NTPC Limited
COMMENTS ON REVIEW OF IEGC

A. INTRODUCTION:

The need for review of the Indian Electricity Grid Code (IEGC) has become essential in light of the recent developments in the sector having implications on all the stakeholders of the Indian Power Sector including the System Operators. In the next phase of the power sector, Grid operations shall have to accommodate two major developments; rapid addition of Renewable Energy Capacity and strengthening of the market mechanism.

While these two developments remain the most challenging areas that needs to be addressed in the revamped Grid Code, the third element, which is ensuring safe, secure and reliable operation of the Grid, remains the most fundamental requirement and there is a need to strengthen the Grid Code on this aspect. This aspect gains more importance in the light of massive integration of variable resources into the Grid of the future. At the same time market operations has to be seen as an integral part of the system operation as we aspire to move towards a market based system.

Hence, the suggestions of NTPC with respect to various provisions have been formulated mostly based on these three aspects. The suggestions are essentially modification/ amendment of some of the existing regulations/ provisions and introduction of some new provisions.

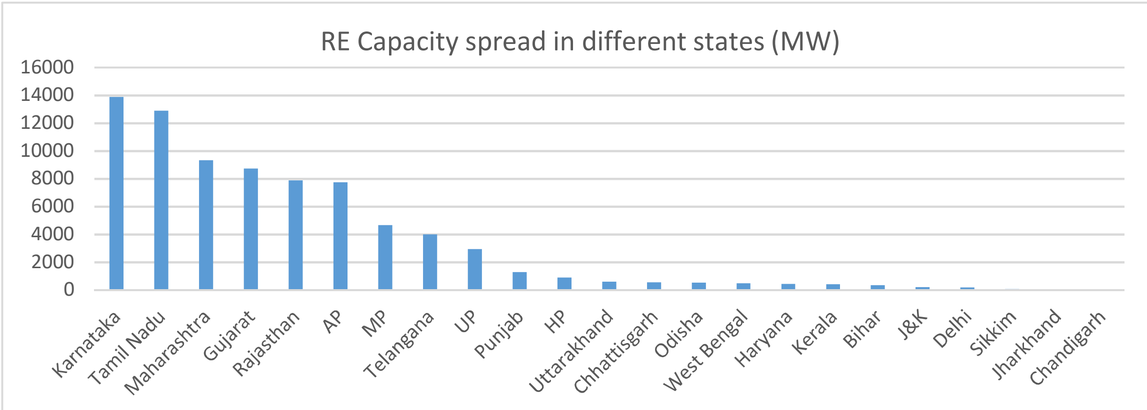
B. PRELIMINARY:

The Electricity Act 2003 provides that the Regional Load Dispatch Centers will comply with the provisions and guidelines of the Indian Electricity Grid Code for scheduling and dispatch purpose. Similarly, the State Load Dispatch Centers shall follow the provision of the State Grid Code. Accordingly, we have the IEGC at the inter-state / central level and different State Grid Codes at different States/ intra-state level. Further, the Electricity Act 2003 also provides that the State Grid code specified by State Commission shall be consistent with the IEGC.

Starting from regional grids, India now has a synchronously operating national grid. With increasing levels of integration, the Indian Grid has evolved to be one of the largest interconnected grids of the world. With the changing structure of the power sector, it is time to move towards a common Grid Code for the entire country. The imperative for this also comes largely from the two developments as described above i.e. large scale RE integration and strengthening of the market mechanism.

1) RE by its very nature is largely concentrated in localized areas. In India the RE resources are mainly concentrated in the Southern and Western region states. The capacity spread

of RE in different states indicate that top 7 states only account for almost 90% of the total capacity in the country.



High wind zones or higher solar insolence areas are ideal for development of RE projects, but the RE generation cannot be integrated / absorbed at the local / State level. In order to utilize fully the benefits of RE power, it needs to be integrated in a coordinated manner across a wider area. A uniform Grid Code across States will be extremely useful for this purpose.

2) Secondly, the country is moving towards nation-wide common electricity market. This essentially means centralized operation of market and the various resources in the power system. Seamless operation of markets across different states can happen only if we have uniform standards of operation.

Hence, it has become essential to harmonize the State Grid Codes with the IEGC or preferably have a single national Grid Code.

