NATIONAL ENERGY TECHNOLOGY LABORATORY

Frequency Instability Problems in North American Interconnections

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Final Report

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Exhibits

Acronyms and Abbreviations

AC	Alternating Current
ACE	Area control error
AGC	Automatic generation control
B	Frequency bias constant
BA	Balancing Authority
CC	Combined cycle
CFC	Constant frequency control
CPS	Control Performance Standards
DC	Direct Current
EI	Eastern Interconnection
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EPRI	Electric Power Research Institute
f	Frequency
FERC	Federal Energy Regulatory Commission
HVDC	High voltage direct current
Hz	Hertz
ISO	Independent System Operator
LMCP	Locational marginal clearing price
MW	Megawatts electric
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
OASIS	Open Access Same-Time Information System
OFLS	Over Frequency Load Shedding
PJM	PJM Interconnection, LLC
RFC	Reliability *First* Corporation
RMCP	Regulation market clearing price
rpm	rotation per minute
RSG	Reserve Sharing Groups
RTO	Regional Transmission Organization
UFLS	Under-Frequency Load Shedding
WECC	Western Electricity Coordinating Council

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Executive Summary

Alternating current power transmission and distribution systems in the United States operate at a nominal (target) frequency of 60 Hz. Large deviations from this frequency can cause network instability, and even small deviations can adversely affect sensitive end-use devices.

Frequency deviations commonly result from a mismatch between energy supply and demand on a power network. If supply is insufficient to meet demand, the system frequency will decrease; if supply exceeds demand, frequency will increase. Over 100 *balancing authorities* within four electrical interconnections in North America manage power flows so that frequency will remain stable.

Over the past decade, the North American Electric Reliability Corporation (NERC) has observed an increase in frequency stability problems. For example, *frequency response* in the Eastern Interconnection has deteriorated significantly over this period, so that progressively smaller power disturbances are able to induce significant frequency deviations. Several causes of this have been proposed, including changes in:

1. An interconnection's moment of inertia;
2. Load types;
3. Generation control practices;
4. Types of reserves and their availability;
5. Frequency control (monitoring and regulating) practices.

Proposed Cause 1: Interconnection's moment of inertia. The *Moment of inertia,* or rotational inertia, is the rotational analog to mass. Power systems with multiple smaller turbine generators on-line (i.e., a primarily distributed generation system) have less rotational inertia than systems with fewer but larger turbine generators (i.e., a more centralized generation system), giving the more distributed system less kinetic energy immediately available to mitigate frequency changes. Furthermore, as more non-rotating (photovoltaic, fuel cell) and slowly rotating (wind) generators come on line, the kinetic energy per unit of generating capacity available to the overall power system to stabilize frequency decreases.

Proposed Cause 2: Load types. Some end-use devices, such as electric motors, contribute to frequency stability because they use more power at higher frequencies and less power at lower frequencies, thereby helping demand adjust to meet supply. As the load in North America changes, with less industrial consumption and more commercial and residential consumption, it includes more electronics and variable-speed drives that do not demonstrate the same beneficial frequency-power relationship as inductive motors.

Proposed Cause 3: Generation control practices. Deregulation and competition in the generation industry have provided operators with incentives to operate plants at peak local efficiency (versus what is optimal for the overall power system) resulting in changes in *generation control practices*. Unfortunately, some operating practices can result in a lowering of the available range of governor control of on-line generators. This reduces the available level of *primary frequency control*, the ability of the system to react within a few seconds to stabilize system frequency.

Proposed Cause 4: Types of reserves and their availability. Deregulation and competition also have provided control area operators with incentives to keep *generation reserves* at a minimum. To reduce costs, some operators have organized into reserve sharing groups (RSGs) that collectively meet their reserve requirements. Since the RSGs and generators can choose the market into which to sell services, lower levels of reserves may be available to respond to frequency disturbances.

Proposed Cause 5: Frequency control practices. Frequency control regimes include primary, secondary, and tertiary means. Primary control reacts in seconds to stabilize the system frequency, usually at a level different from nominal. It is implemented through governor control, assisted automatically by the system's moment of inertia and frequency-dependent load response. Secondary control is used over a few minutes to bring frequency back to the nominal range. It primarily consists of automatic generation control (AGC) to control multiple generators and reduce area control error (ACE) to within acceptable limits. Tertiary controls bring available generators on-line over a period of minutes to hours to re-stabilize the frequency at the nominal level, freeing up AGC to respond to future disturbances.

The generator units are bidding power and price in the ancillary services market, but they do not bid technical characteristics. The ancillary market is cleared such that minimum cost service is provided, but this does not ensure that the power supplied for ancillary services has the optimal technical characteristics. Consequently, selecting providers of ancillary services in this manner does not necessarily ensure that the system will respond to disturbances as desired

While the technical implementation of frequency control is directly responsible for an interconnection's frequency stability, the standards and regulations have both direct and indirect effects on the ability to implement the technical control. For example, the implementation of Federal Energy Regulatory Commission (FERC) Orders 888 and 889 has had significant indirect effects on frequency control, through the opening of electricity markets to competition and the re-allocation of responsibilities for system reliability. Specifically, the FERC Orders established market conditions that deeply influenced the investment decisions with respect to new generation projects changing the mix of the generation portfolio. Also, in Order 888, FERC made transmission providers, rather than generators, responsible for the delivery of frequency regulation and response.

Some unintended effects resulted in greater incentives for private investment in smaller, more distributed generation, which tends to provide fewer frequency stability benefits than larger plants. The higher reliability of smaller distributed units is not counterbalanced by the possible detrimental effects on grid frequency stability. The ideal system component for effecting primary control is a (or a limited number of) large baseload unit(s) with a considerable moment of inertia in order to absorb and arrest the perturbation to the overall power system. Such a need is best served by coal-fired power plants, since other operational constraints keep nuclear plants from accepting primary governor control

As part of the first set of mandatory reliability standards approved by FERC Order No. 693 in 2007, NERC issued resource- and demand-balancing standards that directly impact frequency stability. As originally issued, the regulations were missing key recommended NERC guidelines with respect to generator governor control for primary frequency response. In its Order 693, FERC directed NERC to modify the standards to determine the appropriate periodicity of surveys necessary to ensure reliability standards were being met, and to define the frequency response required for reliable operation, along with the methods of obtaining and measuring that the frequency response is achieved.

In March 2010, FERC issued an Order setting a deadline for compliance to Order 693. Subsequently, technical conferences have been held to address concerns by NERC and the various Regional Transmission Organizations with respect to the Order. In the absence of a clear and well-defined frequency response reliability standard, regional entities, reliability councils, and balancing authorities have developed local standards to try to maintain 60 Hz frequency, keep system stability, and provide reliable supply.

The most concerning issue with frequency stability is the observed decline in the primary frequency response and its effect on frequency stability. Until 2007, qualified facilities smaller than 80 MW were not required to provide spinning reserve for primary control at all. FERC, NERC, and the Independent System Operators (ISOs) have recognized this limit as too high, and currently all power plants larger than 10 MW are required to participate in primary control. This change does not seem to be sufficient to address lack of primary control, and NERC standardization committees are working on a new set of requirements which will define in much better terms how the primary frequency response should function to improve frequency response characteristics.

1 Introduction

For a stable and reliable electrical power system, several operational parameters must be maintained within tolerance levels. Both generation and demand depend on these parameters for their own stable and reliable operations. The most important parameters are system frequency and voltage. Frequency is a system-wide characteristic while voltage is a local feature. This report focuses on frequency stability issues in the United States.

This report correlates the increased number of larger and longer-lasting frequency excursions with electricity market design and frequency control regulations. In order to make the connection between direct (technical) causes and indirect (non-technical) causes, both the physics of the problem and the regulatory environment (i.e., regulations, standards, and policies) must be understood first. The purely physical dimension of the issue can be broken down into the physical laws governing the frequency stability phenomenon and system control efforts responsible for maintaining the nominal system frequency. Similarly, the indirect effects of the regulatory environment can be broken down into the impact of policy on market design which in turn affects frequency stability and the regulations directly affecting frequency control practices. The report concludes with recommendations, covering both technical and policy aspects of the issue, to improve frequency stability in the NERC-regulated territory.

Alternating current power transmission and distribution systems, generation, and demand equipment in the United States are designed to operate at the nominal frequency of 60 Hz. Tight adherence to this target permits multiple generators to provide stable power to a single network. Large deviations from this frequency can cause network instability, and even small deviations can adversely affect sensitive end-use devices. The definition of what is a large and what is a small deviation depends on the system topology and the generation and demand conditions. Frequency deviations result from a mismatch between power supply and demand on a power network. If supply is insufficient to meet demand, the system frequency will decrease; if supply exceeds demand, frequency will increase. Over 100 Balancing Authorities nationwide are responsible for managing power flow between regions so that frequency will remain stable. [1] Although almost all of the generators are synchronous generators set to generate 60 Hz electricity, the system frequency is rarely exactly 60 Hz. Small power mismatches cause small frequency deviations, which are expected and easily handled. Large frequency deviations can be a problem leading to equipment damage and even blackouts. Large frequency deviations are usually caused by sudden loss of generation but can also be caused by sudden, unexpected changes in demand. Frequency deviations of less than 0.05 Hz are usually considered small although these could be significant depending on the interconnection and even operating conditions. The IEEE recommends that frequencies within +/-0.036 Hz around the nominal frequency be considered as nominal.[2] Frequencies lower than 59.3 Hz automatically trigger the

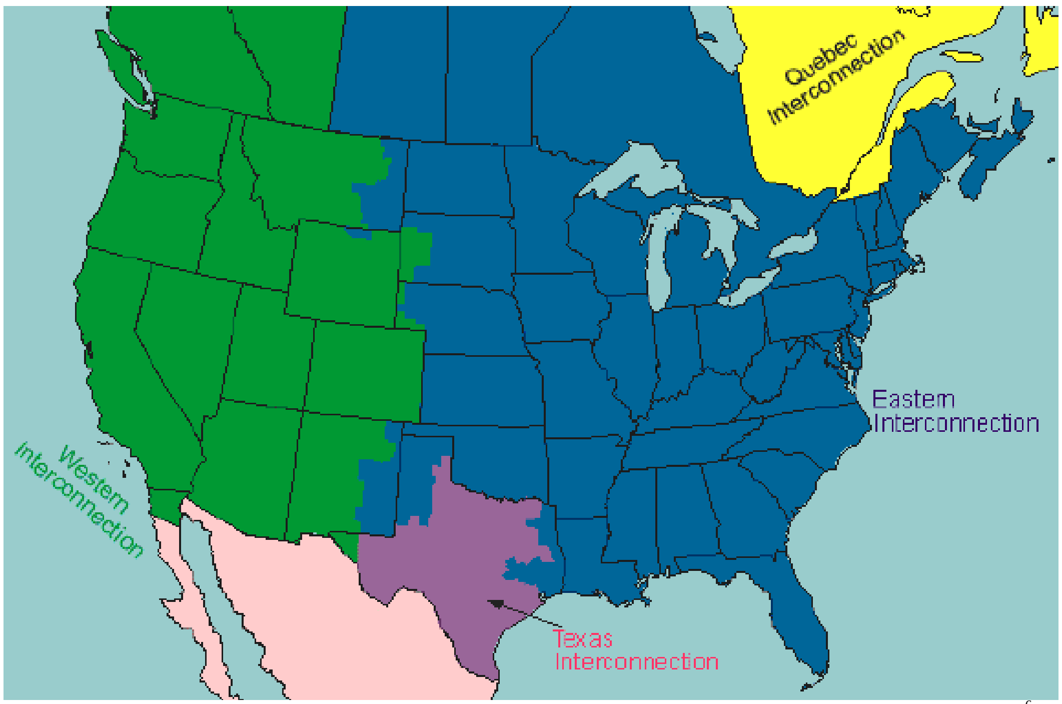
[1] North American Electric Reliability Corporation (NERC) Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.

[2] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

first level of under-frequency load shedding (UFLS). [3,4] If the frequency drops below 57 Hz or rises above 61.8 Hz, during some time period, manufacturers could recommend that generators should be disconnected to prevent generator damage. These limits are not fixed and they depend on generator type and previous generator condition.[5]

The entire North American electrical power system is partitioned into four interconnections that maintain their own frequency as close to 60 Hz as possible. The partitioning and different interconnection frequencies are achieved by using high voltage direct current (HVDC) lines and back-to-back HVDC links. HVDC lines have AC/DC and DC/AC converters at both ends of the line allowing for different frequencies. The four North American interconnections, shown in Exhibit 1-1:

Exhibit 1-1 North American Interconnections



Source: NERC 2009 [6]

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[3] UFLS is usually done in three levels. For example, ERCOT UFLS provides 5 percent system load relief if frequency drops below 59.3 Hz, an additional 10 percent if frequency drops below 58.9 Hz, and an additional 10 percent if frequency drops below 58.5 Hz. In total, ERCOT UFLS provides 25 percent load relief. Source: ERCOT, *ERCOT Nodal Operating Guide – Section 2: System Operations and Control Requirements,* December 2009, p. 2-15.

[4] EPRI, *Power System Dynamics Tutorial,* Final Report, Palo Alto, California, July 2009.

[5] IEEE Power Engineering Society, *ANSI/IEEE C37.106 – IEEE Guide for Abnormal Frequency Protection for Power Generating Plants*, New York, New York, 2004.

[6] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

- The Eastern Interconnection (EI) (covering Central Canada eastward to the Atlantic coast (excluding Québec), and south to Florida
- Electric Reliability Council of Texas (ERCOT) which encompasses most of Texas
- The Western Electricity Coordinating Council (WECC), west of Kansas to the Pacific coast, stretching from Western Canada, south to Baja California in Mexico
- The Quebec Interconnection, which is linked to and considered a part of the EI.

Although power is exchanged between these four interconnections, the frequency in each interconnection can be controlled independently due to the HVDC links among them. In recent years, the North American Electric Reliability Corporation (NERC) has observed an increase in frequency stability problems in all four interconnections.

