~~Agenda Item 3h~~
~~Attachment 9~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BALANCING AND FREQUENCY CONTROL (Part 1)

A Technical Concepts Document Prepared by the NERC Resources Subcommittee

to ensure the reliability of the bulk power system

November 9, 2009

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

Table of Contents

Introduction

Background
The NERC Resources Subcommittee drafted this reference at the request of the NERC Operating Committee as part of a series on Operating and Planning Reliability Concepts. The document covers the basics of balancing and frequency control. This is part 1 of a 2 volume set. Part 1 deals with the fundamentals, while Part 2 covers deeper technical details. Send questions and suggestions for changes and additions to balancing@nerc.com.

Note to Trainers
The end of this reference contains questions that can be used to support local training on these concepts. Trainers are encouraged to develop and share materials based on this reference. The Resources Subcommittee will post shared material at:
http://www.nerc.com/filez/rs_tutorials.html.

Disclaimer
This document is intended to explain the concepts and issues of balancing and frequency control. The goal is to provide a better understanding of the fundamentals. Nothing in this document is intended to be used for compliance purposes or establish obligations.

Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections. These Interconnections can be thought of as independent islands. The Interconnections are:

- Western – Generally everything west of the Rockies.
- Texas - Also known as Electric Reliability Council of Texas (ERCOT).
- Eastern – Generally everything east of the Rockies except Texas and Quebec.
- Quebec

Each Interconnection is actually a large machine, as every generator within the island is pulling in tandem with the others to supply electricity to all customers. The "speed" of the Interconnection is frequency, measured in cycles per second or Hertz (Hz). If the total Interconnection generation exceeds customer demand, frequency increases beyond the target frequency, typically 60 Hz[1], until a balance is achieved. Conversely, if there is a temporary generation deficiency, frequency declines until balance is again restored at a point below the scheduled frequency. Balance is initially restored in each case due to load that varies with frequency because some electric devices, such as electric motors, use more energy if driven at a higher frequency and less at a lower frequency.

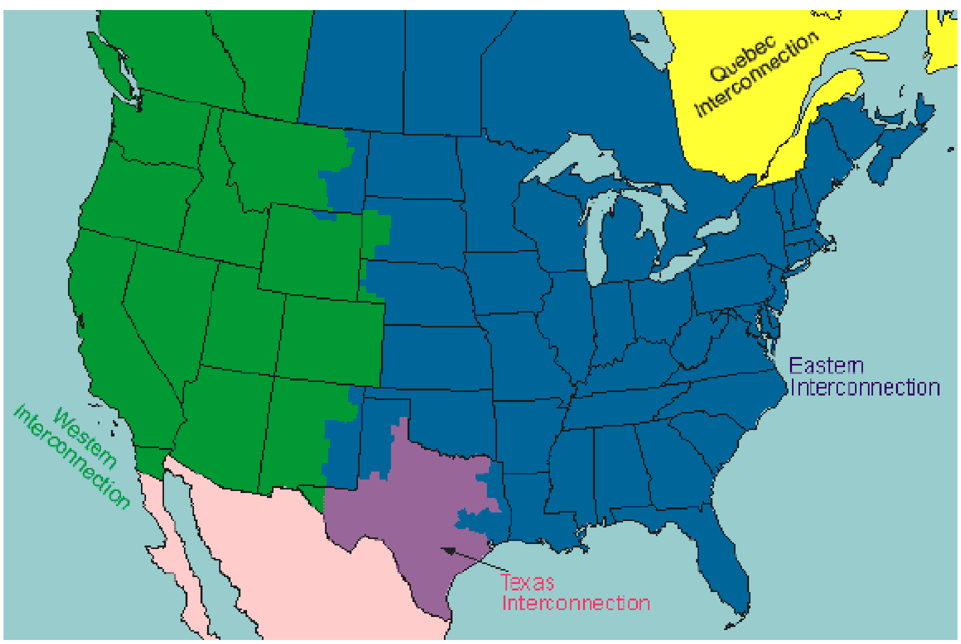

Figure 1. North American Interconnections

1 Target frequency (termed Scheduled Frequency) is sometimes offset by a small amount (presently +/- 0.02Hz) via a mechanism called Time Error Corrections.

The actual operation of the Interconnections is handled by entities called Balancing Authorities. The Balancing Authorities dispatch generators in order to meet their individual needs. Some Balancing Authorities also control load to maintain balance.