C. CHALLENGES FOR GRID OPERATION IN NEAR FUTURE:

1. FREQUENCY CONTROL:

Load generation balance remains one of the critical challenges in the Indian Grid. Going forward with large-scale entry of variable RE power, this is going to present a much bigger challenge. It is suggested that to have a more reliable operating regime, the frequency control framework may be reviewed as follows:

Reference / Nominal Frequency:

Reference point is an essential part of any control system. In the power systems for effective control of the system frequency, there has to be a reference point. The

Committee of Experts formed for this purpose has submitted its recommendations to this effect as under.

"Reference frequency for the purpose of control *Any control system would need a reference value; in case of frequency control, it would be the target frequency or reference frequency. For the Indian system, the same has to be the nominal frequency of 50.0 Hz.* ***It is therefore recommended that the reference frequency for the purpose of frequency control is considered as 50.0 Hz, and the same is notified in the IEGC."***

Therefore, nominal frequency of 50 hertz for the Indian Grid may be considered for incorporation in the IEGC.

2. OPERATIONALIZATION OF RESERVES:

The basic characteristics of Primary Reserve is that it is the most reliable reserve, which can act without any manual intervention of anybody and can act very fast. This reserve is mandatory in nature available in all the machines connected to the grid but it is important that this reserve be preserved for the most critical events / contingency in the Grid.
Accordingly, it is suggested that the primary reserves should be used only to take care of the contingency situations and act as a means for containment of frequency when it reaches the outer limits of the operating range and not for regular efforts to restore the frequency, which can be done by the Secondary Reserves. Internationally, in most of the countries all generators are required to provide Primary Reserve. Further, there is dead-band defined to take care of the controller sensitivity and an intentional dead band introduced where primary reserves are not operated.

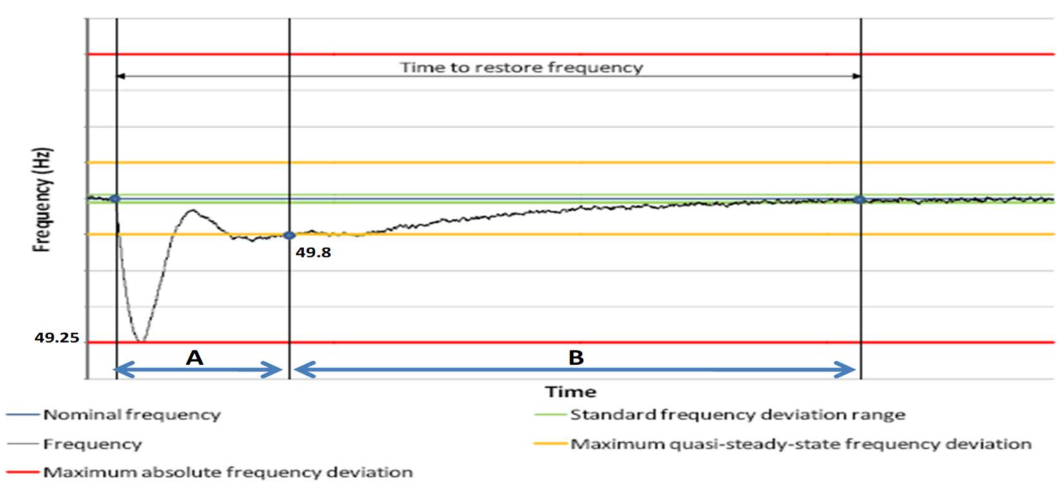
The Expert Group (appointed by CERC) to review and suggest measures for bringing power system operation closer to national Reference Frequency has also recommended "to gradually phase out the RGMO by 1st April 2018 and instead have speed control with droop." Expert Group also recommended that "CEA may notify the Technical Standards for connectivity to the grid in respect of RE generation at the earliest mandating primary control from RE resources also".

Primary control (governor control) is used for frequency stabilization after a large disturbance which operates in seconds (proportional control), the Secondary control restores the primary reserves & frequency to target frequency (50 Hz) and operates in minutes (Integral control) and the tertiary control restores secondary reserves and operates in tens of minutes. For keeping primary reserves, it is necessary to define "event" / "disturbance" and also the quasi steady state frequency by which entire reserves should be harnessed. In absence of secondary control in Indian grid (at present implemented only at Dadri-II, Simhadri-II and Mouda-II only in the form of AGC but restricted), target frequency is also not fixed.

However, considering the target frequency of 50 Hz and a quasi-steady state frequency of 49.8 Hz (Δf = - 0.2 Hz) due to outage of largest power station in the country as a credible contingency, following example can be considered for working out the *primary reserve required.*

- Power demand and corresponding generation considered as 2,20,000 MW at 50 Hz at the time of disturbance as per CEA estimate for 2021-2022.
- "Disturbance" / "Event": Outage of largest power station i.e., 5,000 MW considered as event of credible contingency.
- Load damping of 4% and Governor Droop setting of 5% assumed.