For example, based on historic data,

Exhibit 0-1 and Exhibit 1-3 illustrate the number of high (> 60.05 Hz) and low (< 59.95 Hz) frequency (*f*) events between 2002 and 2008. In the EI, during 2002, there were about 250 low-frequency events per year while in 2007 there were more than 1,000 low-frequency events per year. In 2006, NERC was granted the role of the Electric Reliability Organization (ERO) to monitor and enforce the reliability standards.[7] In 2007, NERC's voluntary reliability standards and recommendations became enforceable reliability standards[8] and the number of low-frequency events declined to about 850 per year. This number is still 240 percent higher than it was in 2002. The cause of the change in frequency behavior is not clear. Direct, technical causes can be traced, but the indirect causes are more elusive.

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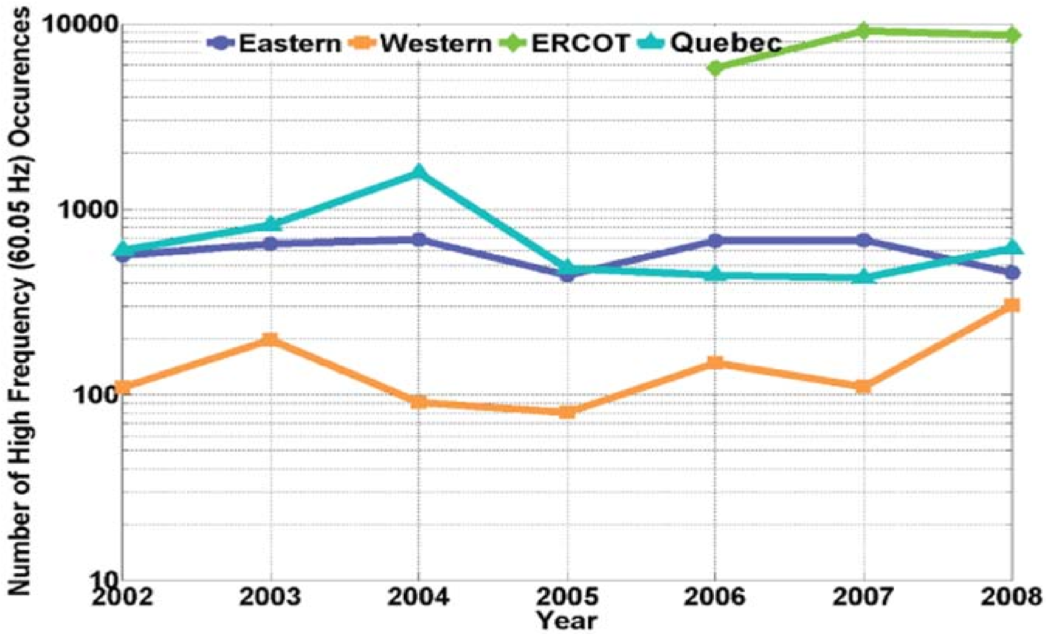
[7] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (July 20, 2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

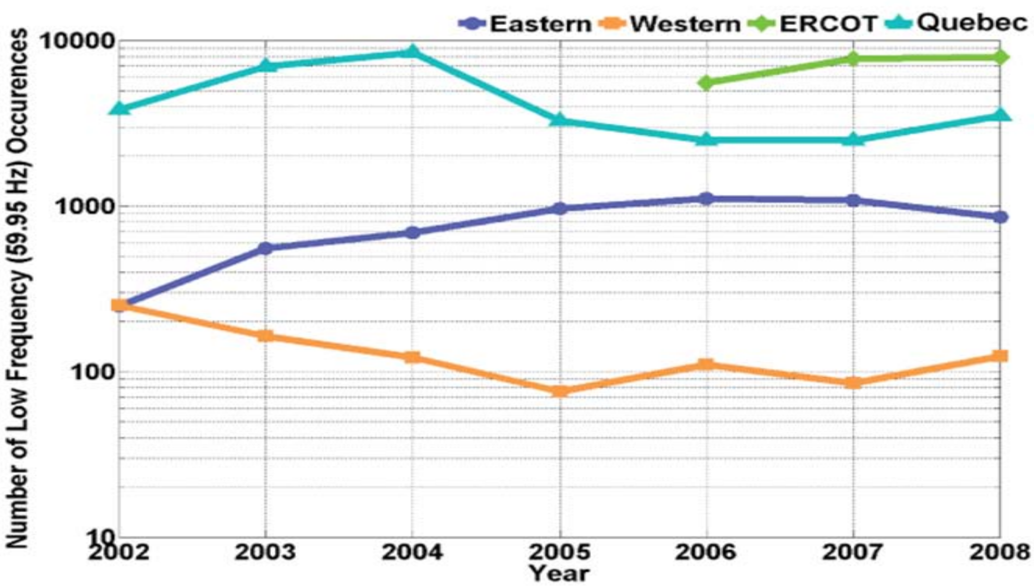
[8] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, 72 FR 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), order on reh'g, 120 FERC ¶ 61,053 (2007) (Order No. 693-A) [hereinafter Order No. 693] "approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC)."

Exhibit 0-1 Number of High-Frequency Events by Interconnection (*f* > 60.05 Hz)



Source: NERC - *Frequency Excursions (High)* [9]

Exhibit 0-2 Number of Low-Frequency Events by Interconnection (*f* < 59.95)



[9] NERC, "*Frequency Excursions (High*)", available at http://www.nerc.com/page.php?cid=4|37|257|270|271 (accessed on September 12, 2010).

Source: NERC - *Frequency Excursions (Low)* [10]

This report correlates the increased number of larger and longer-lasting frequency excursions with electricity market design and frequency control regulations. In order to make the connection between direct (technical) causes and indirect (non-technical) causes, both the physics of the problem and the regulatory environment (i.e., regulations, standards, and policies) must be understood first. The purely physical dimension of the issue can be broken down into the physical laws governing the frequency stability phenomenon (covered in Section 2.1 below) and system control efforts responsible for maintaining the nominal system frequency (covered in Section 2.2 below). Similarly, the indirect effects of the regulatory environment can be broken down into the impact of policy on market design which in turn affects frequency stability (covered Section 3.1 below) and the regulations directly affecting frequency control practices (covered in Section 3.2 below). The report concludes with recommendations, covering both technical and policy aspects of the issue, to improve frequency stability in the NERC-regulated territory.

[10] NERC, "*Frequency Excursions (Low),*" available at http://www.nerc.com/page.php?cid=4|37|257|270|271 (accessed on September 12, 2010).

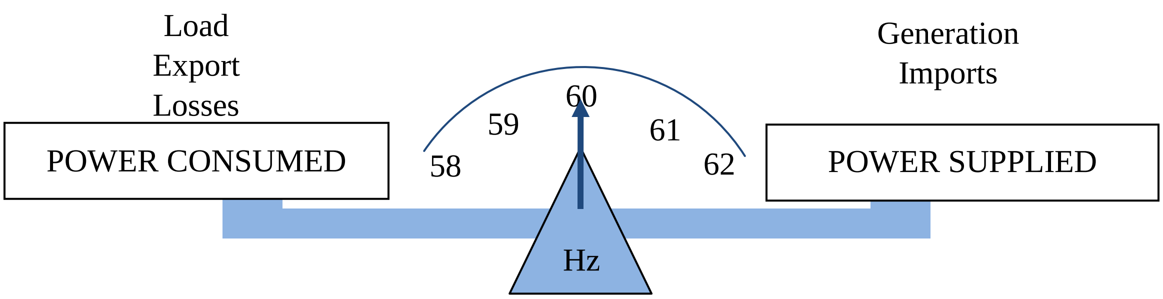
2 Technical Aspects of the Frequency Stability Issue

2.1 Physics of Power Balancing and Frequency Stability

Electrical power demand and power supply must be continuously balanced. If the demand and supply are not balanced, or if there is not enough stored energy[11] in the system to temporarily supply the imbalance, generation and demand equipment can be damaged and the entire system could collapse. A power imbalance occurs as a result of a mismatch between generation and load. While there are minor mismatches that exist on the grid most of the time, significant imbalances in either magnitude or time span can be catastrophic for a power system (e.g., result in system black outs and/or equipment damage).

Almost all alternating current (AC) power is generated by synchronous generators controlled to produce 60 Hz electricity. When generated power exactly matches power demand, the frequency could be either a nominal 60 Hz or in its vicinity, but it would be stable (Exhibit 2-1). Unless an imbalance between generation and demand is quickly mitigated, frequency could decrease to 0 Hz in a case of demand exceeding generation or increase until equipment is damaged in a case of generation exceeding demand. Even a very small, but long-lasting power mismatch can cause a significant decrease in frequency.

Exhibit 2-1 Power Balance



Data Source: EPRI [12]

The four interconnections, discussed in the Introduction, are connected using high voltage direct current (HVDC) links. The HVDC links allow each interconnection to have a different frequency, while the frequency inside an interconnection is the same for any point in that system. For example, the frequency in Los Angeles, CA, can be different from the frequency in Bangor, ME, yet the Bangor frequency is the same as the frequency in Miami, FL. This also means that imbalances in Bangor should not affect Los Angeles frequency but could potentially affect frequency in Miami, since they are in the same interconnection. All four interconnections try to

[11] Either passive storage, such as a battery, or kinetic energy within the power system could offset the power imbalance.

[12] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

maintain their frequencies within a narrow band around 60 Hz[13] specific to their own operating standards. For example, the normal frequency is between 59.95 Hz and 60.05 Hz for the Eastern Interconnection, and between 59.856 Hz and 60.144 Hz for the Western Interconnection.[14]

A mismatch between generation and demand is the direct cause for frequency instability. There are five main system characteristics and operational practices that influence the severity of, and recovery from, power mismatches:

1. An interconnection's moment of inertia;
2. Load types;
3. Generation control practices;
4. Types of reserves and their availability;
5. Frequency control (monitoring and regulating) practices.

An interconnection's moment of inertia does not cause power imbalances, but it does affect the system's inherent response to those disturbances and the frequency control methodology used to recover from those disturbances. Some load types are frequency-dependent and since most of such loads are inductive in nature, they actually act as natural frequency stabilizers. Generation control practices are closely related to generation efficiency and as such have a direct effect on the profit margins; this could be a serious issue in deregulated market environments. Spinning and non-spinning reserves are critical during primary and secondary frequency control (defined and described in detail below); reserve operations can also be affected by market design. Monitoring and data collection enable control of frequency during real-time operations and also form the basis of intelligent, data-driven formulation of standards and regulations.

2.1.1 Power System Moment of Inertia

A system's moment of inertia is the total moment of inertia of the connected power generating units, including both the prime mover and the generator of each unit. The moment of inertia is defined as the product of rotating mass and the square of the distance from the center of rotation. A rotating mass has characteristics of an energy storage device. Rotational speed of synchronous generators, which is the same for all interconnected generators, is actually the system frequency. During acceleration, energy is stored, and during deceleration, it is released. In the case of a negative frequency deviation, during acceleration, the system's moment of inertia works against frequency control efforts because it is storing rotational energy; during deceleration the moment

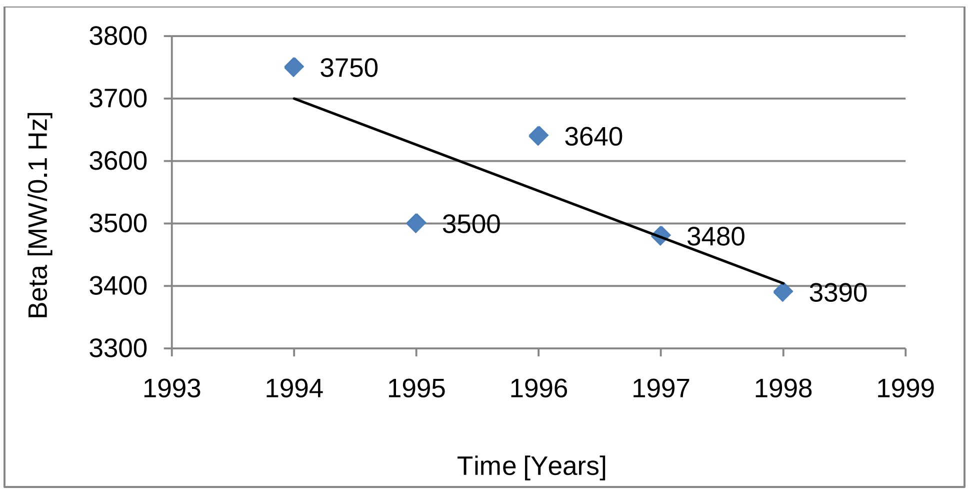
[13] 60 Hz is the nominal frequency for the United States. The nominal frequency can be offset by ± 0.02 Hz (scheduled frequency is equal 59.98 Hz or 60.02 Hz) during Time Error Correction. The NERC Glossary defines "time error correction" as "an offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value." Further, the NERC Glossary defines the "time error" as "the difference between Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology."

[14] NERC, "Leading Indicators: *Frequency Excursions*," available at http://www.nerc.com/page.php?cid=4|37|257|270 (accessed September 12, 2010).

of inertia helps to control frequency by releasing previously stored rotational energy. It is important to remember that it is not the moment of inertia that affects the frequency response but the energy stored. For example, a two-pole generator that must rotate at 3600 rpm to produce 60 Hz has four times the stored energy (i.e., kinetic energy contained within the system) of a generator with four poles rotating at 1800 rpm also producing a nominal 60 Hz and having the same moment of inertia. Wind power plants are usually described as having negligible moment of inertia, which is not necessarily true, but they do have negligible stored energy due to their slow rotational speed.

Along with the magnitude of a power imbalance, the moment of inertia at synchronous speed is a major variable that defines the initial frequency deviation. The lower the moment of inertia is, the larger the deviation produced, and the higher the moment of inertia is, the smaller the deviation. Over the last 10 to 20 years, the electric power generation industry has experienced a significant shift from large, centralized power plants with significant moment of inertia to small, more distributed, and renewable power plants with much less moment of inertia. Over the same time period, the frequency response characteristic, measured as the imbalance per 0.1 Hz frequency deviation (β), of the Eastern Interconnection has decreased as shown in Exhibit 2-2. A decreasing frequency response means that progressively smaller power disturbances cause the same frequency excursion of 0.1 Hz.

