FREQUENTLY ASKED QUESTIONS

Version 20170212

1. **What is derogation?**

   The Derogation is a mechanism that may exempt the Entities to comply with technical standard/s with respect to the provisions of the Philippine Grid Code through specified circumstances and to a specified extent. A User of the Grid may request or apply for a derogation provided that the Entity seeking derogation can prove its exemption from any of the provisions of the PGC.

2. **Why do we need derogation?**

   Derogation is needed to arbitrate situation wherein an Entity see the improbabilities to comply with any provision(s) of the PGC due to some technical issues (e.g. unique configuration of a power plant or a generating unit) and correcting the non-compliance(s) will require significant amount of time and/or will not be the best option from a technical and economical point of view.

   The primary thrust is to improve the system and/or facilities through the cooperation of power stakeholders and not to penalize a Grid User.

3. **When Entities applied for derogation, does it mean that Entities are exempted from complying with the requirement which it applied for exemption?**

   It **DEPENDS** on what prevents a Grid User from complying with the PGC - whether it could be remedied [through variance or alternative method] or not. The Entity applying for a derogation has the burden of proof to justify its request, in order to be granted an exemption from the requirement(s) of the PGC, subject to the review and approval of the ERC through the GMC.

   For clarity, no Grid Users shall claim a variance or exemption from any provision(s) of the PGC without application of derogation to, and review of, the GMC. It is the responsibility of the entity that needs a variance or exemption to identify that need and initiate the process through application of derogation.

4. **Are the sizes of the Large Generating Plants as specified in the PGC 2016 Edition permanent?**

   No. Basically it will change because this depends on the dynamics of the system.

5. **What is the reason for changing the terms of the reserves in the PGC?**

   The reason for the change is to set hierarchy on the deployment of resources when a contingency event occurred in the Grid. Notably, the vague provisions identified in the PGC Amendment No. 1 were clarified and revised so that all stakeholders will have a better understanding on their importance of reserves on the reliability of the Grid. This is further discussed in Frequency Control discussion. Please see the table below for comparison of the hierarchy and deployment of the existing resources and as revised in the PGC 2016 Edition.

Table 1- Comparison of Resource Hierarchy and Deployment

<table>
<tr><th rowspan="2">Hierarchy</th><th colspan="2">PGC Amendment No. 1</th><th colspan="2">PGC 2016 Edition</th></tr>
<tr><th>Resources</th><th>Control Mode</th><th>Resources</th><th>Control Mode</th></tr>
<tr><td rowspan="3">1</td><td></td><td></td><td>Primary Response (Inertial Energy)</td><td rowspan="2">Governor Control (GC)</td></tr>
<tr><td rowspan="2">Regulating Reserve
• Primary Response
• Secondary Response</td><td>Governor Control (GC)</td><td rowspan="2">Primary Reserve (MW injection)</td></tr>
<tr><td>Automatic Generation Control (AGC)</td><td></td></tr>
<tr><td rowspan="2">2</td><td rowspan="2">Contingency Reserve
• Spinning Reserve (manual control)
• Backup Reserve (manual control)</td><td rowspan="2">*GC or AGC/Manual</td><td>Secondary Response</td><td rowspan="2">AGC</td></tr>
<tr><td>Secondary Reserve</td></tr>
<tr><td>3</td><td>*Dispatchable Reserve</td><td>Manual</td><td>Tertiary Reserve</td><td>Manual or AGC</td></tr>
</table>

Note: * as provided in ASPP

6. **Why should the Generator be obligated to provide reactive support for voltage control at the Connection Point when, in fact, there is Ancillary Service in place for that purpose?**

   Because of insufficiency of reactive support as Ancillary Service.

   For clarity, in all cases, the Grid Users have the responsibility to comply with the voltage limits. The TNP improve this performance (e.g. installing compensation devices into the network). System Operator (SO) also utilizes the Ancillary Service for that purpose. However, there are instances where reactive support as ancillary service is not sufficient to maintain the voltage. This is why, as an immediate measure to control the voltage during operations, the SO taps the help of other generating plants to generate reactive power provided that the limits imposed by the generator's capability curve are not exceeded.

