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Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard (FRS).[1] The intent is to explain the rationale and considerations for the Requirements and their associated compliance information. The document also provides good practices and tips for Balancing Authorities (BA) with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission (FERC or the Commission) directed additional changes to BAL-003-0.1b.[2] This document explains how those directives are met by BAL-003-1.

The original Standards Authorization Request (SAR), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process more objective and to provide this objective data to Planners and Operators for improved modeling. The improved models will improve understanding of the trends in Frequency Response to determine if reliability limits were being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits were approached.

This document will be periodically updated by the FRS Drafting Team (FRSDT) until the Standard is approved ~~(expected to occur during Spring of 2012)~~. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

Frequency Control

Most system operators have a good general understanding of frequency control and Bias Setting as outlined in the balancing standards and the references in the NERC Operating Manual. This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response. Frequency control can be divided into four overlapping windows of time as outlined below.

Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

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[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency to arrest that change in frequency. ~~Primary~~ Frequency Response is automatic, ~~and~~ is not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide ~~Primary~~ Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

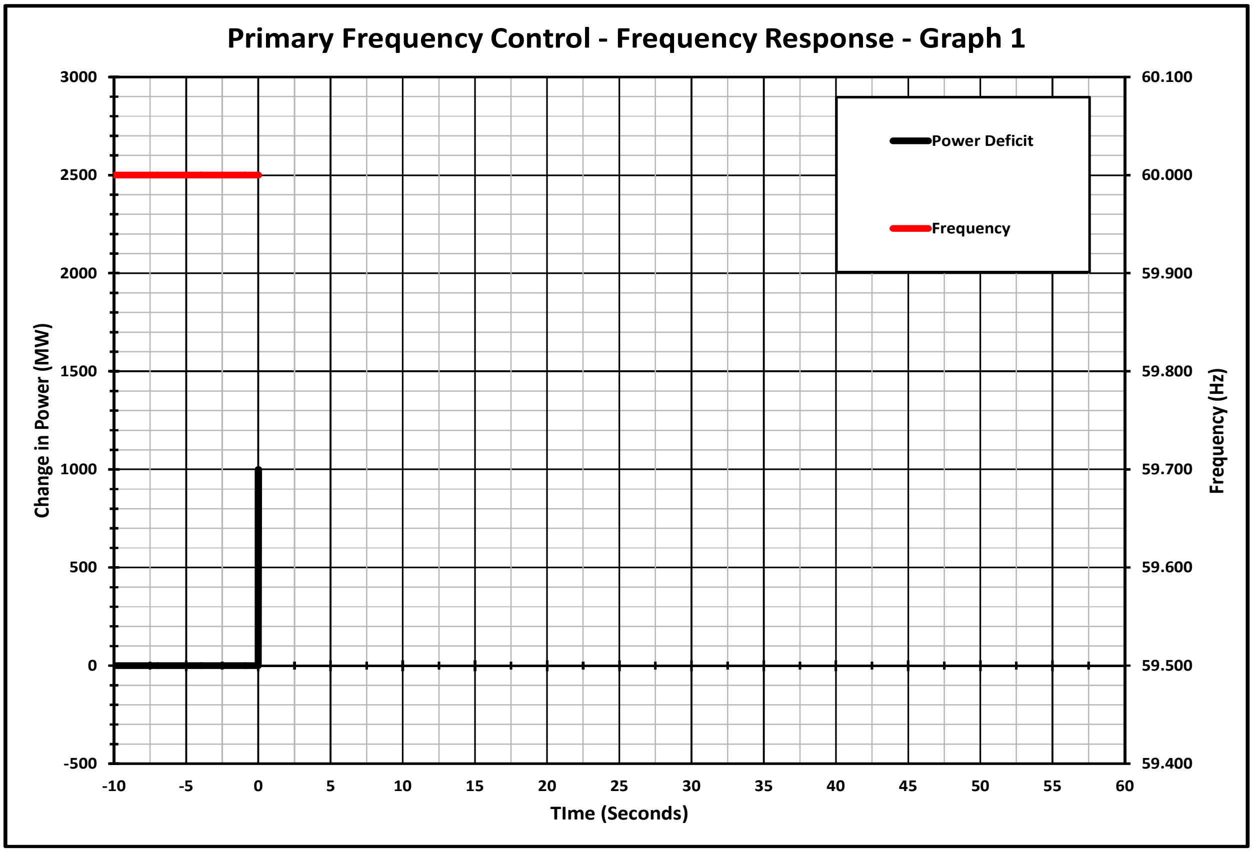
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction ~~ability~~ or response of power from a system or power from elements of the system ~~to react or respond~~ to a change in locally sensed system frequency.
- (System) The sum of the change in demand, ~~plus~~ and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections that reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS ~~Frequency Response standard~~ requires an understanding of each of these components and how they relate to each other.

