COMMITTEE ON FGMO OF THERMAL GENERATING UNITS

CONSTITUTED BY CERC, VIDE ORDER DATED 24.09.2014

DISSENT REPORT

By P P Francis, Member of the Committee

(Representing NTPC Limited)

1. PREAMBLE:

The draft report of the Committee was sent to the members of the committee, including the undersigned, through email by a CERC staff member of the Committee Secretariat, on the 26th of August 2015 and comments, if any, was sought by 2nd September 2015, allowing just one week to the committee members for studying the draft and making comments. Though the preparation of the draft report had taken more than six (6) months, since the last meeting of the Committee held on 16th March 2015, the time allowed (just one week) to the members of the committee for studying and making comments was too less. Nevertheless, considering the urgent need for ensuring that the committee does not submit a fundamentally flawed report, the undersigned dutifully submitted comments on the vital contents of the draft within the prescribed time line itself. Detailed point wise comments and corrections were incorporated in the draft report which was also submitted to the committee secretariat by email on 7th September 2015. No response on the matter had been forthcoming on the subject for a long time.

On 11th November 2015 yet another mail was received from the Committee's Secretariat stating the following:

> ***"Please find attached Final Report of the Committee on FGMO of Generating Units as submitted by the Chairman of the Committee to Chairman CERC".***

Found attached to the mail was a soft copy of the report, purportedly submitted to the Hon'ble Commission unilaterally by the Chairman of the Committee.

The said report at best represents the views of the Chairman and does not contain the collective well thought out views of the committee as a whole. As a member of the said committee the undersigned has the obligation to point out that the said report contains technically incorrect views, factually incorrect statements, meaningless recommendations and above all a non-workable road map for the control objective, arising out of sheer misconception about the issue at hand. Obviously the committee's secretariat and the Chairman of the committee had relied on limited and flawed understanding of the subject, in preparing the said report, contents of which are misleading. The correct perspective, presented by the undersigned in response to the draft report circulated, does not even find a place in the annexure to the report. If the subject is not presented to the Hon'ble Commission, in the right perspective, it will have long term ill effect on the development of the Power Sector in the country. It is categorically stated once again that the undersigned does not agree with the central viewpoints presented in the report submitted unilaterally by the Chairman.

Under the above circumstances, the undersigned has no option but to submit this dissent report to the Hon'ble Commission, for favor of kind consideration, with an appeal to the Hon'ble Commission to look at the divergent views on merit.

While the undersigned member cannot speak for other members of the committee, it is apparent that at least some of them will be sharing the sentiments and views of the undersigned, on this matter.

2. TERMS OF REFERENCE OF THE COMMITTEE:

With reference to the terms of reference of the Committee the views of the undersigned member are summarized here.

1. To look into the problems of generating units in implementing RGMO / FGMO:

The basic problem in the operation of generating units in RGMO/FGMO arises from the need for almost continuous modulation of output in either direction prompted by the random and unpredictable frequency pattern. The machines are never under stable operating condition with full throttle margin being perpetually in a mode of delivery and withdrawal of reserves.

Particularly with reference to Steam Turbine units, electrical power off-take from the unit has to be dynamically balanced with the steam generator output. The steam generator can only respond with considerable time lag of the order of 4 – 6 minutes. Unless the continued requirement of the new power balance at the end of this 4 – 6 minutes period is known, it will be counterproductive to change the firing in the steam generator. This change in boiler firing cannot be made, since the requirement is not certain by the time the response of the steam generator is realized, the changed power output change is still required. Frequency changes being random, the Power off-take change by FGMO response to frequency could well be in the opposite sense, by the time the steam generator response will be realized. Further, having once acted, no mechanism exists in FGMO scheme to return the machine to the original level and recoup.

RGMO, if attempted without boiler firing change, the pressure deviation forces to reset the output change quickly. RGMO response will not be available on machines operating in the overload regime. Above all, RGMO response, which peaks in about a minute and is permitted to be fully withdrawn in 5 minutes, serves no useful purpose to the system control.

2. To suggest measures for implementation of FGMO with suitable modifications / amendments in CERC Regulations / IEGC

Once the complete frequency control mechanism, comprising of Primary Control (Governor Control aka FGMO), Secondary Control (known as AGC, if automated) and Tertiary Control, is in place the situation is different. Under normal operation of the power system, the slow frequency changes are perpetually corrected by Secondary Control, thus maintaining frequency within the Governor Dead Band (0.03Hz as per IEC) and Governor Control is not called up to respond. When a large frequency deviation event (disturbance) occurs, like a large generating unit tripping, Governor Control responds with full might. Since it is known that the frequency will take up to 15 – 30 minutes to be returned to the target constant value, by the Secondary Control, fuel firing rate can be readily changed. The increased fuel firing will then be again corrected back, as the secondary control restores the deployed Primary Control Reserve. Many supplementary actions are also necessary to be taken to achieve the quick delivery of Reserve capacity. This aspect is dealt in some detail elsewhere, in this report.

Thus, to make Frequency Control meaningful and workable the existing IEGC regulations need to be amended to introduce “Secondary Control” urgently, which is a pre-requisite to successful constant frequency operation, which will also enable Governor Control to function for its intended duty. Without Secondary Control and reserves for that duty (Spinning Reserve) FGMO or RGMO will not serve any purpose. Introduction of Secondary Control involves working out an efficient arrangement for implementing the same. It will be necessary to hire the services of an international consultant for the purpose, as nobody in the industry in India has clear understanding or any experience of constant frequency control.

3. Any other recommendations to facilitate FGMO operation

It can be categorically stated that RGMO/FGMO prescriptions in IEGC needs to be immediately suspended, being fundamentally flawed. The flaws in the current prescription are brought out elsewhere in this report. It is also necessary that the process of implementing Constant Frequency Control to be initiated without further delay. It must be clearly stated that something which is technically not workable did not and could not have worked in the past 15 years and will not work in future too. The only solution is to adopt frequency control in its entirely, the way the world is doing. The entire process had been explained elsewhere in this report. For a more detailed treatment of the subject UCTE/ENTSOE operation handbook may be referred to.

3. RETROFIT SOLUTION FOR RGMO COMPLIANCE:

The classical governing schemes applicable to all steam turbine units are as stipulated by IEC-45.1. This is a simple proportional control with a characteristic defined as “Speed Regulation” (Droop), expressed as a percentage speed rise for which the generated power will change by 100%. While this control is realized in every turbine generator (in fact, in all rotating generating units), the “restricted governor mode of operation” envisages considerable changes in the control scheme. Such changes cannot be made in the mechanical/hydraulic control system, but are feasible in electronic control. To make these machines capable of complying with the present requirements of IEGC, the entire MHG has to be replaced with EHG for these machines. This involves the following:

1. MHG consists of the classical arrangement of speed sensing, a spring restrained fly-ball device, the position of which is hydraulically converted to an oil pressure signal, amplified and used on the servo motor piston to operate the valve drive shaft. The operation of this drive shaft opens and closes the control valves. These machines do not have the need for a reliable electrical speed sensing system which is required in EHG. For the purpose of speed (rpm) indications, only a shaft driven tachometer is provided.
2. EHG consists of a highly reliable triple redundant electrical speed sensor, output of which is processed to determine the desired load on the machine as per the “Droop” characteristic in a comparator and finally convert the electrical signal output to a hydraulic pressure in an ‘Electro Hydraulic Converter’, which operates the control valve servo motor.
3. Retrofit of EHG will thus require mounting of an appropriate speed sensing mechanism (a toothed wheel in the case of electrical induction type sensors or a disc carrying a number of magnetic strips around the periphery in the case of ‘Hall Effect’ sensors) on the rotor and corresponding sensor receptors. The pulse train obtained in the stationery sensors will have a certain number of pulses per unit time which is proportional to the speed. A number of such sensors are used in a voting system to determine the speed measurement to be used in the electronics. The speed so measured is then converted to a voltage or current signal and used in the control processor. Entire control processing then take place in the electronic platform up to an electro hydraulic converter, which will replace the entire original hydraulic control system.