Exhibit 2-2 Decline in β in Eastern Interconnection Over 5-Year Period



Data Source: Ingleson & Nagle, 1999 [15]

If the β trend in the Eastern Interconnection shown in Exhibit 2-2 is extrapolated to the year 2010, it would be around 2500MW/0.1Hz. This means that a loss of a large 1300 MW generator would cause a frequency deviation of about 0.05Hz. This frequency degradation is not a cause for serious concern yet, but if the trend continues or gets worse there could be some unpleasant consequences in the not so distant future.

[15] Ingleson, J., and Nagle, M., *Decline of Eastern Interconnection Frequency Response*, Fault and Disturbance Conference, Atlanta, GA,1999.

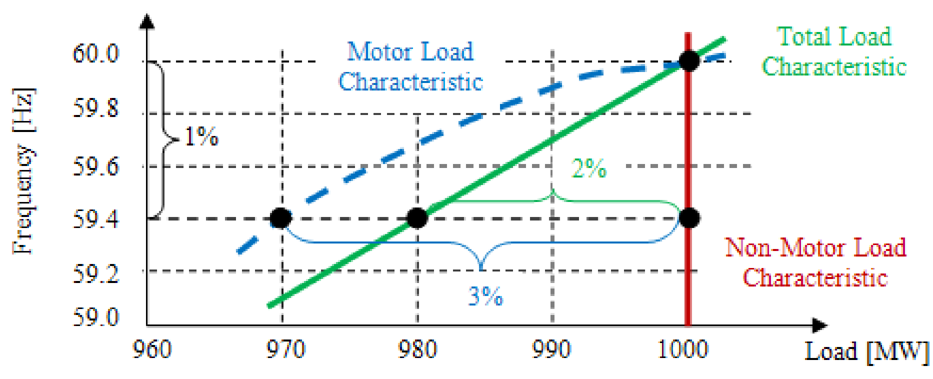
2.1.2 Load Types

Since system demand fluctuates continuously, an interconnection rarely operates at exactly targeted or scheduled frequency of 60 Hz. The ability of a system element, such as generator or load, to react or respond to the inherent fluctuations in system frequency is known as the "element frequency response." There are two types of element responses, controlled and uncontrolled. Generators respond in a control manner due to the application of some control logic. On the other hand, loads with energy storage elements are frequency dependent, having well-defined but uncontrolled elemental frequency response.

In general, loads can be grouped into three major categories: industrial, residential, and commercial. Each load category has its own characteristics. For example, industrial loads tend to be heavy rotating machines with high inertia and good frequency responses. On the opposite side of the load spectrum are commercial and residential loads, which usually include electronically controlled devices with a weaker frequency response. The effect of load type on the frequency response is important to the extent that it has been suggested as a separate input to the frequency response models.[16] Inductive loads, such as rotational electrical machines, are natural frequency stabilizers.

Exhibit 2-3 illustrates three load types: motor load (blue dotted line), total load (green line), and non-motor load (red line). Motor loads (blue dotted line) increase during frequency excursions, which helps stabilize system frequency. However, non-motor loads (red line) are unchanged by frequency fluctuations and, consequently, do not contribute to buffering the system frequency. The total load characteristic frequency response (green line) is the superposition of the various load types frequency response. Therefore, systems with higher motor load content have more muted responses to frequency deviations and therefore have more inherent stability than systems with lower motor load content.

Exhibit 2-3 Motor Load and Frequency Dependence



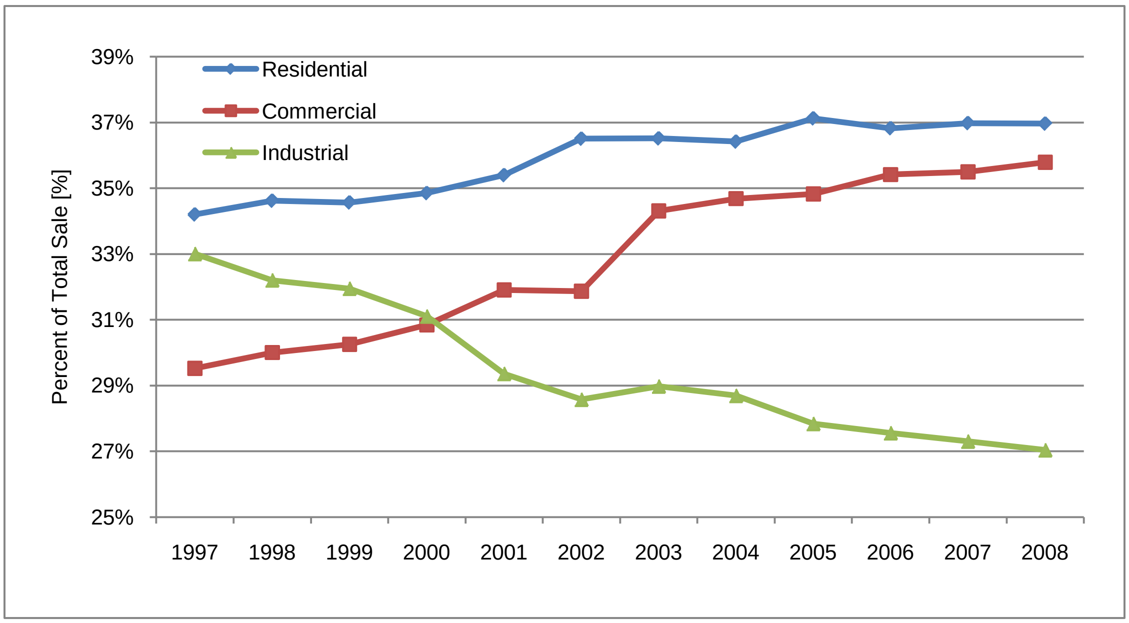
Source: Electric Power Research Institute, 2009, p. 4-8, used with permission [17]

[16] Mitchell, M.A. Lopes, J.A.P., Fidalgo, J.N. and McCalley, J.D., *Using a Neural Network to Predict the Dynamic Frequency Response of a Power System to an Under Frequency Load Shedding Scenario*, IEEE PES Summer Meeting, Seattle, WA, 2000, p. 346-351.

[17] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

The following factors not only affect the magnitude of the load but also the load type affecting the frequency response. In recent years, industrialized countries' load distribution has changed from mostly rotating machine loads to low- and high- power electronics. Relative reductions in rotating machine loads might be a contributor to larger frequency excursions experienced recently by the Eastern Interconnection operators. Loads using AC/DC conversion as well as purely resistive loads are not frequency dependent. Exhibit 2-4 shows the percent of energy sales by load type between 1997 and 2008. Loads are also affected by other drivers, including population, economic situation and growth, temporal behavior patterns, and weather patterns. A change in any of these factors could change load compositions. It might be noted that nearly all of the above factors have recently changed dramatically, from the population to the weather patterns. The US population has increased almost linearly with time (Exhibit 2-5 below) which, in general, shifts load composition away from industrial toward residential and commercial loads while the weather is an inherently dynamic phenomenon.

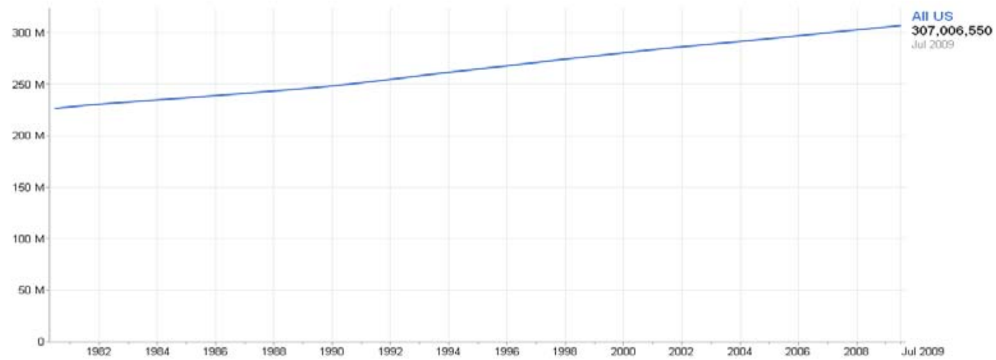
Exhibit 2-4 U.S. Retail Sales of Electricity to Ultimate Customers by Sector



Source: EIA- Electricity [18]

[18] Energy Information Agency (EIA), *Electricity - Table 7.2. Retail Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 1997 through 2008* http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html (accessed on September 12, 2010).

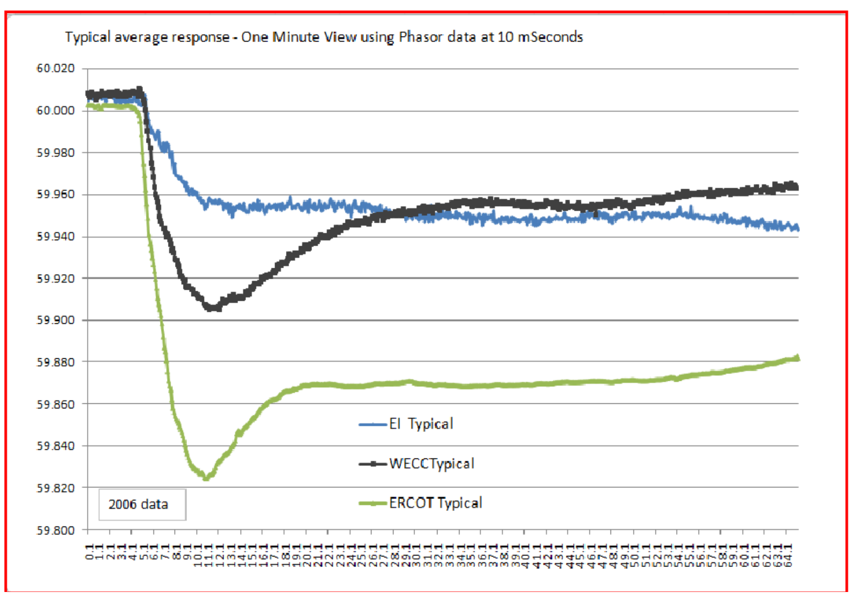
Exhibit 2-5 Near-Linear Population Growth in US



Data Source: US Census Bureau [19]

Frequency response characteristics can be different in interconnections with different type loads. Exhibit 2-6 shows typical frequency response in the Eastern Interconnection, Western Electricity Coordinating Council, and Electric Reliability Council of Texas. The frequency response in the Eastern Interconnection is distinctly different from the frequency responses in WECC and ERCOT. One factor is that the Eastern Interconnection load traditionally consists of more rotating industrial machines than the other interconnections and consequently has better frequency response characteristics. [20]

Exhibit 2-6 Typical Frequency Traces Following a Unit Trip



Source: NERC 2009 [21]

[19] US Census Bureau, Population Division, Washington, D.C., 2009.

[20] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[21] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

2.1.3 Generator Operations and Control Practices

Generators have little to no reason to consider stability of the interconnections frequency when optimizing the operations. Neither the Federal Energy Regulatory Commission (FERC) nor NERC mandates generators to take part in primary frequency control (i.e., actions taken to stabilize frequency in the event of a significant deviation, described in detail in Section 2.2.1 below). Generators larger than 10 MW are expected to participate in primary frequency (governor) control by adjusting their real power output. NERC recommends that each generator larger than 10 MW have a governor control with five percent droop characteristic. As discussed below, on March 18, 2010, FERC issued an Order[22] to NERC to submit a modified BAL-003 reliability standard within six months and to define the necessary amount of frequency response needed for reliable operation. At this time, primary frequency control is only required by some balancing authorities such as ISO New England.

However, as was mentioned in the PJM Interconnection, LLC (PJM) request for clarification and rehearing of the FERC March 18, 2010 Order, this has never been a requirement.[23] For efficiency and financial reasons, generators can choose control schemes that are not the most responsive to frequency deviations but are more financially beneficial to their owners. For example, a generator operator can choose to operate at full capacity leaving no operating margin for the governor control. Operating a unit at full capacity will generate larger profits because the owner would be able to sell more energy at market prices. Since no ancillary services market currently exists for primary frequency control, there is only the ancillary market for frequency regulation;[24] thus, the generator owners do not have strong incentives to participate in frequency response to the best of their ability. Deregulation, the competitive nature of energy markets, and the lack of a primary frequency control standard have driven a large number of generator units to operate at maximum output levels, so they are optimized based on an individual generating unit's financial perspective. Therefore, there is no assurance that generator units will be available for frequency response when they are needed.[25] Certain generator operations are cited as possible contributors to the primary frequency response declines due to control reasons[26,27] such as the following:

[22] *Order Setting Deadline for Compliance*, 130 FERC ¶ 61,218 at P 1 (March 18, 2010).

[23] *Order Setting Deadline for Compliance*, Request of PJM Interconnection, L.L.C. for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010 (April 19, 2010), p. 2, PJM states: "Lastly, the Commission states at Paragraph 16 that '[t]he need to keep some level of frequency response existed in prior NERC policies and procedures.' However, there has never been a requirement that the industry provide for governor response and the Commission's statement to the contrary is inaccurate."

[24] Primary frequency control is not the same as frequency regulation.

[25] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[26] *Order Setting Deadline for Compliance*, Request of the North American Electric Reliability Corporation for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010, p. 9 (April 19, 2010).

[27] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

- Steam turbine sliding pressure control and/or "valves wide open" operation
- Combined cycle (CC) exhaust temperature control
- CC positive frequency feedback
- Nuclear power plant-blocked governor control

Steam power plants can work in two different operating modes: constant pressure and sliding pressure mode. In the constant pressure mode, boiler pressure is kept constant regardless of generator output (load). In sliding pressure mode, boiler pressure is a linear function of generator output where maximum pressure is achieved for maximum generator output. If the steam power plant is used as a continuous base-load unit, it is able to achieve high efficiency in a constant pressure mode. However, non-base-load units need to be able to adapt their operations to variations in the power that they are scheduled to inject into the system. Consequently, steam turbine generators that are not base load (a.k.a., partial-load plants) need to seek other operating regimes to improve their efficiency.