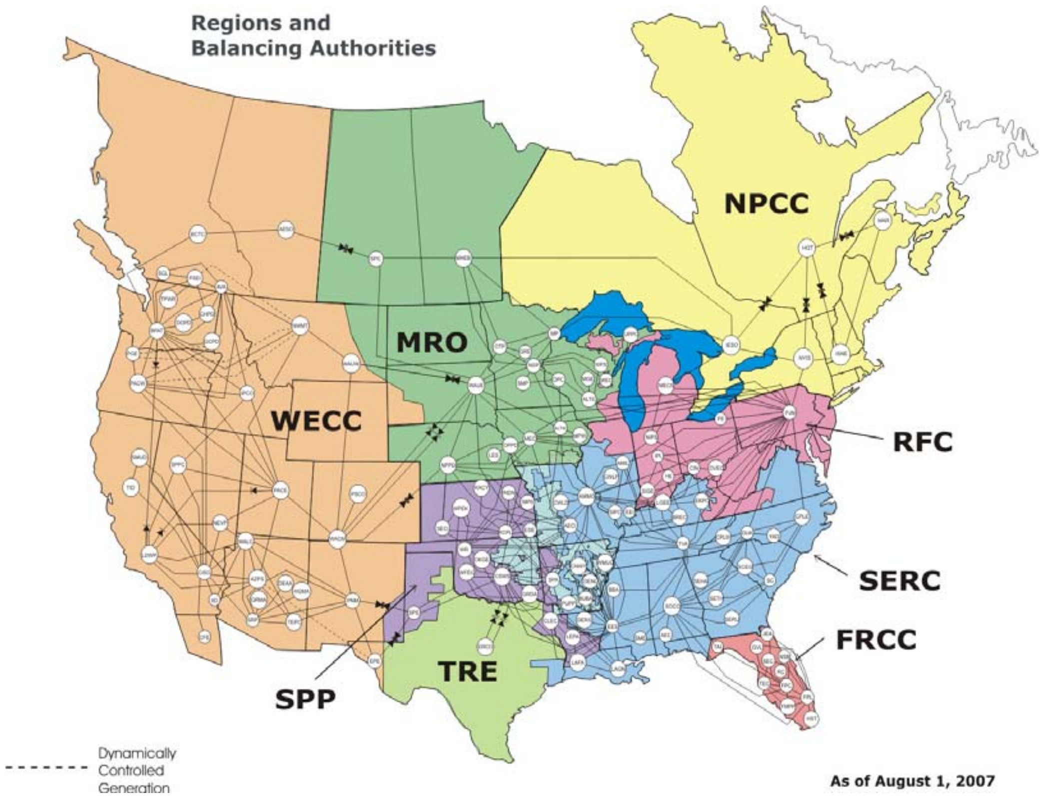

Figure 2. North American Balancing Authorities and Regions

There are over 100 Balancing Authorities of varying size in North America. Each Balancing Authority in an Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring Balancing Authorities. Overseeing the Balancing Authorities are wide-area operators called Reliability Coordinators. The relationship between Reliability Coordinators to Balancing Authorities is similar to air traffic controllers and pilots.

Frequency does not change in an Interconnection as long as there is a balance between resources and customer demand (including various electrical losses). This balance is depicted in Figure 3.

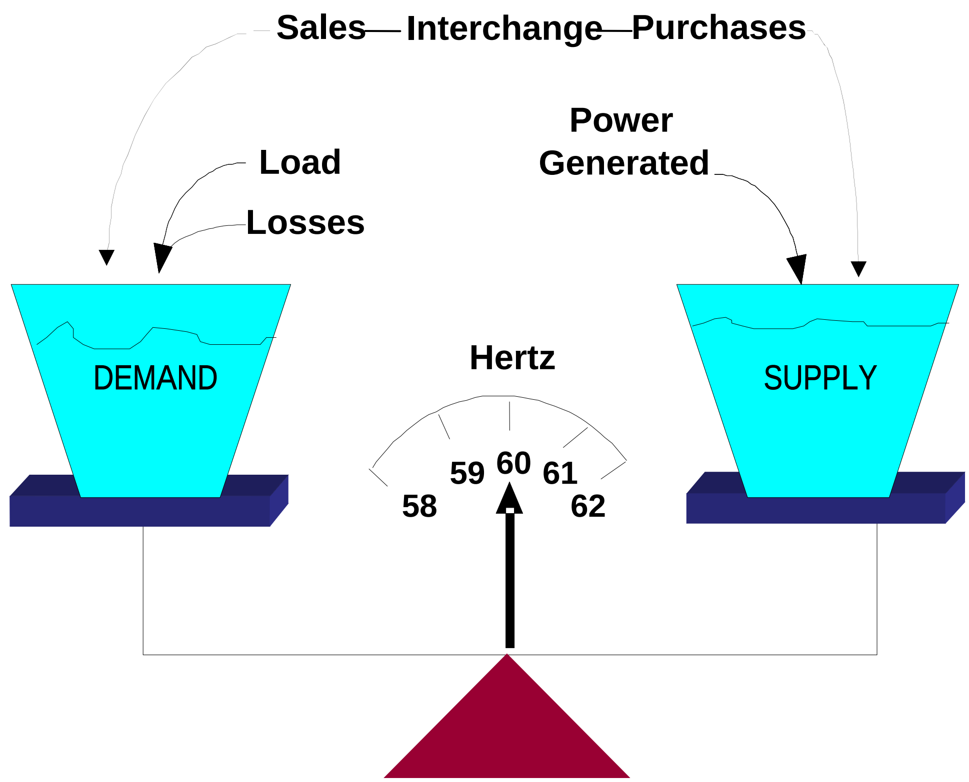

Figure 3. Generation-Demand Balance

To understand how Interconnection frequency is actually controlled, it helps to visualize a traditional water utility. If a municipality operated its own system, it would need sufficient pumps (generation) to maintain level in a storage tank (frequency) to serve its customers. If demand exceeded supply, the level would drop. Level (frequency) is the primary parameter to control in an independent system.