BHEL, Siemens, GE and Alstom made presentations to the Committee about the EHG retrofit solutions they have for the LMZ machines. The entire retrofit will be quite expensive, time consuming and above all, in the opinion of this member, meaningless. It is my considered opinion that the present prescription of "restricted governor mode of operation" is not the appropriate mode of operation, which will be adopted in the long term. The scheme does not conform to any international standard or practice, but is only a corrupted form of Governor Control, arrived at after a series of changes to the original prescription of FGMO, without a full and correct understanding of the mechanism or its function. In this situation such retrofit is not worth being considered for the limited purpose of making these machines RGMO compliant. Instead, a thorough review of the current prescription, identification of the appropriate control mechanism is the need of the hour.

MHG of these machines are fully capable of Governor Control and can perform in the intended ideal duty without any difficulty. The problem presently is that unintended duty is being imposed on it, in defiance of the global industry wisdom.

4. PROBLEMS WITH THE CURRENT IEGC PRESCRIPTION ON RGMO / FGMO:

The current prescription of RGMO / FGMO in the IEGC is reproduced here for ready reference. Regulation 5.2 (f) of CERC (Indian Electricity Grid Code) Regulations 2010 as amended in 2012 provides as under:

QUOTE

5.2 System Security Aspects

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(f) All thermal generating units of 200 MW and above and all hydro units of 10 MW and above, which are synchronized with the grid, irrespective of their ownership, shall have their governors in operation at all times in accordance with the following provisions:

Governor Action

i) Following Thermal and hydro (except those with up to three hours pondage) generating units shall be operated under restricted governor mode of operation with effect from the date given below:

a) Thermal generating units of 200 MW and above,

1) Software based Electro Hydraulic Governor (EHG) system: 01.08.2010

2) Hardware based EHG system 01.08.2010 *b) Hydro units of 10 MW and above 01.08.2010*

ii) The restricted governor mode of operation shall essentially have the following features:

a) There should not be any reduction in generation in case of improvement in grid frequency below 50.05 Hz. (for example if grid frequency changes from 49.9 to 49.95 Hz., then there shall not be any reduction in generation). For any fall in grid frequency, generation from the unit should increase by 5% limited to 105 % of the MCR of the unit subject to machine capability.

b) Ripple filter of +/- 0.03 Hz. shall be provided so that small changes in frequency are ignored for load correction, in order to prevent governor hunting.

c) If any of these generating units is required to be operated without its governor in operation as specified above, the RLDC shall be immediately advised about the reason and duration of such operation. All governors shall have a droop setting of between 3% and 6%.

d*) After stabilization of frequency around 50 Hz, the CERC may review the above provision regarding the restricted governor mode of operation and free governor mode of operation may be introduced.*

iii) All other generating units including the pondage up to 3 hours, Gas turbine/Combined Cycle Power Plants, wind and solar generators and Nuclear Power Stations shall be exempted from Sections 5.2 (f) ,5.2 (g), 5.2 (h) and ,5.2(i) till the Commission reviews the situation.

> *"Provided that if a generating unit cannot be operated under restricted governor mode operation, then it shall be operated in free governor mode operation with manual intervention to operate in the manner required under restricted governor mode operation."*

(g)Facilities available with/in load limiters, Automatic Turbine Run-up System (ATRS), Turbine supervisory control, coordinated control system, etc., shall not be used to suppress the normal governor action in any manner and no dead bands and/or time delays shall be deliberately introduced except as specified in para 5.2(f) above.

(h) All thermal generating units of 200 MW and above and all hydro units of 10 MW and above operating at or up to 100% of their Maximum Continuous Rating (MCR) shall normally be capable of (and shall not in any way be prevented from) instantaneously picking up to 105% and 110% of their MCR , respectively, when frequency falls suddenly. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of

about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements, shall be kept *in operation (synchronized with the Regional grid) only after obtaining the permission of RLDC.*

(i) The recommended rate for changing the governor setting, i.e. supplementary control for increasing or decreasing the output (generation level) for all generating units, irrespective of their type and size, would be one (1.0) per cent per minute or as per manufacturer's limits. However, if frequency falls below 49.7Hz, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability.

UNQUOTE

Let us examine what the above IEGC prescription can be expected to actually achieve, assuming that it can be workable.

1. As prescribed in 5.2 (h), the machine which increased its generation is expected to remain at the increased load as long as frequency remains below 50.05Hz. Only if "*in case continued operation at the increased level is not sustainable, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute".* This means that so long as the frequency remains below 50.05Hz the machine is expected to operate at the new maximum power output. The exception given is to return to the original load at a slow rate, if it is not able to sustain that increased level. The consequence of this is that the Governor (RGMO/FGMO) action is demanded just at the first instance of frequency fall and the control remains unavailable subsequently till the frequency rises above 50.05Hz and the machine returns to the original level by operator intervention or otherwise.
2. If the frequency rises, so long as it remains <50.05Hz any reduction in power output is prohibited, thus making action of the Governor unidirectional, for f <=50.05Hz. As frequency increases and is above 50.05Hz, the prescription does not demand that the machine must reduce output by Governor (RGMO/FGMO) action. The option is left open.
3. In case the machine output increases by 5% (10% for hydro), assuming that the control prescribed is workable, the frequency fall will be temporarily counter acted. When the increased quantum is withdrawn in the next five (5) minutes, frequency dips to the very same value it would have dipped to if Governor (RGMO/FGMO) action were not there. What other corrective action is expected in those 5 minutes? Obviously, nothing significant was achieved.
4. 5.2 (f) ii) b) stipulates introduction of a "ripple filter" of ± 0.03Hz in the Governor Control, "*so that small changes in frequency are ignored for load correction, in order to prevent governor hunting".* The ripple filter referred here is nothing but Governor Dead Band, though the value is simply double of what is prescribed in IEC. It must be recognized that

this stipulation does not make sense in the absence of some mechanism which maintains frequency from breaching this band. In the absence of any such mechanism, frequency change will cumulate to more than this band in any case and will only take more or less time to do so. This is why TANGEDCO has interpreted the prescription (albeit incorrectly) to be stipulating a time rate of change of frequency ± 0.03Hz/second. Inadequate rate of frequency change was stated as the reason for lack of RGMO response, by TANGEDCO in the Special Meeting of SRPC held on 27th August 2014, which went unquestioned in the said SRPC forum for lack of clarity on the matter among the participants. Relevant portion of the MoM of the said meeting is pasted in page no. 225 of the Annexure to the Chairman's report.

5. In fact the whole concept of RGMO proposed by the staff of the Hon'ble Commission, out of eagerness to implement something akin to Governor Control. The entirely meaningless/purposeless prescription of RGMO evolved out of sheer lack of understanding about Power System Control and in particular, the Governor Control. This misunderstanding has been primarily that Governor Control is expected to and capable of maintain frequency close to 50.0Hz. In the eagerness to bring frequency up to 50.0Hz the prescription interpreted the function of Governor to deliver as much Power as possible when frequency is less than 50.0Hz, which in essence is what RGMO demand. Obviously this not what Governor Control is intended to be doing. Governor Control an integral part of the Control System of any Generating Plant Prime Mover (including the small house hold Genset) has a very well defined characteristic, prescribed appropriately by all international standards. By the prescription of RGMO we have modified this to a non-standard arrangement, which will not work whenever the workable frequency control mechanism is introduced.

