ग्रिड-इंडिया
GRID-INDIA

ग्रिड कंट्रोलर ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)
GRID CONTROLLER OF INDIA LIMITED
(A Government of India Enterprise)
[formerly Power System Operation Corporation Limited (POSOCO)]
राष्ट्रीय भार प्रेषण केन्द्र / National Load Despatch Centre

कार्यालय : बी-9, प्रथम एवं द्वितीय तल, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली - 110016
Office : 1st and 2nd Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.grid-india.in, E-mail : gridindiacc@grid-india.in, Tel.: 011- 42785855

07th Aug 2023

Ref: NLDC/IEGC-2023/Jul-23

सेवा में,

All the Stakeholders

विषय: Draft Detailed Procedure for Assessment of Quantum of Secondary Reserve Capacity – Reg.

संदर्भ: Central Electricity Regulatory Commission, Indian Electricity Grid Code, Regulations, 2023

महोदय/महोदया,

In line with the CERC (Ancillary Services) Regulations, 2022, an interim procedure was formulated for estimation of the requirement of reserves for Secondary Reserves and Tertiary Reserves. Stakeholder consultations on the above procedure were conducted by NLDC on 26th July 2022 and 27th July 2022. The suggestions of the stakeholders were incorporated and the procedure was submitted to Hon'ble CERC, and subsequently was notified by Hon'ble CERC on 02nd Dec 2022.

CERC (Indian Electricity Grid Code) Regulations, 2023 mandates preparation of a detailed procedure for the assessment of quantum of secondary reserve capacity. The portions pertaining to the secondary reserves have been extracted from the interim procedure. Suitable modifications have been made in compliance with the CERC (Indian Electricity Grid Code) Regulations 30(11)(k), 2023. Philosophy for estimation of secondary reserves remains unchanged. The changes from the earlier version in line with IEGC are as below –

- Inserted reserve estimation on a three day ahead basis
- Removed reserve estimation on a quarter and week ahead basis

The draft procedure has been published on Grid-India website on 07th August 2023 and is available at: https://posoco.in/notices/.

Stakeholder suggestions/feedback on this draft procedure are invited at ancillary@grid-india.in by 22nd August 2023.

सधन्यवाद,

भवदीय,

(S C Saxena)
Executive Director, NLDC.

Copy to:

1. Secretary, CERC
2. CMD, Grid Controller of India Limited
3. All RLDC Heads

Grid Controller of India Limited (Grid-India)

Formerly Power System Operation Corporation Ltd.

Detailed Procedure

for

Assessment of Quantum of Secondary Reserve Capacity

Prepared in Compliance with Central Electricity Regulatory Commission (Indian Electricity Grid code) Regulations 30(11)(k), 2023

Version History

Document Name:	Detailed Procedure for Assessment of Quantum of Secondary Reserve Capacity		
Document Creation Date:	14 July 2023		
Version History			
Sr. No	Description of Change	Date of Change	Revision No.
1	Initial Document	14 July 2023	0.0

1.0 Preamble

1.1 Every entity shall undertake all appropriate measures to maintain its drawal/injection as per schedule. Each control area has to follow certain Frequency Response Performance (FRP) criteria, as specified in Central Electricity Regulatory Commission (CERC) (Indian Electricity Grid Code) Regulations, 2023 hereinafter referred to as the IEGC, in order to maintain frequency within the IEGC stipulated band under normal operating conditions.

1.2 The objective of Ancillary Services in Indian power system is to maintain the grid frequency close to 50 Hz, restoration of the grid frequency within the allowable band as specified in the IEGC and for relieving congestion in the transmission network, to ensure smooth operation of the power system, and safety and security of the grid.

1.3 Adequate reserves are required to be maintained in a distributed manner with both the regional entities at the regional level and at the State level for each state control area as per the IEGC or the State Grid Code as the case may be.

1.5 National Load Despatch Centre (NLDC) shall, in coordination with Regional Load Despatch Centres (RLDCs) and State Load Despatch Centres (SLDCs), assess the quantum of requirement reserves at the regional level after factoring in the reserves for each state control area, for such period and based on such methodology as specified in the IEGC and publish the same on its website.

1.6 There would be assessment of reserve requirement on year ahead basis, three day-ahead basis, day ahead basis and intra-day basis.

1.7. This procedure has been prepared in accordance with Regulations 30(11)(k) of the IEGC. This procedure supersedes the interim methodology for estimation of secondary reserves prepared in accordance with Regulation 6(1) of the CERC (Ancillary Services) Regulations, 2022.

Quote

30(11)(k) With due regard to the requirement of planning reserve margin and resource adequacy referred to in Chapter 2 of these regulations and based on the

following methodologies, the secondary reserve capacity requirements shall be estimated by RLDCs for their respective regional control areas:

The positive and negative secondary reserve capacity requirements for any control area for a calendar year shall be equal to the 99 percentile of positive and negative ACE respectively of that control area during the previous financial year (Detailed Procedure shall be as per Annexure-3 to these regulations, which may be reviewed as and when considered necessary),

OR

The secondary reserve capacity requirement for any control area shall be equal to the 110 % of the largest unit size in the respective regional control area or state control area plus load forecast error plus wind forecast error plus solar forecast error during the previous calendar year.

OR

Such other methodology as may be stipulated by NLDC after obtaining the due approval of the Commission.

Unquote

1.8 In line with the IEGC, Nodal Agency would consider the above stipulated basis for the assessment of reserves for Secondary Reserve Ancillary Services (SRAS).

1.9 All the words and expressions used in the Procedure shall have the same meaning as assigned to them in various CERC Regulations.

2.0 Objective

2.1 The objective of this procedure is to lay down the roles of various entities and methodology for assessment of the required quantum of reserves for SRAS to be followed by the Nodal Agency i.e. NLDC in coordination with RLDCs and SLDCs.

3.0 Scope

3.1 The procedure shall be applicable to all entities as provided in the IEGC.

4.0 Definitions

4.1 **'Reference contingency'** means the maximum positive power deviation occurring instantaneously between generation and demand and considered for dimensioning of reserves.

5.0 Roles of NLDC (Nodal Agency), RLDCs and SLDCs

5.1 Nodal Agency i.e. NLDC shall, in coordination with RLDCs and SLDCs, estimate the quantum of requirement of SRAS on year ahead basis, three day ahead basis, day ahead basis and real-time basis as per the methodology specified in subsequent sections.

5.2 SLDCs shall furnish data in the stipulated formats and timelines to the Nodal Agency for estimation of the quantum of requirement of SRAS.