Parameter	Unit	Peak Load
Demand	**MW**	**2,20,000**
Generation	**MW**	**2,20,000**
"Disturbance" Generation outage, ΔP_G	MW	**5000**
Post trip Generation, P_G' $(=P_G - \Delta P_G)$	MW	2,15,000
Capacity of Machines on Governor control to deliver primary UP response.	**MW**	**60,000**
D (Load Damping)**	MW/Hz	8,800
1/R (Governing)***	MW/Hz	24,000
AFRC, $\beta = (D + 1/R)$	MW/Hz	32,800
$\Delta f = \Delta P_G \div \beta$	**Hz**	**-0.15**
$f = f_N + \Delta f$	**Hz**	**49.85**
Load Damping will provide (MW)		**1341**
Governor response will provide (MW)		**3659**
Primary Reserve in % of Capacity of Machines earmarked to give UP response		**6.10**



From the above calculation for 2021-22 high RE scenario of Indian grid, it can be seen that the frequency decline can be arrested to -0.15 Hz which is less than - 0.2 Hz (quasi-steady state Frequency at 49.8 Hz if nominal frequency is maintained at 50 Hz by Secondary Control) in case of outage of largest power station. This can be achieved if Primary UP reserve is ensured on units having total capacity of only around 60,000 MW in service (synchronized to Grid) out of total thermal generation of around 100,000 MW. The maximum absolute frequency deviation can also be arrested above 49.25 Hz, which is above the acceptable range of UCTE.

1. Therefore, putting RGMO / FGMO with Manual intervention in almost all machines as stipulated in the IEGC, even for machines with old mechanical governor, 50MW and above Gas Turbines, wind turbines, etc., may not be insisted upon as this entails avoidable expenditure for making the old systems RGMO compliant.
2. Moreover, withholding (by restricting SG to normative DC) cheaper power of pithead stations, like, Sipat, Rihand, Singrauli, Korba, etc., for the purpose of primary response is bottling up cheaper generation, which is also against the theory of economic dispatch.

Hence, our suggestion is to identify and keep Primary UP Reserve margin in those machines whose variable cost is moderately high and operating at part load. System operator should carry out such study and earmark those 60,000 MW plus machines which shall carry governor control Up Reserve of ≈ 3700 MW (contingency of 5000 MW generation loss – 1300 MW relief from load damping at 49.85 Hz). However, all the machines in the system must *always be operated on Governor control* (not RGMO) and support frequency containment in the event of disturbances. Low cost generating units may not keep any Primary UP Reserve Margin or headroom (like Sipat, Rihand, Singrauli, Korba, etc.,) for reducing power purchase cost of the consumers but these machines should participate during high frequency events by Governor Action to reduce generation.

The prerequisite to run machines on Governor Control is to keep frequency within the governor dead band of target frequency of 50 Hz for >99% time by Secondary Control. Hence, AGC in the form of *Secondary Control must be implemented across the country on war footing* and secondary reserves to be identified and maintained in those units by scheduling them for normal dispatch lower than DC. AGC reserves must be necessarily maintained in machines, which are partially scheduled. Storage Hydro /CCGT units are most suited for this duty. Both up and down changes in generation level by AGC command must be commercially paid for.

Based on the discussions above, the Frequency control regime is proposed as follows:

Reference frequency at 50.0 Hz

Operating range of frequency may be set at 49.95 to 50.05 Hz; However, frequency to be kept within dead band of 50 mHz for 99% of time in day through AGC

Primary Down reserves mandatory in all machines, but UP reserve in earmarked Units having higher ECR as per reserve requirement

AGC may be operationalized in identified units based on reserve requirement but most of machines shall be AGC compliant

Frequency restoration through Secondary reserves (AGC) of identified Units (CGS+IPP+State Gencos) of a region. Control area for AGC shall be the Region.

3. INTEGRATION OF RENEWABLE ENERGY IN THE GRID:

The entry of Renewable Energy in the Grid will necessitate a new way of managing the Grid operations. Apart from the fact that Renewable Energy due to its variability requires sufficient conventional capacity as backup; Renewable Energy capacity such as Roof top solar connected in the low voltage distribution network make them invisible to the system operator and makes it difficult to manage.
Some of the ways to manage the integration of RE power in the Grid can be summarized as follows:

a) Forecasting of Load and RE Generation:

Any system operation activity needs to deploy forecasting techniques to estimate the demand and supply expected in the Grid and take proactive measures to maintain the balance. The need for forecasting increases many folds when the share of RE increase in the Grid, mainly to take care of the variability and intermittency of RE generation.
Currently IEGC assigns the responsibility of demand forecasting in different time horizons such as daily, weekly, monthly and yearly on the States.