How did such a prescription, having such inconsistent and incorrect requirements come to be in the IEGC? To appreciate this, it is essential to examine how the FGMO/RGMO prescription evolved in the past 15 odd years. This is described in the next section.

5. HISTORIC DEVELOPMENT OF THE STIPULATIONS ON GOVERNOR CONTROL IN IEGC:

In the past 15 years or so, some prescription or the other about Governor Control has been in existence in the IEGC and no significant results have been achieved. The stipulation itself has undergone many changes, none having been well engineered or thought out. The large number of modifications which the IEGC stipulation had to undergo is indicative of something being seriously wrong with the stipulation itself.

The FGMO stipulation found a place in the IEGC at a time when frequency constancy was not at all a perceived target. Rather, frequency was intended to be a variable and the frequency indexed pricing mechanism of Unscheduled Interchange (UI) was considered a mechanism of trade. When constancy of frequency was not a target at all, there was no perceivable role for anything like “Secondary Control” and FGMO was postulated (without doubt, a misconception that it is possible!) as a crude means of dealing with sharp and large frequency excursions. Much change has since happened in the said premises and presently we have been trying to approach the constant, nominal frequency of 50.0 Hz at any cost, including denial of service. It is time to take a fresh look on the subject since we have already discarded our old stand where it was proudly proclaimed (by POSOCO) that “Secondary Control is absent in India by design”. The new paradigm and its requirements have not been fully recognized by the stake holders. The chronological developments in the IEGC prescription on the subject are indicated below:

1. The prescription of “Free Governor Mode of Operation (FGMO)” [1] appeared in the very first issue of IEGC, drafted and issued by the CTU and approved by the CERC, without much background work being done on the subject and with very limited understanding at that time, i.e. way back in 1999.
2. In 2004, a petition was filed by SRLDC against NTPC Ramagundam, for non-compliance of FGMO, Many other generating entities were also made party in this petition and, CERC vide interim order dated 21.05.2004, referred the matter to a CEA Technical Committee for examining the technical difficulties in the implementation of FGMO. Obviously it had been recognized that the then existing FGMO provisions could not have been implemented.
3. The prescription of FGMO in IEGC was examined technically, by a committee, constituted by CEA vide its order dated 30.04.2004, (on the basis of oral orders of the CERC). This committee, chaired by the then Member (Thermal), CEA, recommended radical changes (indicating the grossly erroneous presumptions in the then existing IEGC prescription), to make the FGMO prescription in the IEGC implementable. CEA had submitted the report of the said committee to the CERC in November 2004. The committee chose however, not to go into the merits of the FGMO prescription, per se, thus leaving the prescription itself being unexamined on merit.
4. CERC, however, did not accept the CEA report in full and explored alternative control logics to be implemented in the Governor Control mechanism. Some changes were thus incorporated in the revised IEGC which was notified to be effective from 01.04.2006 and essentially modified the requirement of holding the increased / decreased generation level by Governor Action for 5 minutes and allowed the return of the machine to the original load at a slow rate of 1% per minute. However, Section 1.6 of the IEGC stipulated that the Free Governor Action will be applicable from the date to be separately notified by the Commission. Thus, effectively the prescription on Free

[1] The word **“Free”** in the nomenclature and the letter **“F”** in the acronym are result of an Indian “innovation” not to be found elsewhere in the world! This term, however, refers to pure and simple Governor Control, applied on the Prime Mover input control valves.

Governor Action remained suspended, till the applicable dates were notified by the CERC, in the revised IEGC 2010, which once again modified the requirements.

5. The prescription on Governor Action (5.2.f) in IEGC 2010 further underwent another quantum change in its requirements. Based on the informal discussions with several Generators including NTPC, the IEGC 2010 stipulating a new “restricted governor mode of operation (RGMO)”. This new control mode required retrofitting of a modified Governor Control logic and was hence made applicable only to machines equipped with Electro-Hydraulic Control. This revision of the prescription was on the basis of the appreciation of the Commission that erstwhile prescription of FGMO was not workable, due to a host of reasons.
6. The IEGC amendment notified on 05.03.2012, which came into effect on 17.09.2012 stipulated that all the applicable machines, which could not be modified as per the ‘restricted governor mode of operation (RGMO)’, shall be operated on FGMO, with manual supplementary action to satisfy the requirements of ‘restricted governor mode of operation’. This stipulation, as already stated, is difficult to comply with. It will be appreciated that the entire modification to RGMO would have been redundant and unnecessary, if this stipulation were to be workable!

The RGMO prescription was developed by the staff of the Commission (2009 – 10) in an effort to introduce Governor Control in some form, without really bothering about the objective or utility. The major misconception which prompted this prescription was that the Governor Action is intended to strive to bring frequency to 50Hz. This prompted the stipulation the Governor Control must not reduce power output if frequency increases while it remains below 50.0Hz!

6. CONTROL REQUIREMENTS:

Since there is considerable lack of clarity on the subject, it will not be out of place to briefly review the Control Requirements in a Power System. Until the last decades of the 20th century, Power Systems in the Indian mainland were mostly isolated single utility systems. These isolated systems were effectively integrated into five (5) Regional Electricity Systems, with the introduction of a number of multi-utility serving Power Producing facilities, by the introduction Power Generation as a separate business, by a 1975 amendment of the ES Act 1948. These Regional Electricity Systems were interconnected asynchronously by HVDC links.

The heavy polarization of Power Generation Resources in the country and the high cost of HVDC links (compared to EHVAC) prompted synchronous interconnection of these Regional Electricity Systems which began when ER & WR systems were synchronized in 2003 over the first EHVAC inter-regional link from Raipur (WR) to Rourkela (ER). By 2013, the whole of Indian mainland has transformed into a single synchronous electricity system.

In the erstwhile isolated utility systems, there was no well engineered Frequency Control system in use. These single utility systems were being operated by crude control mechanisms, involving control by voice commands from the primitive Load Dispatch Centre (LDC) of each utility. When these utility systems were integrated into large Regional Electricity Systems, the same crude control measures continued. Though the system complexity and control needs multiplied, we failed to identify and apply the right control measures. In fact a meaningful scheduling and dispatch system for multi beneficiary generating stations came into vogue only in 2000, when ABT was introduced.

Instead of looking at control requirements and options, we embraced on a large scale implementation of protection systems (Special Protection System, SPS), when the real requirement was to introduce control. Protection without a control measure is absurd, but this aspect went undetected. This lapse occurred due to our lack of any experience of control mechanisms. In fact, we became averse to frequency control itself, since at the very first instant of embarking on a reasonable dispatch methodology with the introduction of Availability Based Tariff (ABT), we also chose a system of deviation settlement at a price indexed to average frequency of the settlement period. This eliminated any need for frequency constancy and legitimized variable frequency. While the economical, managerial and structural reforms of the sector did forge ahead, the same failed to happen in the technical front. In the process, the necessary control strategy and the corresponding control mechanism remained undiscovered. The situation continues.

The real power control requirement in a Single Utility (Single Area) System is only of controlling frequency. The control requirement increases as these utility systems are integrated into Multi Utility Power Pools (akin to our Regional Electricity Systems) and further into Super Pools (the whole country).