5.3 SLDC shall maintain reserves as allocated by Nodal Agency (after considering diversity benefit and reference contingency), as per the estimation carried out by the SLDC in accordance with the IEGC.

6.0 Reserves in Indian Power System

6.1 There shall be different types of reserves, as specified in the IEGC and AS regulations, such as primary, secondary and tertiary for the purpose of frequency control and regulating Area Control Error. The reserves shall be deployed by each control area as per the IEGC and the applicable AS regulations:

6.1.1 Provision for primary response shall be mandatory.

6.1.2 Secondary reserves shall be deployed through a regulated mechanism.

6.1.3 Tertiary reserves shall be procured through the market and deployed

6.2 The deployment of reserves is broadly distinguished on the basis of the time of initiation and duration of response as tabulated in Table-1 below:

Reserve	Start of activation	Full Availability/ deployment	Ability to sustain the full deployment
Primary Response*	Immediately as soon as frequency crosses the dead band	Within 45 seconds	Up to 5 min

Reserve	Start of activation	Full Availability/ deployment	Ability to sustain the full deployment
Secondary control Reserve	**Within 30 seconds after the receipt of Automatic Generation Control (AGC) signal**	**within 15 Minutes**	**Up to 30 min or till replaced by Tertiary Reserves**
Tertiary control Reserve	Within 15 minutes of dispatch instruction from NLDC/RLDC		Upto 60 minutes

Table 1: Reserves and their activation

7.0 Area Control Error (ACE)

7.1 "Area Control Error" or "ACE" means the instantaneous difference between a control area's net actual interchange and net scheduled interchange, taking into account the effects of frequency bias and correction of measurement errors.

7.2 The Area Control Error (ACE) for each control area would be calculated at all the load despatch centres based on telemetered values and external inputs as per the below formula:

ACE = (Ia - Is) - 10 * Bf * (Fa - Fs) + Offset

Ia = Actual net interchange in MW (positive value for export)

Is = Scheduled net interchange in MW (positive value for export)

Bf = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

Fa = Actual system frequency in Hz

Fs = Schedule system frequency in Hz (default 50 Hz)

Offset = Provision for compensating errors such as measurement error; default value zero.

7.3 The detailed methodology to be followed by Nodal Agency for calculation and monitoring of Area Control Error (ACE) is attached at **Annexure – 1**. The ACE shall be worked out for each state and region. Post calculation of the ACE, the outliers would be removed using appropriate statistical techniques.

7.4 ACE is 'positive' means that the control area has surplus generation and the control area's internal generation has to be backed down. ACE is 'negative' means the control area is in deficit and the control area's internal generation

has to be increased. All the frequency control interventions shall be in the direction to drive ACE towards zero.

8.0 Estimation of Reserve Requirement for SRAS on year ahead and three day ahead basis

8.1 IEGC envisages loss of a complete power station or a pooling station or a generation complex or a credible outage scenario as a reference contingency for maintaining primary reserve. The reference contingency for maintaining primary reserve, presently considered in the Indian power system, is the outage of the largest power plant or a sudden load throw-off of 4500 MW, which shall be declared by the Nodal Agency from time to time on the NLDC website.

8.2 The data for assessment of the reserves capacity requirement for SRAS shall be furnished to the Nodal Agency by respective SLDCs pertaining to their state control areas as per following timelines.

8.2.1 Year Ahead Basis – For reserve estimation for the next financial year (FY+1), the data for the previous calendar year shall be furnished by 15th January of the current financial year (FY) **(Format – RAS1).**

(Illustration: If the assessment is being carried out for FY 2024-25, the data for the period 1st Jan 2023 to 31st December 2023 has to be provided by 15th January, 2024)

8.2.2 The reserve capacity requirement as per the methodology in this document shall also be estimated by each RLDC and SLDC respectively by 15th January every year for the next financial year and submitted to NLDC.

8.3 In case of non-availability of data from SLDCs as mentioned above, the data available at RLDCs/NLDC shall be used to estimate the quantum of reserves requirement.

8.4 For estimation of reserve requirement on a Three Day-Ahead basis for day D on D-3, data for the last 7 days (i.e., D-4 to D-10) shall be used.

8.5 The estimation of secondary reserve capacity requirement, on regional basis and state basis (considering diversity benefit), shall be carried out by Nodal Agency as per the following methodology:

8.5.1 The positive (Up Reserve) and negative (Down Reserve) secondary reserve capacity requirement on regional basis would be computed as 99 percentile of negative and positive ACE respectively of that region for year ahead, three day ahead, day ahead and real time.

8.52 The 99 percentile of the positive and negative ACE of each state control shall be computed and aggregated at regional level. This shall be scaled using 99 percentiles of the regional ACE to factor diversity at regional level. The scaled values of 99 percentile of the state ACE shall be used to arrive at the reserve requirement at Inter-state and Intra-state levels.

8.5.3 The drawl by the respective state and its internal-generation at the time of peak demand during the period under consideration shall be used for apportionment of the reserve requirement. The intra state reserves shall be in proportion to the contribution of internal generation at the time peak demand. The Inter-state reserves shall be in proportion to the drawl from the grid at the time of peak demand.

8.5.4 The state level requirement shall be aggregated to arrive at the regional and all India reserve requirement.

8.5.5 If any state control area has net injection in the concerned period, then, entire reserve margin is to be allocated within the state control area.

8.5.6 If any state control area has zero internal generation in the concerned period, then, the required reserve margin is to be allocated at the regional level.

8.6 The all-India total of positive (and negative) secondary reserves capacity requirement on regional basis shall be equal to the reference contingency or secondary reserve capacity requirement as computed above, whichever is higher. If the all-India reserve requirement, computed using 99 percentile of

ACE, is less than the reference contingency such additional reserves shall be considered in the regional requirement.

9.0 Reserve requirement for SRAS on Day ahead and Real time basis

9.1 The all-India reserve requirement on day-ahead basis would be calculated by using the positive (Up Reserve) and negative (Down Reserve) reserve capacity requirement on regional basis, as 99 percentile of negative and positive 10 second ACE during the last 7 days respectively of that region for each time block. The up and down reserve requirement shall be aggregated on an all-India basis.

9.3 In any time block, the minimum up reserve requirement shall be equal to the reference contingency. The all-India credible contingency shall be continuously monitored using the SCADA MW data and the likely availability of the generating units. The quantum of reference contingency may vary across time blocks.

9.4 The quantum and location of the advanced procured reserves before D-2 by SLDCs by any means for SRAS, would be intimated to the Nodal Agency two days before the day of scheduling by 1100 hrs. The modalities for information exchange and timelines in this respect shall be as per **Format-RAS2**. ***(Illustration: The reserves booked in advance for Friday may be intimated in the NLDC web portal on Wednesday by 1100 hrs.)***

9.5 In case of non-submission of data by the SLDCs before 1100 hrs on D-2 basis, advance reserves intimated would be assumed as zero MW, for all the associated calculations.

