EXHIBIT E

Record of Development

Record of Development – BAL-001-TRE-1

Contents

1. Introduction

This Record of Development was written to document the development history of Texas RE Regional Standard BAL-001-TRE-1, and to organize evidentiary documents related to the project for use by NERC and FERC in seeking and granting regulatory approval. The evidentiary documents are attached to this document and referenced herein in brackets as follows: [x-yyy].

Notes:

- *Texas Regional Entity, an independent division of ERCOT, separated from ERCOT on July 1, 2010, becoming Texas Reliability Entity, Inc., an independent non-profit corporation. The name "Texas RE" is used to refer to both entities.*
- *The applicable Standard Development Process changed from the Texas **Regional** Entity Standards Development Process to the Texas **Reliability** Entity Standards Development Process on July 1, 2010. This ERCOT Regional Standard BAL-001-TRE-1 was initiated under the Texas Regional Entity SDP and completed under the Texas Reliability Entity SDP.*

2. Standard Authorization Request (SAR)

A Texas RE Standard Authorization Request (SAR-003) [2-001] was submitted by Farzaneh Tafreshi of Texas RE to the Texas RE Reliability Standards Manager (RSM) on April 15, 2008. SAR-003 was prepared to initiate a FERC-directed standard development project to include requirements concerning frequency response contained in the ERCOT Protocols, section 5.9 (March 2007 version). [2-002] As per FERC Order No. 693 Paragraph 315, FERC expected that Requirements, Measures, and Levels of Non-Compliance would be included in the ERCOT regional standard. The FERC directive was related to the CPS-2 waiver that the NERC Operating Committee approved on November 21, 2002. [2-003]

SAR-003 was posted for comment on the Texas RE Tracking Site from April 24 –May 16, 2008. [2-004] Following this initial comment period, SAR-003 was presented for development by the RSM and approved by the Reliability Standards Committee (RSC) at its May 27, 2008 meeting. [2-005]

3. Standard Drafting Team

On June 24, 2008 the ERCOT Reliability and Operations Subcommittee[1] approved an initial membership for the Standard Drafting Team (SDT) composed of individuals from three different entities. In addition, the ROS approved Farzaneh Tafreshi's proposition to appoint Ananth Palani of EnergyCo, LLC as interim chair. [3-001]

On July 10, 2008, the SAR-003 SDT met for the first time and elected Sydney Niemeyer as Chair and Ananth Palani as Vice Chair. [3-002] The SAR-003 SDT established a future meeting schedule and work plan that included monthly meeting dates throughout the year.

Several additional individuals joined the drafting team, which by early 2010 consisted of [3-003]:

- Sydney Niemeyer – NRG Energy
- Ananth Palani – Optim Energy
- Pamela Zdenek – BP Alternative Energy
- Rick Terrill – Luminant Generation
- Kenneth McIntyre – ERCOT
- Vann Weldon – ERCOT
- Howard Illian – Energy Mark Consulting

Under the revised Texas RE SDP (2010), only one representative from any registered entity could be a voting member of the SDT. ERCOT selected Vann Weldon to remain on the team, and Ken McIntyre was removed. Sandip Sharma of ERCOT also provided valuable contributions to the development of this regional standard.

In April 2011, the RSC approved changes to the Standard Drafting Team composition. Howard Illian (consultant) and Rick Terrill (Luminant) were removed from the SDT roster, and Brenda Hampton (Luminant - generation) was added. [3-004]

[1] The Texas RE Standard Development Process that was in effect in 2008 authorized ERCOT's Reliability and Operations Subcommittee (ROS) to form regional Standard Drafting Teams. In 2010 revisions to the SDP, that responsibility was transferred to the Texas RE Reliability Standards Committee (RSC). [3-005]

4. First Posting for Comments – 2009

The RSC approved posting the proposed regional standard for comments at its meeting on March 4, 2009. [4-001] The BAL-001-TRE-1 Regional Standard [4-002] was posted on the Texas RE Standards Tracking Site for an initial 30-day comment period from March 16-April 14, 2009. [4-003]

A workshop was conducted on March 31, 2009, during the comment period, to allow for education and discussion regarding the proposed requirements. [4-004]

The drafting team considered all of the comments that were submitted and prepared written responses. [4-005] The team continued its work on revising the standard over the following months, in view of comments received and further consideration of the issues.