In a single area system the control requirement is only to balance the load and generation, at the target frequency, in real time. The effort starts with estimating the load demand for each future time intervals. This forms the basis of Generation Scheduling (Load Dispatch). In spite of the best forecasting efforts, mismatches in real time are inevitable. These mismatches must be corrected by making Generation to follow load (Load Following), by delivering and withdrawing generation in real time, recognizing that load is not controllable and is necessarily random. When a load / generation unbalance occurs, the system frequency changes to reestablish this balance, by natural phenomena. Thus, system frequency becomes the robust indicator of this balance and control requirement reduces to modulating generation (Balancing Services in the de-regulated environment) to maintain the frequency at the target. How this can be and needs to be achieved will be discussed subsequently, in this report.

When integrating utility systems into Multi Utility Power Pools (Regional Electricity Systems) and Multi Power Pool, Super Pools (National Grid), an added requirement of control emerges. This is the requirement of Inter Area Exchange (Tie Line Flow) Control. This requirement is posed by the constrained transmission capacities and exchange contracts. Though yet to be discovered in our context, the cost of control is miniscule in comparison to the investment need in transmission capacity, otherwise. Thus the control requirement in Multi Area Power Pools can be recognized as twofold, viz. Constant Frequency and Inter Area Exchange Control. How this can be achieved is discussed subsequently in this report.

7. HOW DOES FREQUENCY CONTROL SYSTEM WORK?

Power System Frequency Control System consists of three components, viz. Primary Control, Secondary Control and Tertiary Control, each of them working to aiding to correct frequency, following deviations from the target, to increase or decrease generation, on generating units carrying reserves for the purpose.

Primary Control:

Primary Control is a Proportional (P) control, also referred to as Governor Control, which changes output of generators, in the negative linear proportion of the frequency change, to contain frequency deviations to acceptable levels. This control is hence also known as "Frequency Containment Service" under Ancillary Services. Primary Control cannot and will not bring the frequency back to the target, following a deviation. This duty will have to be performed by other control components. While it is essential that all generating units in the system operate on Governor Control at all times, only those machines carrying the reserve for the purpose (unless the reserve capacity is carried, it is not possible to increase generation), will be delivering in the generation increase service for a frequency fall event. All generators will, however, reduce load for a frequency rise event.

This control is essentially required only when sudden large mismatches in frequency are caused by large events like a generating unit/station tripping out or large load bus/feeder trips out. It is necessary to preserve this reserve margin for events which can only be managed (assuming that load disconnection is not an option) by sudden and large quantum delivery possible only by this mode of control. This means slow and small quantum unbalances, which occur perpetually in any power system, and the consequent frequency drift will have to be corrected by other controls. Obviously, without such a control Primary Control function can neither be realized usefully nor the machines on this duty can function well. This is one of the fundamental errors in the current prescription in IEGC.

Secondary Control:

Secondary Control is an Integral (I) Control, which will be operating to deliver and/or withdraw control reserve to return the frequency to the target, as frequency deviates even marginally from the target. The requirement of the function can be appreciated by recognizing that it is impossible to forecast load with sufficient accuracy and for sufficiently small time slices, such that there will not be any deviations in real time. Random behavior of consumers and variability of Renewable Energy Sources add to the inevitable and perpetual mismatches in real time. Thus there is a perpetual need to match generation to the load at the target frequency in real time, which is achieved by Secondary Control, by delivery / withdrawal of Secondary Control Reserve (commonly referred to as Spinning Reserve), thus keeping the frequency constant within a very small band, defined by the Governor Dead Band (±0.06%, as per IEC). This control is also known as “Frequency Restoration Service”. Governor Dead Band is a small frequency insensitivity band of Governing systems, at the operating frequency, in which Governor Control will not be responding.

Such a close control of frequency, by the Secondary Control, during normal operation, prevents Primary Control from being ‘called up’ frequently, preserving the primary control reserve for sudden large quantum deviations. Such large and sudden deviations are caused by outage of generating units, load bus bars, tripping of a radial feeders etc. In such large frequency deviation events, the Governor Dead Band is breached and Primary Control acts quickly (full delivery time ≈ 1 minute) to contain frequency deviation. It is again the duty of Secondary Control to return the frequency to target (Frequency Restoration time following a large event ≈ 15-30 minutes). For this reason Secondary Control is also referred to as “Frequency Restoration Service” under the Ancillary Services parlance. As the frequency returns to target, the Primary Control Reserve delivered during the event gets withdrawn, returning these machines to their original operating point, once again carrying the Primary Control Reserve, in readiness for the next large event.

To summarize, Secondary Control serves two functions, viz. Maintain frequency constant at the target (within the Governor Dead Band) under normal conditions and return frequency to the target following a large frequency deviation event contained by the Primary Control. This segregated dual function is essential technically and economically.

In Multi Area Power Pools, there is an additional control requirement of maintaining inter-area exchange to schedule. This control is also performed by Secondary Control, acting in each Control Area, by balancing real power generation and load in that control area. This control in

Multi Area Power Pools has to be necessarily automated (AGC) with a control target of "Inter-Area Exchange, with frequency Bias". The frequency bias assigns the control duty to the responsible control area entity alone.

There is yet another control function performed by Secondary Control, viz. 'Time Error Control', which maintains the average frequency of the system constant, by correcting the time error (integrated frequency deviation) in the system clock, as it drifts by a few seconds from a reference clock time. This control may not be very relevant for our system, for the present.

Tertiary Control:

Tertiary Control, in the strict sense, is not a frequency control measure but is used for recouping Secondary Control Reserve as it nears exhaustion due to deployment, in its frequency control effort. For this reason, this control is also known as "Reserve Replacement Service". As the Secondary Control Reserve gets depleted, the same is restored by rescheduling delivery from the other generating units within the Control Area (if margins exist in the units in service), contracting 'inter area exchange transactions' (with suitable revision of inter-Area Exchange schedules), bringing in quick starting cold reserve units into service, activating Demand Side Management (DSM) contracts (these are contracts the utility enters into, with demand customers, to relieve the system at short notice) and so on. Such a control is termed as Tertiary Control and is always used, in predefined quantum, to restore Secondary Control Reserve.

The control mechanism is depicted diagrammatically for normal operation (slow and small quantum frequency changes) and for disturbances (sudden, large frequency deviations) below. These diagrams are reproduced from a report by Mr. Brendan Kirby, currently a renowned expert consultant on the subject and formerly of Oak Ridge National Laboratory, Tennessee. The complete report is available for free down load at www.science.smith.edu.

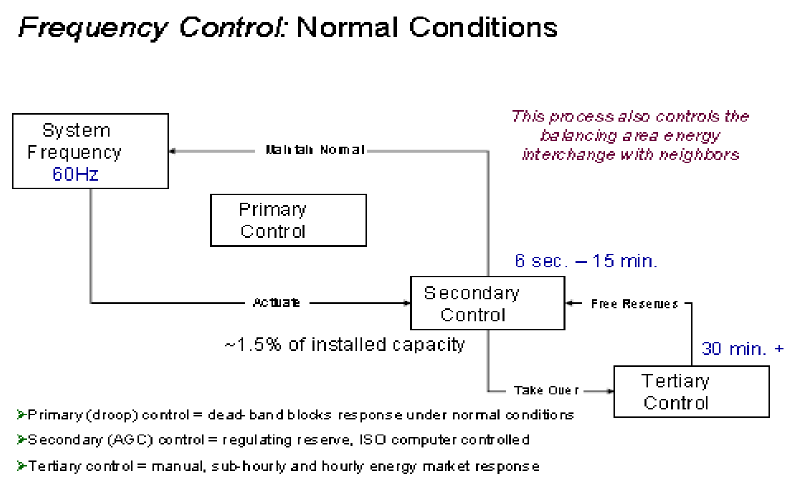


Figure 3 Frequency control is accomplished centrally under normal conditions

It will be noted that Primary Control is shown inactive, in the diagram above, with a note indicating that Primary Control is blocked by the Governor Dead Band, under normal operation. Another note highlighted in a different color on top right hand side mentions the additional function performed under normal conditions of maintaining area interchange with neighbors.