7. **What will be the advantage then when all generating plants provide reactive support to the Grid when the SO called for it?**

   The benefits are as follows:

   1. The tripping of Generating Plant's protective relays could be prevented (including the Relay and MV/HV switchgear room air-conditioning system and other auxiliary equipment that is vital for the continuous operation of the power plants); and
   2. Generating Plants could also help prevent the Loads from being disconnected for the continuous supply of real power to the Customers, especially those plants that have Bilateral Contracts [off-takers].

8. **What do we mean by N-1?**

Single Outage Contingency (N-1) is simply an event caused by the outage of one component of the grid including a generating unit, transmission line, or a transformer.

When the N-1 occurred, the state of the system changed from normal state (N-0) but is still in acceptable status provided that: (1) it is able to tolerate the contingency and (2) the parameters (e.g. Voltage and Frequency) are still within the required levels as prescribed in the PGC.

For operations purposes, when credible N-1 Contingency [provided in GO 6.2.1.1 of the PGC 2016 Edition] occurred, the remaining component of the system (e.g. transmission line) should have enough capability to handle the power flow along the line and that the system or any part thereof must be operated within the limits of the parameters specified in the PGC. Beyond it, the SO must intervene to restore Stability of the Grid.

The SO can impose manual corrective interventions if threat to the security of the Grid has been identified. GMC's stance is that maintaining the security of the Grid is basically SO's role. When the security of the Grid is threatened and probable outages will affect the reliability of the Grid, it will be SO's call, intervention and responsibility to maintain the stability and reliability of the Grid.

For planning purposes, Table 5.1 of the PGC 2016 Edition is provided as metrics for information purposes and for guidance to the Transmission Network Provider in Grid planning studies.

9. **What is Frequency Response?**

It is the response [supposed to be provided by the Load and Generating Units] of the power system to large, sudden loss of generation or disruption of power transfer. It is also known as:

1. Primary Frequency Control (from a Control Center perspective);
2. Primary Response or Governor Response (if viewed at the Generating Plant level); and
3. Load [or Demand] Response (Frequency dependent Loads).

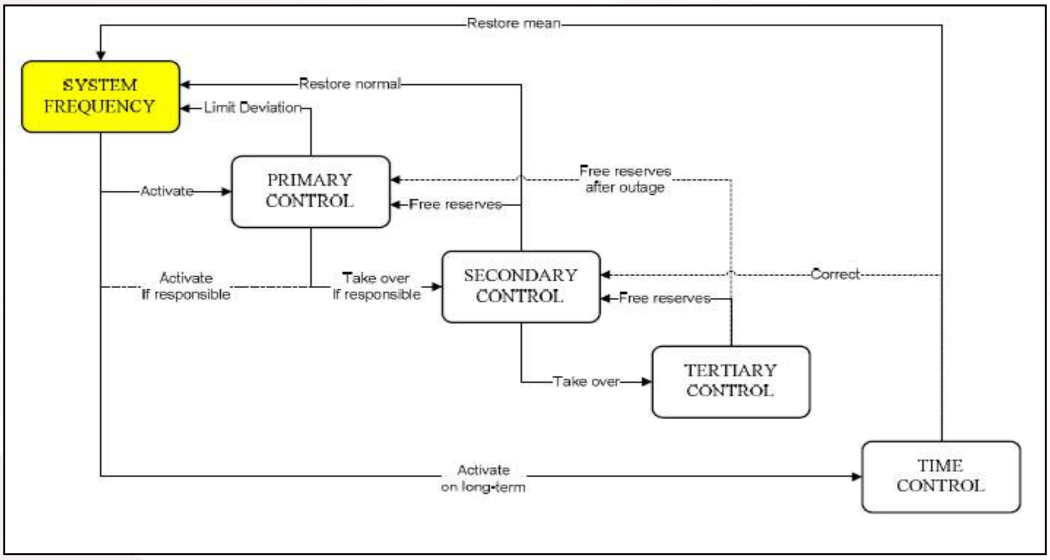
For clarity, **Frequency Response** is the first stage of overall Frequency Control and is the actions (response) provided by the system to maintain the equilibrium between supply and demand, and arrest and stabilize frequency [in response to contingent Events].