9.6 As per the CERC (Ancillary Services) Regulations, 2022, only tertiary reserve procurement through TRAS day-ahead and real-time markets has been mandated. Similar procedure may be adopted in the future for secondary reserve procurement as and when such market segments are made operational by CERC.

9.7 In line with IEGC Regulation 30(11)(t), 30(11)(u) shortfall of reserves would be flagged when availability of reserves is less than the requirement. Shortfall would be calculated using data from Format-RAS2 and Format-RAS5. NLDC, RLDC, and SLDC shall indicate the shortfall in secondary reserves, if any, and announce emergency alerts for such periods.

9.8 The up and down reserve requirement on a day ahead basis for SRAS shall be obtained by subtracting the below from the all-India up and down reserve requirement estimated on a D-1 basis -

9.8.1 Advance procured reserves (before D-2) by SLDCs and RLDCs/NLDC by any means.

9.9 The real-time reserve requirement for SRAS shall be estimated from the reserve estimated on the day-ahead basis, considering factors such as real time system conditions, load/RE forecast, load generation balance, weather, contingencies, congestion etc.

10.0 Information Dissemination

10.1 The reference contingency shall be declared by Nodal Agency by 25th January before the start of each financial year **(Format – RAS3)**. The review of reference contingency may be done by the Nodal Agency any time after the declaration. Accordingly, the figures of reference contingency would be revised and updated on the Nodal Agency website.

(Illustration: The reference contingency for financial year 2024-25 would be declared by 25th January, 2024)

10.2 The assessment of the reserve requirement for SRAS on Year Ahead Basis would be declared by Nodal Agency by 25th January of the current year **(Format – RAS4)**

(Illustration: The reserve requirement for SRAS in financial year 2024-25 would be declared by 25th January, 2024)

10.3 The assessment of the reserve capacity requirement for SRAS on a three day-ahead basis would be declared by the Nodal Agency on a daily basis by 1100 hrs **(Format – RAS5)**

(Illustration: The reserve requirement for SRAS for Friday would be declared by 1100 hrs on Tuesday)

11.0 Revision of the procedures

Notwithstanding anything contained in this Procedure, NLDC/RLDCs may take appropriate decisions in the interest of System Operation. Such decisions shall be taken under intimation to CERC and the procedure shall be modified/amended with the approval of the CERC, as necessary.

Format – RAS1: Data for Estimation of Year Ahead Reserves

Following Data is to be provided by each state control area

1. Assessment of reserves for the FY: 01.04.yyyy to 31.03.yyyy
2. Name of the state:
3. Data for the calendar: 01.01.yyyy to 31.12.yyyy
4. Data furnished (please tick the data submitted):
    a. Actual interchange of the State (10 seconds resolution), (Number of samples = 365*24*60*6 = 3153600 nos.) in excel format
    b. Frequency Response Characteristics of the State for the events posted on NLDC website (https://grid-india.in/frc/)
    c. Peak Demand met
    d. Intra-State Generation (other than ISGS) at the time of peak demand

Actual interchange of the State (10 seconds resolution) for calendar: 01.01.yyyy to 31.12.yyyy	
Date & Time (DD-MMM-YY HH:MM:SS)	Actual interchange of the State (MW)
01-jan-2021 00:00:10	452
01-jan-2021 00:00:20	456
01-jan-2021 00:00:30	461
…..	
…….	
31-Dec-2021 23:59:50	498

Frequency Response Characteristics of the State for calendar: 01.01.yyyy to 31.12.yyyy (In case State has difficulty in computation of FRC, it may seek assistance from respective RLDC)	
Event Details	Frequency Response Characteristics (MW/Hz)
Events 1:	800
Event 2:	815
Event 3:	756

Peak Demand and Intra-State Generation of the State for calendar: 01.01.yyyy to 31.12.yyyy		
State/UT	Peak Demand met (MW)	Intra-State Generation (other than ISGS) at the time of peak demand (MW)
……		

Format – RAS2: Information Exchange Format for intimation of Advance Procured Reserves before 1100 hrs on D-2 by SLDCs to NLDC

Note: Format in line with Regulations 30(11)(q), 30(12)(d) and 30(12)(l) of IEGC

For date: DD/MM/YYYY

Submitted by: <Name of the State/RLDC>

S.no.	Region	State	Plant Name	From time block to time block	Method of dispatch (Secondary/Tertiary)	Earmarked Spinning Reserve as on D-2 (MW)
1	WR	State-1	Station-A	1-96	Tertiary	30
2	WR	State-1	Station-B	1-96	Secondary	20
3						
4						
5						
	Total					50

- The quantum and location of advance procured reserves (before D-2) by SLDCs and RLDCs/NLDC by any means, would be intimated to the Nodal Agency two days before the day of scheduling.
- The information shall be submitted daily at 1100 hrs on a D-2 basis. For example, the reserves booked in advance for Friday may be intimated in the NLDC web portal on Wednesday by 1100 hrs.
- The information shall be submitted by the respective SLDCs/RLDCs on the web portal hosted by NLDC. URL and password for the secure web portal may be collected by SLDC from the respective RLDCs.

Summary of Intra-State Advance Reserves

Note: Format in line with Regulations 30(11)(t), 30(11)(u) and 30(12)(h) of IEGC

S.no.	Region	State /Control Area	Secondary Reserves Requirement Share intimated by NLDC on D-3	Secondary Reserves Earmarked by SLDC/RLDC on D-2	Shortfall in Secondary Reserve Capacity (computed by NLDC on D-2)
1	NR	State-1	50	30	15
		State-2			

2	ER	State-10	50	30	15
		State-11			

3	WR	State-16	50	35	25
		State-17			

4	SR	State-24			
		State-25			

5	NER	State-31			

		State-37			
		Total	100	65	45

Format – RAS3: Reference contingency for Indian Power System

Date: 25 January 2023	Revision No.	
Applicable for FY 2023-24		
Reference Contingency for generation loss (MW)	**4500**	
Reference Contingency for load loss (MW)	**4500**	