Representatives from the drafting team had a productive meeting with FERC staff (Bob Snow and others) in Washington, D.C. on August 27, 2009, to present the approach taken by the proposed standard and to solicit input from FERC staff.

5. Second Posting for Comments – 2010

After continued work on the standard, the SDT received approval from the RSC at its February 5, 2010 meeting to post the revised Regional Standard for a second formal comment period. [5-001] The latest draft of the BAL-001-TRE-1 regional standard [5-002] was posted for comment on the Texas RE Tracking Site from February 12 - March 13, 2010.

A Workshop was conducted on March 3, 2010, during the comment period, to educate stakeholders regarding the state of the standard and to discuss various issues. [5-003]

A number of comments were received from stakeholders during the comment period and the SDT posted responses to the comments. [5-004]

6. Third Posting for Comments – 2010

Following the second comment period, the SAR-003 SDT worked on revising the standard based on comments received during the second formal comment period, discussions with FERC, and further consideration of the issues. The RSC approved the revised Regional Standard at their September 1, 2010 meeting to be posted for a third comment period. [6-001]

The BAL-001-TRE-1 Regional Standard was posted on the Texas RE Standards Tracking site for a third 30-day formal comment period from October 13 – November 12, 2010. [6-002]

A number of comments were received from stakeholders during the comment period and the SDT posted responses to the comments. [6-003]

7. Primary Frequency Response Reference Document

In April 2011 the details of the Primary Frequency Response (PFR) metric calculations were moved out of the Standard itself and into a separate "Primary Frequency Response Reference Document." This simplified the standard requirements considerably, and allowed the calculations to be expanded and explained in greater detail. The PFR Reference Document details how the initial and sustained PFR performance measures are to be calculated. ERCOT acting as BA will calculate the PFR performance measures based on the PFR Reference Document. The PFR Reference Document includes the flowcharts that detail the calculations. [7-001: June 2011 version] The PFR Reference Document was revised through the standard development process and the final version was approved with the final standard. [11-004, flowcharts 11-005 and 11-006]

The PFR Reference Document is not considered to be a part of the regional standard. This document will be maintained by Texas RE, and it will be subject to modification under the oversight of the Texas RE Board of Directors, without being required to go through the formal Standard Development Process. This arrangement provides regional flexibility in adjusting the technical details of the performance metric calculations. The FERC staff member who participated in the development of this standard encouraged this approach, including retaining regional control over the calculation details.

The revision process for the PFR Reference document was set forth in the document and in the regional standard (p. 13) as follows:

> **Revision Process:** The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

8. First Ballot – 2011

After further consideration of issues and revision of the standard, the SDT felt it was ready for ballot. The RSC was given a detailed presentation regarding the current state of the regional standard at its June 2011 meeting [8-001]. The RSC approved posting the BAL-001-TRE-1 Regional Standard for ballot at its August 5, 2011 meeting [8-002].

A ballot pool was formed by notifying members of the Registered Ballot Body (RBB) of an opportunity to become a part of the Registered Ballot Pool for this regional standard. The notice also went out generally to registered entities in the region, and a number of entities joined both the Ballot Body and the Ballot Pool. The Registered Ballot Pool consisted of 41 entities representing all Sectors. [8-003]

The documents constituting the ballot package were finalized and posted in accordance with the Texas RE Standard Development Process. [8-004] The ballot was conducted from September 9 to 23, 2011. A quorum was obtained with 38 entities voting. The ballot failed with a sector-weighted vote of 3.759 in favor and 2.241 opposed. [8-003] A 2/3 favorable vote (4 out of 6) was needed to approve the regional standard.

The SDT considered and responded to the comments received during the First Ballot posting. [8-005]

9. Field Trial

Following the unsuccessful first ballot, the SDT decided to conduct a Field Trial to test the performance metrics of requirements R9 and R10, to demonstrate the application of the standard, and to educate entities regarding the purpose and benefits of the standard. A Field Trial Report [9-001] was written at the conclusion of the trial to document the activity and results. (This report is not confidential, as participants are not identified. More detailed information is available if needed.)

The Field Trial included evaluation of 28 generating units, which included 7 coal, 4 gas, 2 simple-cycle combustion turbine, 5 wind, and 10 combined-cycle units. Primary frequency response performance was calculated for each unit using historical information for 35 Frequency Measurable Events from June 2011 to June 2012. No high-frequency events were evaluated. It was not possible to obtain an 8-event average for some units, typically because the units were not operating when events occurred, or because they had no available capacity to respond to individual events. Most units were evaluated in their existing condition, without tuning for improved performance. Performance results were calculated based on actual unit governor settings, as opposed to the governor settings to be required by this standard.