Operating a plant in a "sliding pressure" mode is a possible solution that increases steam power plant efficiency during partial-load operation. In this mode, the boiler provides only the required pressure to meet demand without any throttling. The disadvantage of the "sliding pressure" mode is the reduced ability to meet short-term demand fluctuation, because fast-responding valves are used as protection for sudden steam pressure increases.[28] The steam power plants that work in "sliding pressure" mode cannot be used for frequency response. In the U.S. there is at least one power plant that works in this mode. It is the Mountain View power plant in California.[29]

Combined cycle (CC) exhaust temperature control regulates the fuel such that a temperature increase/decrease is controlled and the CC unit operates at maximum capacity ratings.[30] In this control mode, a CC unit cannot respond in the upward direction. If the CC unit does not operate at maximum capacity, it can provide some frequency/system disturbance response until the exhaust temperature reaches its upper limit.

CC units can have a positive frequency feedback. This means that when the frequency drops, the CC output will drop as well.[31] Exhibit 2-7 illustrates a CC unit response to frequency change. The blue line represents frequency and the red line is the generator's MW output. The CC unit shown has a positive frequency feedback and will reduce output power by 1.05 MW, which is a 2.5 percent reduction in machine output. This type of frequency response may cause problems, because the generator unit would make the situation worse during an emergency event. This type

[28] Flynn, D., *Thermal Power Plant Simulation and Control*, London, Institution of Electrical Engineers, 2000.

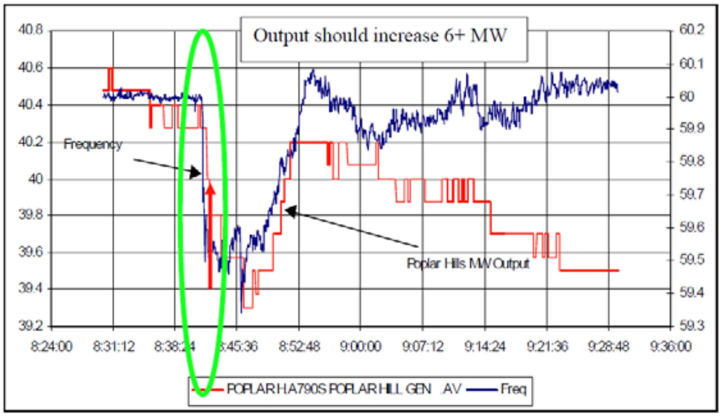
[29] http://tdworld.com/underground_transmission_distribution/SCE-underground-circuits/ (accessed on September 1, 2010).

[30] Grigsby, L, *Power system stability and control*, Boca Raton: CRC Press, 2007.

[31] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

of frequency response can be modified, but plant operators need to be educated about such events and be motivated to respond in a more holistic manner.

Exhibit 2-7 Combined Cycle Response to Frequency Change



Source: NERC 2004[32]

Nuclear power plants are capable of governor response but they are usually operated at maximum capacity rating and cannot respond to frequency deviation or be used for primary frequency control.[33] The steady state nuclear plant power output provides safety benefits for nuclear power plant operations.

2.1.4 Types and Availability of Generation Reserves

The minimum operating reserve differs from region to region; it is usually based on the largest generating unit on-line or the single most severe contingency.[34] For example, the Western Electricity Coordinating Council requires contingency reserves equal to the greater of

- The most severe contingency
- Three percent of load plus three percent of net generation[35]
- Five percent of the load supplied by hydro power plants plus seven percent of the load supplied by thermal generation[36,37]

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[32] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[33] Flynn, D, *Thermal Power Plant Simulation and Control.* London, Institution of Electrical Engineers, 2000.

[34] Reliability standard BAL-002-0 states that “as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency” (effective April 1, 2005).

[35] Reliability standard BAL-002-WECC-1, Requirement R.1.1, (Effective on the first day of the next quarter, after receipt of applicable regulatory approval), available at (http://www.nerc.com/files/BAL-002-WECC-1_Final.pdf (accessed on September 15, 2010).

The Electric Reliability Council of Texas requires 1,354 MW for contingency reserve and at least 2,300 MW for responsive reserve.[38]

The PJM requires the minimum contingency reserve must be sufficient to cover the largest contingency. [39] However, different regional reliability organizations that comprise PJM have additional requirements. For example, the minimum contingency reserve in Reliability *First* Corporation (RFC) should be 150 percent of the largest unit in RFC, or 1,700 MW for the Mid-Atlantic zone. In addition, spinning reserve should be at least fifty percent of contingency reserve, and interruptible load should not be more than twenty-five percent of contingency reserve.[40]

In a vertically regulated industry, the balancing authority (BA) is responsible to provide full reserve for its individual largest contingency and some for multiple contingencies.[41] In a regulated environment, the BA operator most likely owns the generator and knows the technical characteristics of typical units. This knowledge helps the control area operator to select the generation portfolio that would best respond to power imbalance as desired.[42] This is not the case in a deregulated environment.

In the current deregulated environment, control area operators are motivated to reduce operating costs. Consequently, reserve sharing groups (RSG) have been established within a NERC region. An RSG collectively supplies operating reserve[43] such that each BA proportionally contributes to covering the largest RSG contingency, thus reducing overall amount of reserves required to cover the largest contingency and the associated costs for all members of the RSG. Because belonging to an RSG is voluntary, generators can still choose the market in which to sell their services (i.e., energy market, ancillary service market, or both).

Exhibit 2-8 provides an example of hourly regulation services (regulation market clearing price [RMCP] and energy prices (locational marginal clearing price [LMCP]) for the PJM market. The regulation prices are typically, but not always, lower than energy prices. These generator units are bidding power and price in the ancillary services market, but they do not bid technical characteristics. The ancillary market is cleared such that minimum cost service is provided, but

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[36] Reliability standard BAL-STD-002-0, Requirement a.(ii), (will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act), available at http://www.nerc.com/files/BAL-STD-002-0.pdf (accessed September 15, 2010).

[37] Hrist, E., and Kirby, B., *Technical and Merket Issues for Operating Reserves*, Tennessee: Oak Ridge, 1998.

[38] ERCOT, *Operating Procedure Manual – Frequency Control Deck*, available at http://www.ercot.com/mktrules/guides/procedures/ (on line accessed on 9/15/2010).

[39] PJM, *Manual 12 - Balancing Operations (Attachment D)*, effective October 5, 2009, p. 78.

[40] PJM, *Manual 13 – Emergency Operation (Section 2)*, effective August 13, 2010, p. 11.

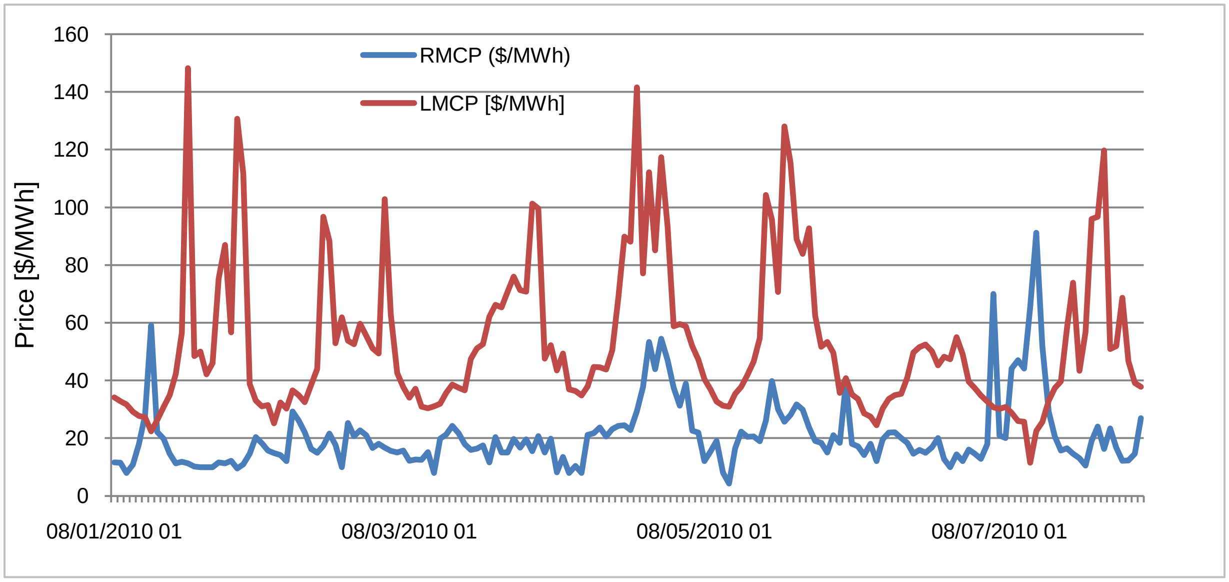
[41] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[42] Hrist, E., and Kirby, B., *Technical and Market Issues for Operating Reserves*, Tennessee: Oak Ridge, 1998.

[43] NERC, *NERC Operating Manual*, New Jersey, 2004.

this does not ensure that the power supplied for ancillary services has the optimal technical characteristics. Consequently, selecting providers of ancillary services in this manner does not necessarily ensure that the system will respond to disturbances as desired. The RSG and generator preference to choose the market where they will provide service leads to less reserve available to respond to frequency disturbances, and to a decline in primary frequency response.[44]

Exhibit 2-8 Hourly Regulation and Energy Prices in PJM



Data Source: PJM [45]

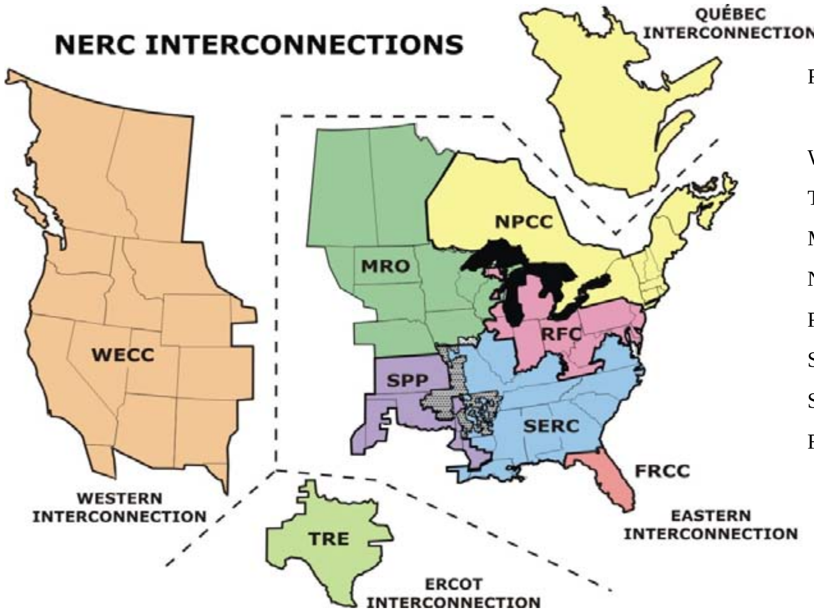
2.1.5 Frequency Control (Monitoring and Regulating) Practices

Frequency monitoring and regulation are crucial to frequency control. Grid interconnections must conform to the criteria set forth by NERC. Within each interconnection, there are a number of Reliability Coordinators. Each Reliability Coordinator coordinates operations of a number of BAs running automatic generation control (AGC) within their balancing authority areas. Exhibit 2-9 shows the North American Interconnections with Reliability Coordinators in each Interconnection.

[44] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[45] http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx (accessed on September 11, 2010) and http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation.aspx (accessed on September 11, 2010).

Exhibit 2-9 NERC Interconnections and Regions



Regional entities

WECC – Western Electricity Coordinating Council
TRE – Texas Regional Entity
MRO – Midwest Reliability Organization
NPCC – Northeast Power Coordinating Council
RFC – Reliability *First* Corporation
SPP – Southwest Power Pool
SERC – SERC Reliability Corporation
FRCC – Florida Reliability Coordinating Council

Source: NERC website[46]

Each BA is connected to its neighboring areas and contributes to the frequency regulation of the entire interconnection by continuously balancing its internal demand and generation to meet scheduled interchanges. The BA, therefore, continuously participates in the overall frequency regulation of the entire interconnection. The BAs are connected to each other through “tie lines,” which monitor the energy flow out as positive and the energy flow in as negative. The difference between the actual interchange and the scheduled interchange is called “inadvertent interchange” and is supplied or absorbed by the interconnection system. The term “inadvertent” emphasizes the expected function of the control area, which is to match the actual interchange to the scheduled. However, this task is often not possible, and therefore, in reality the BA maintains the inadvertent interchange within the limits set by NERC in the Control Performance Criteria.

The BAs contribute to stabilizing the frequency of the interconnection system through their primary control and automatic generation control, both of which are described in detail in Section 2.2. As long as the balance between actual and scheduled interchange is maintained, the area control error (ACE) of a BA is zero. A non-zero ACE value causes a frequency excursion that might affect operations of the entire interconnection during the primary frequency response.

The BAs must adhere to NERC guidelines and standards to ensure they will not burden other balancing areas during normal operations. In addition to NERC, other local or federal regulatory

[46] NERC Interconnections (Color), available at
http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_color.jpg
(accessed on September 11, 2010).

entities might impose their own guidelines and requirements on the operation of the control areas. NERC also provides guidelines for the inadvertent interchange management.

The control performance standards/guidelines are provided by NERC, but there has been considerable discussion in the literature on their efficiency. The current standards are focused on calculating the ACE, as defined by the following equation:[47]

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} \qquad (1)$$

Where:

NI_A = Net Interchange, Actual

NI_S = Net Interchange, Scheduled

B = Balancing Authority Bias

F_A = Frequency, Actual

F_S = Frequency, Scheduled

I_{ME} = Interchange (tie line) Metering Error

A more extensive discussion of ACE follows in Section 2.2.2 below.