In order to adopt better forecasting techniques, it is suggested that forecasting may be undertaken at a centralized level by a centralized authority and made available to the stakeholders free of cost or on paid basis. As we move towards a prominent role of the markets, forecasting will play a major role in bringing stability in market prices unlike the wide variations see sometimes in the Power Exchanges currently.

RE generation forecasting must also be done more seriously for better load-generation balancing. For this purpose, the REMCs have to be strengthened.

b) Larger balancing area:

It is widely known that the most effective way of integrating RE power in a Grid is to make the balancing area as large as possible. In the Indian context, as most of the RE power is located in some RE rich States, better approach would be to mandate all the RE power stations transmit data to the RLDCs/ NLDC even if they are connected in the state grid, so that they are visible to the system operator and accordingly the generation decisions can be suitably

c) Operating the balancing power in a Centralized manner:

One of the solution would be dispatching the pool of conventional power in a centralized manner, which may include the gas, hydro, pumped storage stations, etc. For this purpose, there is a need to identify these resources and RLDCs / NLDC may be made responsible for scheduling these stations. The system operator in non-spinning mode could use some of these resources as and when required.

d) Deployment of energy storages:

There is a need to deploy energy storage systems (pumped hydro plants, batteries) both at grid scale and as distribution energy resources. Its fast ramping capability makes energy storage useful in mitigating the variability of the RE resources. In some markets like California, the utilities are mandated to deploy energy storages, which resulted in increase in stationary energy storage installations increase by almost 350 percent between 2014 to 2016.

Issues in scheduling of the Renewable Energy based power:

a) **Treatment of Infirm power in case of Renewable Energy projects:**
The Renewable Energy Projects before being declared Commercial do need to draw power from the Grid to meet the minor load requirements at the project. At present, there is not clarity about how this power should be treated.

b) **Drawl of power from the Grid by RE projects when they are not generating:**
Renewable Energy projects also need to draw power from the Grid when they are not generating, mostly to meet minor power requirements at the station. For example, during night, most solar plants will need some power for lighting, cleaning and other requirements. At present there is no clarity regarding settlement of this drawl and in the absence of the same different States are following different practices. Some states are charging at the rate of temporary consumer connected at that voltage.

To bring uniformity and certainty to the RE developers, Grid Code should provide settlement of such drawl as per the DSM Regulations. Various State Grid Code may then adopt the same approach as well.

c) **Connectivity of RE projects:**
Currently there is lack of clarity in the control area of the RE projects, particularly in case of Solar parks. RE capacity within solar park normally get developed in phases. So initially, a particular RE project gets connected to the State network at a lower voltage and accordingly scheduling is done by the SLDC of that State. Metering is also at the lower voltage level. As RE capacities in other phases are commissioned the solar park gets connected to the ISTS and scheduling is now done by the RLDCs as per the extant provisions. However, as the metering point now gets shifted to higher voltage level, additional transmission losses are loaded on the RE developers.
This situation can be avoided if the systems are developed from the beginning as Regional Systems and there is clarity in treatment of losses.

4. TECHNICAL MINIMUM OPERATION OF COAL PLANTS:

As per Fourth amendment of IEGC, Technical Minimum load for both supercritical and sub-critical units is 55 % for Inter State Generating Stations Coal and Gas Stations only.

a) Supercritical units are having much higher capital investment as compared to sub-critical units. In return, they are of higher efficiency than their sub-critical counter parts. Operating a Supercritical/ Ultra Super critical plant in part load reduces the efficiency and hence loses its advantage and the higher investment may not get justified. Variation of parameters of supercritical units shall have higher impact on its life as compared to subcritical units and may necessitate midlife replacement of some critical components. Hence, on economy point of view, supercritical plants should be operated as close as possible to the full load considering the fact that if these plants were operated near full load would reduce annual CO_2 emissions and save precious natural resources.

It is proposed that, sub-critical units should back down first and then if required by the grid the supercritical units can operate at part load.