The Field Trial included a debrief meeting with each participant to review its performance results, discuss issues and concerns, and to obtain feedback from the participant. This information obtained was taken into consideration in further revising the proposed standard. Confidential information related to the debrief meetings is available from Texas RE.

Based on the experience gained during the field trial, several significant revisions were made to the proposed regional standard, including:

- The sustained measure calculation (R10) was modified to simplify the calculation and to eliminate problems related to the length of the original averaging window.
    - The “event recovery period” used in prior drafts could last for several minutes, during which the unit performance could be impacted by extraneous events.
    - The sustained measure is now based on an instantaneous measurement based on data from the first minute following the event after the 42-second mark.
- A 5 MW limit was added to the 2% exception criteria, to address an issue related to the capability of smaller generators to provide frequency response near the edges of their operating ranges.

- Examples of “legitimate operating conditions that may support exclusion” were moved from Measures to Requirements R9 and R10 to address concerns expressed by some entities.
- Measure M7 was re-written to focus on notice from GO to GOP of change in Governor status, to address a concern about evidence of compliance.
- The mandated deadband setting was changed from 0.01666 to 0.017 Hz.

10. Second Ballot – 2012

Following the Field Trial and associated revisions to the Standard, the SDT provided a detailed report on the revised standard to the RSC at its meeting on October 3, 2012. [10-001] On January 9, 2013 the RSC approved the latest draft of the standard to be posted for a second ballot. [10-002] The balloted documents are listed below under “Approval by Texas RE Board of Directors.” [11-002 to 11-006]

The Second Ballot was conducted from February 1 to 15, 2013 and it passed with an 80% affirmative vote. Summary voting results [10-003] and detailed voting results [10-004] are provided. Each membership sector voted at least 66% in favor of the standard. The VRF/VSL poll passed with an 81.1% affirmative vote.

The SDT responded to the comments that were received with the second ballot [10-005] before the standard was presented to the Board of Directors for approval.

The RSC approved the ballot results for presentation to the Board of Directors at a special telephone meeting on March 6, 2013 [10-006], followed by an e-mail ballot. [10-007]

11. Approval by Texas RE Board of Directors

The Regional Standard and related documents were posted on the Texas RE Calendar in advance of the April 23, 2013 Texas RE Board Meeting. The Texas RE Board of Directors approved the Regional Standard at that meeting, as evidenced by the resolution that was approved. [11-001]

The specific documents that were approved by the Texas RE Board were as follows:

- Regional Standard BAL-001-TRE-1 [11-002]
- Implementation Plan [11-003]
- Reference Document [11-004]
- Initial PFR Flow Chart [11-005]
- Sustained PFR Flow Chart [11-006]

12. Applicability Issues

There are three specific applicability exemptions listed in part 4.2 of the regional standard [see 11-002]:

- 4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

There are two nuclear generating stations in the ERCOT Region. It is our understanding, after communicating with both plants, that they control energy output based on operating considerations other than system frequency, in accordance with their federal operating licenses. We therefore consider these units to be outside of our jurisdiction in connection with the subject matter of this standard.

- 4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.

Generators operating in synchronous condenser mode do not provide energy to the grid – instead they provide (or absorb) only reactive power to help control system voltage. This exemption was added to make it clear that we do not expect these machines to contribute to primary frequency response.

- 4.2.3 Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

This exemption was added to address the concerns of some older wind generators that they are technically not capable of providing governor response. The ERCOT protocols give ERCOT the authority to exempt certain generators from its own rules that require governor response [See ERCOT Nodal Protocols § 8.5.1.3]. This exemption is intended to align this regional standard with the existing ERCOT requirements, allowing ERCOT (as BA) to exempt wind generators (and potentially others) when appropriate.

13. Approval by NERC Board of Trustees

Regional Standard BAL-001-TRE-1 was presented to NERC on April 23, 2013 for consideration and approval by the NERC Board of Trustees (Board). In accordance with its process, NERC posted the regional standard for a continent-wide comment period from May 31 to July 15, 2013. Several comments were received and responded to by the regional SDT. [13-001]

The regional standard was posted in advance of the NERC Board meeting. [13-002]. The NERC Board approved the Texas RE regional standard on August 15, 2013 by unanimous vote.