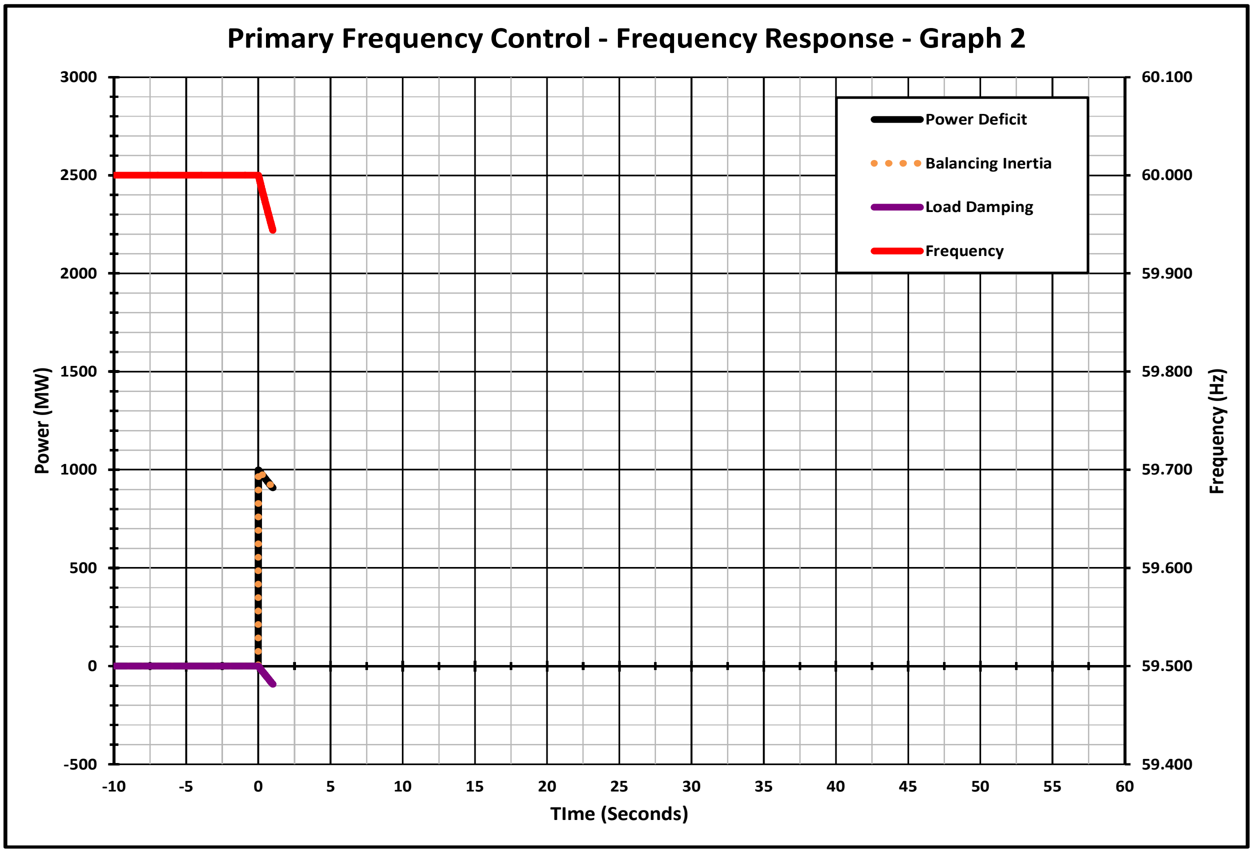
Frequency Response Illustration

This document presents the following simple example to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed ~~d~~Disturbance ~~e~~Event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph, it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a ~~d~~Disturbance ~~e~~Event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This is illustrated by the Power Deficit line shown in Black using the MW scale on the left. -Interconnection Frequency is illustrated by the Frequency line shown in Red using the Hertz scale on the right. Since the scheduled frequency is normally 60 Hz, i~~I~~t is assumed that this is the ~~e~~ Frequency ~~is at 60 Hz~~ when the d~~D~~isturbance e~~E~~vent occurs.

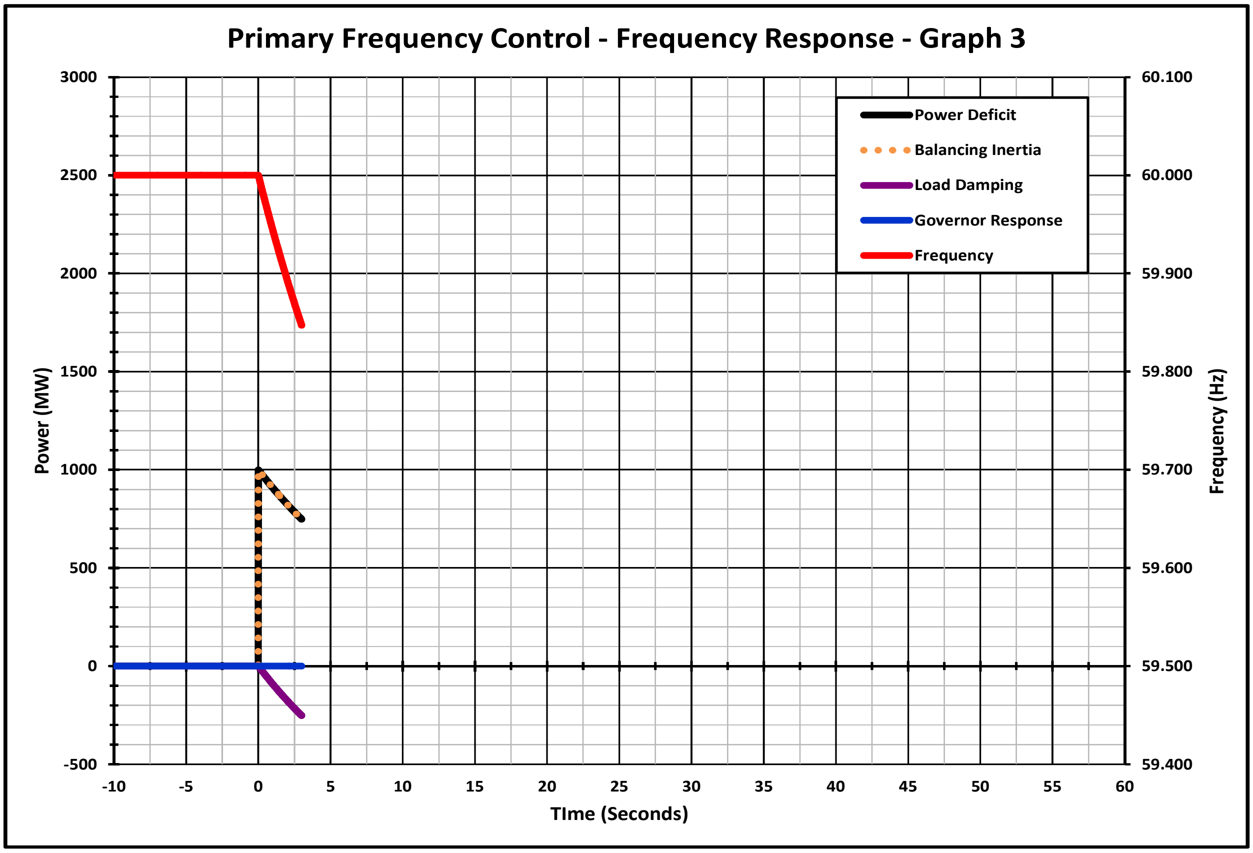
Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The “Law of Conservation of Energy” requires that the 1000 MW must be supplied to the interconnection. This additional 1000 MW of power is extracted from the kinetic energy stored as inertial energy in the rotating mass of all of the synchronized generators and motors on the interconnection using this equipment as a giant flywheel. The energy extracted from the inertial energy of the interconnection provides the Balancing Inertia used to supply the required power to maintain the power and energy balance on the interconnection. As this Balancing Inertia is used the speed of the rotating equipment on the interconnection declines reducing the frequency of the interconnection. This is illustrated on the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the Orange dots representing the Balancing Inertia power that exactly overlay and offset the Power Deficit.