Hence, it is suggested that Supercritical plants may be run at near to full load and accordingly fix the minimum load for such units.

b) Some relatively costlier stations like at Kudgi/Solapur/Mouda/Vallur and even Simhadri are forced to run at 55% of loading most of the time. Some mandatory critical routine operations like LRSB and some contractual obligation like PG test needs the machines to run at higher loading than 55%. So RLDC must be empowered or there shall be provision in scheduling mechanism to take care of the above requirements time to time.

c) Though Inter-state Generating Stations (ISGS) have a technical minimum of 55% as specified in the Grid Code by CERC, Technical minimum in case of State Generators is generally at a substantially higher level. Therefore, while ISGS having lower Energy Charges are backed down, State generators having higher energy charges are not backed down as they have higher technical minimum. This distortion in merit order operation results in increasing the power purchase cost of the Discoms. It is essential that all generators follow uniform technical minimum norms so that merit order operation is not compromised.

d) Merit order should not be based on ECR (Energy Charge Rate) alone. Appropriate weightage of Efficiency or net Heat Rate (NHR) may be devised and should be considered while deciding Merit Order for scheduling. High efficient super critical units need to get preference in scheduling in order to reduce CO_2 emission.

e) While running the stations at Technical minimum level, the credible contingency requirement in case of tripping of various equipment, such as, Mills, Fans and Pumps, etc., needs to be considered.

5. PART LOAD COMPENSATION FOR THERMAL STATIONS:

Present compensation on HR at part load (3% at 50% load for supercritical units while 6% for subcritical units) is not adequate. CEA recommendation (during operational norms fixation of Tariff Regulations 2019-24) to CERC regarding degraded HR & APC due to part load operation may please be implemented which are summarized below:

Sl No	Unit Loading(%)	Unit HR degradation(%)	
		Sub critical units	Super –critical units
1	90-100	0	0
2	80-89.99	1.3	0.9
3	70-79.99	2.8	2.1
4	60-69.99	4.8	3.7
5	50-59.99	7.2	5.7

Similarly degradation in APC has been recommended as per following table:

Sl. No.	Module/plant loading as % of Installed Capacity	Admissible Degradation in AUX(%)
1	90-100	Nil
2	80-89.99	0.25
3	70-79.99	0.50
4	60-69.99	0.80
5	50-59.99	1.20

Similarly, CEA recommendation for CCGT Gas stations should be incorporated in the IEGC; currently IEGC doesn’t provide any table for gas stations for degradation in HR/APC.
CEA proposal for HR:

Sl. No.	Module/plant loading as % of Installed Capacity	Admissible Degradation in plant HR(%)
1	90-100	Nil
2	80-89.99	2.5
3	70-79.99	5
4	60-69.99	8.0
5	50-59.99	12.0

Additional APC admissible at part load proposed by CEA:

Sl. No.	Module/plant loading as % of Installed Capacity	Admissible % Degradation in AUX(%)
1	90-100	Nil
2	80-89.99	0.25
3	70-79.99	0.50
4	60-69.99	0.80
5	50-59.99	1.20

6. RAMP RATES

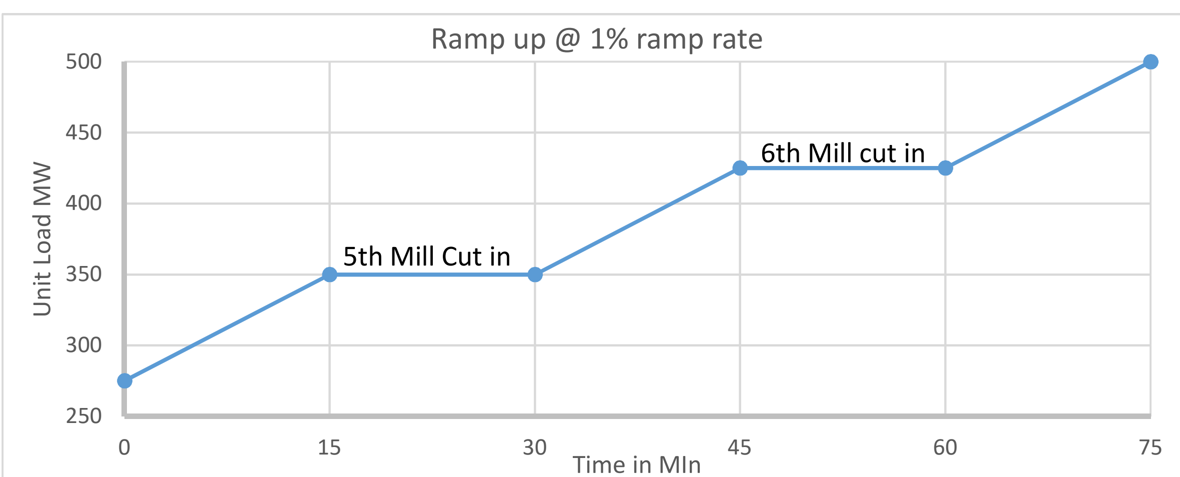
There is need for specifying the permissible step of SG from one time block to the next time block specified and a methodology is described below utilizing the same ramp rate of 1%/min specified under Regulation 5.2 of IEGC:

For a 500 MW unit, 1% ramp rate means 5 MW/min increase or decrease. Now to maintain the ramping rate precisely, Control loops are to be tuned so that this ramping may occur smoothly without any major parameters deviation like steam temp, throttle pressure, flue gas O_2 %, drum level etc.

Because of RE (wind or solar) integration which is uncontrolled, there is a certain requirement of ramp up or ramp down of power from other power sources mainly from coal based thermal power plants. With reference to grid perspective ramping down or up of thermal capacity cannot be limited to a defined load range. So the ramping requirement of coal based station will be from full load operation to minimum load operation.

As per CERC Tariff Regulations 19-24, "*Rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute; b) an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate of 1% per minute, subject to ceiling of additional rate of return on equity of 1.00%*."

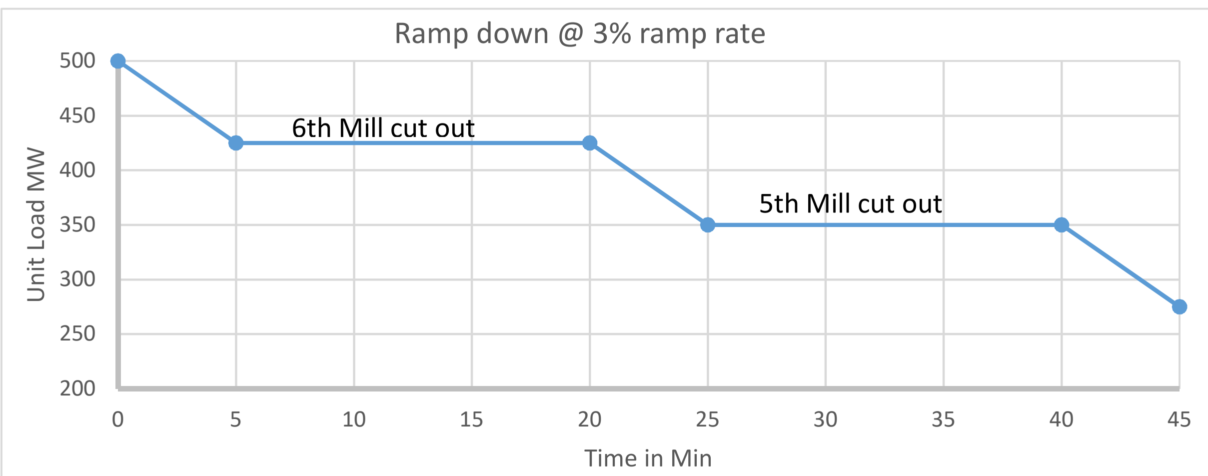
However, there is certain technical aspects of Ramp rate. The units are provided with varying number of coal mills depending upon the coal characteristics and the unit sizes. When the units load is to be reduced the mill loadings are to be reduced. However certain minimum loadings or turn down of the mills are to be maintained otherwise there is a chance of flame out due to very lean fuel air mixture. Hence, load variation by varying the mill loading can only be achieved within certain range. Beyond this range one or more mills are to be cut in / cut out. During these transient periods, the parameters like temperature and pressure varies. Certain stabilization period is required in this range of load change. The cutting in or out of milling system is to be considered as integral part of ramp up or



down operation. Hence achieving continuous load ramp rate from minimum load i.e. 55% till full load (100% load) and vice versa is difficult. The following graph shows practically achievable loads with 1% ramp rate while maintaining safe boiler operation.

With 1 % ramp up rate in 15 min time, load may be increased to 350 MW with 4 mills in service and then 5th mill is to be cut in and is to be stabilized in next 15 min for further ramp up to 425MW. Then 6th mill is to be cut in for further increasing to 500 MW. Thus the time required for ramp down is 75 min instead of 45 min by simple calculation of @ 1%~(5MW/min). The same process will be repeated in reverse order for ramp down as shown in the following figure.