Utilities quickly learned the benefits in reliability and reduced operating reserves expense by connecting to neighboring systems. In our water utility example, an independent utility must have pumps in standby equivalent to its largest online pump if it wants to maintain level. However, if utilities are connected together via pipelines (tie-lines), reliability and economics are improved, both because of the larger storage capability of the combined system and the ability to share pump capacity when needed.

Once the systems are interconnected, the level (steady state frequency) is the same throughout. If one utility (Balancing Authority) loses a pump, there is a drop in level, although it is now much less than in an independent system. The Balancing Authority that needed water (energy) could purchase output from others.

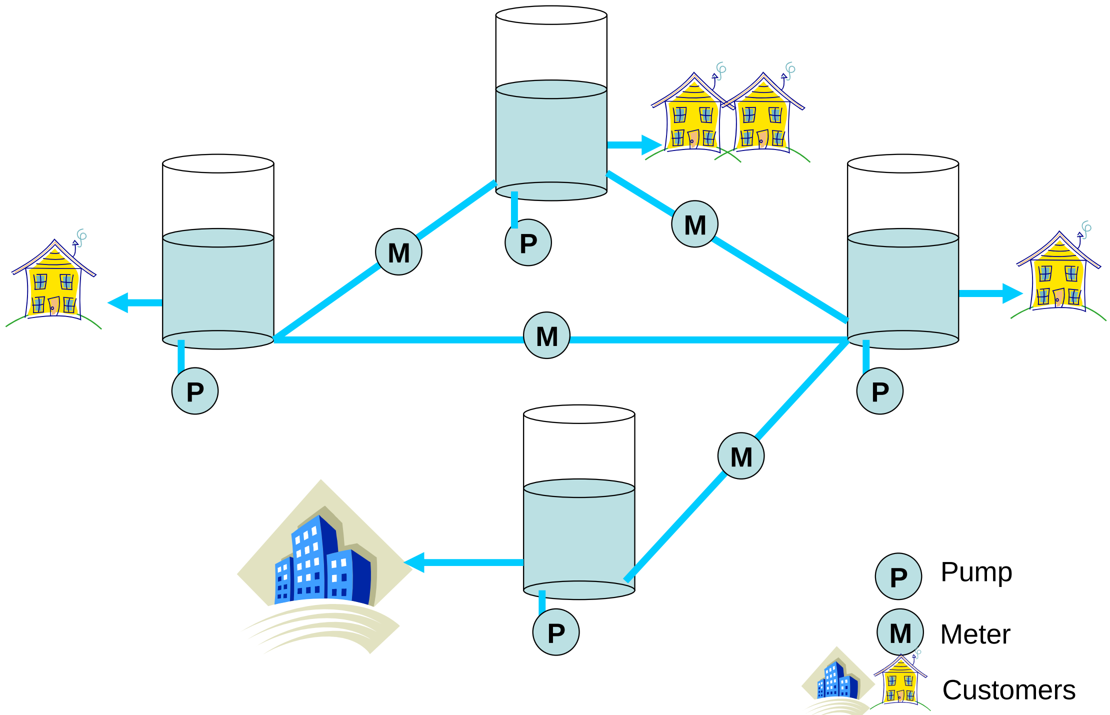

Figure 4. Balancing Authority Analogy

Thus, there are two inputs to the Balancing Authorities' control process[2]:

- Interchange Error, which is the net outflow or inflow compared to what it is buying or selling.
- Frequency Bias, which is the Balancing Authority's obligation to stabilize frequency. In other words, if frequency goes low, each Balancing Authority is asked to contribute a small amount of extra generation in proportion to its size.

Each Balancing Authority uses common meters on the tie-lines with its neighbors for control and accounting. In other words, there will be a meter on one end of each tie-line that both neighboring Balancing Authorities use against which they control and perform accounting. Thus, all generators, load, and transmission lines in an Interconnection fall within the metered bounds of a Balancing Authority.

If the Balancing Authority is not buying or selling energy[3], and its generation is exactly equal to the load and losses within its metered boundary. If the Balancing Authority chooses to buy energy, say 100 Megawatts (MW), it tells its control system to allow 100 MW to flow in. Conversely, the seller will tell its control system to allow 100 MW to flow out. If all Balancing

2 There are two control inputs in multi-Balancing Authority Interconnections. Texas and Quebec are single Balancing Authority Interconnections and need only control to frequency.
3 In most cases, Balancing Authorities do not buy and sell energy. Transactions now are arranged by agents called Purchasing-Selling Entities (PSEs) that represent load or generation within the Balancing Authority.

Authorities behave this way, the Interconnection remains in balance and frequency remains stable. If an error in control occurs, it will show up as a change in frequency.