The above discussion reveals the need for the following:

- Analysis of data from many control areas and reserves with different load profiles to determine optimal control functionalities that could be associated with specific time windows
- Development of statistic-based correlations to identify effective parameters for use in the control performance standards
- Collection of time and location based frequency response data for the above
- Smart methods for collecting statistically meaningful data with sufficient resolution to achieve the above
- Assessment of various periods with different load and generation ramp-rates
- Sensitivity analysis to determine critical metrics for optimal economics and performance
- Validation of the above metrics based on real-world data

2.2 Frequency Control

The purpose of all control systems is to maintain the output of a controlled system at a pre-specified or time-changing value. A control algorithm might have to satisfy certain constraints and objectives. In the case of frequency control, the objective is to maintain the nominal frequency as closely as possible. If there is a disturbance, it is desirable to restore the nominal

[47] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

frequency quickly. Frequency deviations are an indication of power mismatch in the power network. If power generation and demand are not balanced, the frequency continues to increase if generation exceeds demand (or decrease if demand exceeds generation). Eventually connected equipment starts failing and after some time the power system collapses (e.g., power is not delivered at the quality and quantity demanded). For this reason, quick frequency restoration is mandatory.

Frequency control is implemented in stages where each stage acts over a different time scale. At the first stage, called primary or governor control, frequency change is stopped. At the next stage, secondary or automatic generation control restores the frequency to its nominal value using designated AGC generators. Generation is re-dispatched to relieve AGC generators for future control actions at the tertiary stage. Exhibit 2-10 summarizes the frequency control stages along with their timeframes and NERC standards regulating them.

Exhibit 2-10 Control Continuum Summary[48]

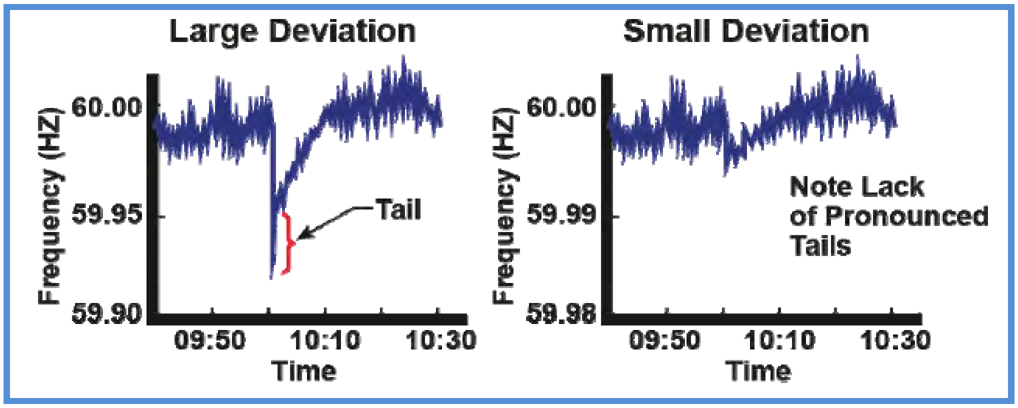
Control	Ancillary Service	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 seconds	FRS-CPS1[a]
Secondary Control	Regulation	1-10 Minutes	CPS1-CPS2
Tertiary Control	Imbalance/Reserves	10 Minutes – Hours	BAAL-DCS
Time Control	Time Error Correction	Hours	TEC

[a]*CPS=Control Performance Standard*

Since demand is the aggregation of a very large number of small loads that turn on and off randomly, frequency continuously fluctuates around some average value. In its statistical nature, this type of fluctuation is small when observed on a short time scale. It is not possible to compensate for small, very fast frequency deviations. The IEEE recommends that frequencies within +/-0.036 Hz around the nominal frequency be considered as nominal.[49] Exhibit 2-11 illustrates typical small- and large-frequency deviations.

[48] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.
[49] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

Exhibit 2-11 Frequency Profile after Large and Small Deviation



Source: Electric Power Research Institute, 2009, p. 4-28, used with permission [50]

The interconnections discussed in the Introduction are partitioned into areas handled by balancing authorities. From scheduled intertie flows, real-time intertie flow measurements, and system frequency, it is straightforward to determine which area is responsible for power imbalance as well as the ACE. Initially, after an imbalance occurs, the entire system participates in frequency regulation, but the area responsible for the imbalance is expected to eventually account for its internal imbalance. Once an imbalance is detected, the system responds at different time scales. Primary control responds within seconds, secondary control within minutes, tertiary control within minutes to hours, and time control within hours.

2.2.1 Primary Frequency Control

The primary control starts within seconds of a disturbance occurrence to prevent further frequency deterioration; the primary control's role is not to return the frequency to its nominal value, but to stabilize it. The primary control is implemented through governor control helped by the system's moment of inertia and frequency-dependent load response. Governor control adjusts the prime mover's power input, which is directly related to the generated electrical power. Governor control is normally activated by a frequency drop below 59.97 Hz or a rise above 60.03 Hz. A governor responds to frequency deviations according to its droop curve. The droop curve determines the generator's power output based on the frequency measurement. A typical droop curve is shown in Exhibit 2-12.

In North America, the industry practice is 5 percent droop.[51] This means that a generator should go from zero to full capacity if the frequency changes by 5 percent (or 3Hz). A 5 percent frequency change, or 3 Hz, corresponds to +/- 1.5 Hz around 60 Hz. Exhibit 2-13 shows a governor response for a 0.1 Hz disturbance. In this case, the frequency will stay at its new operating point of 60.1 Hz unless the AGC reacts as well.

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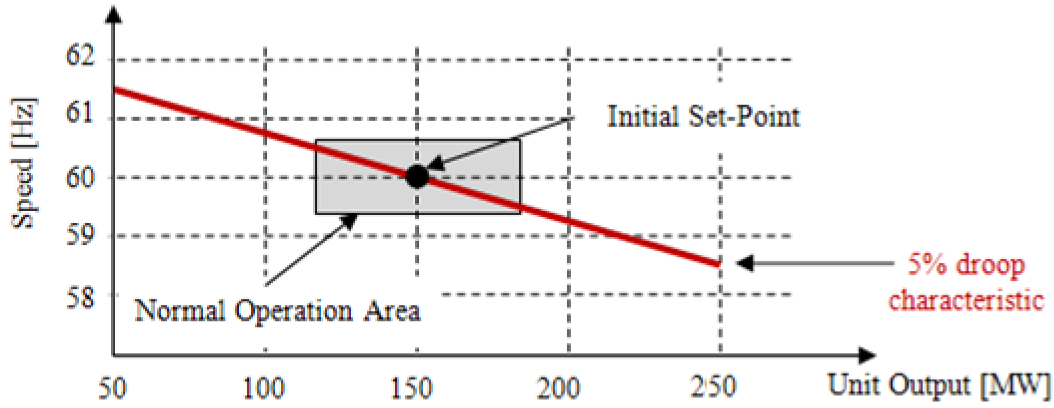
[50] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

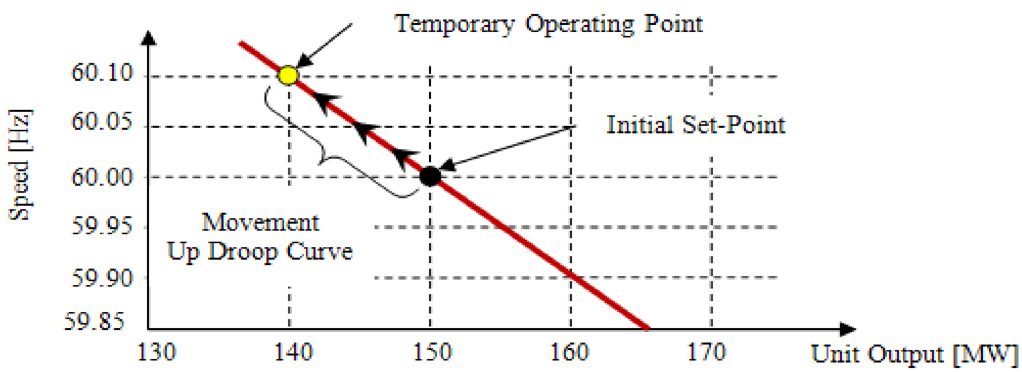
[51] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

Exhibit 2-12 Governor Characteristic Curve (Droop Characteristic)



Source: Electric Power Research Institute, 2009, p. 4-17, used with permission [52]

Exhibit 2-13 Governor Control—New Operating Point



Source: Electric Power Research Institute, 2009, p. 4-8, used with permission [53]

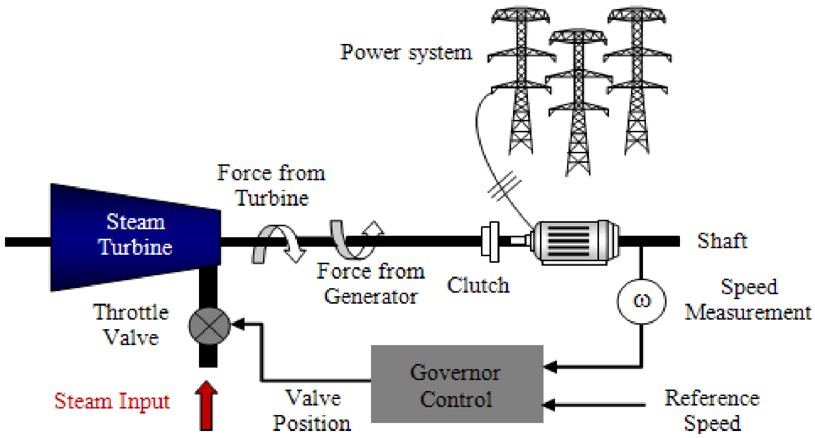
Primary control does not provide complete frequency regulation because it does not return the frequency to its nominal value, and it does not consider the cost of the power used for control. Primary control is designed for a single generator, along with other generators, to prevent the frequency from experiencing further changes. The main reason for such an approach is the need for very fast control response—essentially as soon as the disturbance occurs. Because of the fast response required and a lack of equally fast communication among generators and with the control center, primary frequency control acts in a distributed and independent manner. This is also the main reason for the primary control to arrest the frequency deviations only, rather than to try to reestablish it at its nominal value. If all generators tried to match the power demand and

[52] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[53] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

return the frequency to its nominal value in a distributed way and at the same time, there would be competition among the generators resulting in oscillations. Exhibit 2-14 illustrates a typical primary control hardware setup.

Exhibit 2-14 Typical Primary Governor Control



Data Source: Adapted, with permission, from EPRI (2009), Figure 4-10, p.4-11.[54]

The ideal system component for effecting primary control is a (or a limited number of) large baseload unit(s) with a considerable moment of inertia in order to absorb and arrest the perturbation to the overall power system. Such a need is best served by coal-fired power plants, since other operational constraints keep nuclear plants from accepting primary governor control.

After the primary control arrests frequency deviation, reestablishing the nominal frequency is left to the secondary control: implementing automatic generation control coordinated by the balancing authority and the reliability authority.

2.2.2 Secondary Frequency Control

The primary frequency control effected via governor control typically controls a single unit and it does not return frequency to nominal value (60 Hz). On the other hand, secondary frequency control uses automatic generation control (AGC)[55] to control multiple generators inside a balancing authority area and restore frequency to its nominal value. AGC generators return frequency to nominal value by adjusting power plants' power outputs. The balancing authority

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[54] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[55] The NERC Glossary defines "automatic generation control" as "equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction."

monitors total supply (generation and import), total demand (load demand, losses, and export) and frequency inside its area and computes the area control error. [56]

Recall from Section 2.1.5 above that the ACE is difference between net scheduled and actual interchange. If the ACE is not zero, the balancing authority sends signals to selected generators to adjust their outputs to drive ACE to zero. These generator units are called regulating units. The role of a balancing authority is to ensure that the tie-line flows are as planned and, along with other balancing authorities, to maintain frequency within acceptable limits. Each interconnection has one or more balancing authorities as shown in Exhibit 2-15. AGC systems must control enough generating capacity to supply the balancing authority's internal demand and losses and scheduled interchanges while maintaining the nominal frequency. An AGC system must not interfere with neighboring balancing authorities' normal operations. Each AGC should maintain actual net interchange of its balancing authority close to its scheduled interchange.[57]

Exhibit 2-15 Number of the Balancing Areas[58]

Interconnection	Balancing Authorities
Eastern	90
Western	30
ERCOT	1
Quebec	1

There are three common AGC implementations:[59] constant frequency control (CFC), constant net interchange control, and tie-line bias control. Constant frequency control AGC is common for interconnections with a single balancing authority, such as ERCOT or Quebec. CFC AGC adjusts the power output of the power plants based only on the frequency deviations. If CFC is used in interconnections with more than one balancing authority, it could result in erratic behavior and power swings. Constant net interchange control AGC controls the interchange flows only and ignores frequency deviations. This type of control could be used when a balancing authority loses its AGC frequency source. The tie-line bias control is the most common AGC control method in interconnections with multiple balancing authorities. Under this control method, after frequency deviation is arrested, the balancing authority responsible for

[56] The NERC Glossary defines "area control error" as "the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error."
[57] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.
[58] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.
[59] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

disturbance is responsible for returning frequency to its nominal value. Recall from Section 2.1.5 (Equation 1) that ACE for a tie-line control is defined as:[60]

ACE = [Actual Net Interchange – Scheduled Net Interchange] –

10·B·[Actual Frequency – Scheduled Frequency] – Correction for Meter Error (2)

where B is the frequency bias constant. The B parameter is an estimate of the balancing authority's frequency response characteristic. This is the same as β shown in Exhibit 2-2 but estimated for a single balancing authority only. The B parameter is hard to calculate accurately because it depends on time of the day, load size and type, the size of disturbance, and other factors. Some balancing authorities pay great attention to parameter B estimation due to its role in ACE calculation.

Prior to January 1997,[61] best practices for secondary control implementation included use of the A1 and A2 method. The A1 and A2 method refers to having the ACE comply with the A1 and A2 control criteria with 90 percent conformance. The A1 criterion requires the return of ACE to zero every 10 minutes. The A2 criterion requires the average of ACE to be within $\pm L_d$ for each 10-minute period. L_d is the compliance limit for the A2 criterion or the "allowable limit of average deviation surveys" obtained from the annual surveys included in the control performance criteria training documents.

The A1 and A2 criteria have been replaced as a best practice for secondary frequency control because of the lack of a theoretical basis for the A1 and A2 criteria, and therefore the inability to relate these criteria to any reliability parameter. They have been ruled out as being based on "mature operating experience and judgment" [62] and not suitable to the needs of today's market. Additionally, the A1 limit would unnecessarily show a violation of the standard if ACE were close to zero for more than ten minutes. This could result in inefficient generation dispatch. The A1 and A2 criteria could also allow the control areas to operate just above the lower A2 limit 99 percent of the time as long as the ACE would cross zero once every 10 minutes.