10. **What is Frequency Control?**

It is the act of controlling the frequency through contribution of responses from different elements of the power system and the balancing of energy supply and demand which is done by the System Operator.

In a power system, imbalance between generation and energy demand manifests as a frequency deviation (δ) from the nominal value (60 Hz). For example, if the generation of the power system exceeds the energy demand, the frequency increases beyond the nominal value. On the other hand, if there is a deficiency in generation, the power system frequency falls below its nominal value.

To control the frequency, there are different controls used. These are the Primary Control, Secondary Control and Tertiary Control.



Scheme and actions starting with the system frequency

11. What are the differences between the Primary, Secondary and Tertiary control?

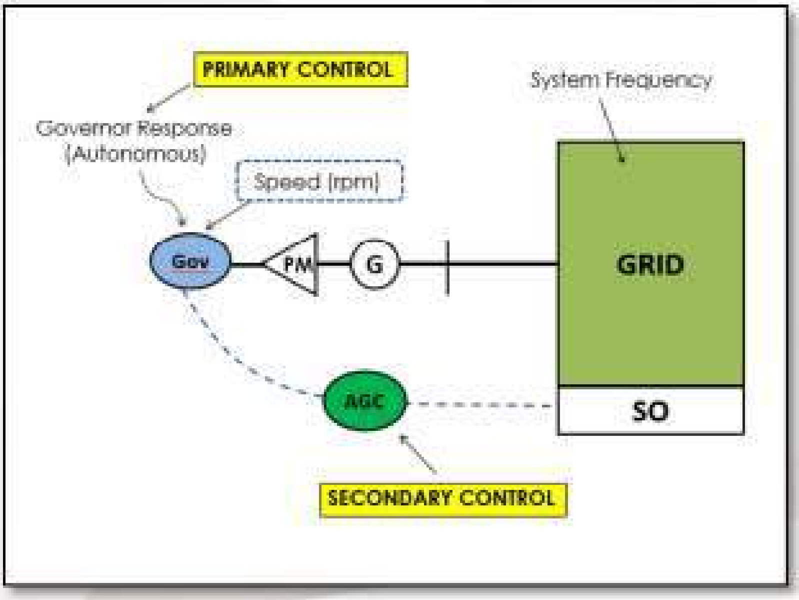


Figure 2 - Difference of Primary Control and Secondary Control

Primary Control is the first line of defense in arresting the frequency when Contingency occurred. It is attributed to the Governor Control of the generating unit which provides the Primary Response and Primary Reserve (formerly "Contingency Reserve"). The objectives of the Primary Control are the following:

1. **RELIABILITY** - Role of **Primary Response**
   - To minimize the Frequency Nadir (maximum deviation of the frequency when a loss of inertial energy of the synchronize generators in the system)

2. **RESERVE (MW)** – Role of the **Primary Reserve**
   - Megawatt (MW) Injection to replace the lost capacity (largest unit online)

By the joint action of all interconnected Generators, PRIMARY CONTROL, ensures the operational reliability for the power system of the synchronous area. Maintains the balance between the Load and Generation using turbine speed governor.

It is an automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a frequency deviation in the synchronous area. It should be emphasized that the Governor Control is “local” control of the Generating Unit – meaning, SO has no control over how the plant will correct itself against the Frequency excursion when contingent event occurred. But it is incumbent upon all the Generating Plants to help maintain the reliability of the Grid.

Secondary Control is the fastest “centralized” control in the system that are usually due to Automatic Generation Control (AGC) that are issued through System Operator's Energy Management System (EMS) for Load Frequency Regulation. It is attributed to the Secondary Response and to Secondary Reserve (formerly "Regulating Reserve").

Secondary Control is a centralized automatic function to regulate the generation in a control area based on **Secondary Reserves** in order to:

1. Maintain its interchange power flow at the control program with all other control areas (and to correct the loss of capacity in a control area affected by a loss of production); and at the same time

2. (in case of a major frequency deviation originating from the control area, particularly after the loss of a large generation unit) Restore the frequency to its set value to free the capacity engaged by the primary control (and to restore the Primary Reserve)

Tertiary Control encompasses dispatch actions taken by the System Operator to get resources in place to handle current and future contingencies. It should have the same attributes as to the type of reserve being replaced.