Format RAS4: SRAS Reserve Requirement on an Annual Basis

SRAS and TRAS Reserve requirement for year 2022-23																
State/UT	Actual 99 Percentile Negative ACE (MW)	Actual 99 Percentile Positive ACE (MW)	Scaled 99 Percentile Negative ACE (MW) (a)	Scaled 99 Percentile Positive ACE (MW) (b)	Max. Demand met (c)	Internal Gen. at the time of max demand (d)	Drawl from ISTS (e=c-d)	State Internal Generation/ State Maximum Demand (f=d/c)	State drawl from ISTS/ State Maximum Demand (g=e/c)	Secondary Reserves in ISGS (h=a*g)	Secondary Reserves at Regional Level {sum of reserves in all states of the region as given in "h"}	Secondary Reserves within state (i=a*f)	Tertiary Reserves in ISGS (j = h)	Tertiary Reserves within state (k = i)	Largest Unit Size of internal generation (l)	Total Tertiary Reserves within state (m=k + 0.5*l)
Punjab	307	505	125	310	13431	6014	7417	0.45	0.55	69		56	69	56	700	406
Haryana	411	443	167	272	12120	2953	9167	0.24	0.76	126		41	126	41	660	371
Rajasthan	730	735	296	451	15696	9701	5995	0.62	0.38	113		183	113	183	660	513
Delhi	156	273	63	168	7305	645	6660	0.09	0.91	58		6	58	6	216	114
Uttar Pradesh	658	847	267	520	24795	12302	12493	0.50	0.50	135	725	133	135	133	660	463
Uttarakhand	200	198	81	122	2318	812	1506	0.35	0.65	53		28	53	28	76	66
UT Chandigarh	45	76	18	47	426	0	426	0.00	1.00	18		0	18	0	0	0
Himachal Pradesh	165	173	67	106	1955	675	1280	0.35	0.65	44		23	44	23	100	73
UT Jammu & Kashmir	296	260	120	160	2743	240	2503	0.09	0.91	110		11	110	11	150	86
NR state Sum	2968	3510	1205	2154												2091
Northern Region	1205	2154														
West Bengal	319	336	237	201	9316	6800	2516	0.73	0.27	64		173	64	173	500	423
Bihar	364	381	270	228	6868	400	6468	0.06	0.94	255		16	255	16	250	141
Odisha	281	336	209	201	6008	3903	2105	0.65	0.35	73	522	136	73	136	600	436
Jharkhand	154	164	114	98	1718	394	1324	0.23	0.77	88		26	88	26	210	131
DVC	272	273	202	163	3487	5638	-2151	1.62	-0.62	0		202	0	202	600	502
Sikkim	57	48	42	29	132	0	132	0.00	1.00	42		0	42	0	0	0
ER state Sum	1447	1538	1075	921												1633
Eastern Region	1075	921														
Maharashtra	547	625	424	404	25644	16595	9049	0.65	0.35	149		274	149	274	660	604
Gujarat	657	594	509	384	19431	10416	9015	0.54	0.46	236		273	236	273	800	673
Madhya Pradesh	488	607	378	392	15917	5991	9926	0.38	0.62	236		142	236	142	660	472
Chhattisgarh	232	232	180	150	4870	2172	2698	0.45	0.55	100	829	80	100	80	500	330
UT Dadra Nagar Haveli	56	33	43	21	888	0	888	0.00	1.00	43		0	43	0	0	0
UT Daman Diu	39	22	30	14	369	0	369	0.00	1.00	30		0	30	0	0	0
Goa	45	41	35	26	698	0	698	0.00	1.00	35		0	35	0	0	0
WR States Sum	2064	2154	1598	1392												2079
Western Region	1598	1392														
Andhra Pradesh	571	442	302	265	11472	5319	6153	0.46	0.54	162		140	162	140	800	540
Tamil Nadu	609	641	322	384	16846	7624	9222	0.45	0.55	176		146	176	146	600	446
Karnataka	587	535	311	320	14367	9354	5013	0.65	0.35	108	620	202	108	202	800	602
Kerala	183	191	97	114	4284	1519	2765	0.35	0.65	62		34	62	34	130	99
UT Puducherry	35	60	19	36	452	0	452	0.00	1.00	19		0	19	0	0	0
Telangana	391	418	207	250	13688	7561	6127	0.55	0.45	93		114	93	114	800	514
SR State Sum	2376	2287	1257	1369												2202
Southern Region	1257	1369														
Assam	111	111	72	87	2132	340	1792	0.16	0.84	60		11	60	11	50	36
Meghalaya	41	39	27	31	391	114	277	0.29	0.71	19		8	19	8	42	29
Tripura	59	60	38	47	327	172	155	0.53	0.47	18		20	18	20	21	31
Manipur	25	26	16	20	244	0	244	0.00	1.00	16	154	0	16	0	0	0
Mizoram	16	23	10	18	144	54	90	0.38	0.63	6		4	6	4	6	7
Nagaland	20	30	13	24	153	14	139	0.09	0.91	12		1	12	1	8	5
Arunachal Pradesh	34	42	22	33	162	0	162	0.00	1.00	22		0	22	0	0	0
NER State Sum	306	331	198	260												108
North-Eastern Region	198	260														
All India	5333	6096	5333	6096									2850			8112
Total Tertiary Reserves Requirement in India													10963			

Summary of Reserve Requirement on an Annual Basis

	Year-Ahead					
	Secondary Reserves			Tertiary Reserves		
State/UT	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total
Punjab	69	56	125	69	406	475
Haryana	126	41	167	126	371	497
Rajasthan	113	183	296	113	513	626
Delhi	58	6	63	58	114	171
Uttar Pradesh	135	133	267	135	463	597
Uttarakhand	53	28	81	53	66	119
UT Chandigarh	18	0	18	18	0	18
Himachal Pradesh	44	23	67	44	73	117
UT Jammu & Kashmir	110	11	120	110	86	195
West Bengal	64	173	237	64	423	487
Bihar	255	16	270	255	141	395
Odisha	73	136	209	73	436	509
Jharkhand	88	26	114	88	131	219
DVC	0	202	202	0	502	502
Sikkim	42	0	42	42	0	42
Maharashtra	149	274	424	149	604	754
Gujarat	236	273	509	236	673	909
Madhya Pradesh	236	142	378	236	472	708
Chhattisgarh	100	80	180	100	330	430
UT Dadra Nagar Haveli	43	0	43	43	0	43
UT Daman Diu	30	0	30	30	0	30
Goa	35	0	35	35	0	35
Andhra Pradesh	162	140	302	162	540	702
Tamil Nadu	176	146	322	176	446	622
Karnataka	108	202	311	108	602	711
Kerala	62	34	97	62	99	162
UT Puducherry	19	0	19	19	0	19
Telangana	93	114	207	93	514	607
Assam	60	11	72	60	36	97
Meghalaya	19	8	27	19	29	48
Tripura	18	20	38	18	31	49
Manipur	16	0	16	16	0	16
Mizoram	6	4	10	6	7	13
Nagaland	12	1	13	12	5	17
Arunachal Pradesh	22	0	22	22	0	22
Northern Region	725	480	1205	725	2091	2816
Western Region	829	769	1598	829	2079	2908
Southern Region	620	637	1257	620	2202	2822
Eastern Region	522	553	1075	522	1633	2155
North-Eastern Region	154	44	198	154	108	262
All India	2850	2482	5333	2850	8112	10962