Contrary to the older A1 and A2 method, the current Control Performance Standards, CPS1 and CPS2 are statistical methods with a basis in frequency base theory. The CPS1 utilizes the impact of ACE measurements on frequency over a 12-month period. By doing so, it can refer different actions to different control areas for variations in the interconnection efficiency while it takes other factors into account, such as the size of the control area and nature of the deviation (load/generation). CPS2, on the other hand, places limits on the fluctuations in the ACE value.

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[60] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

[61] B.J.Kirby, J. Dyer, C. Martinez, Rahmat A. Shoureshi , R. Guttromson, and J. Dagle, *Frequency Control Concerns in North American Electric System,* Oak Ridge National Laboratory, 2002, available at http://www.ornl.gov/sci/btc/apps/Restructuring/ORNLTM200341.pdf (accessed September 16, 2010).

[62] Control Performance Standards. http://www.nerc.com/docs/oc/ps/tutorcps.pdf (accessed August 18, 2010).

With this approach, the historic frequency data replaces the A2, making the ACE control more realistic.

The non-linear frequency portion of the CPS could be attractive to control areas with better control systems, as well as an incentive for the weakly-controlled control areas to invest more in their control system. However, the CPS system is still vulnerable to net unscheduled power flows. Moreover, a coherence analysis of data from several control areas has revealed inconsistency in the level of tracking.[63] This analysis has shown the CPS approach to be highly case sensitive and often worse than the A1 and A2 method.

2.2.3 Tertiary Frequency Control

Tertiary control is part of the regular market clearing mechanism. Once the nominal frequency is restored, AGC-assigned generation should be substituted by energy obtained through regular energy market procedures, releasing the AGC generation for future control actions. Tertiary control acts on minute-to-hours time scale.

2.2.4 Time Control

The system frequency is never exactly 60 Hz, and time control is responsible to keep long term frequency average as close to 60 Hz as possible. For this purpose, a single interconnection time monitor compares the time provided by the National Institute of Standards and Technology (NIST) to time obtained using system frequency, and if there is a significant difference, the time error monitor notifies the Reliability Coordinators in each Interconnection and corrective action is carried out by the balancing authorities.[64] On March 18, 2010, FERC initiated a Notice of Proposed Rulemaking to remand the proposed revised NERC-developed Time Error Correction Reliability Standard (BAL-004-1) in order for NERC to develop several modifications to the proposed Reliability Standard.[65,66]

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[63] B.J.Kirby, J. Dyer, C. Martinez, Rahmat A. Shoureshi, R. Guttromson, and J. Dagle, *Frequency Control Concerns in North American Electric System,* Oak Ridge National Laboratory, 2002, available at http://www.ornl.gov/sci/btc/apps/Restructuring/ORNLTM200341.pdf (accessed September 16, 2010).

[64] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

[65] NERC and other parties subsequently filed comments on April 28, 2010 (*Time Error Correction Reliability Standard,* Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking, Docket No. RM09-13-000 (April 28, 2010)), requesting FERC to host a technical conference to consider removing the Time Error Correction Standard. On August 20, 2010, NERC filed a request for FERC to defer action regarding the BAL-004-1 Time Error Correction standard until August 20, 2011, to allow NERC sufficient time to conduct research and analysis to determine the usefulness of Time Error Corrections and propose appropriate follow-on actions (*Time Error Correction Reliability Standard*, Motion to Defer Action, Docket No. RM09-13-000 (August 20, 2010)).

[66] On Feb 22, 2011 NERC submitted a status report on the development of Reliability Standard BAL-004-1 — Time Error Correction which was six months from the date of the Motion for informational purposes its status report as per the Motion to Defer Action filed on August 20, 2010. The NERC Operating Committee passed a motion in Dec 2010 directing that the Resources Subcommittee develop a field trial to eliminate manual Time Error Correction. (*continues on next page*)
(*continued from previous page*) NERC has developed a communication plan, to determine the path moving forward.

3 **Policy Aspects of the Frequency Stability Issue**

While the technical implementation of frequency control is directly responsible for an interconnection's frequency stability, the policy, i.e., standards and regulations, have both direct and indirect effects on the ability to implement the technical control. NERC is directly involved in formulating operational requirements. The Federal Energy Regulatory Commission (FERC) is responsible for overseeing NERC's activities and monitors and investigates the electrical energy market[67].

3.1 Standards and Regulations Indirectly Related to Frequency Stability (Impact of Market Design)

Unlike the regulatory restructuring of the 1920s and 1930s, the restructuring of the electric power industry over the last 20 years is not motivated by industry misconduct but a desire to improve industry efficiency by spurring competition. Furthermore, a more open and competitive landscape has been further enabled by technological innovations and policy changes that lowered barriers to entry into the energy market. Over the last two decades, several actions by the FERC have transformed the electric power industry into an unbundled and deregulated market.

Before the passage of the Energy Policy Act of 1992 provided a firm legal basis for competitive energy markets, FERC fostered this market transition beginning in the mid-1980s by encouraging the use of market-based rates for wholesale electric power. Thirty-one requests to use market-based rates for the sale of wholesale electric power were handled by FERC between 1985 and mid-1991.[68] Armed with significant authority to command transmission-owning utilities to wheel power and to mitigate barriers to accessing the transmission and distribution infrastructure, FERC issued a series of policy statements and Orders that essentially created the competitive, deregulated, wholesale electric power market in the United States.

In July 1993, with the intent of settling disputes over the use of transmission services by direct negotiation instead of litigation before FERC, FERC issued a policy statement encouraging formation of Regional Transmission Groups.[69] The following spring FERC instituted guidelines granting third-parties comparable access to the transmission and distribution system at similar

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NERC expects the communication plan to begin in the Spring 2011, followed by the beginning of the Field Test. NERC will provide an additional filing on or before August 20, 2011 to FERC.

[67] *About FERC*, last modified June 28, 2010, http://www.ferc.gov/about/ferc-does.asp (accessed on October 1, 2010).

[68] EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*," October 2000, p. 62. For a helpful overview, see also Lamoureux, M., "FERC's Impact on Electric Utilities," *IEEE Power Engineering Review*, August 2001.

[69] Policy Statement Regarding Regional Transmission Groups, 58 FR 41,626 (August 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993) (RTG Policy Statement) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

terms and conditions as the owners of the system.[70] By issuing its Transmission Pricing Policy Statement in October 1994, FERC recognized the need to realign transmission pricing methodology with a competitive market by going beyond simple postage stamp or contract path pricing.[71] These actions laid the groundwork for subsequent FERC Orders which definitively deregulated the electric power industry and established a truly competitive market.

Paramount among the many actions of FERC that established a competitive market were the issuing of Orders 888 and 889, (in 1996) and Order 2000 in 1999. Issued in April 1996, Order 888[72] established FERC's legal authority to require utilities owning transmission lines to permit the use of their transmission assets by third parties. Three critical concerns were addressed by Order 888: opening access of transmission lines to competing power generators, the unbundling of functional charges, and establishing a mechanism for recovery of "stranded costs." The provisions of Order 888 allowing for recovery of stranded costs and reinforcing existing contracts were minor, but essential, details to ease the transition to competition. Consequently, they had little influence on the eventual equilibrium point of the new competitive market.

The major and lasting provisions of Order 888 that enabled truly competitive markets for wholesale electric power by promoting fair, practical, and open access to the transmission and distribution system are discussed below.

Order 888 required utilities to publish separate rates for wholesale generation, transmission, and ancillary services; this action is often referred to as "functional unbundling." Furthermore, transparent information about capacity and submission of wheeling requests needed to be on a common electronic network. In addition, the Open Access Transmission Tariff requirement meant participating utilities, as of July 1996, must articulate the minimum required conditions in order to access point-to-point and network transmission services. While participation in power pools was not made mandatory by Order 888, participating utilities were required to file a pro forma tariff with the regional power pool by December 1996.

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[70] *American Electric Power Service Corporation*, 67 FERC ¶ 61,168 (1994) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

[71] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Policy Statement, *FERC Statutes and Regulations* ¶31,005 (1994); 59 Fed. Reg. 55031, Nov. 3, 1994. (Policy Statement) and *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Docket No. RM93-19-001, 71 FERC ¶61,195 (May 22, 1995), -summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

[72] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080 (April 24, 1996), 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (Order No. 888), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997) (Order No. 888-A), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), appeal docketed, Transmission Access Policy Study Group, et al. v. FERC, Nos. 97-1715 et al. (D.C. Cir.) [hereinafter Order No. 888] - Cited in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

Order 888 also established the principle of reciprocity in that a utility selling power via wheeling must permit the sale of wheeled wholesale power within their service territory by other utilities. Order 888 made FERC's Transmission Pricing Policy Statement, mentioned above, compulsory. Furthermore, transmission-owning utilities were required to set prices for network, point-to-point, and ancillary services related to the transmission of wholesale power. Through Order 888, FERC made transmission providers responsible for delivery of six core services: (1) scheduling, dispatch, and control (control of power in and out of a service area); (2) supply of reactive power and voltage control; (3) frequency regulation and response; (4) prevention and management of energy imbalances (i.e., handling discrepancies between scheduled and actual delivered power within the ± 1.5% tolerance); (5) operating and spinning reserve (in case of a system power deficiency); and (6) operating and supplemental reserve (to maintain supply as generation is brought on-line). The latter four services are optional, but the former two services must be purchased as part of a valid wheeling agreement.

Issued in conjunction with Order 888, FERC Order 889[73] facilitated competitive markets by assuring transparency, accuracy, and consistency in sharing of information critical to making intelligent competitive decisions. Order 889 established a common standard of conduct among power industry participants. In order to prevent gaming or obscuring of information, Order 889 required accounting systems for transmission, distribution, and generation facilities to be separate. Additionally, FERC Order 889 obligated all investor-owned utilities to share availability of transmission capacity, ancillary services, scheduling of power transfers, economic dispatch, current operating conditions, system reliability, and responses to systems conditions on an Open Access Same-Time Information System (OASIS; formerly referred to as Real-Time Information Networks). Order 889 created the obligation of investor-owned utilities to gather and supply information on power generation using the OASIS. Since the emerging non-profit regional Independent System Operators (ISOs) had the mission of impartially managing the power market, they undertook the role of administering the OASIS sites. The Internet-based OASIS went live in January 1997. In less than 4 years, 166 transmission-owning utilities were participating in OASIS and 23 Internet OASIS nodes were functioning.

In support of Orders 888 and 889, FERC issued Order 592[74] in December 1996 streamlining and changing the evaluation criteria involved in the process of receiving merger approval. Order 592 facilitates the accumulation of necessary financial and intellectual capital by new market entrants allowing them to compete effectively against entrenched players. Additionally, during 1997 and 1998 FERC approved five ISOs (PJM Interconnection, Midwest ISO, California ISO, New England ISO, and the New York ISO). Several positive market developments occurred because

[73] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 75 FERC ¶ 61,078 (April 24, 1996), 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 FR 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

[74] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 FR 68595 (Dec. 30, 1996), III FERC Stats. & Regs. ¶ 31,044 (Dec. 18, 1996), reconsideration denied, Order No. 592-A, 62 FR 33341 (1997), 79 FERC ¶ 61,321 (1997) (Policy Statement).

of the issuance of Orders 888 and 889. Specifically, existing generation facilities had clear and tangible economic drivers to invest in becoming more efficient, and new merchant plants, creating more competitors, were built due to the economic opportunity created by these Orders.

However, a second tier of significant barriers to the development of competitive electric power markets remained and quickly became evident. Owners of transmission and distribution assets were perceived to be discriminating against independent power companies (those that did not own transmission assets). Second, functional unbundling under Order 888 failed to provide adequate separation between the transmission business and the business of marketing and selling power. This limited separation further facilitated discrimination against market players without transmission assets. Another issue was the incomplete regionalization of grid operations; in other words, ISOs were formed in some regions but not in others. The subsequent rise in market players and trading following Orders 888 and 889 significantly impacted grid performance, particularly with respect to reliability and congestion. Consumer benefits from Orders 888 and 889 were muted by pancake pricing, in which a fee was tacked on every time power crossed a regional boundary.

Responding to the market inefficiencies that remained following the implementation of Orders 888 and 889, FERC took further action to drive the wholesale electric power market to a more competitive landscape. FERC ambitiously used further regionalization of the grid to mitigate these issues through the formation of fully independent regional transmission organizations (RTOs).[75] FERC issued Order 2000 in December 1999[76] mandating the creation of RTOs throughout the United States, albeit participation is voluntary. The intent of Order 2000 was to remove the residual barriers to a competitive market.

Order 2000 delineated several of FERC's expectations such as regional operation of high-voltage transmission, elimination of discriminatory practices leaving minimal economic or operational obstacles to trade, open access to the network and information about the network (e.g., OASIS), and true access and exit from the transmission network establish ease of opportunity. To meet these expectations Order 2000 established that RTOs should have full independence from market participants, as well as responsibility and authority regarding short-term grid stability, operational control of all transmission assets in their region, and an appropriate regional configuration. In support of these characteristics, each RTO assumed key market and technical functions within its area, such as design and administration of tariffs, management of congestion and parallel path flows, and continual development of OASIS, monitoring the market, and planning and expansion of transmission assets.

[75] A clear and succinct yet detailed description of RTOs and their roles and responsibilities is given in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 69-72.

[76] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999), 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 FR 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), affirmed sub nom. Public Utility District No. 1 of Snohomish County, Washington, v. FERC, 272 F.3d 607 (D.C. Cir. 2001) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

Remaining barriers to entry for new market participants were subsequently removed by FERC Orders 2003 and 2006. Order 2003 issued in December 2004 established Large Generator Interconnection Agreements and Procedures facilitating power inputs from asynchronous generators such as wind. Issuance of Order 2006 in May 2005 established Small Generator Interconnection Agreements and Procedures to facilitate the addition of small power inputs, facilities with significantly less stored kinetic energy to the grid. Also, Order 2006 specifically exempts small wind generators from requirements to supply reactive power.[77]

While not an inclusive list of all of the FERC actions that shaped the electricity power market, these are the actions that had the most influence on market response to deregulation that is relevant to affecting the frequency characteristics of the system. The predominant effect on the technical characteristics of the electric power generation, transmission, and distribution system is the increase in the proportion of distributed generation in the system. One of the salient consequences of this shift is its influence on frequency stability and response discussed below. Specifically, the FERC Orders established market conditions that deeply influenced the investment decisions with respect to new generation projects changing the mix of the generation portfolio.