12. **What's the difference between the Primary Response and Primary Reserve considering that the two are attributed to the Primary Control (which uses Governor Control)?**

    Primary Response is NOT an Ancillary Service. It is autonomous actions (response) provided by the generators through the turbine speed generators to arrest and replace the Balancing Inertia power to stop the extraction of inertial energy from the Synchronized Generating Units of the system and to stabilize Frequency in response to contingent Events. Hence, Primary Response is an inertial energy contributed by the Synchronized Generating Units and is NOT an injection of power (MW) that is being delivered to the Grid.

    Primary Reserve is the allocated MW capacity to be injected to the Grid to replace the capacity lost during contingent events. It is provided by the Generating Units operating under Governor Control mode [certified and contracted by the System Operator or offering in the WESM.]

13. **What happens to the system when a contingent event [loss of large capacity] occurs and how does the system responds to the frequency change?**

    The simplified example is based on an assumed disturbance event due to the sudden loss of 1,200 MW of generation. Although a large event is used to illustrate the response components, even small events can result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not preclude the need for Frequency Response.

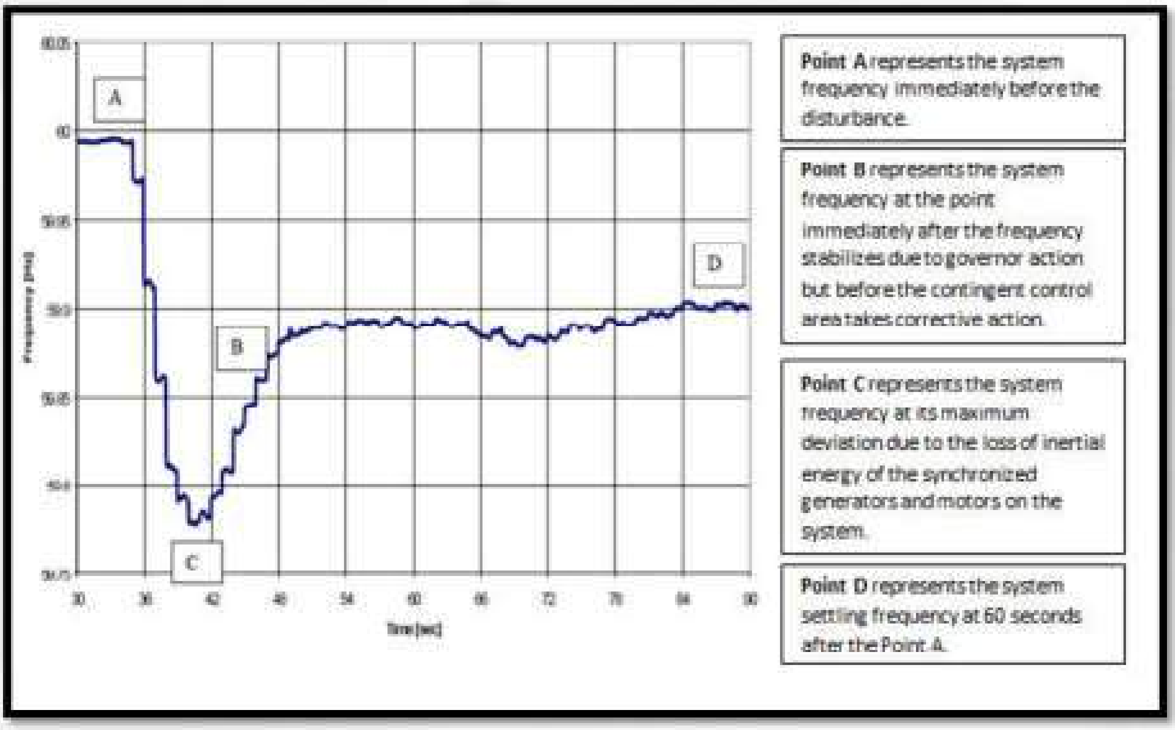


Figure 3 *– Typical Frequency Excursion*

Figure 4 shows the graph of a contingent event where the tripping of a 1,200 MW generator occurred.