As the frequency decreases, synchronized motors slow and the work they are providing also declines resulting in a decrease in load called "Load Damping." This Load Damping is the reason that the Power Deficit initially declines. Only synchronously operated motors will contribute to Load Damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to Load Damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to Load Damping or Frequency Response.

It is important to note that the Power Deficit exactly equals the Balancing Inertia thus indicating that there is no power or energy imbalance at any time during the process. What is normally considered as balancing power or energy is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the Balancing Inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

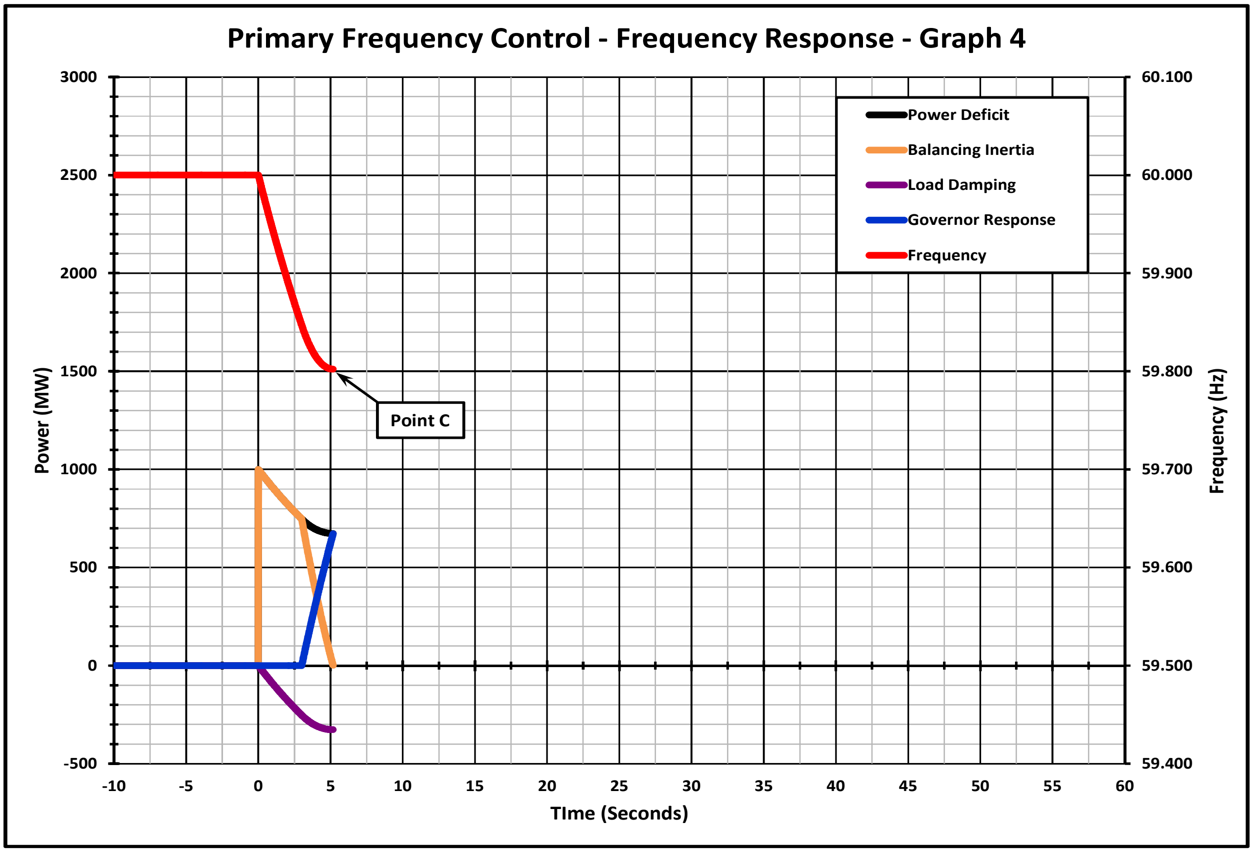
During the initial seconds of the d~~D~~isturbance e~~E~~vent the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine blades where the power is converted to electrical energy.



Note that 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 interconnection. The reduction in load also continues as the effect of Load Damping continues to reduce the load as frequency continues to decline. During this time delay before the Governor Response begins the Balancing Inertia limits the rate of change of frequency.