The separation of generation and transmission operations instituted by Order 888, and completed by Order 2000, removed the reliability of the transmission system from the economics related to generation investment decisions. Specifically, grid reliability is the concern of the RTO not the investors in a generation project. Therefore, when considering facility choice, the higher reliability of smaller distributed units is not counterbalanced by the possible detrimental effects on grid reliability.[78] Furthermore, economies of scale for generation facilities are not as dramatic as they were 50 years ago; hence, smaller distributed systems can make economic sense. The greater and guaranteed accessibility to the market created by the FERC Orders mentioned above increased the number of possible entrants for whom the lower initial capital demands of distributed generation are more palatable. Even for entrenched market players, since guaranteed capital recovery was eliminated in deregulated markets, the ability to raise capital for traditional large baseload generation is also constrained, favoring distributed generation.

A direct consequence of Orders 888 and 2000 is the elimination of incentives for a generating business to invest capital in adding transmission capacity that may be required to bring a large baseload unit on-line. Hence, the capital requirements for the transmission from an investor’s facility to the grid and any incremental investment in the grid to absorb the large quantities of power from a new traditional baseload facility do not appear to be justifiable, nor are costs recoverable as under a traditional, regulated utility model. But the transmission and distribution systems will have niches that can absorb the low to moderate power inputs of distributed generators. These considerations are exacerbated by the congestion issues caused by

[77] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 70 FR 34189 (June 13, 2005), FERC Stats. Regs. ¶ 31,180 (2005) (Order No. 2006), order on reh'g, Order No. 2006A, 70 FR 71760 (November 30, 2005), FERC Stats. Regs. ¶ 31,196 (2005) P 387.

[78] Willis, L., and Scott, W., *Distributed Power Generation*, CRC Press, New York, 2000.

deregulation. Increased congestion is also the result of deregulated markets allowing larger and more complex purchases over larger distances. The congestion issue may also encourage smaller generation builds closer to loads. Similarly, the lack of guaranteed cost-plus economics in deregulated markets make considerations such as the cost, logistics, and availability of fuel as well as potential options to be feed-flexible, tilt some investment decision toward distributed generation options.

A final consequence of the FERC Orders is that, while eliminating obvious price inequities such as pancake pricing, the deregulated market that resulted, now encourages a generator to add new capacity as close to their customer as possible in order to minimize cost. Distance directly impacts generator-born costs for transmission losses and the charges for wheeling power. As such, the optimization of the size of generation facility can often favor a portfolio of distributed generation assets versus one large central facility.

The market response to deregulation was the addition of considerable distributed generation capacity. Emerging governmental actions such as state-level renewable energy standards are too nascent to know their specific impact on the generation portfolio, but one would anticipate they would reinforce the trend toward small distributed power generation. As the generation portfolio changes, so do the technical characteristics of the system, leading to new challenges in maintaining system performance.

The net effect of the deregulation process, as relevant to frequency stability, is the major shift towards building small generators. This resulted in the decreased system moment of inertia that is critical before and during primary control response.

3.2 Standards and Regulations Directly Related to Frequency Stability (Impact on Frequency Control Practices)

NERC was formed in 1968, shortly after the Northeast U.S. blackout in 1965. It was a voluntary organization with the function of promoting reliable and efficient power system service. After 1996, when FERC Order No 888 was adopted, it became clear that voluntary compliance was no longer adequate. In 2005, Part II of the Federal Power Act was amended by adding section 215 in which Congress directed the development of mandatory and enforceable electricity standards and establishment of the Electric Reliability Organization (ERO) to monitor and enforce the reliability standards.[79] In July 2006, NERC was granted the role of the ERO.[80] As the ERO, NERC proposes and enforces reliability standards for the bulk power system in the United

[79] Energy Policy Act of 2005.

[80] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (July 20, 2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009), p. 4.

States.[81] However, all reliability standards are subject to FERC approval. The first set of 83 mandatory reliability standards was approved by FERC Order No. 693 in 2007.[82] These standards are grouped into 14 categories:

1. Resource and Demand Balancing (BAL)
2. Communications
3. Critical Infrastructure Protection
4. Emergency Preparedness and Operations
5. Facilities Design, Connections, and Maintenance
6. Interchange Scheduling and Coordination
7. Interconnection Reliability Operations and Coordination
8. Modeling, Data, and Analysis
9. Nuclear
10. Personnel Performance, Training, and Qualifications
11. Protection and Control
12. Transmission Operations
13. Transmission Planning
14. Voltage and Reactive

The first category, Resource and Demand Balancing, is relevant to maintaining frequency at 60 Hz. This category consists of multiple individual standards shown in Exhibit 3-1 that support the FERC-defined ancillary services "Regulation and Frequency Response Service" and "Operating Reserve."

[81] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006), p. 1.

[82] Order No. 693, *supra* note 8 at P 1.

Exhibit 3-1 Resource and Demand Balancing Reliability Standards[83]

Number	Title	Purpose	Parameters/Limits	Mandatory Implementation Date[84]/Applicability
BAL-001-0.1a	Real Power Balancing Control Performance	To maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply.	• NERC Operating Committee reviews and sets as necessary limit for CPS1 (ACE variability). The limit is derived from a targeted frequency bound • Limit for CPS2 (ACE magnitude) is the targeted root-mean-square value of ten minutes average frequency error over a year	05/13/09 Balancing Authorities
BAL-002-0[85]	Disturbance Control Performance	To ensure that Balancing Authority is able to utilize its Contingency Reserve such that after a disturbance (loss of supply) frequency is returned within defined limits. *This standard is limited to the loss of supply and does not include the loss of load.	• Contingency Reserve should at least cover the most severe single contingency • Disturbance Recovery Period = 15 minutes • Contingency Reserve Restoration Period = 90 minutes • MW size of disturbance should be measured as close as possible at the site of the loss	06/18/07 Balancing Authorities; Reserve Sharing Groups; Regional Reliability Organizations
BAL-002-WECC-1[86]	Contingency Reserve	To ensure that Balancing Authority is able to utilize its	• Contingency Reserve = min[an amount of reserve equal to loss of the most severe	Balancing Authority; Reserve Sharing Group

[83] NERC Reliability Standards, available at http://www.nerc.com/page.php?cid=2|20 (accessed on September 9, 2010).

[84] http://www.nerc.com/filez/standards/Mandatory_Effective_Dates_United_States.html (accessed on September 9, 2010).

[85] This standard has been modified to address Order No. 693 directives "develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2" contained in paragraph 321. New version BAL-002-1 was adopted by Board of Trustees on August 5, 2010, and it is awaiting regulatory approval.

[86] This standard is awaiting regulatory approval.

		Contingency Reserve such that after a disturbance (loss of generation or transmission equipment) frequency is returned within defined limits.	single contingency, (3% of the load + 3% of net generation)] (+Interchange Transaction) • At least half of the contingency reserve shall be spinning reserve • Spinning reserve has governor or other control • Acceptable reserve must be fully deployable within 10 minutes • Disturbance Recovery Period = 15 minutes • Contingency Reserve Restoration Period = 90 minutes	
BAL-003-0.1b	Frequency Response and Bias	To provide a consistent method for calculating the Frequency Bias component of ACE	• Frequency Bias Setting ≥ Balancing Authority's Frequency Response • Frequency Bias Value is based on straight-line[87] or variable[88] function of Tie Line deviation versus Frequency Deviation • AGC operating mode is tie-line frequency bias • Frequency Bias setting should be at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change	5/13/2009 Balancing Authorities
BAL-004-0[89]	Time Error Correction	To ensure Time Error Correction that will not affect	• Frequency schedule offset is 0.02 Hz and	06/18/07

[87] The BAL-003.01b states that "the Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours."

[88] The BAL-003.01b states that "the Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency."

[89] New version BAL-004-1 was approved by Board of Trustees on September 13, 2007, and it is awaiting regulatory approval.

		the reliability of the system	normal Frequency Bias setting, or • Net Interchange Schedule offset (MW) is 20% of Frequency Bias Setting	Reliability Coordinators ; Balancing Authorities
BAL-004-WECC-01	Automatic Time Error Correction	To maintain Interconnection frequency and to ensure effective Time Error Correction that will not affect the reliability of the system	• Automatic Error Correction is a part of AGC • Each Balancing Authority should be able to switch between different AGC operating modes	07/01/09 Balancing Authorities
BAL-005-0.1b	Automatic Generation Control	To provide requirements for AGC necessary for ACE calculation and deployment of Regulating Reserve	• AGC controls Regulating Reserve to meet the Control Performance Standards • AGC operating mode is tie-line frequency bias • AGC operates continuously • Data acquisition and ACE calculation at least every six second • All dynamic schedules should be included in ACE calculation as part of Net Scheduled Interchange • Ramping rates should be included in the Scheduled Interchanged values for ACE calculation • All tie line flows should be included into calculation	05/13/09 Balancing Authorities; Generator Operators; Transmission Operators; Load Serving Entities
BAL-006-1	Inadvertent Interchange	To ensure that Balancing Authorities do not depend over the long time on other Balancing Authorities for meeting their demand		05/13/09 Balancing Authorities

BAL-502-RFC-02[90]	Planning Resource Adequacy Analysis, Assessment and Documentation	To establish common criteria for the analysis, assessment and documentation of Resource Adequacy	• Planning reserve margin such that it satisfies "one day of loss in 10 year" criterion	Planning Coordinator
BAL-STD-002-0	Operating Reserve	To address Operating Reserve requirements of the WECC	• Minimum Operating Reserve = Regulating Reserve + Contingency Reserve[91] + Additional Reserve • Reserve should be restored within 60 minutes	06/18/07 Balancing Authority; Reserve Sharing Group

[90] New version BAL-502-RFC-02 was approved by the Board of Trustees on August 5, 2009.

[91] BAL-502-RFC-02 defines the contingency reserve as "The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation."

The Regulation and Frequency Response Service, according to FERC, is necessary to provide power balance, and to maintain Interconnection frequency at 60 Hz. This service is achieved predominantly using automatic generation control equipment.[92] On October 15, 2002, NERC filed comments on the Commission's Notice of Proposed Rulemaking on Standard Market Design. [93] NERC recognized that Regulation and Frequency Response ancillary service only addresses AGC as the frequency response and does not include primary frequency response (governor control) as part of the service. NERC suggested changing the name of the Regulation and Frequency Response ancillary service to Regulation service so that the name corresponds to industry practice. Furthermore, NERC recommended deciding if governor characteristic should be a part of Frequency Response ancillary service or a part of generator interconnection and operation agreement. In addition, it recommended that:[94]

- Each unit larger than 10 MW should be equipped with governor control for frequency response; and
- Units that are equipped with governor control should be able to immediately respond to abnormal frequency conditions and have droop characteristic of five percent.

When the NERC reliability standards became mandatory in 2007, these NERC guidelines were not included in the BAL-003-0 standard, Frequency Response and Bias. However, in Order 693, the Commission directed NERC to develop certain modifications for this standard. These includes (1) determining the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met;[95] and (2) developing a modification to BAL-003-0 that 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.[96]

On March 18, 2010, FERC issued an Order[97] setting a deadline for compliance. It directed NERC to submit required modifications within six months. On April 19, 2010, NERC requested a hearing and clarification of the FERC's Order.[98] NERC submitted that there was a technical

[92] Order No. 888, *supra* note 72, states that "Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load," schedule 3, original sheet No. 117.

[93] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Comments of the North American Electric Reliability Council, Docket No. RM01-12-000 (October 15, 2002) available at http://www.nerc.com/docs/docs/ferc/RM01-12-000-SMD.pdf (accessed on September 15, 2010).

[94] NERC, *NERC Operating Manual.* New Jersey. 2004.

[95] Order No. 693, *supra* note 8 at P 369.

[96] Order No. 693, *supra* note 8 at P 370 and P 372.

[97] *Order Setting Deadline for Compliance*, 130 FERC ¶ 61,218 (March 18, 2010).

[98] *Order Setting Deadline for Compliance*, Request of the North American Electric Reliability Corporation for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010, p. 9 (April 19, 2010) [hereinafter Docket No. RM06-16-010].

error in the March 18 Order and that six months was an unreasonable time for developing a frequency response standard, given the complexity of the frequency response issue. Furthermore, NERC stated that it plans on issuing a Recommendation to the Generation Owners and Generator Operators so that they report back to NERC on their operating status with respect to governor installation,[99] governors free to respond,[100] governor droop,[101] and governor limits.[102] These recommendations correspond to guidelines of the NERC Operating Policy in 2004.[103] This was followed up with an Order Granting Rehearing for Further Consideration and Scheduling a Technical Conference (issued May 13, 2010).[104] The Technical Conference was held on September 23, 2010. PJM also submitted a request for clarification and rehearing on the March 18 Order. PJM stated that frequency response requires explicit definition[105] because inertia, governor response, regulation, economic dispatch, and reserve response all provide frequency response and they are under the control of different functional entities. In addition, PJM suggested that the old policies need to be reviewed so they correspond to the current environment. PJM concluded that in the March 18 Order, the Commission was interpreting the NERC guidelines about the governor control as a requirement. However, there has never been such requirement.[106] In the meantime, due to the lack of a clear and well-defined frequency response reliability standard, the regional entities, reliability councils and balancing authorities try to maintain 60 Hz frequency, keep system stability, provide reliable supply, and comply with existing reliability standards.

For example,

- PJM requires that:

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[99] Docket No. RM06-16-010, *supra* note 98, at p. 12, “Governor Installation - Whether generating units with nameplate ratings of 10 MW or greater are equipped with governors operational for frequency response.”

[100] Docket No. RM06-16-010, *supra* note 98, at p. 12, “Governors Free to Respond – Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.”