In the diagram below, depicting a disturbance event, Primary Control acts quickly to contain frequency deviation. The highlighted note that states the use of load disconnection for larger events is also worthy of being noted.

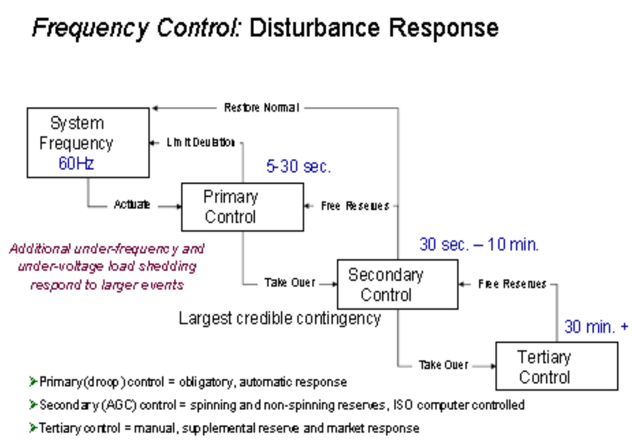


Figure 4 Generator governors provide immediate response to restore system frequency under contingency conditions.

The deployment plot of the different reserves during a disturbance event is depicted in the diagram below reproduced from the UCTE Operations Handbook. The same deployment diagram is presented in the Chairman's report also, but without the trace of frequency (the shaded, red colored envelop) and without the mention that it depicts the deployment trace for a disturbance event.

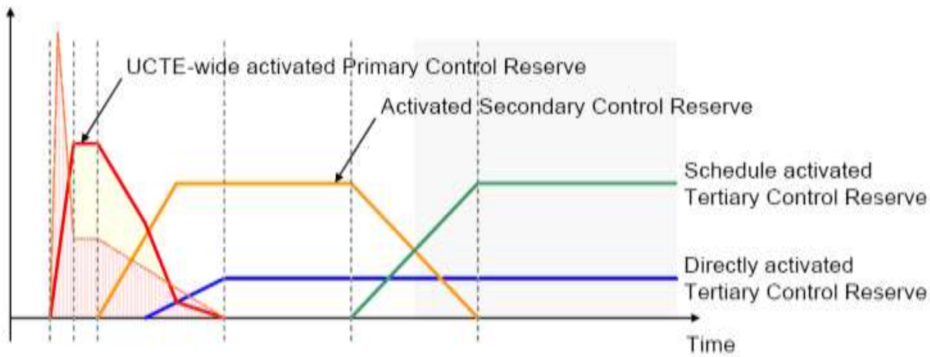


Figure 3: Principle frequency deviation and subsequent activation of reserves

8. COST OF CARRYING RESERVES:

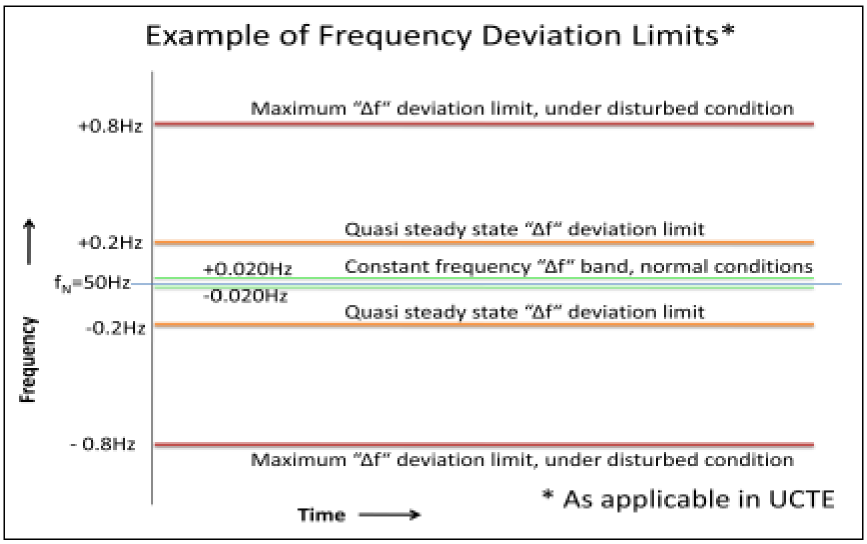
Carrying Reserves of any kind has a cost. There is hence a strong reason to minimize the Reserve Quantum to be carried. Secondary Control Reserves can be reduced (but not eliminated) by carrying more Tertiary Control Reserves. Primary Control Reserves can be reduced or even fully eliminated (if so chosen), by under frequency load disconnection. If one has the luxury of large quantum of interruptible loads, carrying Primary Control Reserve can simply be avoided. Irrespective of whether Primary Control Reserves are carried or not, all the machines in the system must invariably be operating on Governor Control, as they are required to work in the opposite direction to reduce generation when frequency rise event occurs. Exceptions could be free energy sources like Run of River Hydro, Spilling Hydro, RE sources, bottom cycle in a CCGT plant etc.

Primary Control Reserves:

The current prescription in IEGC mandates Primary Control Reserves of about 5% to be carried on all Steam and Hydro units. It does not make any distinction even in the case of Hydro machines during the high inflow period, necessitating spilling. It is necessary to make such exceptions, for economic reasons.

Assuming that 120,000MW capacity of machines in our system is mandated to carry 5% (or 10% for hydro) reserve for Governor Control. The quantum so mandated works out to more than 6000MW. Is it necessary to carry so much Primary Control Reserve?

Primary Control Reserves need to be carried globally in the synchronous system, as widely dispersed as practically possible, since the delivery of the same should stress the transmission system to the least. The quantum of Primary Control Reserve required to be carried is determined by two factors, viz. the largest credible loss of generation event and the maximum acceptable frequency deviation in the immediate and quasi steady state time frame. For estimating the quantum required, the acceptable limits of frequency needs to be defined. The diagram below depicts these limits as adopted in UCTE / ENTSO-E.



The European Power System adopted these limits based on the most stringent limits which were in vogue in the participating countries. Thus the limits adopted are ± 0.02Hz for normal operation (corresponding to Governor Dead Band of ±0.015Hz as per IEC, allowing for measurement inaccuracy), ± 0.2Hz for quasi steady state (the time taken by Secondary Control to restore frequency to normal operating band following a disturbance and deployment of Primary Control) and Instantaneous maximum deviation of ± 0.8Hz for the largest credible contingency). There are no hard and fast rules regarding these limits. The instantaneous maximum deviation must of course be such that under frequency load disconnection is not invoked. The instantaneous maximum deviation limit and the quasi steady state maximum deviation limit both influences the quantum of Primary Control Reserve to be carried. Remembering that reserves cost money, these limits in the opinion of the undersigned need not be as stringent as UCTE.

If we set the instantaneous maximum deviation limit and the quasi steady state maximum deviation limit as ± 1.0Hz and ± 0.4Hz respectively, assume the size of the synchronous system to be 120,000MW, Largest credible generation loss event to be the tripping of a 4000MW power station, the effect load damping (the reduction in power consumption in the system load with frequency) to be 4800MW/Hz (2% ΔP_D for 1%Δf) and Governor Droop to be 5% (across all machines carrying Primary Control Reserve), the Primary Control Reserve required to be carried works out to just 2080MW, carried on machines aggregated capacity of only 13,000MW. The current prescription is far too large and must be corrected. The Chairman's report endorses the current prescription, mindlessly.