Ramp down with 3% : As per OEM recommendation :*These control loops are to be tuned up to ramp rate 3% /min or 5%/ min but for a limited time period and in defined load range. For example 3% ramp rate(15MW/ min) for a period of 5 min for a 500 MW unit means load reduction from 500 MW to 425 MW in 5 min duration and vice versa.* With this conditions PG tests are conducted to see the deviations of MW achieved in 5 min along with monitoring of important parameters deviation in a limited range. The latest 500 mw unit operating on CMC is capable of this 3% ramping limited to a defined load range e.g. from full load to 425 MW in a period of 5 min but no recommendation is given from OEM for further down below. Thus ramp down with 3% ramp is possible with fine tuning of auto loop and load can be reduced to 425MW in 5 min and subsequently mill to be cut out and allowed to be stabilized for another 15 min and so on. Thus load reduction from full load to tech min load may be achieved in 40



min as per stair-case curve given below. With block wise ramp down may be to tune of **75 MW per 15 min** time block. Similar way ramp up may also be possible at such rate.

Further, with a declared ramp rate of 1% per min, the load needs to be changed by 15% within a block of 15 minutes. If the schedule in block number-1 is, say 60%, then with 1% ramp rate it is only possible to achieve a load of 75% at the end of block-2 only. Hence, the average load during block-2 is 67.5% only which translates into effective ramp rate of 0.5% (not 1%). However, in the present scheduling system, the schedule given in block-1 is 60% and block-2 the schedule is 75%, which requires a ramp rate of 2% to achieve it.

While scheduling the loads, above aspects also need to be kept in mind. Further in order that the operating staff prepare for cutting in / cutting out the mills, the schedule should be known at least 4 blocks in advance.

Thus as per table mentioned below the effective ramp rate from full load to 55% tech min load with 1% and 3% ramp rate both up and down are considered for a 500 MW unit

Ramp rate / min	Effective rate	Remark
1%	0.5%	Single Milling system cut in/ out and stabilization time taken 15 min
3%	1.125%	

Thus effective ramp down per 15 min time block will be average of (500+425)/2 i.e. 462.5 MW for subsequent block. For 1% ramp down block wise will be (500-462-425-387-350-312-275 MW) on gross generation approximately **(37-38) MW per 15 min** time block.

7. OTHER SUGGESTIONS:

i. **Definition of Control Area:** Operation policy to be defined in operating code. It is suggested that frequency and inter regional exchange control to be implemented initially, considering each region as a control area. It is also reasonable to treat ER and NER as one control area. Without this definition AGC (including governor control) implementation can't proceed further.

ii. **Fault (under voltage) ride through capability** must be included in the Grid code for all types of Generators. Presently this stipulation is only for Wind Generators in the Grid code.

iii. **Protection Code** is missing in IEGC, needs to be included. The CBIP manual can be taken as the base document for the purpose.

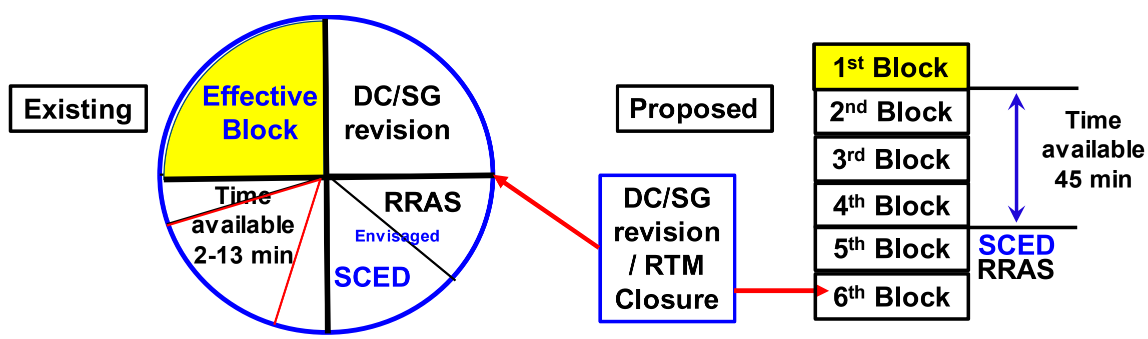
iv. **Synchronous Condenser:** Definition of synchronous condenser proposed to be included as these may form part Ancillary services in near future. It is also proposed to include Reactive power exchange through synchronous condenser as Ancillary service.
As voltage management plays an important role in inter-state transmission of energy, special attention shall be accorded, by CTU, for planning of capacitors, reactors, SVC and Flexible Alternating Current Transmission Systems (FACTS), *Synchronous*

condenser etc. Similar exercise shall be done by STU for intra-State transmission system to optimize the utilization of the integrated transmission network.