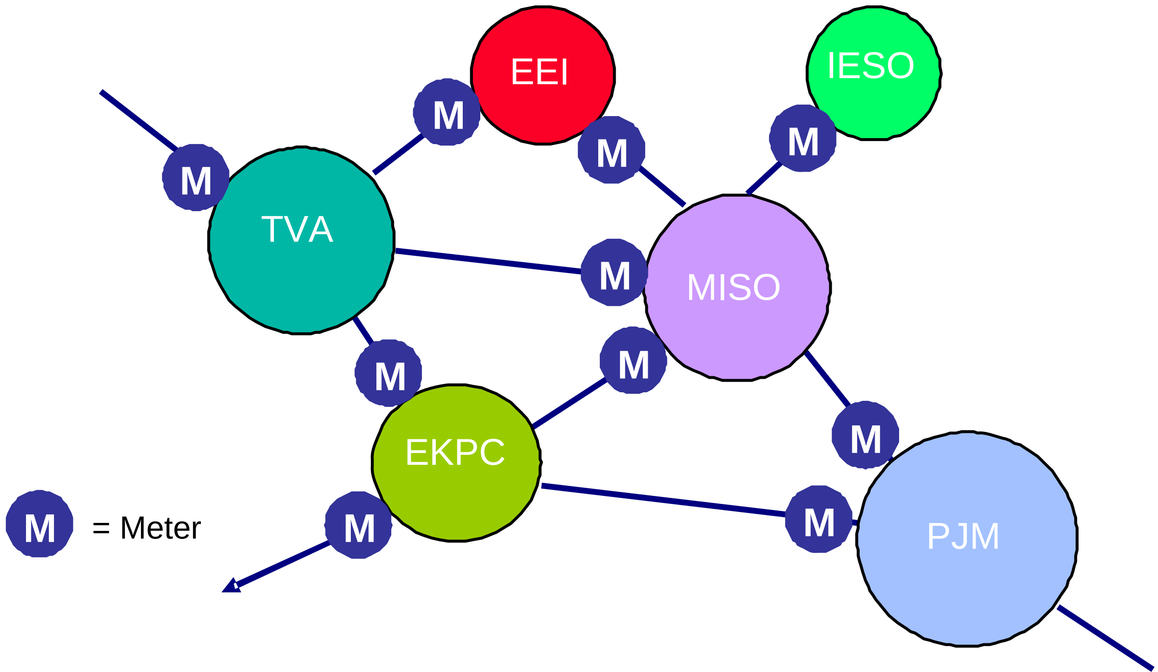

Figure 5. Interconnected Balancing Authorities

Customer demand and generation are constantly changing within all Balancing Authorities. This means Balancing Authorities will have some unintentional outflow or inflow at any given instant. This mismatch in meeting a Balancing Authority's internal obligations, along with the small additional obligation to maintain frequency, is measured via a real-time value called area control error (ACE), measured in MW.

Dispatchers at each Balancing Authority fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to Balancing Authority size. This balancing typically is accomplished through a combination of computer-controlled adjustment of generators, telephone calls to power plants and through purchases and sales of electricity with other Balancing Authorities, and possible emergency actions such as automatic or manual load shedding.

Conceptually, ACE is to a Balancing Authority what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE causes Interconnection frequency to drop. Highly variable, or "noisy" ACE tends to contribute to similarly "noisy" frequency. However, it depends on whether ACE is coincident with frequency error. Frequency error tends to be made larger when ACE is of the same sign as the error, and is made smaller when ACE is of opposite sign to the frequency error. This principle is captured in the way CPS1 measures performance.

Failure to maintain a balance between load and resources causes frequency to vary from its target value. In addition, other problems on the grid, such as congestion or equipment faults also dictate rapid adjustments of generation or loss of load and are seen as changes in frequency. Frequency can therefore be thought of as the pulse of the grid and a fundamental indicator of the health of the power system.

Control Continuum

Balancing and frequency control occur over a continuum of time using different resources, represented in Figure 6.