The current prescription mandates all 120,000MW machines to carry Primary Control reserves. Let us imagine our 120,000MW system carrying a Primary Control Reserve Capacity of 6,000MW (5% uniformly on all machines). Let us also assume for simplicity 50% of the entire capacity is low cost energy (Pit Head Stations, Hydro etc) having an average variable cost of ₹1.25/kWh and the other 50% capacity has an average variable cost of ₹3.25/kWh. Our stipulation of carrying 5% capacity reserve uniformly on all machines, translates to 3,000MW of the low variable cost capacity and 3,000MW of high variable cost capacity, remaining unused, for near 100% time. Obviously, 3,000MW load in the system, vacated by the first 3,000MW capacity, will have to be served for 100% time from the high variable cost units. By dispatching the low cost capacity fully and carrying the 3,000MW additional reserve capacity on the higher variable cost units (10% on 50% capacity of 60,000MW) we will be deploying 3,000MW generation at Re1.25/kWh while withdrawing the same quantum at Rs3.25/kWh. The annual saving made would be ₹5256Cr, a colossal economic disaster. The solution is simple; the entire Primary Control Reserve must be carried on the highest variable cost machines committed in service.

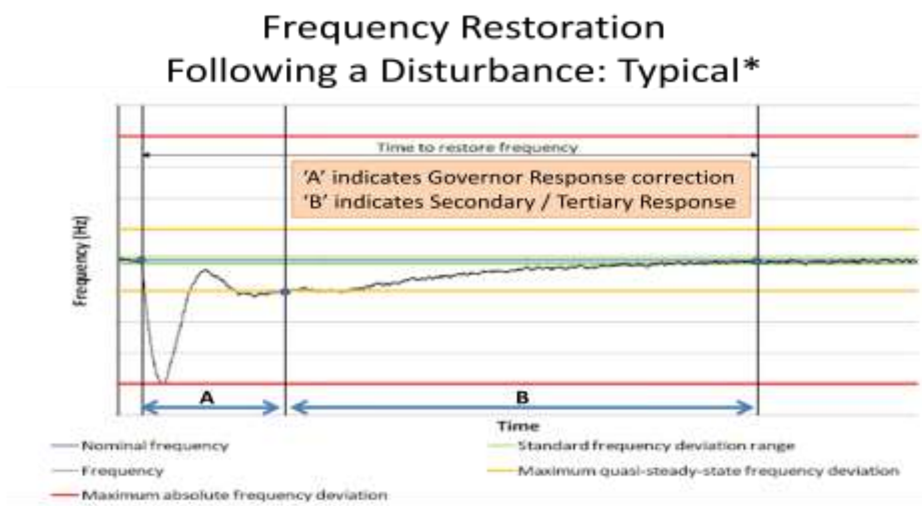
Secondary Control Reserves:

Secondary Control Reserves, on the contrary, needs to be carried Control Area wise. The quantum necessary to be carried is a function of the largest unit size, the accuracy of generation dispatch scheduling etc. A thumb rule governing this quantum can be 1 – 3 % of the Control Area capacity, with a minimum of one unit capacity. The larger the Control Area the quantum can approach the minimum. The Secondary Control quantum is also influenced by Tertiary reserves and their deployment time. The quantum must be in both up regulation and down regulation direction as well. For instance if we consider Southern Region Electricity System as a Control Area, it should carry a Secondary Control Reserve of ± 1000MW and must operate normally with 1000MW deployed (Secondary Control Power) and 1000MW in hand (Secondary Control Margin). The Control System will then be capable of deploying up to 1000MW (if a unit trip event occurs) and withdrawing up to 1000MW (if a load loss event or RE generation loss event occurs).

The Control Areas as defined currently needs to be re-defined more scientifically. Many of our currently defined Control Areas do not have any control capability at all. Regional Electricity Systems form an ideal control area for Control purposes.

Along the same principles of economics, illustrated in the case of Primary Control, Secondary Control Reserve (both in service and held in hand) must also be carried on highest marginal variable cost machines in service, to the extent possible.

How the system works for a large deviation event (disturbance) is depicted in the diagram below, reproduced from ENTSO-E sources. Before the event and after restoration the only control working is Secondary Control.



* Reproduced from ENTSOE sources

9. RECOMMENDATIONS:

There is an urgent need to change a lot many things in our currently existing system for adopting a properly functioning Frequency and Net Exchange Control System for our country. The requirement needs to be looked at in a much wider ambit than this Committee having a limited mandate. It is also necessary that the people with the right competency are identified for the purpose. The following are essential basic actions to approach the issue in the right direction.

1. It would be desirable to contract the services of a renowned international consultant for determining the appropriate way forward and chalking out an implementation plan. The consultant must have wide terms of reference. However much we may pretend to be competent, the fact remains that none of us, repeat, none of us have first hand understanding of the mechanism or implementation capability.
2. A task force, preferably region wise and at the national level, consisting of representatives of all state and union territory utilities and other stake holders, nmay be constituted, to redefine Control Areas and suggest inter utility exchange settlement principles.

3. All stipulations in IEGC regarding Governor Control need to be suspended, just as the same remained suspended from 2004 to 2010, to be re-introduced in its uncorrupted form as “Governor Control”, at a future point in time.
4. There is no need for any EHG retrofit on MHG machines for making them compliant to a fundamentally incorrect RGMO prescription, RGMO being a corrupted and meaningless control scheme.
5. All the unconventional and non-standard changes incorporated in the Governor Control logic by several generators to meet the stipulations of RGMO and FGMO needs to be discarded. Also discard the locally coined terms of FGMO and RGMO from use and align with the internationally accepted terminology of “Governor Control”. Re-establish uncorrupted Governor Control in all our machines. This has also been recommended by M/s Solvina International, during their presentation to the committee.
6. Introduce Secondary Control in a time bound manner, duly supplemented by Tertiary Control. This will involve redefinition of Control Areas, introduction of Control algorithm and interface facilities at RLDCs, establishing necessary communication facilities and command interface at the stations/units identified for the duty. Automatic Generation Control (AGC) will be unavoidable in our multi area system and specifications and implementation must also be part of the consultant’s assignment. A brief description of AGC and how the mechanism works for ‘Inter Area Exchange Control with Frequency bias’ is enclosed as Annexure to this report.
7. Once we introduce Secondary Control and Tertiary Control successfully, it is the firm opinion of the undersigned that we will be able to control frequency constant and Inter-Regional exchanges to schedule for more than 99% of the time. The only deviations remaining to be taken care of will then will be, the large frequency deviation events (like a large unit tripping, loss of large load area etc).
8. Now we are ready for introducing Primary Control. All generating units with the exclusion of spilling hydro, waste heat recovery units, RE sources must then be operated on Governor Control in its purest form. Still, since we have not commenced carrying reserves for Primary Control, the Governor control will work only in the direction of reducing generation for large frequency rise events. All machines on Governor Control must provide this service.
9. By now, we are ready to introduce Primary Control Reserves. The minimum required quantum of primary Control reserve must be carried on the committed generating units in highest incremental cost bracket. Large pondage hydro units having no risk of spilling, if committed in service will also be an ideal choice. Each of these machines may carry 10 – 20% of its capacity as Governor Control Reserve, for economic reasons.
10. This quantum of Governor Control Reserve required to be carried can of course be worked out easily. If we set the instantaneous maximum deviation limit and the quasi

steady state maximum deviation limit as ± 1.0Hz and ± 0.4Hz respectively, assume the size of the synchronous system to be 120,000MW, Largest credible generation loss event to be the tripping of a 4000MW power station, the effect load damping (the reduction in power consumption in the system load with frequency) to be 4800MW/Hz (2% ΔP_D for 1%Δf) and Governor Droop to be 5% (across all machines carrying Primary Control Reserve), the Primary Control Reserve required to be carried works out to just 2080MW, carried on machines aggregated capacity of only 13,000MW.