v. Also as indicated above, Machines with mechanical governors (MHG) like in VSTPS-I, Singrauli, Kahalgaon-I, may be exempted from complying RGMO stipulations, unless Governor Control in classical form is adopted. Retrofitting them with EHG would entail a huge financial burden on power sector as it will ultimately be passed on to the customers. Primary reserve margin need not be kept in all machines on bar as explained above.

vi. **Ripple Filter**: Additionally IEGC Regulation 5.2(f) (ii) b prescribe ripple filter of +/- 0.03 Hz to avoid frequent governor hunting. But considering International standards, it shall be revised to at least +/- 0.05 Hz in line with other developed countries. It will help in restricting primary control action more frequently in power system and frequency will remain in frequency band as prescribed above by 50 Hz committee most of the time.

vii. **RRAS and SCED** scheduling mechanism shall also be prescribed in scheduling code of IEGC. Frequency of Schedule change due to SCED is very high (≈> 200 per day) as optimization software of SCED is run every block. Generators shall get enough time to adjust to new schedule. Regulatory intervention required for introducing early gate closure. Final schedule should be available 3 clear blocks in advance as enumerated below:



viii. Changes in Scheduling process: As per the current Scheduling process the schedules decide on the Day Ahead basis can be revised before 4 time blocks on the date of delivery both by the beneficiaries and the generators. Recently Hon'ble Commission has introduced several new concepts such as Reserve Regulations Ancillary Services, AGC and SCED. Through these concepts, the schedules get revised as per directions of the RLDCs/ NLDC. IEGC needs to be amended to this effect.

ix. **Web based Scheduling & RPC Account Statements:**

Uniformity in web-based schedule publication formats across all RLDCs need to be ensured. There are discrepancies in naming of Gencos and entities across RLDC's web application softwares. ISGS having beneficiaries in multiple regions are scheduled by respective RLDCs but this data may be made available in the website of the RLDC where it is geographically located, for e.g., in case of Kahalgaon-II having beneficiaries in ER, NR and other regions, one has to look for multiple RLDC website to know its drawal schedule of its beneficiaries. It is suggested that the same may be available in one website, e.g., ERLDC.

Similarly, RPC energy, DSM, RRAS, SCED account statements are also published in different formats across regions. It is very difficult to automate the account verification process for CGS like NTPC. This also needs to be made uniform across the country.

x. **Power Markets:** The CERC (5th Amendment) Regulations provides for a detailed mechanism for sale of URS power in the market based on the consent of the beneficiary states. However, in the past three years, the URS utilized has been quite insignificant. One of the primary reasons for this is that only a very few beneficiaries are forthcoming to allow the utilization (Sale) of URS power. Many states are reluctant to give their consent for sale of URS power beforehand mainly due to the following reasons:

a) As per the current provisions, though the beneficiaries drawal schedules for the next day are decided in the evening before, beneficiaries have to convey their consent by 09:45 Hrs. In the absence of a robust demand forecasting mechanism and uncertainty about the estimated supply positions leads to uncertainty in the URS position for the next day.
b) Beneficiaries tend to keep sufficient margin to take care of any uncertainty such as outage of a unit, increase in demand etc.
c) Lack of an alternate market to meet the power demand in case of emergencies in real time.

This results in non-utilization of the URS power, sometimes URS from relatively cheaper stations.

The proposed solutions are as follows:

a) Strengthening of the real time market, as proposed in the staff paper of CERC.

b) Introduction of the concept of Gate Closure for the hourly markets;

c) Schedule as decided on Day Ahead basis should be firm with revision allowed before the gate closure on the date of delivery.

xi. Scheduling Provision for Power Cleared in PX

a) The IEGC Regulation 6.5 (14) RLDCs while finalizing the schedules of stations must consider that the schedules are operationally feasible, particularly with respect to the ramp up/ down rates. Accordingly the final schedules are made as per the declared ramp rates. However it has been seen that 1) As per when URS power is sold in the market and when it get cleared in some sporadic blocks, many times it is above the ramp rates of the generator, which causes DSM liability on the generators. As ramp rates are not part of the bids submitted by the generators, this may be considered by the RLDC/ NLDC while finalizing the total schedule of the generator considering all the schedules. This practice is being followed by RLDC/ NLDC while operating the RRAS and SCED mechanism, the same may be considered for the PX sale also.

b) In case of unit tripping, DSM should be exempted for power sold in the Day Ahead Markets of PX. There should be a mechanism for revisions of the schedule in such cases.