Attachment 2-001

Standard Authorization Request Form

E-mail completed form to rsm@texasre.org

Texas RE to Complete
SAR No: 003

Title of Proposed Standard: FERC-Ordered Modification to ERCOT Waiver to R2 of BAL-001-0 CPS2	
Request Date	April 15, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Farzaneh Tafreshi	☐	New Standard
Primary Contact Farzaneh Tafreshi	☐	Revision to existing Standard
	☐	Revision to the Standard Development Process
Telephone 512-225-7251	☐	Withdrawal of existing Standard
Fax 512-225-7165	☒	Variance to a NERC Standard (Indicate which one)
E-mail Farzaneh.Tafreshi@texasre.org	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

The purpose of this standard will be to address FERC-directed modification to the ERCOT regional difference to include requirements concerning frequency response contained in the ERCOT Protocols, section 5.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

FERC finds that the existing ERCOT approach to Interconnection frequency control is necessary to assure reliability in that Interconnection (Section 5 of ERCOT's Protocols concerning frequency control).

As per FERC Order No. 693 Paragraph 315, FERC expects that Requirements, Measures, and Levels of Non-Compliance be included in the ERCOT regional difference, similar to other existing regional differences.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

FERC approved the ERCOT regional difference as mandatory and enforceable and found that ERCOT's approach under section 5 of the ERCOT protocols to be a more stringent practice than Requirement R2 in BAL-001-0. However, as stated in FERC Order No. 693, FERC expects the ERCOT regional difference to include Requirements, Measures, and Levels of Non-Compliance sections.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

The purpose of BAL-001-0 is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. BAL-001-0 establishes two requirements that are used to assess the proficiency of a balancing authority to maintain Interconnection frequency by balancing real power (MW) demand, interchange, and supply.

On November 21, 2002, NERC approved a regional difference for ERCOT by allowing it to be exempt from Requirement R2 in BAL-001-0 (ERCOT Waiver of CPS2), because of the following reasons: (1) ERCOT, as a single control area asynchronously connected to the Eastern Interconnection, cannot create inadvertent flows or time errors in other control areas, and (2) CPS2 may not be feasible under ERCOT's competitive balancing energy market.

FERC approved the ERCOT regional difference as mandatory and enforceable and found that ERCOT's approach of determining the minimum frequency response needed for reliability and requiring appropriate generators to have specific governor droop to be a more stringent practice than requirement R2 in BAL-001-0.

FERC also found the ERCOT approach to Interconnection frequency control to be necessary to ensure reliability in that interconnection and more critical to system reliability. However, FERC directed NERC to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols.

FERC Order No. 693 also states, "As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections".

Reliability Functions

For a more detailed description of the Reliability Functions, please refer to ***NERC Function Model_V3***

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*	
☐ Transmission Owner	☐ Transmission Service Provider
☐ Generator Owner	☐ Generator Operator
☒ Balancing Authority	☐ Interchange Authority
☐ Reliability Coordinator	☐ Purchasing-Selling Entity
☐ Resource Planner	☐ Load-Serving Entity
☐ Distribution Provider	☐ Planning Coordinator
☐ Transmission Planner	☐ Transmission Operator

Reliability and Market Interface Principles

Applicable Reliability Principles (*Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.

☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
BAL-001-0	Real Power Balancing Control Performance

Related SARs

SAR ID	Explanation

Attachment 2-002

ERCOT Protocols – Section 5.9
March 1, 2007 Version

5.9 Frequency Response Requirements and Monitoring

5.9.1 Generation Resource and QSE Participation

5.9.1.1 Governor in Service

At all times a Generation Resource is on line, its turbine governor shall remain in service and be allowed to respond to all changes in system frequency. Generation Entities shall not reduce governor response on individual Resources during abnormal conditions without ERCOT's consent (conveyed by way of the Generation Entity's QSE) unless equipment damage is imminent.

5.9.1.2 Reporting

Generation Entities shall conduct applicable generating governor speed regulation tests on Resources as specified in the Operating Guides. Test results and/or other relevant information shall be reported to ERCOT and ERCOT shall forward results to the appropriate TSPs.

Resource governor modeling information required in the ERCOT Planning Criteria shall be determined from actual Resource testing described in the Operating Guides. Within thirty (30) days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the connected TSP.