Format RAS5: Assessment of the reserve capacity requirement for SRAS on a three day-ahead basis

State/UT	Actual 99 Percentile Negative ACE (MW)	Actual 99 Percentile Positive ACE (MW)	Scaled 99 Percentile Negative ACE (MW) (a)	Scaled 99 Percentile Positive ACE (MW) (b)	Max. Demand met (c)	Internal Gen. at the time of max demand (d)	Drawl from ISTS (e=c-d)	State Internal Generation/ State Maximum Demand (f=d/c)	State drawl from ISTS/ State Maximum Demand (g=e/c)	Secondary Reserves in ISGS (h=a*g)	Secondary Reserves at Regional Level (sum of reserves in all states of the region as given in "h")	Secondary Reserves within state (i=a*f)	Tertiary Reserves in ISGS (j = h)	Tertiary Reserves within state (k = i)	Largest Unit Size of internal generation (l)	Total Tertiary Reserves within state (m=k + 0.5*l)
Punjab	307	505	125	310	13431	6014	7417	0.45	0.55	69		56	69	56	700	406
Haryana	411	443	167	272	12120	2953	9167	0.24	0.76	126		41	126	41	660	371
Rajasthan	730	735	296	451	15696	9701	5995	0.62	0.38	113		183	113	183	660	513
Delhi	156	273	63	168	7305	645	6660	0.09	0.91	58		6	58	6	216	114
Uttar Pradesh	658	847	267	520	24795	12302	12493	0.50	0.50	135	725	133	135	133	660	463
Uttarakhand	200	198	81	122	2318	812	1506	0.35	0.65	53		28	53	28	76	66
UT Chandigarh	45	76	18	47	426	0	426	0.00	1.00	18		0	18	0	0	0
Himachal Pradesh	165	173	67	106	1955	675	1280	0.35	0.65	44		23	44	23	100	73
UT Jammu & Kashmir	296	260	120	160	2743	240	2503	0.09	0.91	110		11	110	11	150	86
NR state Sum	2968	3510	1205	2154												2091
Northern Region	1205	2154														
West Bengal	319	336	237	201	9316	6800	2516	0.73	0.27	64		173	64	173	500	423
Bihar	364	381	270	228	6868	400	6468	0.06	0.94	255		16	255	16	250	141
Odisha	281	336	209	201	6008	3903	2105	0.65	0.35	73	522	136	73	136	600	436
Jharkhand	154	164	114	98	1718	394	1324	0.23	0.77	88		26	88	26	210	131
DVC	272	273	202	163	3487	5638	-2151	1.62	-0.62	0		202	0	202	600	502
Sikkim	57	48	42	29	132	0	132	0.00	1.00	42		0	42	0	0	0
ER state Sum	1447	1538	1075	921												1633
Eastern Region	1075	921														
Maharashtra	547	625	424	404	25644	16595	9049	0.65	0.35	149		274	149	274	660	604
Gujarat	657	594	509	384	19431	10416	9015	0.54	0.46	236		273	236	273	800	673
Madhya Pradesh	488	607	378	392	15917	5991	9926	0.38	0.62	236		142	236	142	660	472
Chhattisgarh	232	232	180	150	4870	2172	2698	0.45	0.55	100	829	80	100	80	500	330
UT Dadra Nagar Haveli	56	33	43	21	888	0	888	0.00	1.00	43		0	43	0	0	0
UT Daman Diu	39	22	30	14	369	0	369	0.00	1.00	30		0	30	0	0	0
Goa	45	41	35	26	698	0	698	0.00	1.00	35		0	35	0	0	0
WR States Sum	2064	2154	1598	1392												2079
Western Region	1598	1392														
Andhra Pradesh	571	442	302	265	11472	5319	6153	0.46	0.54	162		140	162	140	800	540
Tamil Nadu	609	641	322	384	16846	7624	9222	0.45	0.55	176		146	176	146	600	446
Karnataka	587	535	311	320	14367	9354	5013	0.65	0.35	108	620	202	108	202	800	602
Kerala	183	191	97	114	4284	1519	2765	0.35	0.65	62		34	62	34	130	99
UT Puducherry	35	60	19	36	452	0	452	0.00	1.00	19		0	19	0	0	0
Telangana	391	418	207	250	13688	7561	6127	0.55	0.45	93		114	93	114	800	514
SR State Sum	2376	2287	1257	1369												2202
Southern Region	1257	1369														
Assam	111	111	72	87	2132	340	1792	0.16	0.84	60		11	60	11	50	36
Meghalaya	41	39	27	31	391	114	277	0.29	0.71	19		8	19	8	42	29
Tripura	59	60	38	47	327	172	155	0.53	0.47	18		20	18	20	21	31
Manipur	25	26	16	20	244	0	244	0.00	1.00	16	154	0	16	0	0	0
Mizoram	16	23	10	18	144	54	90	0.38	0.63	6		4	6	4	6	7
Nagaland	20	30	13	24	153	14	139	0.09	0.91	12		1	12	1	8	5
Arunachal Pradesh	34	42	22	33	162	0	162	0.00	1.00	22		0	22	0	0	0
NER State Sum	306	331	198	260												108
North-Eastern Region	198	260														
All India	5333	6096	5333	6096									2850			8112
									Total Tertiary Reserves Requirement in India				10963			