11. In the above sequence, finally we would have achieved a full-fledged frequency/interchange control system, at par with any other electricity system in the world. This would take about three years to realize (by a rough estimate by this member) and must be approached patiently, with this time frame in mind. Quick fix solutions will not take us anywhere.
12. Capacity building exercise on this subject is much needed, since none of the Indian engineers have any depth of understanding of the subject. This must be carried ou by way of training sessions, workshops, seminars etc.
13. Renewable Energy Integration is a topic having currency today. This must not be treated as an independent issue, but in reality is a subset of the Frequency Control Paradigm. These issues must be dealt concurrently and not separately.
14. A number of our current regulations are expected to be in conflict with the constant frequency control. An obvious case in point is DSM regulations. DSM regulation assigns a unique and different target frequency to each power generating facility, corresponding to its energy cost. Each of these stations would tend to force frequency to their respective targets. This situation needs to be remedied.

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Annexure

Automatic Generation Control (AGC): A brief note

P P Francis, GM (OS), NTPC

Introduction:

In the erstwhile isolated utility systems, the function of the Secondary Control used to be limited to keeping frequency of the system constant, within the prescribed band. While it was possible to achieve this manually, by modulating the generation on one generating unit at a time, the control function had also been automated in some cases by incorporating an automatic integral frequency control function in one or two generating units. This automated control function used to be popularly known as "Automatic Load Frequency Control" abbreviated as "ALFC". In India a few machines in DVC are known to have had such a control function built into its mechanical governing system.

As the system sizes increased, the function could no more be achieved from one machine at a time (on account of the need for larger control reserve quantum delivery per unit time) and the control came to be centralized at the System Control Centre, wherein, the control is executed by the at the operator at the System Control Centre, the execution command being issued to one or more machines at a time, over a communication link. This arrangement would give larger quantum increase per unit time. Maximum output change per minute realizable from a steam power unit, for example, is not more than 3% per minute, which translates as 6MW/minute for a 200MW unit. By giving simultaneous command to two machines 12MW/minute rate can be achieved. Still the control was essentially performed manually by the operator, satisfactorily. Even today there are a number of single area electricity systems where this is practiced. Integration of the erstwhile electricity systems into Power Pools rendered the manual control inadequate as the control target became Area Control Error (ACE) in place of frequency and automatic control became essential. Gradually the name "Automatic Generation Control" abbreviated as "AGC" came to be preferred. The old terminology of ALFC is still used in some literature to this date.

When the erstwhile isolated systems got integrated into large Power Pools, this introduced an additional control need of Inter-Utility Exchange control (tie line power flow control). Also, a new control algorithm was necessary to meet the new control need. Nathan Cohn (1960s) proposed what has since come to be referred to as "Net Exchange Control with Frequency Bias", applied control area wise, by changing the control target from frequency (**$\Delta f = 0$**) to ACE (**$B^*\Delta f - \Delta P_E = 0$**). **"B"** here is the Frequency Bias factor, a negative quantity. The said control algorithm, with minor differences, is working all over the globe. The architecture and working of AGC are discussed in the following paragraphs, with reference to multi area power pools.

AGC Structure:

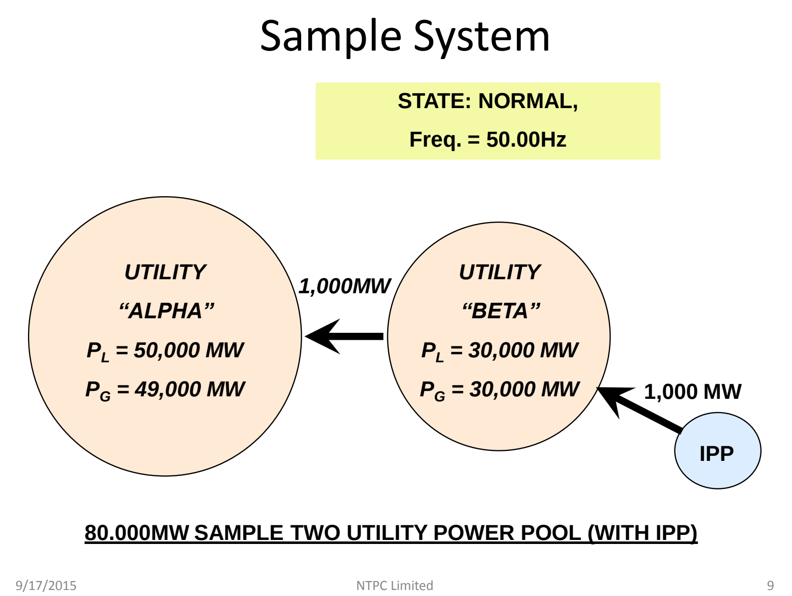
AGC is applied Control Area wise. Multiple Control Areas can have distributed or centralized control. The heart of the AGC, the computing processor, resides at the System Control Centre. Any deviation from the target set will be corrected by issuing a series of tele-commands to change the Governor Set Point Reference of one or more machines, chosen for the duty. Ideally, a large number of candidate machines must be chosen, have reliable and redundant communication link with the System Control Centre for the purpose. At any given point in time, a few of these machines will be chosen for the control duty. All generating units do have the arrangement to receive such remote commands to change the Governor Set Point Reference, which will change its output, in either raise / lower direction.

For a Single Control Area, the control Target of AGC will be to offset the frequency deviation, i.e. $\mathbf{\Delta f = 0}$. For Control Areas in multi area power pools the target will be to correct the Net Exchange deviation, duly corrected for frequency deviation, termed as ACE i.e. $\mathbf{B*\Delta f - \Delta P_E = 0.}$

Frequency of the system is tele-metered from several strategic bus bars in the system, to a resolution of at least 3 decimal places, voted to select and forms one input to the AGC, as a numerical value. Similarly, Net Exchange with the neighboring Control Area is also tele-metered on each tie line from either end, and is fed to the AGC. AGC of both the neighboring areas must use the tele-metered data from the same selected end of the tie line. The reference frequency and Net Exchange Schedule are to be set by the Operator. The reference frequency set point at times will be different from the nominal frequency of 50Hz, but within the Governor Dead Band, during the time error control process. In addition, the settings required to be made in AGC would be the "Gain" and "Frequency Bias Factor".

How does AGC achieve the Control Objective in Multi-Area Power Pools?