When the governor of a Generation Resource is blocked while the Resource is operating, the QSE shall promptly inform ERCOT. The QSE shall also supply governor status logs to ERCOT upon request.

Any short-term inability of a Generation Resource to supply governor response shall be immediately reported to ERCOT.

If a Generation Resource trips Off-line due to governor response problems, the Generation Entity shall immediately report the change in the status of the Resource to ERCOT and the QSE.

5.9.2 Primary Frequency Control Measurements

For the purposes of this section, the A Point is the last stable frequency value prior to a frequency disturbance. For a decreasing frequency event with the last stable frequency value of 60.000 Hz or below, the actual frequency is used. For a decreasing frequency event with the last stable frequency value between 60.000 and 60.036 Hz, 60.000 Hz will be used. For a decreasing frequency event with the last stable frequency value above 60.036 Hz, actual frequency will be used. For an increasing frequency event with the last stable frequency value of 60.000 or above, the actual frequency is used. For an increasing frequency event with the last stable frequency between 59.964 and 60.000 Hz, 60.000 Hz will be used. For an increasing frequency event with the last stable frequency value of 59.964 or below, the actual frequency is used. ERCOT shall determine the A Point frequency for each event.

For the purposes of this section, the C Point is the lowest frequency value during the first five seconds of the event.

For the purposes of this section, the B Point is the "recovery" frequency value after the C Point. The B Point should occur after full governor response of the turbines has occurred, usually between ten (10) and thirty (30) seconds after the A Point, but not greater than sixty (60) seconds after the A Point. ERCOT shall determine the B Point for each event.

B Point Plus Thirty Seconds: At thirty seconds following the B Point, an analysis will be performed by ERCOT with the assistance of the appropriate ERCOT subcommittee to determine if primary frequency control response is sustained.

For the purposes of this section, a "Measurable Event" is the sudden change in interconnection frequency that will be evaluated for performance compliance will have i) a frequency B Point between 59.700 Hz and 59.900 Hz or between 60.100 Hz and 60.300 Hz, and ii) a difference between the B Point and the A Point greater than or equal to +/- 0.100 Hz.

5.9.2.1 ERCOT Required Primary Frequency Control Response

The combined response of all Generation Resources interconnected in ERCOT to a Measurable Event shall be at least 420 MW / 0.1 Hz. This value should be reviewed on an annual basis by ERCOT and the appropriate ERCOT subcommittee for system interconnect reliability needs.

ERCOT will evaluate, with the assistance of the appropriate ERCOT subcommittee, primary frequency control response during Measurable Events. The actual Generation Resource response will be compiled to determine if adequate primary frequency control participation was available.

ERCOT and the appropriate ERCOT subcommittee will review each Measurable Event, verifying the reasonableness of data. Data that is in question may be requested from the QSE for comparison and/or individual Resource data may be retrieved from ERCOT's database.

ERCOT's performance will be averaged using the most recent six (6) Measurable Events to determine its rolling average contribution.

5.9.3 ERCOT Data Collection

5.9.3.1 Data Collection

ERCOT will collect all data necessary to analyze each Measurable Event. This will include the following real-time data:

(1) Interconnection Frequency;

(2) Regulation Service deployed;

(3) Responsive Reserve Service deployed;

(4) QSE available Responsive Reserve Service;

(5) QSE total Generation;

(6) QSE SCE;

(7) QSE Bias;

(8) QSE LaaR MW;

(9) LaaR deployed;

(10) QSE Responsive Reserve Service; and,

(11) ERCOT Load and individual Resource(s) that contributed to the frequency deviation.

Attachment 2-003

Approved by Operating Committee: November 21, 2002

Waiver Request – Control Performance Standard 2

Organization

ERCOT

Operating Policy

ERCOT requests a waiver from Policy 1, "Generation Control and Performance," Section E, "Performance Standard" as follows:

Standards

1.2. **Control Performance Standard (CPS2)**. The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}.

Requirements

2. **Control Performance Standard (CPS) Compliance**. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).