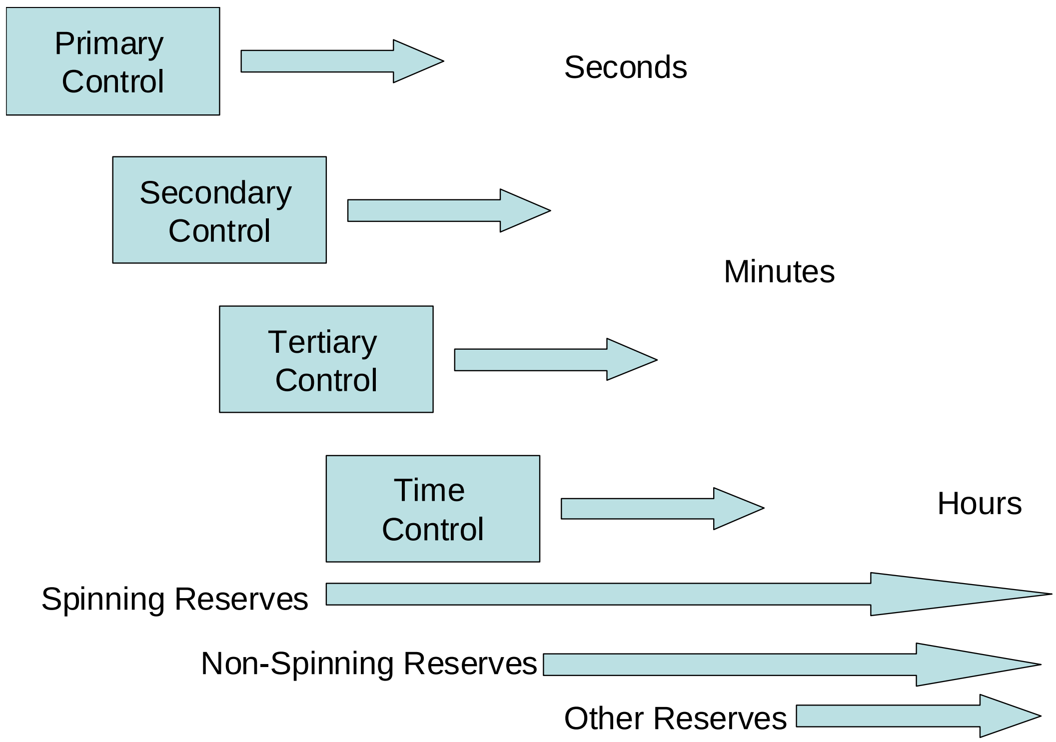

Figure 6. Control Continuum

Primary Control

Primary Control is more commonly known as Frequency Response. Frequency Response occurs within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency Response is provided by:

1. Governor Action. Governors on generators are similar to cruise control on your car. They sense a change in speed and adjust the energy input into the generators' prime mover.

2. Load. The speed of motors in an Interconnection change in direct proportion to frequency. As frequency drops, motors will turn slower and draw less energy. Rapid reduction of system load may also be effected by automatic operation of under-frequency relays which interrupt pre-defined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability (or Ancillary) services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios.

These load characteristics assist in stabilizing frequency following a disturbance.

The most common type of disturbance in an Interconnection is associated with the loss of a generator, which causes a decline in frequency. In general, the amount of (frequency-responsive) Spinning Reserve in an Interconnection will determine the amount of available Frequency Response.

Primary Control relates to the supply and and load responses, including generator governors (speed controls) that stabilize Interconnection frequency whenever there is a change in load-resource balance. Primary Control is provided in the first few seconds following a frequency change and is maintained until it is replaced by AGC action. Frequency Response (or Beta) is the more common term for Primary Control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 7 shows a trace of the Western Interconnection's frequency resulting from a generating unit trip. The graph plots frequency from 5 seconds prior to the loss of a large generator until 60 seconds thereafter.

NERC references three key events to describe such a disturbance. Point A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, which occurs about 5–8 seconds after the loss of generation. Point B is the settling frequency of the Interconnection.

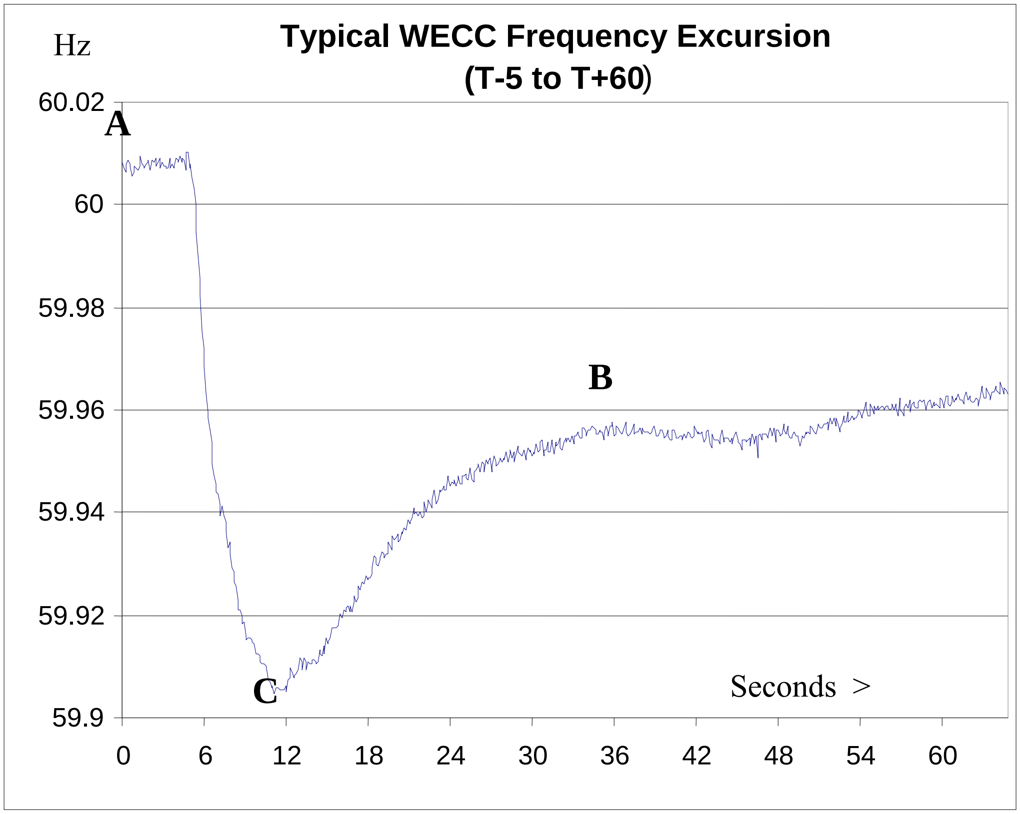

Figure 7. Points "A", "B" and "C"