At 30-35 seconds

Even though the generation has tripped and power injected by the generator has been removed from the system, the loads continue to use the same amount of power. The “Law of Conservation of Energy” requires that the 1,200 MW must be supplied to the Grid, which is extracted from the kinetic energy stored as inertial energy in the rotating mass of all of the synchronized generators and motors on the system. The energy extracted from the inertial energy of the Grid provides the Balancing Inertia to maintain the power and energy balance on the Grid. As this Balancing Inertia is used, the speed of the rotating equipment on the Grid declines, resulting in a reduction of the Grid frequency.

At 35- 40 sec (point A to C)

At this phase, only synchronously operated motors contribute to Load Damping; adjustable or variable speed drive motors are effectively decoupled from the frequency of the Grid through their electronic controls, and they do not contribute to Load Damping. In general, any load that does not change with frequency, such as resistive loads, will not contribute to Load Damping or Frequency Response.

In accordance with the laws of physics, the amount of energy extracted from rotating machines as Balancing Inertia exactly equals the power deficit, thus indicating that there is no power or energy imbalance at any time during the process. At this point in the example, no other energy injection has yet to occur through any governor control action.

As the rotating machines slow down, reflected as a decline of frequency, the generator governors, which are the controls that “**govern**” the speed of the generator turbines, sense this as a change in turbine speed.

In this example, the change in frequency will be used to reflect this control parameter. Governor action then takes physical action such as injecting more gas into a gas turbine, opening steam valves wider on a steam unit (also injecting more fuel into the boiler), or opening the control gates wider on a hydraulic turbine. This control action results in more combusted gases, steam, or water to impart more mechanical energy to the shaft of the turbine to increase its speed. The turbine shaft is coupled to the generator where it is converted into additional electric energy. The time it takes for the turbine to slow, the change in speed to be detected, and the additional mechanical energy to be injected is not instantaneous.

Until the additional mechanical energy can be injected, the frequency continues to decline due to the ongoing extraction of Balancing Inertia power and energy from the rotating turbine generators and synchronous motors on the Grid. As frequency continues to decline, the reduction in load also continues as the effect of Load Damping continues to reduce the load.

When frequency declines, synchronous generators sense it and then provides Governor Response that injects additional energy into the system. After a short time delay, the Governor Response begins to increase rapidly in response to the initial decline in frequency.

In order to arrest the frequency decline, the Governor Response must offset the power deficit and replace the Balancing Inertia power to stop the extraction of inertial energy from the rotating machines of the Grid. At this point in time, the Balancing Inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the Governor Response.

If the time delay associated with the delivery of Governor Response is reduced, the amount of Balancing Inertia required to limit the change in frequency for the disturbance event can also be reduced. This supports the conclusion that Balancing Inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, the shortening of the time delay associated with its delivery is also important.

Therefore, two important components of Frequency Response are related to (1) the **length of time** before the initial delivery of Governor Response begins and (2) **how much of the response is delivered** before the frequency change is arrested.

From a system standpoint during this time delay, the amount of inertia on the Grid available to be extracted from rotating machines determines the slope of the frequency decline – the less inertia there is, the steeper the slope. This is important in the relationship between the Balancing Inertia and the time delay associated with the Governor Response.

For a given delay in Governor Response, the steeper the slope, the lower frequency will dip before it is arrested. Conversely, for a given Balancing Inertia and slope of frequency decline, the faster Governor Response can be provided, the sooner the frequency decline is arrested, making the nadir less severe.

Therefore, as traditional rotating generators are replaced by electronically coupled resources, such as wind turbines and solar voltaic resources, which provide less overall system inertia, the speed of delivery of Governor Response should increase or other methods be provided that support fast-acting energy injection to minimize the depth of frequency excursions.