After a short time delay, the Governor Response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor Response exactly offsets the Power Deficit at the point in time that the frequency decline is arrested. 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 d~~D~~isturbance e~~E~~vent can also be reduced. This supports the conclusion that Balancing Inertia is required to manage the time delays associated with the delivery of Frequency

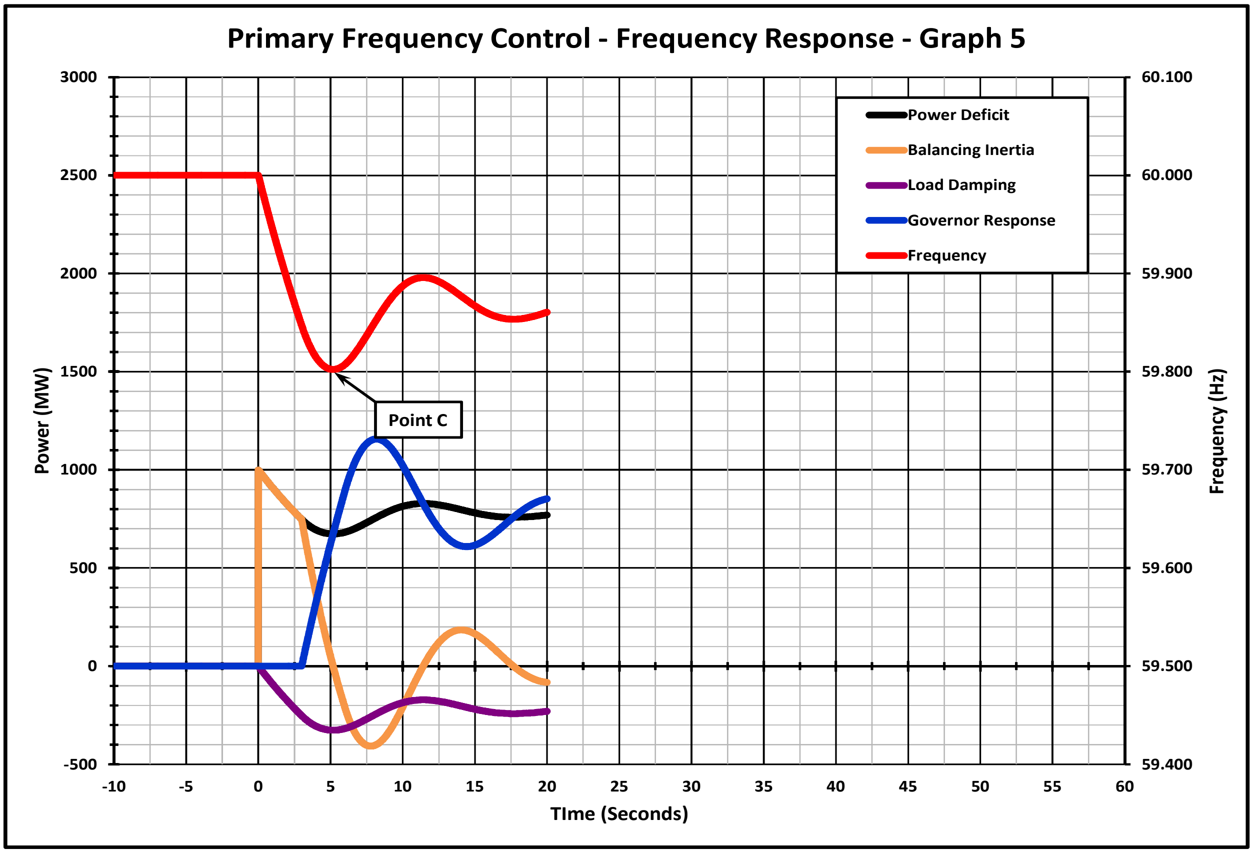
Response. Not only is the rapid delivery of Frequency Response important, the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are related to how long the time delay before the initial delivery of response begins and how much of the response is delivered before the frequency change is arrested.