[101] Docket No. RM06-16-010, *supra* note 98, at p. 12, “Governor Droop – All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 MHz).”

[102] Docket No. RM06-16-010, *supra* note 98, at p. 13, “Governor Limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.”

[103] NERC, *NERC Operating Manual.* New Jersey. 2004.

[104] *Mandatory Reliability Standards for the Bulk Power System* , Order Granting Rehearing for Further Consideration and Scheduling Technical Conference 131 FERC ¶ 61,218 (May 13, 2010).

[105] Docket No. RM06-16-010, *supra* note 98, at p. 2, PJM explains that “Based upon the Commission’s statement set forth in Paragraph 13 of the March 18 Order, it appears that the Commission equates “frequency response” to “generator governor response.””

[106] Docket No. RM06-16-010 , *supra* note 96 at p. 2, PJM states that “Through the March 18 Order, the Commission is extending that guide and interpreting that guide as a requirement, despite the absence of any historical ad hoc governor response requirement.”

  - Any capacity resource with a capability of more than 10 MW must be explicitly modeled in the PJM Energy Management System.[107] In addition, PJM requires that all generators who participate in the capacity market are required to submit real-time tele-metered data (real power and reactive power). However, generators with capacity of less than 10 MW that do not participate in the capacity market may not be required to supply real-time information.
  - Generators that participate in the regulation market must have governor control and be able to receive AGC signal.[108] PJM does not specify an exact number for droop characteristics, but in training material, they use governor with 5 percent droop characteristic (NERC recommendation).[109]

- ISO New England requires that every market participant with a capability of 10 MW or greater provide and maintain a functioning governor. In the ISO New England area, the governor should have 5 percent droop characteristic unless technical consideration dictate otherwise.[110]
- WECC is drafting WECC-0070 Governor Droop Criterion.[111] Currently, the WECC minimum operating reliability criteria requires the governor to be set at five percent. However, WECC is looking for more technical droop characteristic settings or control. It is considering an effective governor droop response for an area and a range for droop settings.

The NERC Resource and Demand Balancing standards support the FERC Operating Reserve ancillary service that is required to serve load in a case of a contingency and used to return frequency to 60 Hz when a large generator or a transmission line unexpectedly fails. FERC defines two types of operating reserves: spinning reserve and supplemental reserve.[112] The spinning reserve serves load immediately after contingency and it is usually provided by on-line generating units that are not fully loaded. The supplemental reserve serves the load within a short

[107] PJM, *Manual 14D – Generator Operational Requirements*, effective June 1, 2010, Energy Management System Model, p. 22.

[108] PJM, *Manual 11 - Energy & Ancillary Services Market Operations*, effective June 23, 2010, Section 3: Overview of the PJM Regulation Market, p.54.

[109] Lovasik, C., *NERC Resource and Demand Balancing Standards*, available at http://pjm.acrobat.com/p93522443/ (accessed on September 15, 2010).

[110] ISO New England, *Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands*, effective date June 1, 2010, requires specific governor control: "The Market Participant is obligated to provide and maintain a functioning governor on all Generators with a capability of ten (10) MW or greater. The governor should be set in accordance with industry standards unless technical considerations dictate otherwise (governor droop set at five percent [5%]). If technical considerations dictate otherwise, ISO should be so informed by the Designated Entity per Master Local Control Center Procedure No. 10. The Market Participant is responsible for periodic testing and maintenance of the governor."

[111] http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=70&Source=/Standards/Development (accessed on September 15, 2010).

[112] Order No. 888, *supra* note 72, Original Sheet No. 122 and Original Sheet No. 123.

period of time after contingency. Similarly to FERC, NERC defines operating reserve as combination of spinning and non-spinning reserve. However, its operating reserve definition includes regulation, load-forecasting error, outages and area protection.[113] Furthermore, NERC adds interruptible load as an operating reserve. The NERC definition includes both commercial and forecasting issues and reliability issues, while the FERC definition includes only reliability issues.[114] Commercial and forecasting issues include power imbalance due to load-forecasting errors, generation and transmission maintenance, and load diversity while the reliability issues include power imbalance due to unexpected outages.

The most concerning issue is the observed decline in the primary frequency response and its effect on the frequency stability. Until recently, qualified facilities smaller than 80 MW[115] were not required to provide spinning reserve for primary control at all. FERC, NERC, and the ISOs have recognized this limit as too high and currently all power plants larger than 10 MW are required to participate in primary control. This change does not seem to be sufficient to address lack of primary control, and the NERC standards committees are working on a new set of requirements which will define in much better terms how the primary frequency response should function to improve frequency response characteristic. Additional information is provided in the Appendix of this report.

[113] The NERC Glossary defines operating reserve as "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve."

[114] Hirst, E., and Kirby, B. ,*Electric-Power Ancillary Services*, Tennessee: Oak Ridge National Laboratory, 1996.

[115] *Applicability of Federal Power Act Section 215 to Qualifying Small Power Production and Cogeneration Facilities*, 72 FR 14,254 (2007), "The Commission reasoned that, given the statutory directive that all users, owners and operators of the bulk-power system must comply with mandatory reliability standards under section 215, it may not be appropriate to allow QFs [qualified facilities] a continued exemption from compliance with the newly adopted mandatory and enforceable reliability standards that apply to generator owners and operators."

4 **Summary and Recommendations**

Over the past decade, the frequency response of the North American interconnections has been slowly but consistently declining. This suggests that frequency stability is becoming more vulnerable to sudden supply and demand changes. NERC has identified this problem as one that requires significant effort by the electricity sector to ensure the continued reliability of the North American bulk power system. Some of the more likely and prominent constituents of the complex set of interrelated causes of this degrading frequency response include recent changes in:

- Total moment of inertia of generators on the interconnections, i.e., reduction in total moment of inertia due to movement toward smaller distributed generators
- The nature of the typical load; i.e., reduction in rotating loads
- Generator operations under competitive pressure (deregulated wholesale markets)
- Generator reserves under competitive pressure
- Insufficient or ineffective regulations and incentives to maintain frequency response

System frequency is difficult to regulate due to the complex interplay of the different technical and nontechnical factors, as well as the size of the interconnections. Technical difficulties are mostly caused by a declining frequency response characteristic and the time scale on which the primary control must respond. The cause of the declining frequency response characteristic cannot be definitively assigned. From a technical perspective the reduction in system inertia due to the movement to smaller distributed generators and a reduction in motor driven loads tend to negatively impact frequency response. Furthermore, some Smart Grid initiatives and direct and indirect regulations and standards have incentivized the deployment of small generators leading to a degradation of the interconnections frequency response. For example:

- Small generators are favored over large central plants since FERC introduced open transmission access and other deregulation-oriented Orders.
- Open transmission access reduced the Available Transmission Capacity of the interconnections at the same time that the unbundling of the transmission service did not provide any incentives for transmission owners to build additional transmission lines.
- Small generators can be built closer to the load, sometimes even located on the distribution system requiring no transmission access at all, thus avoiding transmission charges.
- Small, distributed generation is also encouraged and subsidized by different governmental programs such as Renewable Portfolio Standards. These small generators contribute to the solution of the transmission capacity problem and energy delivery reliability but under the current regulations cause problems for frequency response. Small generators have less moment of inertia than the large ones and under current regulations are not required to provide spinning reserve for primary control if smaller than 10 MW.

FERC seems to be fully aware of these issues and has requested that NERC develop a new comprehensive set of rules and regulations to address them. However, the declining frequency response characteristic and how to deal with it requires more analysis and clarification.

The following recommendations, made as part of the findings of this study, are separated into policy and standards, and technical recommendations.

Policy and Standards Recommendations

- More monitoring and analysis of the interconnections' operations should be conducted including generation and demand amount and type, disturbance types, and frequency response in order to better and more quantitatively understand the problem and enable more data driven and advanced real-time frequency control strategies.
- Standards should be more technically specific about the amount of required reserves and how they should be used, specifying reaction times, generation compositions, and type.
- A set of adjustable parameters should be established that can be deduced periodically from continuous system monitoring.
- Standards for the response time of primary and secondary control should be defined and enforceable.
- Policies should require more operators to provide some sort of primary frequency response contribution, either directly, through a pooling method, or through purchase as an ancillary service. It may be appropriate to use a penalty provision for not delivering appropriate primary frequency response support to the system.
- More specifically, policies regarding contributions to primary frequency response should require specific operating standards such as free-governor mode requirements or speed-droop regulations, or a more general set of frequency response standards or requirements.
- Policy response should require new, targeted data reporting requirements to assist with developing better updated performance standards.
- Policies should increase incentives for generators to bid for ancillary services.
- Construction of very large generating stations such as coal baseload generators should be encouraged in order to provide the power system with the increased moment of inertia that is critical during a disturbance.

Technical Recommendations:

Primary control is probably the most critical part of frequency control. If the primary control does not react properly, a perfectly functioning secondary control might not have a chance to respond at all. To address primary control issues, NERC could:

- Reexamine whether the commonly used droop of 5 percent is appropriate. This droop characteristic corresponds to 3 Hz deviations over a generator's entire generation range. Frequency deviations of +/-1.5 Hz are very unusual in North American interconnections.

- Reexamine whether the same droop should be used by small and large generators. Small generators can respond much faster than the large generators and might be more useful if using steeper droop.
- Clearly define and enforce spinning reserve dedicated to primary control.
- Define how fast the governor controller must respond based on real-time frequency response characteristic.
- Recommend real-time frequency response characteristic monitoring and its use for primary control algorithms.
- Require smaller generators to provide spinning reserve.
- Improved data collection efforts should be developed to better characterize the load and the magnitude of the effect, and development of system frequency response standards that appropriately address the dynamics and variability of primary load response.

Appendix - Recent Developments Regarding Frequency Instability

As the problem of frequency instability in the North American interconnections is a serious concern, activity on this subject is very high. Consequently, a considerable amount of relevant information was released between the end of the main period of performance of this study and the final publication of this report. For the convenience of the reader, some of the more salient recent contributions to understanding the frequency instability issue are summarized briefly below.

NERC submitted "Comments of the North American Electric Reliability Corporation Following September 23 Frequency Response Technical Conference" to FERC on October 14, 2010[116]. NERC stated that some of the reasons for frequency decline are:

- Larger governor dead band settings
- Steam turbine sliding pressure mode
- Loading generator units at 100 percent
- Blocked governor response
- Gas turbine inverse response
- Generators limited time of response
- Load frequency response change

NERC outlined a list of technical tasks associated with NERC's Frequency Responsive Initiative. The technical tasks include:

1. Collecting data and information from generator owners, generator operators, and balancing authorities
2. Developing clear terminology
3. Analyzing primary and secondary control response performance (current and historical)
4. Developing frequency performance metrics
5. Automating methods for indentifying frequency deviation events used to measure primary control
6. Developing methods for automatically collecting and analyzing frequency response and frequency control events
7. Analyzing appropriate frequency response and control to maintain system reliability
8. Determining an appropriate bias setting for use in AGC

[116] *Comments of the North American Electric Reliability Corporation Following September 23 Frequency Response Technical Conference*, Docket Nos. RM06-16-010 and RM06-16-011 (October 14, 2010).

9. Improving generators' and other devices' primary response dynamic models
10. Developing generators' and other devices' mid-term primary response dynamic models
11. Determining what factors influence inertial response
12. Examining renewable resources and smart grid load primary frequency response
13. Analyzing change in inertial response if inertial generators are displaced with electronically decoupled resources

On October 25, 2010, NERC submitted to FERC a proposed schedule for developing a frequency response requirement. On December 16, 2010, FERC issued an Order accepting NERC's filing.[117]

The NERC Resources Subcommittee published a discussion draft of its Position Paper on Frequency on November 23, 2010. NERC Resources Subcommittee believes that the interconnections frequency response is adequate at this time. It proposes a standard that will allow each interconnection to withstand at least two emergency events (N-2) before activating Under Frequency Load Shedding. It suggests that Frequency Response and Bias standard should be defined such that it brings more frequency responsive resources. The Frequency Response and Bias standard should also be adjustable such that it can be modified as the industry learns more. The Subcommittee recommended field testing that will provide data for analysis and standard improvement. It also recommended encouraging Smart Grid technologies to provide frequency response services. The position paper was open for comment until February 1, 2011.

FERC published the report "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation" on January 21, 2011. The report was open for comments until March 7, 2011[118]. The report lists a set of metrics and tools that include new wide-area information and processing capabilities to measure frequency response adequacy inside the interconnection. The leading metric is primary frequency response. Impacts of increased renewable generation, such as lower system inertia, displacement of primary frequency control, and increased requirements of secondary frequency control are analyzed in the report. In addition, dynamic simulations studies were conducted for the Western Interconnection, Texas Interconnection, and Eastern Interconnection. The main recommendations of the report are to better understand the interconnection and balancing authority requirements for frequency control, to schedule adequate primary and secondary frequency control reserves, to expand frequency control capabilities and to develop comprehensive planning and operating procedures.

FERC also published five supporting documents:

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[117] *Mandatory Reliability Standards for the Bulk-Power System*, 130 FERC¶ 61,212, at P 1 (December 16, 2010 Order).

[118] On February 18, 2011 FERC issued a notice for an extension of time for filing comments up to and including May 6, 2011 under AD11-8 *Frequency Response Metrics to Assess Requirements for Reliably Integrating Renewable Generation.*

- *Analysis of Wind Power and Load Data* – Illustrates new methods of wind and load data analysis. The methods should help to better characterize volatile wind power output and to establish correlation between wind power and load.
- *Dynamic Simulation Studies of the Frequency Response* – Analyzes the effects of three different levels of wind generation on frequency behavior following an emergency event, such as a sudden loss of a generator, in the Western, Texas, and Eastern Interconnections.
- *Frequency Control Performance Measurement and Requirements* – Describes the history of frequency control performance measurement and its future requirements.
- *Interconnection Frequency Performance* – Reviews frequency performance based on historical data collected by NERC, with a focus on frequency response following an emergency event, for the Western, Texas and Eastern Interconnections.
- *Power and Frequency Control* – Reviews frequency and power control principles and illustrates the role of primary and secondary control.