Note: Would be published every day at 1100 hrs on NLDC webiste

Summary of Reserve Requirement on a Three-Day Ahead Basis

	Secondary Reserves			Tertiary Reserves		
State/UT	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total
Punjab	69	56	125	69	406	475
Haryana	126	41	167	126	371	497
Rajasthan	113	183	296	113	513	626
Delhi	58	6	63	58	114	171
Uttar Pradesh	135	133	267	135	463	597
Uttarakhand	53	28	81	53	66	119
UT Chandigarh	18	0	18	18	0	18
Himachal Pradesh	44	23	67	44	73	117
UT Jammu & Kashmir	110	11	120	110	86	195
West Bengal	64	173	237	64	423	487
Bihar	255	16	270	255	141	395
Odisha	73	136	209	73	436	509
Jharkhand	88	26	114	88	131	219
DVC	0	202	202	0	502	502
Sikkim	42	0	42	42	0	42
Maharashtra	149	274	424	149	604	754
Gujarat	236	273	509	236	673	909
Madhya Pradesh	236	142	378	236	472	708
Chhattisgarh	100	80	180	100	330	430
UT Dadra Nagar Haveli	43	0	43	43	0	43
UT Daman Diu	30	0	30	30	0	30
Goa	35	0	35	35	0	35
Andhra Pradesh	162	140	302	162	540	702
Tamil Nadu	176	146	322	176	446	622
Karnataka	108	202	311	108	602	711
Kerala	62	34	97	62	99	162
UT Puducherry	19	0	19	19	0	19
Telangana	93	114	207	93	514	607
Assam	60	11	72	60	36	97
Meghalaya	19	8	27	19	29	48
Tripura	18	20	38	18	31	49
Manipur	16	0	16	16	0	16
Mizoram	6	4	10	6	7	13
Nagaland	12	1	13	12	5	17
Arunachal Pradesh	22	0	22	22	0	22
Northern Region	725	480	1205	725	2091	2816
Western Region	829	769	1598	829	2079	2908
Southern Region	620	637	1257	620	2202	2822
Eastern Region	522	553	1075	522	1633	2155
North-Eastern Region	154	44	198	154	108	262
All India	2850	2482	5333	2850	8112	10962

Annexure I

National Load Despatch Centre
Power System Operation Corporation Limited

Guideline for Calculation and Monitoring of Area Control Error

This document provides the detailed guidelines to be uniformly adopted by the NLDC, RLDCs, SLDCs, and REMCs for measurement, calculation, monitoring, and archival of Frequency, Tie-Line Flows, Frequency Bias, Metering Errors, and Area Control Error (ACE). ACE is an important parameter which depicts the health of the power system. This document enables uniform notation for ACE, thereby allowing all the load despatch control rooms pan India to pass on information about this grid security aspect with one another.

Table of the Contents

1. Formula of Area Control Error (ACE)

The Area Control Error (ACE) for each control area[1] would be calculated at all the load despatch centres based on telemetered values and external inputs as per the below formula[2].

ACE = (Ia - Is) - 10 * Bf * (Fa - Fs) + Offset

Ia = Actual net interchange in MW (positive value for export)

Is = Scheduled net interchange in MW (positive value for export)

Bf = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

Fa = Actual system frequency in Hz

Fs = Schedule system frequency in Hz (default 50 Hz)

Offset = Provision for compensating errors such as measurement error; default value zero.

In the above formula, ACE has three components as below.

1. Interchange deviation component **(Ia-Is)**
2. Frequency deviation component -**10*Bf*(Fa-Fs)**
3. Offset or Metering Error

Sign convention adopted for interchange MW values is, positive value for export and negative value for import. Bf is a negative value. System Frequency (Fa) is a positive value, close to the National Reference Frequency[3] of 50 Hz.

ACE is positive means that the control area has surplus generation and the control area's internal generation has to be backed down. ACE is negative means the control area is in deficit and the control area's internal generation has to be increased. ACE has to be driven towards zero for better frequency control and grid security.

[1] *Control Area means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas and contributes to regulation of frequency as specified;*
Definition from the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020. https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

[2] Formula as given in the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020.

[3] Defined in the Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020.

2. Measurement of Frequency

System frequency is an important input for calculating ACE. Typically, ACE is used for taking generation increase/decrease actions using the below applications

a. Secondary frequency control through AGC
b. Tertiary frequency control through TRAS
c. Monitoring and manual generation rescheduling

All the above three applications operate in the time frame of a few seconds to several minutes. Hence it should suffice that the system frequency signal is captured using a sampling time of a few seconds for calculation of ACE.

Suggested sampling time for frequency: 4 seconds, i.e., take a fresh frequency data point every four seconds.

2.1. Choosing the master list of redundant frequency sources

The frequency signal taken should be free from noise. To ensure the same, the signals from such stations shall be selected as the frequency sources, whose historical data is proven to be at least 99.9% noise-free in the past three months. To identify noise, the frequency data of different stations shall be plotted in a time series graph. The graph should be free from spikes. Choose 10 such stations to act as redundant frequency sources in ACE calculation. This list may be reviewed quarterly.

2.2. Location of redundant frequency sources and host server

For the applications a, b, and c, mentioned above, frequency source from any geographic location should serve the purpose as the time range of interest is in seconds. Typically, in time frame of a few seconds, all the electromagnetic transients and most of the electromechanical transients usually get damped and settled[4]. Hence, stations from different geographic locations can be chosen as redundant frequency sources. Having a mix of at least 10 redundant frequency sources from SCADA and URTDSM (PMU) is advised. Frequency data from URTDSM server are generally imported into SCADA[5] for the purpose of ACE calculation.

2.3. Algorithm for selecting the Primary Frequency Source

The ACE calculation program can look at the quality tags of all the redundant signals and choose one of the signals as the primary source. The update of the

[4] For applications b & c, as the dispatches are time block-wise, there is no need of consideration about frequency oscillations. For AGC, oscillations in ACE are further smoothened by the exponential moving average filters and the PI controller (low pass filter) which are typically part of the AGC software. The integration time in AGC is in generally between 10s -120s and hence the electromechanical oscillations and any noise get further damped.

[5] PMUs are not available on all the tie-lines. Hence calculating ACE is recommended through SCADA.

quality tags happens along with the sampling of the data in the EMS system, as a general practice. In case the quality of the primary frequency source becomes 'suspect', then the next signal with 'good quality tag' shall be selected as the primary frequency source automatically. This logic may be developed into the calculation program gradually, if not immediately.

Algorithm outline:

Initialize Primary Freq= 50 Hz

Initialize K=1

Initialize J=1

Initialize Flag = Good

Call Subroutine-A

Subroutine-A ()

Select the Kth frequency signal in the list as 'primary' and read its quality tag.

If the quality tag is good, set J=1, exit Subroutine-A and GOTO Subroutine-B.

If, J=11, Primary Freq = 50 Hz, exit Subroutine-A and GOTO Subroutine-B.

Else, K=K+1, J=J+1 and Call Subroutine-A.