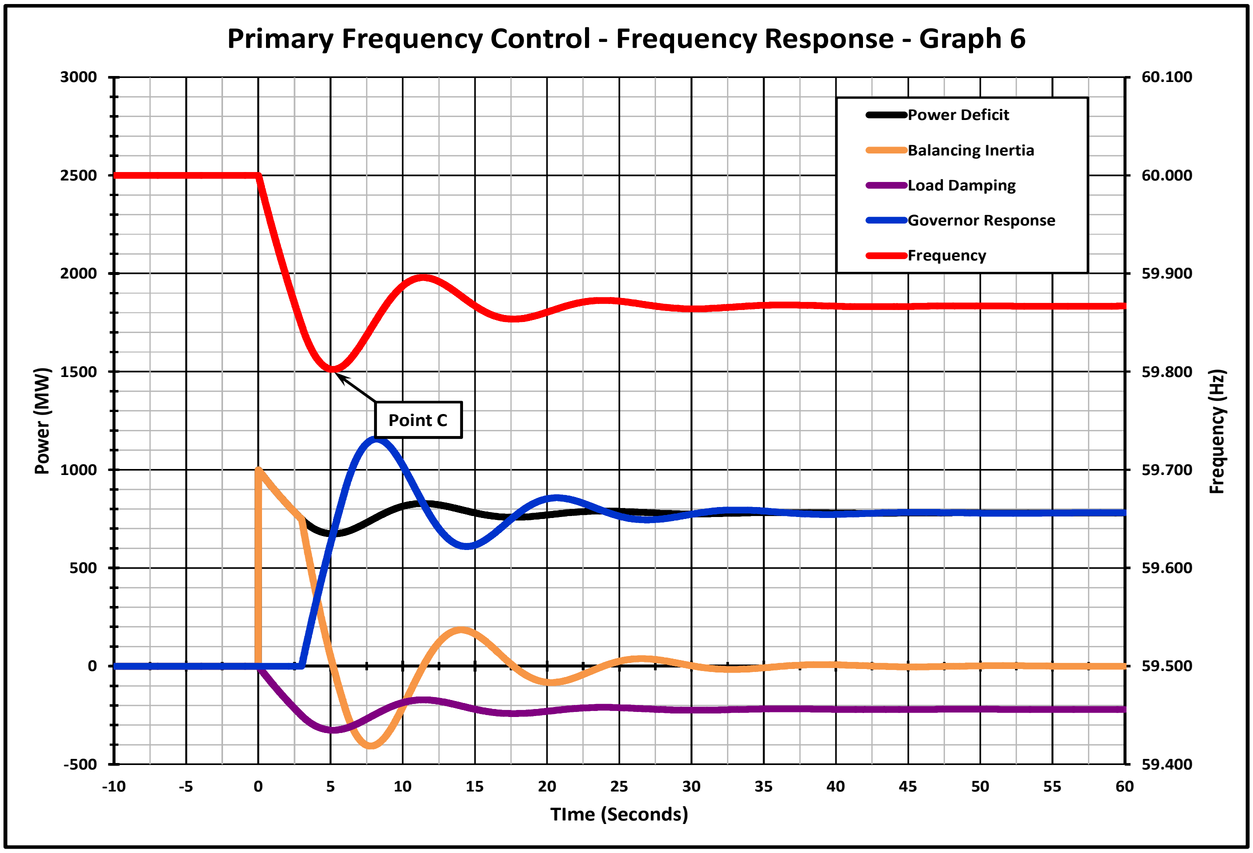


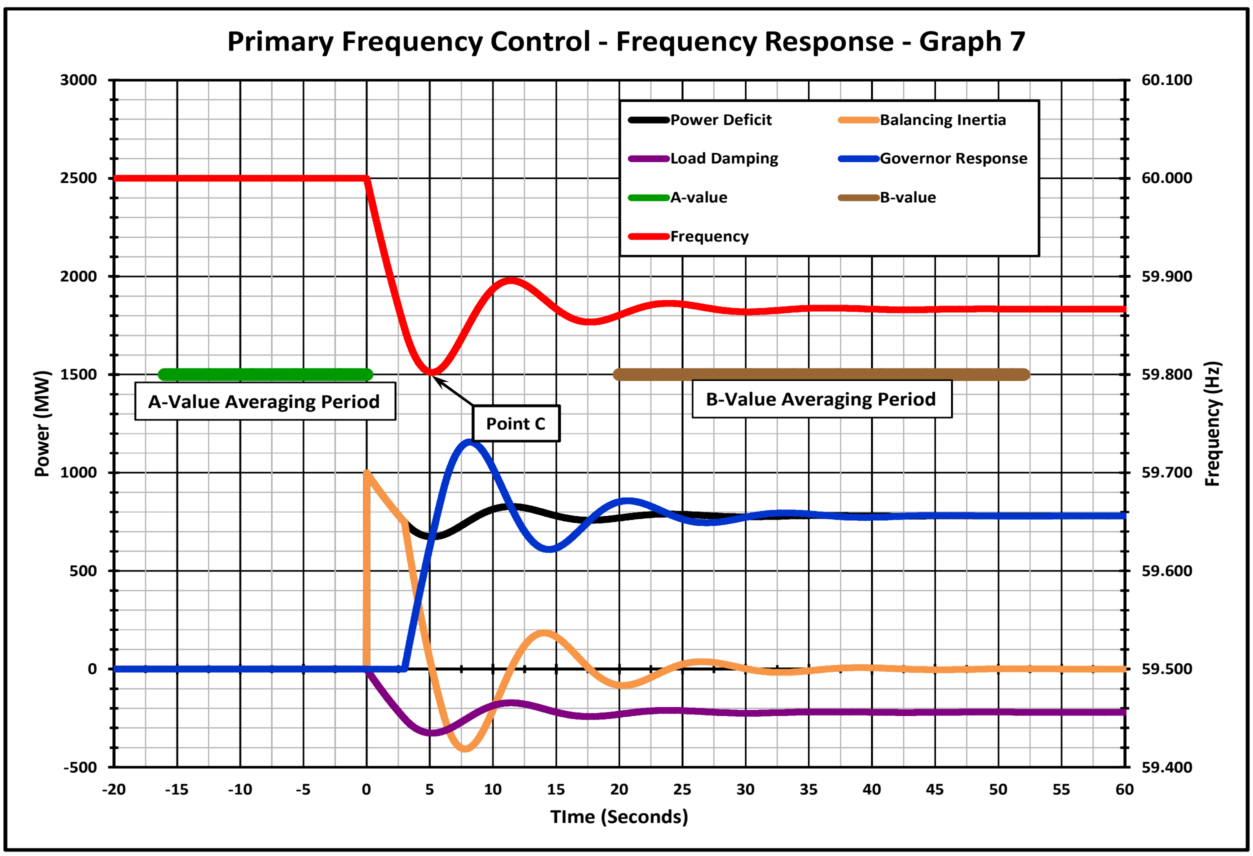
This point, at which the frequency is first arrested, is defined as Point C and Frequency Response calculated at this point is called the "**Arrested Frequency Response**." The Arrested Frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a d~~D~~isturbance e~~E~~vent. This minimum frequency is the frequency that is of concern from a reliability perspective. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. [DFL1]Frequency Response delivered after frequency is arrested at this minimum provides ~~no greater~~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.

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 around 20 seconds after the d~~D~~isturbance e~~E~~vent. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.

The total d~~D~~isturbance e~~E~~vent illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this settled period is called the “Settled Frequency Response.” The Settled Frequency Response is the best measure ~~as~~ to use as an estimator for the “Frequency Bias Setting.”




Primary Frequency Control - Frequency Response - Graph 6
Power Deficit
Balancing Inertia
Load Damping
Governor Response
Frequency
Point C
Power (MW)
Frequency (Hz)
TIme (Seconds)
3000
2500
2000
1500
1000
500
0
-500
60.100
60.000
59.900
59.800
59.700
59.600
59.500
59.400
-10
-5
0
5
10
15
20
25
30
35
40
45
50
55
60


Primary Frequency Control - Frequency Response - Graph 7
Power Deficit
Balancing Inertia
Load Damping
Governor Response
A-value
B-value
Frequency
A-Value Averaging Period
B-Value Averaging Period
Point C
Power (MW)
Frequency (Hz)
TIme (Seconds)
3000
2500
2000
1500
1000
500
0
-500
60.100
60.000
59.900
59.800
59.700
59.600
59.500
59.400
-20
-15
-10
-5
0
5
10
15
20
25
30
35
40
45
50
55
60

The final d~~D~~isturbance e~~E~~vent illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value Averaging Period and the post--disturbance B-Value Averaging Period used to calculate the Settled Frequency Response. A discussion of the measurement of Frequency Response immediately follows these graphs~~ and discussion illustrating Frequency Response and its components~~. This discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.

Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown in Fig. 1 Frequency Response Characteristic, are used for ~~this~~ measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, whose most recent copy can be found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response M~~m~~easure has recently been more specifically named "**Settled Frequency Response**." Settled Frequency Response has been used because it provides the best Frequency Response M~~m~~easure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in the real world setting of multiple Balancing Authority interconnections.

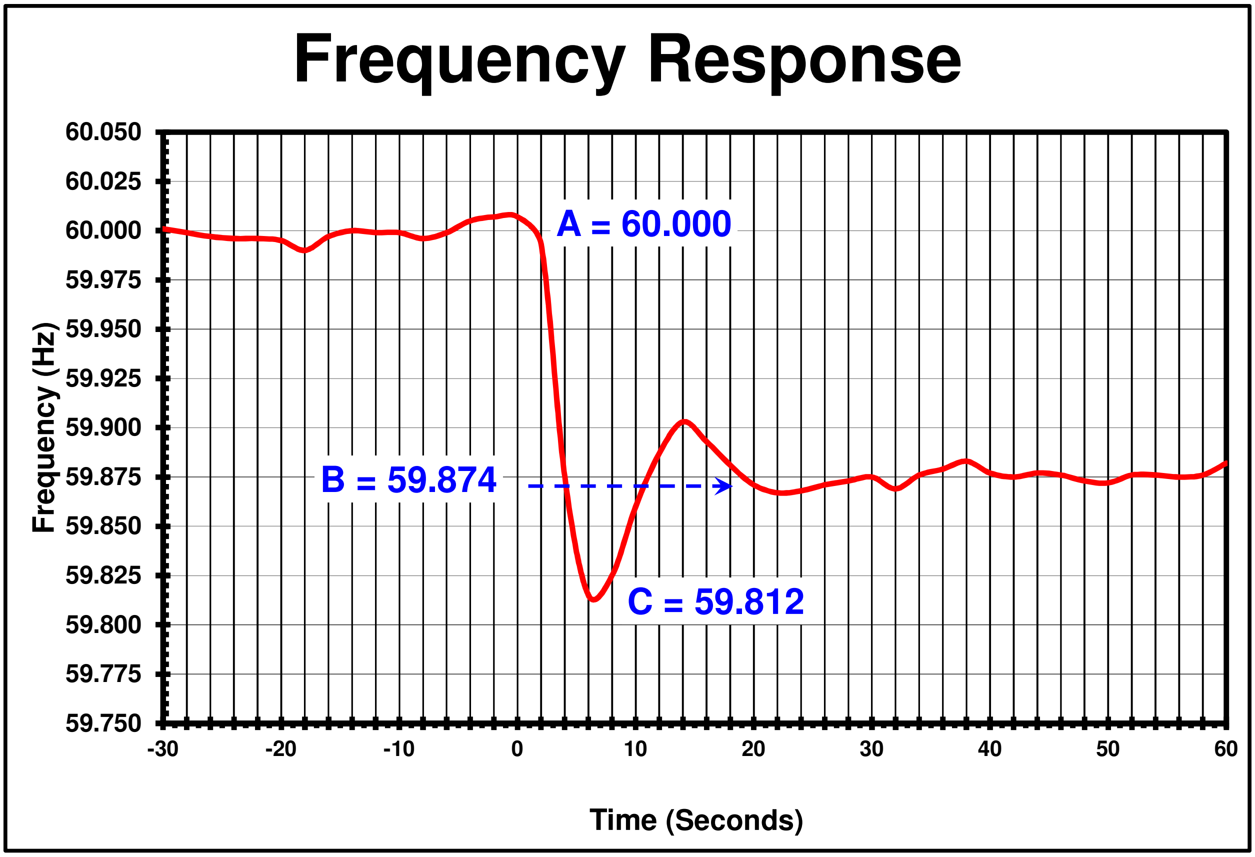


Figure 1. Frequency Response Characteristic

Measuring an Interconnection's Settled Frequency Response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the disturbance and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the excursion.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of Settled Frequency Response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (all time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after P~~p~~rimary F~~f~~requency R~~r~~esponse was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made related to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the Frequency at Point A and the Frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**Actual Net Interchange Immediately Before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**Actual Net Interchange Immediately After Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