The working of AGC in a multi-area power pool can be best appreciated considering its working in a simple two utility power Pool. A sample two utility Power Pool consisting of two utilities ALPHA and BETA, having a total capacity of 80,000MW, operating at the rated (target) frequency will be considered for illustrating the control performance. A scheduled transfer of 1,000MW from BETA to ALPHA is meeting the generation deficit in ALPHA. For the sake of simplicity, the IPP is considered to be within the BETA Control Area. For the sake of simplicity, it is assumed that the nature and composition of the load in either utility is identical. The two-utility sample system is represented in the diagram below:



Area Frequency Response Characteristic (AFRC, represented by '***β'***) of an electricity system is the combined effect of both 'Load Damping' (D) & 'Governor Control' (1/R). AFRC is defined for the synchronous area and/or each of the Control Areas.

$$\boldsymbol{\beta} \quad = \quad \boldsymbol{D + 1/R},$$

Effect of an 800MW generating unit outage in the Power Pool treated as one single synchronous area can be appreciated as follows:

In our 80,000MW sample system, the following parameters apply for the entire synchronous area,

$\boldsymbol{D}$ = 4% of 80,000 = **3,200 MW/Hz** ………. (Load Damping)

$\boldsymbol{1/R}$[2] = 40% of 80,000 = **32,000MW/Hz** ………. (Governor Control)

AFRC, β of the Pool = (3,200 + 32,000) = **35,200 MW/Hz**

For an 800MW unit tripping, the steady state frequency change will be,

$\boldsymbol{\Delta f}$ = $\boldsymbol{\Delta P_G / \beta}$ = (–800MW/35,200MW/Hz) = **– 0.02273Hz**

$\boldsymbol{\Delta P_G'}$ = $\boldsymbol{\Delta f \times (-)\, 1/R}$ = (–) 0.02273Hz x (–) 32000MW/Hz = **727.4MW**

[2] Governor Control, at uniform 5% droop, reserves assumed to be carried on all machines (for illustration only, not practiced normally)

Secondary Control must, however, deliver the entire 800MW, to return the system to target (scheduled) frequency, as the Load Damping vanishes as the frequency is restored.

Large Frequency Deviation Event in a Multi-Area Power Pool:

Now let us consider the case of the pool as a multi area system, for the same event of tripping of an 800MW generator, in “ALPHA” Area of our sample system. There is no way the Control System can have this knowledge. We know as designers of the event, that “ALPHA” must deliver 800MW reserve by Secondary Control. Can the Control System achieve the desired correction? The answer is YES, by using AGC on: “Net Exchange Control with Frequency Bias”. The functioning of this control mechanism can be appreciated as follows:

Frequency breaches ‘Governor Dead Band”, during the event and Governor Control Acts in both “ALPHA” and “BETA” areas, in the same proportion. The event creates a ‘Net Exchange Deviation’ from schedule as well as a ‘frequency deviation’. AGC corrects ‘Net Exchange Deviation, with freq. bias. Frequency bias quantum is added to the Net Exchange Deviation Correction in “ALPHA”, while it offsets the same in “BETA”. The control behavior is illustrated in the following tables:

Sample System Parameters

Parameter	Unit	Alpha	Beta	Pool
Demand (P_D)	**MW**	**50,000**	**30,000**	**80,000**
Generation (P_G)*	**MW**	**49,000**	**31,000**	**80,000**
D (Load Damping)**	**MW/Hz**	**2,000**	**1,200**	**3,200**
1/R (Governing)***	**MW/Hz**	**19,600**	**12,400**	**32,000**
AFRC, β = (D + 1/R)	**MW/Hz**	**21,600**	**13,600**	**35,200**

***	IPP Generation of 1000MW considered within ‘Beta’, for simplicity***
***	Considered 4% / Hz arbitrarily (fairly close to reality too)***
****	Uniform 5% droop and Control Reserve on all machines assumed***

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After the event, before AGC action the system would appear as shown below, with proportional correction in generation in either system by Governor Control.

Sample System after 800MW unit outage in 'Alpha'

Parameter	Unit	Alpha	Beta	Pool
$\Delta f = \Delta P_G \div \beta$ = (-) 800MW/(35200MW/Hz)	Hz	–0.02273	–0.02273	–0.02273
$f = f_N + \Delta f$	Hz	49.97727	49.97727	49.97727
$\Delta P_D = D \times \Delta f$ (Load Damping)	MW	–45.4 = –0.02273*2000	–27.3 = –0.02273*1200	–72.7 = –0.02273*3200
New Demand (P_D') (At new Frequency)	MW	49,954.6	29,972.7	79,927.3
$\Delta P_G = (-1/R) \times \Delta f$ (Governor Action)	MW	445.5 =19600*0.02273	281.8 =12400*0.02273	727.3 =32000*0.02273
New Generation (P_G') (At new Frequency)	MW	48645.5	31281.8	79927.3

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'Net Exchange Control with Frequency Bias' for the Sample System

Parameter	Unit	Alpha	Beta	Pool
Δf	Hz	–0.02273	–0.02273	–0.02273
ΔP_E (= $P_G' - P_D'$) (+^{ve} is Export)	MW	–309	+309	0
B (= $-\beta$)* (Frequency Bias)	MW/Hz	–21600	–13600	–35200
B x Δf (Frequency Correction)	MW	+491 = (– 21600)x(– 0.02273)	+309 = (– 13600)x(– 0.02273)	+800 = (– 352600)x(– 0.02273)
$-\Delta P_E$ + B x Δf ** (AGC Correction)	MW	800 =491+309	0 =309-309	800 =800+0

* Bias "B" is considered equal to "–β" in the illustration; in practice B is larger

** "Net Exchange Control with Frequency Bias" gives the desired control

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It will be seen from the last table that AGC of ALPHA has corrected the net exchange deviation of 309MW (Import) and frequency correction due to Bias, amounting to 491MW, adding up to 800MW generation increase in ALPHA to correct the deviations. It will be informative to know, what happened in BETA. It was having a positive deviation of 309MW (export) and frequency bias demanded an increase in generation of 309MW. 309MW excess generation (positive net exchange deviation) and 309MW generation increase demanded by AGC offset each other and AGC in BETA remained dormant. The control system did achieve what we knew was needed, without being privy to the information we had. An elegant solution and no wonder, it has such wide acceptance. The spectacular result of AGC of ALPHA alone doing the correction and AGC of BETA being dormant could be achieved by setting the frequency bias factor **'B'** of either control area to be equal to **'– β'**, which cannot be achieved in practice. In reality, **'B'** would be invariably different in magnitude from the AFRC as it is dynamically varying. The result would be a few oscillations induced by the control system before the control target is achieved. It has been shown that it is desirable to set 'B' higher and not otherwise for good performance of the control system.

Small/Slow Frequency Deviation Events in a Multi-Area Power Pool:

Let us now see how the system works for small/slow deviations. Let us consider an increase of 40MW load, in "BETA". What changes happen in the pool?

$$\Delta f = -\,0.0125\text{Hz } (= \Delta P_D/D = -\,40\text{MW}/3200\text{MW/Hz})$$

In the above computation it will be noted that 'D' is used and not 'β', as we know that the Governor Control is absent in the Dead Band. Frequency deviation Δf is less than the Governor Dead Band (0.015Hz) and hence no Governor Action. ΔP_E is however created, as the loads in either area release power, which serves the added load in BETA. Pre-existing Load in *"ALPHA"* falls by 25MW and in *"BETA"* by 15MW and consequently*, "BETA"* starts importing 25MW from *"ALPHA".* In other words the net export of BETA falls from the schedule of 1,000MW by 25MW.. Net Exchange has deviated, to make P_E = 975MW. AGC corrects 'Net Exchange Deviation, with Frequency Bias', till *BETA*'s generation increases by 40MW. AGC of BETA will see a correction requirement of 195MW generation increase and the error will be very quickly corrected.

$$\Delta f \times B - \Delta P_E\ (BETA) = \{(-\,13600) \times (-0.0125) - (-25) = 170 + 25 = 195MW$$

AGC in "ALPHA" also contributes to frequency correction initially, eventually withdrawing, as frequency returns to target. Initially, AGC of ALPHA will see a correction requirement of 245MW, due to the high contribution from frequency bias, which will quickly vanish as the frequency recovers.

$$\Delta f \times B - \Delta P_E\ (ALPHA) = \{(-\,21600) \times (-0.0125) - 25 = 270 - 25 = 245MW$$

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