Explanation

ERCOT requests a waiver from the CPS2 Standards and Requirements listed above for the following reasons:

1. On July 31, 2001, the ERCOT Interconnection began operating as a single CONTROL AREA, asynchronously connected via two DC ties to the Eastern Interconnection. At that time, ERCOT changed from the traditional tie-line bias generation control algorithms in which ten CONTROL AREAS participated, to a single 15-minute interval competitive balancing energy market and a frequency control system that regulates around the balancing energy schedule on two-to-foursecond intervals. ERCOT requests that the Operating Committee reconsider CPS2 to ensure it is feasible under this new type of market-based control.

   If the Operating Committee believes that the CPS2 is feasible, then ERCOT would suggest that Policy 1 (or the appropriate Compliance document) provide for a "test period" of six months to allow CONTROL AREAS making such a transition the opportunity to test new control algorithms *provided* they can show that reliability is not degraded during that period. ERCOT also believes that its L_{10} may not be appropriate as it is less that half of the L_{10} of another NERC CONTROL AREA of similar load size.

2. The ERCOT Interconnection is now a single CONTROL AREA asynchronously connected to the Eastern Interconnection, and cannot create inadvertent power flows or frequency errors in other CONTROL AREAS. Therefore, the ISO questions whether the CPS2 Standard is necessary or even beneficial for such asynchronous operation. ERCOT is currently performing a study that compares its single CONTROL AREA performance against that of the former ten CONTROL AREA operations. Initial results of that study show that while the ten CONTROL AREAS *individually* met CPS2 standards, the *aggregate* CPS2 performance of the ten CONTROL AREAS did not, and was actually below that of the current single CONTROL AREA.

Current Operating Reliability

ERCOT does not believe that Frequency control within its new single CONTROL AREA INTERCONNECTION is less reliable as a result of non-compliance with the CPS2 Standard following its conversion. ERCOT Interconnection frequency control has been, and continues to be, very reliable since that conversion.

The table below shows ERCOT's CPS2 performance for August through December 2000 as an INTERCONNECTION with ten Control Areas. The average CPS2 compliance was 74.82%. CPS2 compliance for ERCOT as a single control area for August 2001 was 83.88%, an improvement of approximately nine percentage points.

	% of Frequency Data Available	Supplier Of Frequency Data	Single Control Area CPS1 %	CPS2 %	Average of Absolute1 min Averages Freq Deviation	Average of Absolute10 min Averages Freq Deviation
August-00	79	ERCOT	140.99	76.50	0.011978483	0.008299971
September-00	100	ERCOT	134.89	76.02	0.012366	0.009495
September-00	100	REIT HLP	135.91	77.01	0.012221795	0.008443165
October-00	23	ERCOT	199.68	76.90	0.013910426	0.00857111
October-00	100	REIT HLP	114.01	78.58	0.014621429	0.008120248
November-00	65	ERCOT	105.19	67.20	0.015061531	0.010523159
December-00	60	ERCOT	192.59	72.60	0.013428052	0.009330552
Average	(See Note 1)		134.71	74.82	0.013439915	0.009062032
August-01	None (See Note 2)	None (See Note 2)	127.30	83.88		

Note 1: Weighted Average Based on ERCOT for August, September November and December and REIT for October.
Note 2: From ERCOT CPS report. ERCOT is working on providing frequency data for August 2001.

Attachment 2-004

Reliability Standards Tracking
Comments & Responses

SAR-003-TRE-1 FERC-Ordered Modification to ERCOT CPS2 Waiver to R2 of BAL-001-0

04/24/2008 **through** 05/16/2008

1. Do you agree that there is a reliability need for the proposed SAR?

Name: **Ness, Thad K**
Phone: **614-716-2053**
Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**
Segment: **Investor-Owned Utility**
Answer: **No**

Comment	Response
"The answer to this question can be yes or no depending upon the interepretation of the FERC directive. It is clear that some activity needs to occur as a result of FERC Order 693. However, it is not clear if the FERC order recommended an update to the Continent-wide NERC standard to address this as a ""Regional Variance/Difference"" or if this should be developed into a Regional Reliability standard. What is the impact of this SAR and potentially forthcoming Regional Standard if the NERC BAL-007 through BAL-011 (BAAL metrics) are implemented?"	Texas RE is following the NERC definition of a regional variance to satisfy this FERC Order. The NERC definition for a regional variance is: a variance provides an alternative approach to meeting the same reliability objective as a NERC standard and is typically dictated by a physical difference. It may also modify a NERC Reliability Standard to address a unique circumstance requiring an exception to the North American-wide standard. After much discussion with both FERC and NERC on this issue, Texas RE is proceeding with the drafting of a regional variance to BAL-001-0. BAL-007 is still in the testing and discussion phase. Last time it was up for ballot, it was defeated. Texas RE is not sure when it will come up for ballot again and if it will pass. Given this situation, we are proceeding with drafting the regional variance to satisfy the FERC Order. If BAL-007 passes and replaces BAL-001 to be the new standard, then the Texas RE regional variance for BAL-001 will be obsolete.