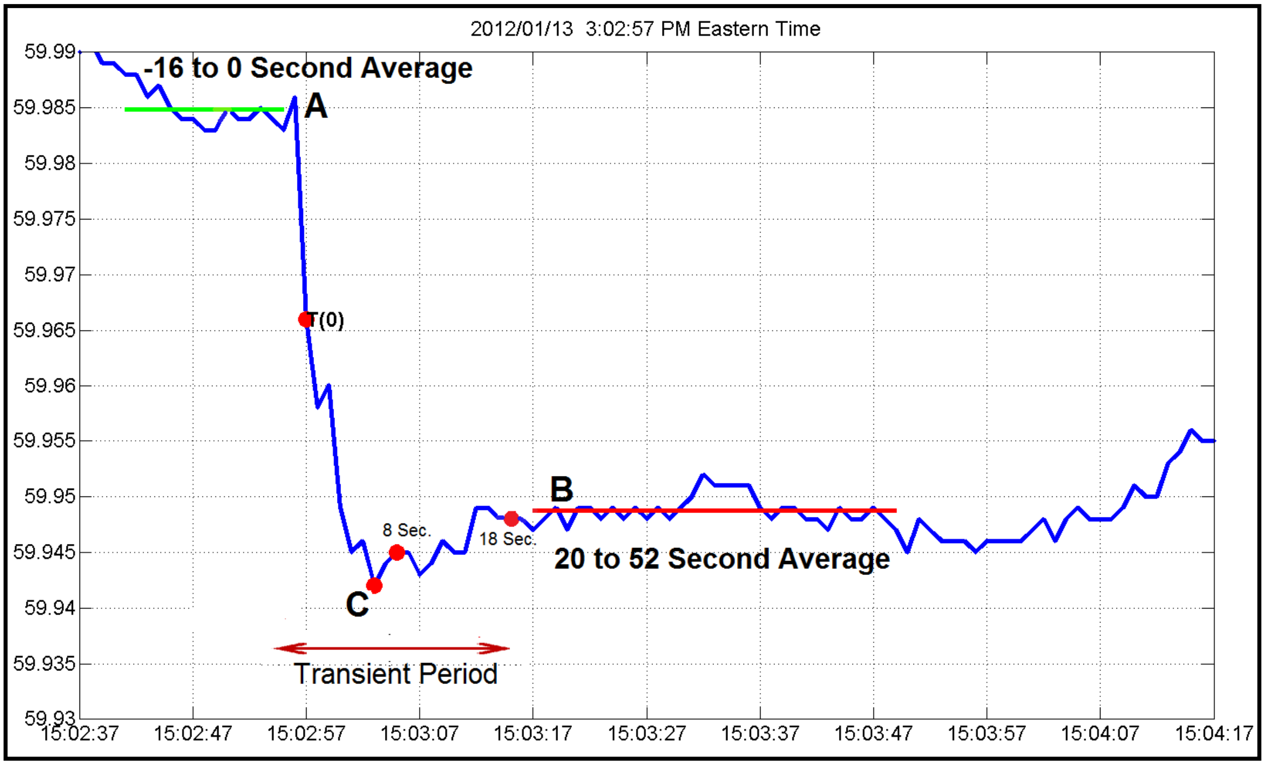


Figure 2. Frequency Response Measurement

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid blue lines on the graph. Since the FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting; but, will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response M~~m~~easure has recently been named **Arrested Frequency Response**. This Frequency Response is significantly affected by the Inertial Frequency Response, the Governor Frequency Response and the time delays associated with the delivery of Governor Frequency Response. It is calculated by using the change in Frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, Arrested Frequency Response cannot currently be measured using the existing EMS based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the Net Actual Interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of Arrested Frequency Response and Settled Frequency Response tends to be stable on an interconnection. This allows the Settled Frequency Response value to be used as a surrogate for the Arrested Frequency Response and implement a reasonable measure upon which to base a standard. One consequence of using the Settled Frequency Response as a surrogate for the Arrested Frequency Response is the inclusion of a large Reliability Margin in Interconnection Frequency Response Obligation to allow for the difference between the Settled Frequency Response as measured and the Arrested Frequency Response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the Arrested Frequency Response while the Frequency Bias Setting will continue to be based on the Settled Frequency Response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate Arrested Frequency Response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining case by case whether the individual contributors to the Frequency Response M~~m~~easure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response
   Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.
2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
   a. time delay before the beginning of the response
      Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.
   b. reduction in the rate of response delivery
      There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.
3. **Proportional** – the amount of the total response is proportional to the frequency error
   a. No Deadband – the response is proportional across the entire frequency range
   b. Deadband – the response is only proportional outside of a defined deadband
4. **Bi-directional** – the response occurs to both increases and decreases in frequency
5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)
6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value
This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of Inertial Response is low. If all time delays associated with the Frequency Response could be eliminated, then Inertial Response would have little value.

The value of Inertial Response is the greatest on small interconnections because the size of the d~~D~~isturbance e~~E~~vents is larger relative to the Inertia of the interconnection. Electronic controls have been developed to provide synthetic Inertial Response from the stored energy in asynchronous generators to supplement the natural Inertial Response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic Inertial Response when required.

Immediate Response is provided by Load Damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system), Load Damping requires very little Inertial Response to limit arrested frequency effectively. Synthetic Immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an Immediate Response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor Response has time delays associated with its delivery. Governor Response provided with shorter time delays has a higher reliability value because those shorter time delays require less Inertial Response to arrest frequency. Governor Response is provided by the turbine-generators on the interconnection. Time delays associated with Governor Response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[3]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[4]

Gas turbines typically have the ~~fastest~~shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[5]

[3] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[4] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response supplied has a higher reliability value because it can be supplied immediately without significant time delay thus requiring less Inertial Response and achieving smaller arresting frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one ~~party~~source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor Response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load Damping provides a proportional response.

Continuous Response is response that has no discontinuities (step changes) in the frequency versus response curve. Step discontinuities (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the discontinuities. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A Uni-directional Response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial Response, Governor Response and Load Damping are all Bi-directional Responses. Certain loads are capable of providing Proportional Bi-directional Response while others are capable of providing Non-Proportional Bi-directional Response.

The ERCOT Load Resource~~AARs~~ program is a Uni-directional Response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the Non Bi-directional Response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a Uni-directional Response has occurred, it is unavailable for a second decline before reset.

Step or Proportional Responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in Continuous Response between the trip and reset frequencies in Step or the Proportional Response rate of change is greater than the underlying continuous response. A Step Bi-directional Response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional Response obviously has a greater reliability value than Uni-directional Response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure ~~will~~may drop after a time as the result of the additional steam flow from governor action. However, this has not been a problem in general because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that is later may later be reduced~~withdrawn~~, while the hydro turbine-generators provide a slower response, contributing less to the Arrested Response, offsetting ~~the~~any ~~withdrawal~~reduction by the steam turbine-generators to assure a Sustained Response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Economics

In every economic system there are two sides of the market, the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with providing Frequency Response, some method of appropriate compensation ~~sh~~could be made available to those resources providing

Frequency Response. Without compensation providers of Frequency Response will be put in the position of incurring additional cost that can only be avoided by reducing or eliminating the response they provide. These costs are incurred independent of whether a provided is in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be Capacity Opportunity Costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.
5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources there are costs associated with the amount of Frequency Response that must be acquired that are influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of Real Time Pricing and Dynamic Pricing. If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making the interconnection less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

R1. Each Balancing Authority or Frequency Response Sharing Group (FRSG) shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each Balancing Authority or FRSG to maintain an adequate level of Frequency Response in the Interconnection.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

A group of two or more Balancing Authorities, that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Standard.

