coordinated Universal time(UTC)) of generated inverter event data is not available (or the feature is absent).

5. However, the stepped up 33kV HV Side of the transformer (e.g. 800V/33kV in case of Amguri solar plant) has installed protection relays (refer fig. 11). The response of the inverter can be studied by configuring the DR parameters at the HV side of step up transformer. An idea of the inverter response can be achieved through analysis of the DR data extracted from HV side during grid disturbances.

6. The numerical relays to be installed at Solar plant (Amguri) support MODBUS communication. It is proposed that all numerical relays installed at RE generation plant should be IEC 61850 complaint.

7. It may be proposed that, future RE generation plants should have instrument transformers installed at each voltage level to facilitate installation of numerical relays to record grid disturbance data. The possibility of Digital Fault Recording (DFR)data (such as bus voltage phase quantities, Bus frequency, Current phase quantities, calculated active &reactive power output, dynamic reactive element voltage, frequency, current and power output) equippedwith inverters should also be explored.

8. Installation of stand-alone Disturbance recorder devices, Event logger (with GPS time synch and standard sampling frequency) should be explored.

9. Installation of Phasor measurement units(PMUs) at station bus of RE generation plants can also be explored.

10. Active/Reactive power and voltage oscillation detection feature is generally not available at relays procured for line feeders (33kV and above). DR channels associated with these functions would enable more efficient monitoring of RE Generation at Grid substation

level. The availability of the features for such RE Generation connected features may be explored (discussion and OEM support)

The basic criteria of DR parameter standards for RE Generation plants should be such that, the response of the inverter to grid disturbances and status of the protection functions of the inverters (AC side and DC side) should be recorded in analog and digital form with adequate sampling frequency rate (>=1000Hz) with settable pre and post fault time window.

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2. MiCOM Technical Manual
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8. Alberta Reliability Standard Disturbance Monitoring and Reporting Requirements PRC-002AB-2
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15. Alberta Reliability Standard Disturbance Monitoring Equipment Installation and Data Reporting PRC-018-AB-1

Annexure C.1

Name of the line	Status as updated in 56/57th PCC meeting	Latest Status
132 kV Agia - Mendipathar	PLCC works completed. AR operation configuration to commence from March'22. Latest Status to be intimated.	
132 kV EPIP II - Byrnihat D/C		
132 kV EPIP II - Umtru D/C		
132 kV Kahilipara - Umtru D/C		
132 kV Khliehriat – Mustem		
132 kV Mustem - NEHU line		
132 kV Khliehriat (MePTCL) - Khliehriat (PG) Ckt#II		
132 kV Khliehriat- NEIGRIHMS		
132 kV NEHU – Mawlai		
132 kV Mawlai - Umiam Stage I		
132 kV Mawphlang - Nongstoin		
132 kV Mawphlang - Umiam Stg I D/C		
132 kV Mawphlang- Mawlai		
132 kV Mendipathar – Nangalbibra		
132 kV Myntdu Leshka - Khleihriat D/C		
132 kV Nangalbibra – Nongstoin		
132 kV NEHU – NEIGRIHMS		
132 kV NEHU – Umiam		
132 kV Sarusajai - Umtru D/C		
132 kV Umiam - Umiam St I	By March'22	
132 kV Umiam St I - Umiam St II		
132 kV Umiam St I - Umiam St III D/C		
132 kV Umiam St III -Umiam St IV D/C		
132 kV Umiam St III - Umtru D/C		
132 kV Umtru - Umiam St IV D/C		