2. Do you agree with the scope of this proposed SAR?

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **No**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
See notes above. It would be beneficial to provide more background on the history of the existing ERCOT waiver to the CPS 2 criteria as part the SAR."	ERCOT's Waiver Request--Control Performance Standard 2 can be accessed on the NERC Web Site, and outlines the history and reasons for the waiver. The Waiver was approved on November 21, 2002 by NERC. While some additional history to SAR-003 might have been beneficial to those not familiar with it, the history is not really necessary considering we have a direct Order from FERC to develop this variance.

3. Can you identify any additions that should be incorporated into this SAR? If yes, please be specific.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **No**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Attachment 2-005

**May 27, 2008
9:30 a.m. – 12:00 p.m.**

7620 Metro Center Drive
Austin, Texas 78744

Conference Call Information

Dial-in Number: 512.225.7284 **|** **Conference Code:** 6571

WebEx Information: N/A

Administrative

1. Introduction and Attendance

Rick Keetch welcomed the attendees to the meeting.

The attendees were as follows:

Name	Company	Present	Called- In
Dale Bodden	CenterPoint Energy	x	
Rick Keetch	Reliant Energy	x	
Robert Kelly	Brazos Electric	x	
Nick Fehrenbach	City of Dallas		
Paul Johnson	AEP		
Paul Gabba	Dow Chemical Company	x	
Brian D. Bartos	Bandera Electric Coop	x	
Les Barrow	CPS Energy	x	
Thane Twiggs	Direct Energy		
Frank Owens	Texas Municipal Power Agency	x	
Danny Bivens	Office of Public Utility Counsel		
Matt Samsel	Exelon Generation		
Darrell Scruggs	Calpine Corp.		x
Cesar Seymour	Suez Energy Marketing		
Read Comstock	Strategic Energy		
Judith James	Texas RE	x	
Farzaneh Tafreshi	Texas RE	x	
Jack Thormahlen	LCRA	x	
Tom Jackson	Austin Energy	x	
Vann Weldon	ERCOT ISO	x	
Tom Burke	Luminant	x	
Lauro Garza	CPS Energy	x	
Carla Harryman	BP Alternate Energy	x	
Dwight Yarbrough	Sharyland Utilities	x	
Carlos Benavides	Topaz Energy	x	
Joel Firestone	Direct Energy	x	
Walter Bukowski	CPS Energy	x	

Matt Pawlowski	FPL Energy	x	
Tony Shiekhi	Texas RE	x	
Jeff Whitmer	Texas RE	x	

The IREP segment representatives were not present at the meeting. At least one representative from each of the other six segments was present.

2. Antitrust Admonition

The Texas Regional Entity (Texas RE) Anti-Trust Admonition was displayed for the members. The attendees were reminded that it is both Texas RE and ERCOT policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

3. Approval of Minutes

Rick Keetch asked the attendees whether there were any comments on or changes to the draft meeting notes from March. (There was no RSC meeting in April.) He moved to approve the draft notes. Frank Owens and Les Barrow seconded the motion. The motion carried by voice vote. The notes were approved.

RSC Discussions and Activities

1. Report from Interim Vice Chair of SAR-001 Standard Drafting Team

Walter Bukowski reported that the SAR-001 Drafting Team met on May 7 for the first time. Many members were not present therefore a quorum was not established to elect a permanent Chair or Vice Chair. He mentioned that the team reviewed the SDT procedures and documents that will be impacted due to this SAR. The next SDT meeting is scheduled for June 3, 2008. He explained that the team is going to review the Texas RE Standards Development Process at that time, and still strives to have the first draft posting by August 2008.

2. Review of RSC Actions on SARs

Rick Keetch gave an overview of RSC responsibilities on disposition of SARs prior to proceeding to the next agenda item.