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on non-coincident peak load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$FRO_{BA} = FRO_{Int} \times \frac{\text{Annual Generation}_{BA} + \text{Annual Load}_{BA}}{\text{Annueal Generation}_{Int} + \text{Annual Load}_{Int}}$$

$$FRO_{BA} = FRO_{Int} \times \frac{\text{Peak Gen}_{BA} + \text{Peak Load}_{BA}}{\text{Peak Gen}_{Int} + \text{Peak Load}_{Int}}$$

Where:

- Peak Gen_{BA} is the average of monthly "Output of Generating Plants", FERC Form 714, column f of Part II - Schedule 3.
- Peak Load_{BA} is the average of "Monthly Peak Demand (MW)", FERC Form 714, column j of Part II - Schedule 3.
- Peak Gen_{Int} is the sum of all Peak Gen_{BA} values reported in that interconnection.
- Peak Load_{Int} is the sum of all Peak Load_{BA} values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation:

- Largest category C loss-of-resource (N-2) event.
- Largest total generating plant with common voltage switchyard.
- Largest loss of generation in the interconnection in the last 10 years.

Given the fact that the Interconnections currently have sufficient Frequency Response, few BAs should encounter problems meeting R1, particularly with the options the Standard provides with regard to obtaining Frequency Response. [A2]

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds will be provided to support the computation.

In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the field trial will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the ~~Frequency Response Standard Drafting Team~~ ~~(~~FRSDT~~)~~ indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

Median as the Standard's Measure of Balancing Authority Performance

The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure~~ (FRM)~~. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the east may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise [NERC3]in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The ~~Frequency Responsive Reserve Standard Drafting Team (~~FRSDT~~)~~ performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have noise in them, as most operational personnel who have computed the frequency response of their BA ~~Balancing Authority~~ can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one -BA~~Balancing Authority~~'s subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to linear regression in the presence of these described data quality problems in other analyses conducted by the FR~~R~~SDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FR~~R~~SDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FR~~R~~SDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

Linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc.~~,~~ The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

Sample Size

In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

FERC Order No. 693 also directed the Standard (at P 375) to ~~should~~ identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider[A4].
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane~~in~~ as single-BA Interconnections.

Consider a small BA ~~that~~ whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this ~~. To do otherwise~~ would treat multi-BA Interconnections ~~tens of times~~ more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

R2. Each Balancing Authority that is a member of a multiple Balancing Authority interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO to ensure effectively coordinated Tie Line Bias control.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard~~Attachment B~~ is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard~~Attachment B~~ balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.

- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.

- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.

- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing authority interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting shall have an absolute average Frequency Bias Setting, computed from clock minute samples of its Frequency Bias Setting when the clock minute samples of its Interconnection's frequency is greater than 60.036 Hz or less than 59.964 Hz, that equals or exceeds the greater of the absolute values of its Frequency Response Measure from the previous evaluation period and its Interconnection's minimum as specified in Attachment A.

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the deadband range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either:

- *The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or*

- *The Frequency Bias Setting as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Generation}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annueal Generation}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Peak Gen}_{\mathrm{BA}} + \text{Peak Load}_{\mathrm{BA}}}{\text{Peak Gen}_{\mathrm{Int}} + \text{Peak Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that believes [A5]each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Future Work

The drafting team evaluated a proposal on a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. Full evaluation could not be completed in time to support version 1 of BAL-003. Initial information on this approach is posted on the Resources Subcommittee website. Further research on this approach is encouraged.

Good Practices and Tools

Background

This section outlines tips and tools for Balancing Authorities to help them meet the Frequency Response Standard or to operate more reliability. If you have suggested additions, send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of F~~f~~requency R~~r~~esponse remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of P~~p~~rimary F~~f~~requency R~~r~~esponse of resources.

One method of gaining better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained P~~p~~rimary F~~f~~requency R~~r~~esponse and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow P~~p~~rimary F~~f~~requency R~~r~~esponse to be sustained by the control systems of the resource. Other improvements in implementation of P~~p~~rimary F~~f~~requency R~~r~~esponse have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected P~~p~~rimary F~~f~~requency R~~r~~esponse, have improved the delivery of quality P~~p~~rimary F~~f~~requency R~~r~~esponse while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of P~~p~~rimary F~~f~~requency R~~r~~esponse.

Once ~~P~~Pprimary ~~F~~Ffrequency ~~R~~Rresponse sources are known the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

Field Trial

This section is a summary of the Field Trial activities that have been or will be conducted by the ERO, the Resources Subcommittee and the FRS Drafting Team.

1. The NERC BA recommendation (alert) and observations.√
2. The NERC governor recommendation (alert) and observations.√
3. The 2011 bias calculation √
    1. Evaluate measurement methodology√
    2. Serve as initial training for BAs√
    3. Evaluate median, mean, regression and possibly other measures√
    4. Evaluate sample size (to address the directive of frequency of surveys) √
    5. Evaluate impact of inclusion/exclusion of internal contingencies √
    6. Improve FRS Form 1√
4. Create supporting process for FRS Form 1 √
    1. For Interconnection benchmarking (proving adequacy of frequency response)
    2. Evaluating trend
    3. Test process for developing candidate list for FRS Form 1
5. 2012 bias calculation √
    1. Further refinement of items in 2011 bias calculation
    2. Test the FRO allocation methodology
    3. Test approach for handling variable bias
    4. Evaluate 12 month vs. 24 month rolling average approach to performance
6. Evaluate reduction in bias setting floor below 1% (initially 0.8% in 2013) to evaluate impact on frequency and calculated CPS and BAAL performance.
7. Evaluate effectiveness of administrative process to support the standard.
8. Evaluate a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The "60 Hz load" decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation "leading" the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator's leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation "leading" the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator's leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA's "60 Hz load" is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error.