End Subroutine-A ()

Subroutine-B ()

While Flag = Good

Read the quality tag of the Kth signal at time t

If the quality tag is good, t=t0+4s, Flag=Good

Else Flag = Bad

End While

GOTO Subroutine-A

End Subroutine-B

3. Measurement of Tie-Line Flows

3.1. Actual Tie-Line Flows

Actual tie-line flows shall be sampled every 4 seconds[6] similar to frequency and shall be used in the ACE calculation. The update of the quality tags happens along with the sampling of the data in the EMS system, as a general practice. Say, the data is acquired only every 12s by the SCADA because of delays[7], the ACE calculation program shall repeat the data thrice in those 12s. Some Tie-Line flows have the problem of becoming suspect often. Such data should be identified and rectified immediately by following up with site/substation. Efforts shall be made by respective utilities that the clock synchronization across all the stations taken into consideration by the respective LDC and its calibration shall be done once every year in order to ensure the synchronicity of time stamping of the collected data. Every tie-line flow can be obtained from 3 different sources viz.,

i. Primary Side (choose the Metering End as per IEGC)
ii. Secondary Side (side other than the Metering End as per IEGC)
iii. State Estimator output

Primary side data shall be normally used for ACE calculation. In case the quality of the primary side becomes 'suspect', then let the ACE calculation program automatically choose the secondary side. If flow at both the ends goes suspect, use the state estimator output. If the state estimator is not running, replace the suspect data manually with 'last good value', rather than retaining garbage value. Information of manual interventions shall be monitored, carried forward and updated frequently in every shift. Sign convention adopted for interchange MW values is, positive value for export and negative value for import.

Note that all the tie-lines should be accounted for, while calculating the Net Actual Tie-Line Flow (Ia), i.e., algebraic sum of the flows. If any of the tie-lines is non-observable, the data of the same can be replaced with a fixed value as informed by site/substation telephonically to the control room.

[6] At NLDC, the tie line flow acquisition delay (around 10s) includes the delay introduced while acquiring data from RLDCs through ICCP, apart from the delay in acquiring tie line data from RTUs to the RLDCs. For other RLDCs/control areas, delay (~ 5s) is mainly introduced in acquiring tie line data from RTUs to the RLDCs. However, this data acquisition timing has to be improved further by all the control areas.

[7] Higher updation time as well as non-simultaneity can lead to inconsistent frequency response assessment and incorrect ACE calculations. Ideal would be to have PMUs on all inter-regional lines to begin with, followed by all inter-state tie lines.

3.2. Scheduled Tie-Line Flows

The Net Scheduled Tie-Line Flow (*Is*) of a control area should generally be the output of a scheduling software program, from which the data is imported into SCADA for all the 96-time blocks. ACE is calculated using the net tie-line flow, and path-wise scheduled flows are algebraically added based on direction.

Net Scheduled Tie-Line Flow of the control area can be calculated every time block by adding the algebraic sum of scheduled MW export contracts (from the control area to all the other control areas; positive values) and the scheduled MW import contracts (to the control area from all the other control areas; negative values) and the MW sum of resultant of the virtual entities. In line with the tie-line flow convention, sign convention for TRAS Up regulation is positive, TRAS Down is negative. Note that for ACE calculation, we are interested in the net control area values, and not the path-wise values.

For example, if a particular control area imports 2000 MW from the other control areas through tie-lines, exports 500 MW to the other control areas through tie-lines, TRAS Up of 200 MW is dispatched and SCED Down of 100 MW is dispatched. Then Is = -2000+500+200-100 = -1400 MW for that time block.

Note that the Net Scheduled Tie-Line Flow value shall be always less than the Export Available Transfer Capability (ATC) and greater than the Import ATC value. While calculating ACE, this 15-minute data has to be updated/refreshed every 4 seconds.

4. Assessment of Frequency Bias

The 2017 IEEE Task Force Report[8] on "Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response," recommends using Frequency Response Characteristic (FRC) calculated after the power and frequency transients have settled, for the Frequency Bias Coefficient (Bf) used in the ACE equation. A sample size of twenty (20) FRC events has been deemed adequate for estimating the frequency response characteristic to rule out human error. Several other references[9] also have been studied, which support the IEEE Task Force Report recommendations.

[8] IEEE Task Force Report. 2017. "Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response," Technical Report PES-R-24, October. https://resourcecenter.ieee-pes.org/publications/technical-reports/PESTECRPTGS0001.html

[9] J. L. Willems, "Sensitivity Analysis of the Optimum Performance of Conventional Load-Frequency Control," in IEEE Transactions on Power Apparatus and Systems, vol. PAS-93, no. 5, pp. 1287-1291, Sept. 1974, doi: 10.1109/TPAS.1974.293852. https://ieeexplore.ieee.org/document/4075491

FRC computation procedure has been clearly provided in the draft IEGC 2020[10]. A sample template for FRC assessment is enclosed as Annexure-I.I. FRC shall be computed for every control area for all events involving a sudden 1000 MW or more load/generation loss or a step change in frequency by 0.10 Hz. All these FRC values shall be archived along with date, time and reasons of the event.

4.1. Bf value assessment

In the calculation of ACE, the value of Frequency Bias Coefficient in MW/0.1 Hz (negative value) shall be based on median Frequency Response Characteristic. Median[11] value of the past 20 events would be used for updating the FRC. The occurrence of these 20 events is actually expected to cover the entire previous year, thereby subsuming the seasonality aspect of load and generation. The all-India, region-wise and state-wise Bf value, used in the reserve estimation computation, would be provided on the Nodal Agency website as per ***Format RAS8***. Bf value shall be reviewed by the Nodal Agency.

4.2. Bf update timing

The Bias (Bf) value may be reviewed in the ACE calculations at the LDCs, once in every quarter on the 24th day of the month after the completion of the previous quarter. The literature studied and mentioned in the footnotes-6,7 suggests updating the bias values once in a year for practical power systems. However, due to the developing nature of Indian power system, a quarterly update has been suggested. For example, update the Bias (Bf) value on 25th July, after the completion of the quarter April – June. The updated Bf value in SCADA shall also be shared continuously through ICCP bottoms up, from SLDCs to RLDCs, and from RLDCs to NLDC for all the relevant control areas. An offline all India compilation in Excel/DB may be maintained by NLDC for all the control areas. While calculating ACE, this quarterly data has to be updated/refreshed every 4 seconds.

NERC, Frequency Response Standard Background Document. November, 2012. https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/Bal-003-1-Background_Document-Clean-2013_FILING.pdf

P. Kundur, Power System Stability and Control, Chapter 11, McGraw-Hill, New York, 1994.

[10] Report of the Expert Group: Review of Indian Electricity Grid Code, January 2020. https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

[11] The median is a better choice as the FRC value is susceptible to a small number of extreme values, or outliers. These outliers are possible when incorrect information regarding the exact quantum of load/generation lost in the control area is received for an FRC event.