The nadir of the frequency deviation, at which the frequency is first arrested, is defined as **Point C** and Frequency Response calculated at this point is called the **"Arrested Frequency Response."** The Arrested Frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a disturbance event. This minimum frequency is the frequency that is of concern from a reliability perspective. The goal is to arrest the frequency decline so frequency remains above the under-frequency load shedding (UFLS) relays with the highest settings so that load is not tripped. Frequency Response delivered after frequency is arrested at this minimum provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

At 40-45 sec (point C to B)

Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (Arrested Frequency) until power flows and frequency settle during the transient period that ends seconds after the disturbance event.

Please be noted that **Governor response** from properly tuned units occurs in the 3-10 second timeframe and is responsible for the bottoming of frequency at Point C and the partial recovery of frequency to Point B.

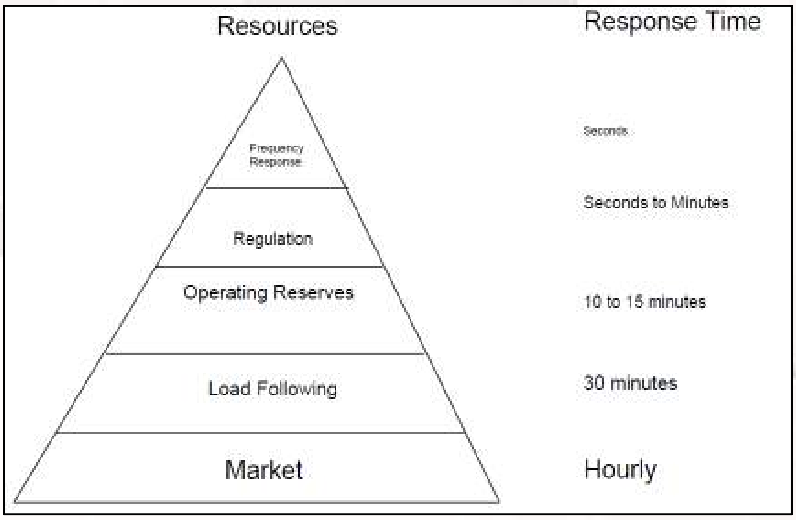
At 45-90 sec (point B to D)

Point B to D shows the frequency at the point immediately after the frequency stabilizes due to governor action (point B) and the **Primary Reserves** takes corrective action (injection of MW) until a new settling frequency (point D) at 60 seconds after the Point A.

The combined response of all connected generators and loads in the Grid will cause the frequency to settle at some value different from the pre-disturbance value. It will not return
frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the SO through the AGC corrects that imbalance [through deployment of the **Secondary Reserves**], thus returning the frequency to its pre-disturbance value.

14. How does the System Operator respond to the frequency deviations?

It is implemented through balancing and proper deployment of the Reserves after the Primary Response of the Generators were provided. Ideally, an integrated set of performance-based balancing standards should be in place that monitors the entire spectrum of the Adequacy component of Reliability.



The **Figure 5** shows the interrelationships of the set of this "balancing", which ultimately checks that Control Areas have and deploy adequate resources to maintain reliability.

***Figure 4** - Resource Pyramid Diagram*

15. What are the means/resources needed to achieve Frequency control?

Frequency control can be achieved through the utilization of the **Reserves** which is a specific form of **Ancillary Service**. Referring to PGC GO 6.6.4.1 *"The Grid Frequency shall be controlled by the timely use of Primary, Secondary and Tertiary Reserve, and Demand Control."*

For clarity, there are other kinds of Ancillary Services such as **Network Support (Reactive Power Support) Ancillary Service** that provides voltage control and **Black Start Ancillary Service** for restoration periods in the grid.

16. Why was the Primary Reserve made mandatory?

It is mandatory because it has a significant role in the Reliability of the Grid when Contingent Event occurs. Accordingly, the SO should prioritize the testing of AS Capability of Generating units to be <u>certified and contracted</u> as Primary Reserve provider.

17. Now that the Generating Units are mandated to participate to Frequency Response, would that mean that the Generating Units shall react immediately when there is disturbance? When should the Generating units reacts or delivers contracted reserves when a disturbance occurs in the Grid?