Figure 8 overlays frequency traces following a trip of a large generator from the Eastern, Western and ERCOT Interconnections. The frequency data is from 5 seconds before the unit tripping until 60 seconds thereafter.

The difference in profiles is due to the load and generation differences (size) and also they types of generation within the Interconnections. The Eastern Interconnection has the most load and generation. The Western Interconnection has proportionally more hydroelectric generation, which provides slightly slower primary control.

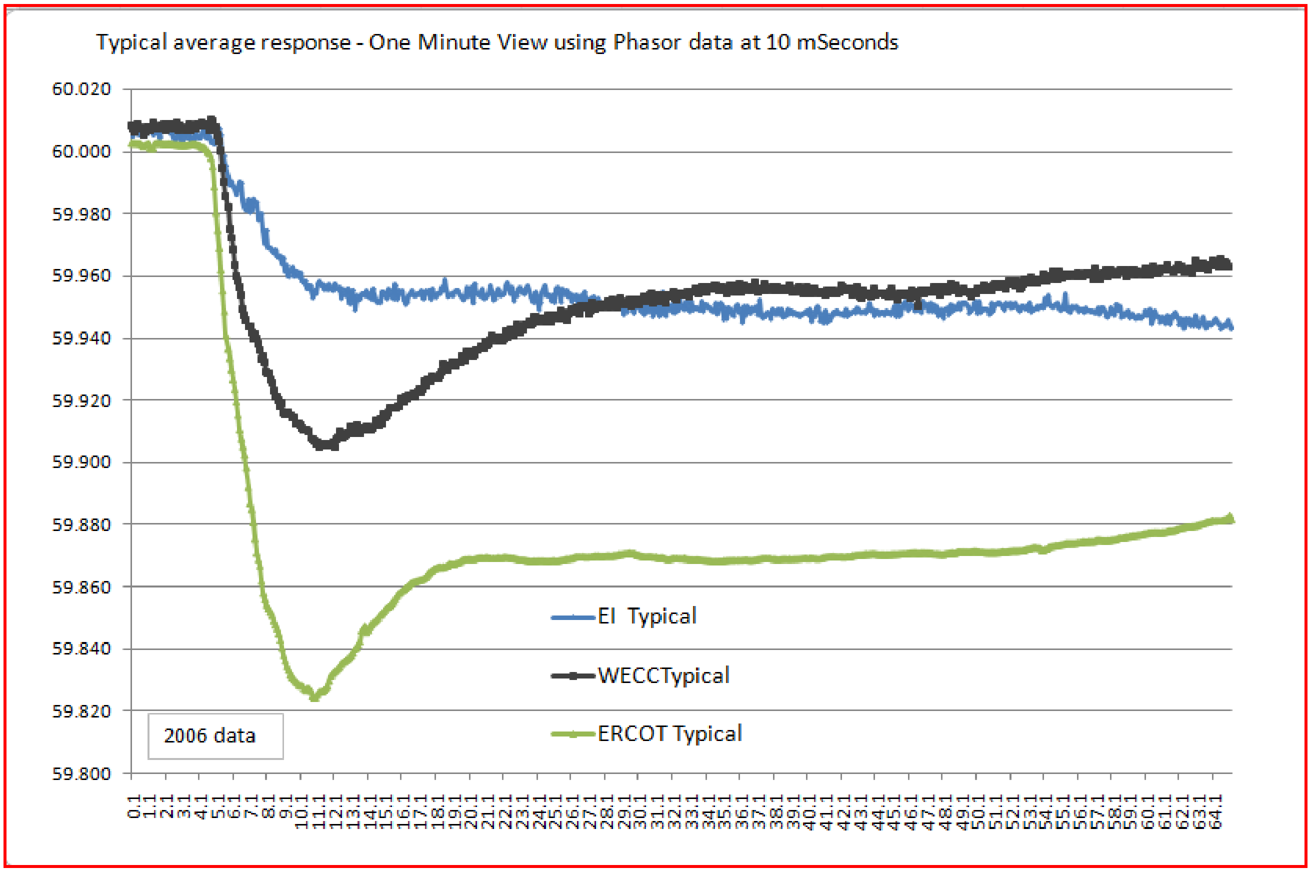

Figure 8. Typical Frequency Traces Following a Unit Trip

It is important to remember that Primary Control will not return frequency to normal, but only stabilize it. Other control components are used to restore frequency to normal.