5. Measurement of Metering Errors - OFFSET

Typically, the accuracy level of the SCADA Remote Terminal Unit (RTU) is 0.5%. Also, there is a chance of error in the instrumentation and communication. Inherent latency and non-simultaneous reporting of SCADA might also cause metering error. Hence, while calculating ACE using the RTU metered tie-line flows, there is a probability of metering errors corrupting the actual value. OFFSET shall be used if such a metering error has been established using long-term data/statistical analysis.

In case of un-observable tie-line flows, where it is not feasible to replace the actual tie line flow data manually, OFFSET can be used to substitute the tie-line flow with correct sign convention. Information of manual interventions shall be monitored, carried forward and updated frequently in every shift. Sign convention adopted for interchange MW values is, positive value for export and negative value for import. While calculating ACE, OFFSET data has to be updated/refreshed every 4 seconds.

6. Calculation of ACE

Scheduled Interchange (Is), Actual Interchange (Ia), Actual Frequency (Fa), Scheduled Frequency (Fs), Frequency Bias (Bf) and Offset shall be updated/refreshed every 4 seconds in the calculation. The formula, techniques and details have already been mentioned in the earlier sections. With the above data, ACE may be calculated every 4 seconds, i.e., refresh the value of ACE every 4 seconds.

7. Archival of different parameters

It is important to archive the individual parts of the ACE into a database every 4 seconds. That means, apart from the calculated ACE, Interchange deviation (Ia-Is), Frequency deviation (Fa-Fs), Frequency Bias (Bf) and Offset shall also be separately archived in the database every 4 seconds. This is necessary to build and calculate what-if scenarios for reserve estimation, forecasting, etc.

8. Monitoring of ACE and Suggested Corrective Actions

All the control rooms of the control areas shall prominently monitor ACE, apart from the tie-line deviation and frequency deviation.

ACE is positive means that the control area has surplus generation and the control area's internal generation has to be backed down. ACE is negative means the control area is in deficit and the control area's internal generation has to be increased. All the frequency control interventions shall be in the direction to drive

ACE towards zero. ACE remaining in the same direction for several minutes without crossing zero is a strong indicator that the frequency control interventions have to be kicked in.

9. Calculating ACE for Regional Entity Control Area

Each Regional entity power station is a control area by itself. ACE for a regional entity power plant can also be worked out separately for the purpose of monitoring. The bias would depend on the number of units on bar (40% of capacity on bar per Hz assuming 5% droop plus a small load response from the unit auxiliaries). When there are fragmented control areas and virtual power plants operated from a single control center, this aspect assumes importance.

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Annexure-I.I

Sample Template for Frequency Response Characteristic Calculation

Frequency Response Characteristic Calculation for All India based on NLDC SCADA Data

EVENT: As reported at 16:02 Hrs on 11th June 2021, 220 kV Akal-Bhu -1&2 tripped due to snapping of B-phase jumper which resulted into 1200MW wind generation loss and 300MW solar generation loss in Northern region. At the same time, 400kV Barmer-Jaisalmer-1&2 also tripped due to over voltage after tripping of wind and solar generation.It appears that two events happen in quick succesession, total generation loss of around 1500 MW as per reported region has been considered for FRC calculation.

S No	Particulars	Dimension	NR	ER	WR	NER	SR	Nepal	Bhutan	#Bangladesh	Combined cross border	All India
1	Actual Net Interchange before the Event (16:02:30)	MW	11313	-5678	-8306	21.2	1850	109	1241	1039	2390	164388
2	Actual Net Interchange after the Event (16:03:50)	MW	12241	-6128	-9200	-21.5	1469	105	1241	1038	2384	164088
3	Change in Net Interchange (2 - 1)	MW	928	-451	-895	-42.7	-381	-4	-1	-1	-6	-300
4	Generation Loss (+) / Load Throw off (-) during the Event	MW	1500	0	0	0	0	0	0	0	0	1500
5	Control Area Response (3 - 4)	MW	-572	-451	-895	-43	-381	-4	-1	-1	-6	-1800
6	Frequency before the Event	HZ	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09
7	Frequency after the Event	HZ	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
8	Change in Frequency (7 - 6)	HZ	-0.090	-0.090	-0.090	-0.090	-0.090	-0.090	-0.090	-0.090	-0.090	-0.090
9	Frequency Response Characteristic (5 / 8)	MW/Hz	6353	5007	9939	475	4233	47	6	11	64	20000
10	Net System Demand met before the Event	MW	57737	18219	47210	2249	38974	--	--	--	--	--
11	Internal Generation before the Event (10 - 1)	MW	46424	23897	55516	2228	37124	--	--	--	--	--
12	Ideal load response assuming 4% per Hz (0.04*Row 10)	MW/Hz	2309	729	1888	90	1559	--	--	--	--	--
13	Ideal generator response assuming 5% droop.....40% per Hz (40% of Row 11)	MW/Hz	18570	9559	22206	891	14849	--	--	--	--	--
14	Composite ideal response (12 + 13)	MW/Hz	20879	10287	24095	981	16408	--	--	--	--	--
15	Percentage ideal response	%	30.4%	48.7%	41.2%	48.4%	25.8%	--	--	--	--	--

(*) - Data may be constant/suspected during the event
Note: +ve exchange=> import ; (-)ve exchange => export

Flow of 132kv Surjamani-comilla D/c is included in Bangladesh interchange,

Total Generation All India

Total Change in (MW)	1500
FRC for NEWS GRID (dp/df) MW/Hz	**16667**
Power Number (net change in MW/maximum change in frequency)	**8824**

Source Wise Generation (MW)	GAS	HYDRO	NUCLEAR	Thermal	WIND	SOLAR
	4834	22342	5088	98676	20669	12686

Percentage of non responsive generation(nuclear+ wind+ solar as a percentage of total generation)	23.40%

Format RAS8

All-India, Region-wise and State-wise Frequency Bias Coefficient

State/Region/All India	Frequency Bias Coefficient (value in MW/0.1 Hz)
Punjab	
Haryana	
Rajasthan	
Delhi	
Uttar Pradesh	
Uttarakhand	
UT Chandigarh	
Himachal Pradesh	
UT Jammu & Kashmir	
West Bengal	
Bihar	
Odisha	
Jharkhand	
DVC	
Sikkim	
Maharashtra	
Gujarat	
Madhya Pradesh	
Chhattisgarh	
UT Dadra Nagar Haveli	
UT Daman Diu	
Goa	
Andhra Pradesh	
Tamil Nadu	
Karnataka	
Kerala	
UT Puducherry	
Telangana	
Assam	
Meghalaya	
Tripura	
Manipur	
Mizoram	
Nagaland	
Arunachal Pradesh	
ER	
NR	
NER	
SR	
WR	
All-India	

Updated as on: dd/mmm/yyyy