It is noted that the Generation Companies are concerned on the specifics of the provision [as to the Bias, droop and deadband requirements], now that it is in effect. However, it should be clarified that PGC is the general provisions and standards to be followed by the Grid Users and other Entities.

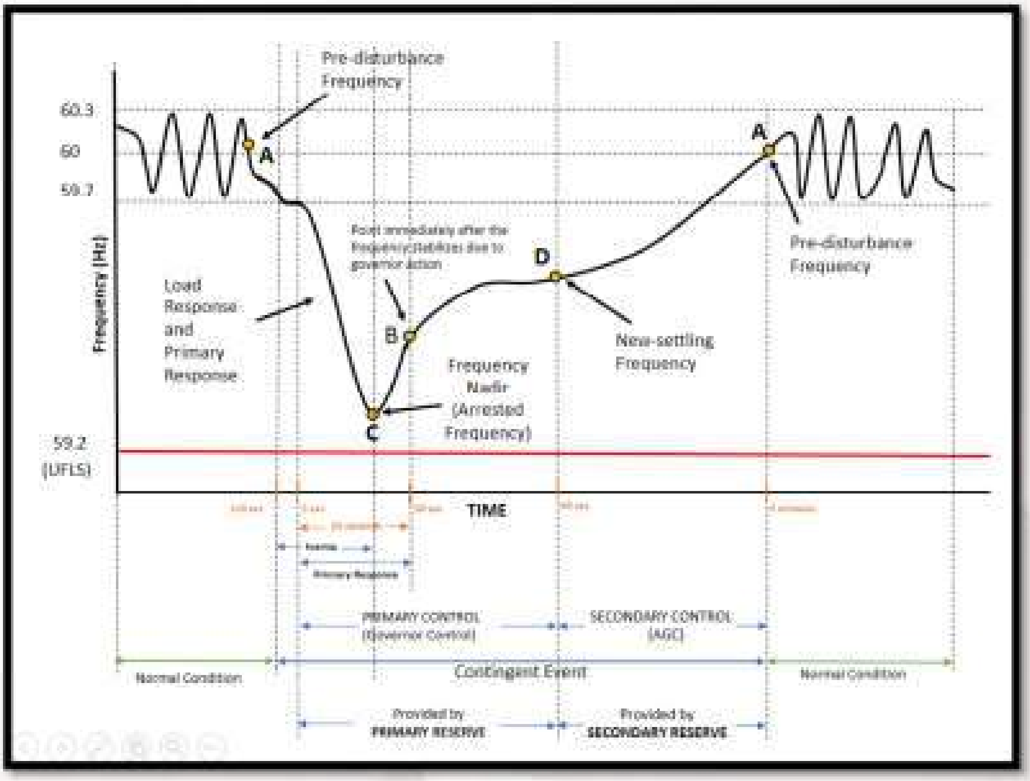
The GMC would like to clarify that mandating the Generating Units of providing primary response does not mean that they would react immediately in the disturbance. The NGCP is encouraged to look into what should be the right measures to be used (e.g. the deadband) to be imposed to the Generating Plants in the Philippine setting. It should be noted that the deadband is applicable to the governing action [during contingent event] but not on the frequency regulation [during normal condition] where the generating units are contracted by the SO to participate.

The Details and specifics of the General Guidelines of the implementation of Primary Response and Contracting of Reserves must be indicated in, and will depend on, the study of the Technical Working Group (TWG) assigned for the revision of the Ancillary Service Procurement Plan (ASPP) that is now called Ancillary Service Requirement and Specifications (ASRS).

As such, the Generation Companies are encouraged to participate on the drafting of the ASRS to attain a Specific, Measurable, Attainable, Realistic and Timely (S-M-A-R-T) plan.

18. Why include a provision on Frequency Response Obligation (FRO)?

For illustration purposes, see **Figure 6.**



Note: For illustration purposes only

If the system cannot withstand and absorb the shock after the contingent event, cascading outages will then occur resulting blackout in the Grid. That is why it is necessary to always maintain the equilibrium- that is the role of FRO.