Operating Tip: Frequency Response is particularly important during disturbances and islanding situations. Operators should be aware of their frequency responsive resources. Blackstart units must be able to control to frequency and arrest excursions.

Secondary Control
Secondary Control typically includes the balancing services deployed in the "minutes" time frame. Some resources however, such as hydroelectric generation, can respond faster in many cases. This control accomplished using the Balancing Authority's control computer[4] and the manual actions taken by the dispatcher to provide additional adjustments. Secondary Control also includes initial reserve deployment for disturbances.

In short, Secondary Control maintains the minute-to-minute balance throughout the day and is used to restore frequency to its scheduled value, usually 60 Hz, following a disturbance. Secondary Control is provided by both Spinning and Non-Spinning Reserves. The most common means of exercising secondary control is through Automatic Generation Control (AGC).

Tertiary Control
Tertiary Control encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and Reserve restoration following a disturbance are common types of Tertiary Control.

Time Control
Frequency and balancing control are not perfect. There will always be occasional errors in tie-line meters, whether due to transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors, plus normal load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency cannot always be maintained at exactly 60Hz, and that average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a Time Control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a Reliability Coordinator as a "Time Monitor" to provide Time Control.

The Time Monitor compares a clock driven off Interconnection frequency against "official time" provided by the National Institute of Standards and Technology (NIST). If average frequency drifts, it creates a Time Error between these two clocks. If the Time Error gets too large, the Time Monitor will notify Balancing Authorities in the Interconnection to correct the situation.

For example, if frequency has been running 2 mHz high (60.002Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10 hour interval (i.e. 60.002 Hz-60.000 Hz)/60 Hz * 10 hrs * 3600 s/hr = 1.2 s). If the Time Error accumulates to a pre-determined value (for this example, +10 seconds in the Eastern Interconnection), the Time Monitor will send notices for all Balancing Authorities in the Interconnection to offset their scheduled frequency by -0.02Hz (Scheduled Frequency = 59.98Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (which would be +6 seconds for our example in the eastern interconnection).

4 Terms most often associated with this are "Load-Frequency Control" or "Automatic Generation Control".

A positive offset (Scheduled Frequency = 60.02Hz) would be used if average frequency was low and Time Error reached its initiation value (-10 seconds for the eastern interconnection). See the NAESB business practice on Manual Time Error Correction for additional information, including the initiation and termination Time Error values for North American interconnections.

Control Continuum Summary
Table 1 summarizes the discussion on the control continuum and identifies the service[5] that provides the control and the NERC standard that addresses the adequacy of the service.

Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

Table 1. Control Continuum Summary

Area Control Error (ACE) Review

The Control Performance Standards are based on measures that limit the magnitude and direction of the Balancing Authority's Area Control Error (ACE). The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Where:

NI_A is Net Interchange, Actual
NI_S is Net Interchange, Scheduled
B is Balancing Authority Bias
F_A is Frequency, Actual
F_S is Frequency, Scheduled
I_{ME} is Interchange (tie line) Metering Error

NI_A is the algebraic sum of tie line flows between the Balancing Authority and the Interconnection. NI_S is the net of all scheduled transactions with other Balancing Authorities. In most areas, flow into a Balancing Authority is defined as negative. Flow out is positive.

The combination of the two (NI_A - NI_S) represents the ACE associated with meeting schedules, without consideration for frequency error or bias, and if used by itself for control would be referred to as "flat tie line" control.

The term 10B (F_A - F_S) is the Balancing Authority's obligation to support frequency. B is the Balancing Authority's frequency bias stated in MW/0.1Hz (B's sign is negative). The "10"

5 NERC calls these services "Interconnected Operations Services" while the FERC uses the term Ancillary Services.

converts the Bias setting to MW/Hz. F_S is normally 60 Hz but may be offset ± 0.02 Hz for time error corrections. Control using "10B (F_A - F_S)" by itself is called "flat frequency" control.

I_{ME} is a correction factor for meter error. The meters that measure instantaneous flow are not always as accurate as the hourly meters on tie lines. Balancing Authorities are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a metering error, a value should be added to compensate for the estimated error. This value is I_{ME}. This term should normally be very small or zero.

Here is a simple example. Assume a Balancing Authority with a Bias of -50 MW / 0.1 Hz is purchasing 300 MW. The actual flow into the Balancing Authority is 310 MW. Frequency is 60.01 Hz. Assume no time correction or metering error.

ACE = (-310 - - 300) – 10* (-50) * (60.01 – 60.00) = (-10) – (-5) = -5 MW.

The Balancing Authority should be generating 5 MW more to meet its obligation to the Interconnection. Even though it may appear counterintuitive to increase generation when frequency is high, the reason is that this Balancing Area is more energy-deficient at this moment (-10 MW) than its bias obligation to reduce frequency (-5 MW). The decision on when or if to correct the -5 MW ACE would be driven by control performance standard (CPS) compliance.

Bias (B) vs. Frequency Response (Beta)

There is often confusion in the Industry when discussing Frequency Bias and Frequency Response. Even though there are similarities between the two terms, Frequency Bias (B) is not the same as Frequency Response (β).