NERTS

Status of installation of Line Differential Protection is as given below: -

Sl. No.	Line details	Length (in kM)	No. of dark fibre pairs required	Status
1	132 kV RC Nagar-Agartala-I	8.384	01	Commissioned
2	132 kV RC Nagar-Agartala-II	8.384	01	
3	132 kV Aizawl-Melriat	6.7	01	By Aug'23
4	132 kV Badarpur-Badarpur	1.023	01	Commissioned
5	132 kV Kumarghat-PK Bari	1.5	01	By Nov'23
6	132 kV Khliehriat-Khliehriat-I	7.801	01	Commissioned
7	132 kV Dimapur-Dimapur I	0.347	01	
8	132 kV Dimapur-Dimapur II	0.95	01	By Aug'23
9	132 kV Imphal-Imphal-I	1.5	01	Commissioned
10	132 kV Imphal-Imphal-II	0.339	01	
11	132 kV B'Chariali - Pavoi - I	12.931	01	
12	132 kV B'Chariali - Pavoi - II	12.931	01	
13	220KV Balipara-Sonabil-I	11	01	By Aug'23
14	220KV Salakati-BTPS-I	4	01	By Nov'23
15	220KV Salakati-BTPS-II	4	01	
16	220kV Mariani (PG)-Mariani (AEGCL)	1.5	01	Commissioned
17	132kV Badarpur - Kolasib	107	01	
18	132kV Badarpur - Khliehriat	76.54	01	By Nov'23
19	132kV Badarpur -Silchar - I	19.2	01	Commissioned
20	132kV Badarpur - Silchar- II	19.2	01	
21	132kV Silchar - Hailakandi I	30	01	By Nov'23
22	132kV Silchar - Hailakandi II	30	01	
23	132kV Khliehriat-Khandong - II	40.92	01	Commissioned
24	132kV Khandong-Kopili-II	11	01	
25	132kV Melriat- Zemabawk	10.12	01	
26	132kV Nirjuli - Lekhi	8.301	01	By Jul'23
27	132kV Namsai - Tezu	99.5	01	By Aug'23
28	132kV Roing - Tezu	73	01	
29	132kV Roing - Pasighat	102.85	01	
30	132kV Mokokchung - Mokokchung I	1.44	01	Commissioned
31	132kV Mokokchung - Mokokchung II	1.44	01	
32	132kVSilchar - Srikona I	1.2	01	Commissioned
33	132kVSilchar - Srikona II	1.2	01	
34	132kV Jiribam - Badarpur	67.21	01	By Sep'23
35	132kV Jiribam- Haflong	100.6	01	
36	132kV Aizawl - Kolasib	67	01	By Aug'23
37	132kV Aizawl - Luangmal	0.8	01	
38	132kV Kumarghat - Karimganj	94.94	01	By Nov'23
39	132kV Haflong- Haflong (State)	1.2	01	By Sep'23

Further, for end-to-end communication, SDH has also been utilised for Line Differential Protection as pilot project in following lines: -

1. 132kV Silchar Melriat#1&2
2. 132kV Aizawl Kumarghat

MePTCL

STATUS OF LINE DIFFERENTIAL PROTECTION PROJECT UNDER PSDF

SL. No	Feeder Name	Installation		Commissioning	Remarks
		End A	End B		
1	EPIP-I - EPIP II Line I	Completed	Completed	Completed	
2	EPIP-I - EPIP II Line II	Completed	Completed	Completed	
3	EPIP -I - Killing Line I	Completed	Completed	Completed	
4	EPIP -I - Killing Line II	Completed	Completed	Not Completed	Fiber Network Not Available
5	EPIP -I - M/S Maithan Alloy	Completed	Completed	Not Completed	
6	EPIP -I - Shyam Century	Completed	Completed	Not Completed	
7	EPIP-II - Umtru Line I	Completed	Completed	Completed	
8	EPIP-II - Umtru Line II	Completed	Completed	Completed	
9	EPIP II - New Umtru	Completed	Completed	Completed	
10	EPIP II - Killing Line I	Completed	Completed	Not Completed	Fiber Network Not Available
11	EPIP II - Killing Line II	Completed	Completed	Not Completed	
12	Umtru- New Umtru	Completed	Completed	Completed	
13	LUMSHNONG- M/S MCL	Completed	Completed	Not Completed	Fiber Network Not Available
14	LumSHNONG- M/S ACL	Completed	Completed	Not Completed	
15	Lumshnong - M/S MPL	Completed	Completed	Not Completed	
16	UMIAM - Stage I	Completed	Completed	Not Completed	
17	Umiam - NEHU	Completed	Completed	Completed	
18	UMIAM STAGE-I - Umiam Stage II	Completed	Completed	Not Completed	Fiber Network Not Available
19	NEHU - NEIGHRIMS	Completed	Completed	Not Completed	Awaiting for Commissioning of fiber under NERFO
20	NEHU - MAWLAI	Completed	Completed	Completed	
21	KHLIEHRIAT (MePTCL)-KHLIEHRIAT(PG) line-II	Completed	Completed	Completed	
22	Stage-III - Stage IV Line I	Completed	Completed	Not Completed	Fiber Network Not Available
23	Stage-III - Stage IV Line II	Completed	Completed	Not Completed	