The philosophy for the FRO is for the SO to control large frequency excursion (as seen from point A to C) that the Grid can withstand without loss of load. FRO is intended to provide the SO a target Contingency Protection Criteria to prevent the Frequency nadir from hitting the first step of the Under-Frequency Load Shedding (UFLS) – that is **59.2 Hz** and in order to obligate them to buy necessary Reserve for that purpose.

19. What will then be the impact to the Generating Plants if the response will be free of charge because before the PGC was amended, response was paid through reserves?

Primary response does not always involve downward movement in power output of a generating unit. We can clearly observe from a frequency chart that the system frequency normally fluctuates within the 60.0 ± 0.3 Hz bandwidth. Further, without primary response and relying solely on primary reserve, the power system will most of the time be subjected to Automatic Load Dropping (ALD) when a large generator trips out. This will result in lost revenue to the distribution utility and to the generators as well.

Besides, the requirement for the Frequency Response is a fraction of connected generation capacity that is in Governor Control mode. When all the generating units participate with the Frequency Response, the frequency dip will be minimized (Point C).

The GMC encourages the Generation Companies to let their Generating Plants provide response to arrest and stabilize the frequency (locally) that will, in turn, help the Grid to decrease the dip of Frequency that may prevent hitting the UFLS setting. If the Generating Plants will not participate in the Frequency Response, everybody will suffer and greater loss will be the consequence. However, GMC supports to let the big contributor (Reserve providers) to restore the frequency be paid.

20. Given the importance of the Frequency Control in the Grid, what would be the guarantee for generator that all will be fair and that all will participate in the Frequency Response?

There is no such thing as 100% compliance. Even if we benchmark with other jurisdiction like in UCTE, it is basically impossible to achieve that due to some technical issues and circumstances (e.g. the Generating Unit are contracted in full load, therefore, will have no contribution to MW injection but its governors will react). What will be contributed in the example is only the inertia and NOT fuel (MW) injection.

The GMC's hired consultant for PGC revision studied that in the Union for the Co-ordination of Transmission of Electricity (UCTE) in Europe, the fraction of the generating units in Governor Control mode as 100% is impossible that even simulation of 80% is also impossible. So they are looking for compliance of all generating units about less than that. Meaning, GMC is not expecting 100% compliance of all Generating Units but are expecting that many will join and participate in the Frequency Response.

It should also be realized that Grid is dynamic. Just as life. There's no such thing as fair.
Grid is dynamic that we can't even expect it to be controlled by rules. It's about all those that can happen to the Grid that we have no control over. It is just like when you buy a new house and lightning hits it and burns it down the night before you move in. Life just isn't fair.

GMC, as established by the ERC, to monitor compliance and initiate an enforcement process for any perceived violations of the PGC pursuant to the GC 1.3.1, will therefore implement undertakings to achieve the objectives of the EPIRA. The GMC will notify the Generating Plant who allegedly violated the requirement and will make recommendations to the ERC for its non-compliances.

In the process, GMC through its Compliance Team will gather data and information on the facts and description of possible violation to study it and develop report to be submitted to the ERC.

21. Why are there provisions of MRUs, Constrained-on and Constrained-off included in the PGC?

The DOE have issued a policy (Department Circular No. DC2014-10-0021) regarding MRUs which is adapted to the PGC 2016 Edition.

MRU is still needed to be included in the PGC since it has important role to play in maintaining Grid Security. It is the duty of the System Operator to ensure Grid Security. However, given the current ASPP, the SO cannot entice enough Generating Plants to engage in agreements as Primary Reserves.

MRUs are asked to run during contingencies to keep support its surrounding area. Voltage control is also another contribution of MRUs. The provision about the MRUs shall be retained until after the ASRS is established and the requirements of it are in effect.

22. Is the ROR in the PGC considered as VRE?

Yes. This is because Run-of-River (ROR) Hydroelectric Generating Plant is subject to natural water variability, and has no reservoir to store water unlike a pondage. In fact, even the definition of Variable Renewable Energy (VRE) as stated in PGC 2016 Edition was revised - not limiting it to wind and solar. However, the operational and connection requirement of ROR Hydroelectric Generating Plant should follow the requirements on the conventional generating plants.

Notes