Frequency Response, defined in the NERC Glossary, is the mathematical expression of the net change in a Balancing Area's actual net interchange for a change in interconnection frequency. It is a fundamental reliability service provided by a combination of governor and load response. Frequency Response represents the actual MW primary response contribution to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias prevents AGC withdrawal of frequency response following a disturbance. If B and β were exactly equal, a Balancing Authority would see no change in ACE following a frequency decline, even though it provided a MW contribution to stabilize frequency.

Bias and Frequency Response are both negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1Hz

> **Important Note:** When people talk about Frequency Response and Bias, they often discuss them as positive values (such as "our Bias is 50MW/0/1Hz"). Frequency Response and Bias are actually negative values.

Early research (Cohn) found that it is better to be over-biased (absolute value of B greater than the absolute value of β) than to be under-biased.

Useful References

Cohn, N. (May 1982). Decomposition of Time Deviation and Inadvertent Interchange on Interconnected System, Parts I & II. *IEEE PAS, Vol. PAS-101, No. 5*.

Cohn, N. (1956). Some Aspects of Tie-Line Bias Control on Interconnected Power Systems, *AIEE Transactions, vol. 75, pt. III (Power Apparatus and Systems)*, 1415-1436.

Cohn, N. (1984). Recollections of the Evolution of Realtime Control Applications to Power Systems, *Automatica, vol. 20, no. 2*, 145-162.

Electric Power Research Institute (1992). *Impacts of Governor Response Changes on the Security of North American Interconnections*.

Electric Power Research Institute (1996). *Control Performance Standards and Procedures for Interconnected Operations, EPRI RP3555-10*.

Ingleson, J., & Nagle, M. (May, 1999). *Decline of Eastern Interconnection Frequency Response.* Prepared for the Fault and Disturbance Conference at Georgia Tech. Retrieved May 19, 2004 from http://truc.org/files/1999/fda1999_jwi_final.pdf.

Ingleson, J., & Ellis, D. (2005). *Tracking the Eastern Interconnection Frequency Governing Characteristic*. Summer, 2005 IEEE/PES.

Jaleeli, N. & VanSlyck, L.S. (August 1999). NERC's New Control Performance Standards. IEEE T-PWRS Vol. 14, No. 3, pp 1092-1099.

Jaleeli, N., VanSlyck, L. S., Ewart, D. N., Fink, L. H. and Hoffmann, A. G. (August 1992). Understanding Automatic Generation Control. IEEE T-PWRS Vol. 7, No. 3, pp 1106-1122.

Kirby, B., Dyer, J., Martinez, C., Shoureshi, R., Guttromson, R., & Dagle, J. (December 2002). *Frequency Control Concerns In The North American Electric Power System, ORNL/TM-2003/41*. Oak Ridge, TN: Oak Ridge National Laboratory.
Lindahl, S.(2002). *Verification of Governor Response during Normal Operation*. Retrieved November 5, 2003 from http://www.eeh.ee.ethz.ch/downloads/psl/research/psdpc/.

Moran, F. & Williams, D.R. (April 1968). Automatic control of power-system frequency by machine controllers, *Proceeding of the IEE, vol. 115, no. 4*, 606-614.

Moran, F., Bain, D.K.S., & Sohal, J.S. (July 1968). Development of the equipment required for the loading of turbogenerators under automatic power-system control, *Proceedings of the IEE, vol. 115, no 7*, 1067-1075.

NAESB WEQ Manual Time Error Correction Standards - WEQBPS – 004-000

NERC (2002, August 28). *Frequency Excursion Task Force Report*. North American Electric Reliability Council.

NERC (2006). *Frequency Response Characteristic Survey Training Document.* North American Electric Reliability Council.

NERC Frequency Response Standard White Paper, April 6, 2004

NERC (2004). *Inadvertent Interchange Accounting Training Document.*

NERC (2004). Performance *Standard Training Document*. North American Electric Reliability Council.

NERC (2004). *Area Interchange Error Survey Training Document*. North American Electric Reliability Council.

NERC. *Area Interchange Error Reports*. Available at www.nerc.com/~filez/aie.html.

NERC Joint Inadvertent Interchange Task Force (2001). *Draft Guiding Principles for an Inadvertent Interchange Standards*. North American Electric Reliability Council.

NERC *Reliability Standards for the Bulk Electric Systems of North America*. North American Electric Reliability Council.

UCTE. *Policy 1 — Load-Frequency Control and Performance*. Draft Operating Standard for Europe. Available at: http://www.entsoe.eu/resources/publications/ce/oh/

VanSlyck, L.S., Jaleeli, N. & Kelley, W.R. (May, 1989). Implications of Frequency Control Bias Settings on Interconnected System Operation and Inadvertent Energy Accounting. *IEEE Transactions on Power Systems, vol. 4, no. 2*, 712-723.

U.S.-Canada Power System Outage Task Force (2004, April 5*). Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*. Retrieved November 5, 2004 from www.nerc.com/~filez/blackout.html.