3. Review and disposition of New SARs

- SAR-002-TRE-01: Development and Documentation of Regional UFLS Programs

  Brian Bartos currently serves as a member of the NERC UFLS Drafting Team. He went over a presentation by Bob Millard (NERC UFLS Chair). He explained the scope of UFLS project, the project goal, and the directives that the team was charged to address. He also added that the draft standards are to be posted for industry comment soon.

As a follow up to Brian Bartos' presentation and to answer some of the questions and concerns by the attendees, Farzaneh Tafreshi explained that at the last NERC Regional Reliability Standards Working Group (RRSWG) meeting in May, Bob Millard had briefed the RRSWG regarding the UFLS project. The NERC Standards Committee prioritizes the work to be posted for industry comment. UFLS documents are simply waiting in queue. He also had added that UFLS will be a NERC directive rather than a NERC continent wide standard. Regardless of the mechanics or the approach, the regions are still to be directed to develop the technical detail specific to their region to meet the directive.

Farzaneh further added that all other regions have already initiated their regional process and are waiting for the NERC UFLS draft to be posted in order to determine the appropriate direction they ought to take. Farzaneh also explained that the intent of initiating this particular SAR is to establish the core group of experts prior to the NERC posting so the team can review and comment appropriately on behalf of the region. Two comments on this SAR were received via the Reliability Standard Tracking (RST) site, and they were both in agreement with the development of this SAR.

The motion to approve SAR-002-TRE-01 as submitted was initiated by Rick Keetch. Brian Bartos and Doc Kelly seconded the motion. The motion was approved by a formal vote. There was no opposition or abstentions.

Quorum: 6/7 present
Vote: 6.00

- SAR-003-TRE-01: FERC-Ordered Modification to ERCOT Waiver to R2 of BAL-001-0 CPS2

  Farzaneh explained the SAR scope and reviewed the language from the FERC NOPR and Order 693 addressing this waiver. One comment on this SAR was received via the RST, and it was not in agreement stating that it was not clear if FERC meant for this to be an update to a continent wide standard or a regional difference. The commenter also asked for more history on the ERCOT waiver.

  The motion to approve SAR-003-TRE-01 as submitted was carried by a voice vote. There was no opposition or abstentions.

- SAR004-TRE-01: ERCOT-Specific Sabotage Reporting Regional Standard

  Tony Shiekhi and Jeff Whitmer presented the SAR. They explained the concerns and the possible impacts on reliability that instigated the initiation of this particular SAR.

  The team collectively agreed that the current NERC standard does not match the communications paths between RC (ERCOT ISO) and the applicable entities mentioned in the CIP-001. Although the current market rule does meet the intended reliability objectives, the NERC CIP-001 may release some responsible entities in the ERCOT region from the obligations to comply with this standard.

Several discussions and possible approaches to achieve the same reliability goals were discussed. Two comments on this SAR were received via the RST. One was in agreement and the other was not. The commenter not in agreement stated that, while valid issues were raised by this SAR, it was not clear if this applied just to the ERCOT region or should be more appropriate for a NERC standard revision. Also, it was stated that it was not clear if this really applied to DPs.

Doc Kelly motioned to remand the SAR for further work to add specificity to reflect the discussions and points that were brought up by the attendees. Brian Bartos seconded that motion. The motion to remand was carried by voice with no opposition or abstentions.

4. Next Meeting: June 24, 2008.

More information about the meeting location to follow

5. Adjourn

Attachment 3-001

DRAFT
Reliability and Operations Subcommittee (ROS) Meeting
ERCOT Austin – 7620 Metro Center Drive – Austin, Texas 78744
Thursday, June 12, 2008 – 9:30 a.m. – 3:30 p.m.

Attendance

Members:

Armke, James	Austin Energy	
Boehnemann, Robin	Exelon Generation	Alt. Rep. for M. Samsel
Garrett, Mark	Direct Energy	
Green, Bob	Garland Power & Light	
Hatfield, Bill	LCRA	
Helyer, Scott	Tenaska	
Holloway, Harry	SUEZ	Alt. Rep. for J. Sweeney
Jonte, John	CenterPoint Energy	Alt. Rep. for P. Rocha
Jones, Randy	Calpine	
McCann, James	Brownsville PUB	
Quinn, Mike	Oncor	Alt. Rep. for K. Donohoo
Ryan, Martin	NRG Energy	
Ryno, Randy	Brazos Electric Power Coop.	
Vo, Trieu	CPS Energy	Alt. Rep. for B. Williams

The following proxies were assigned:

- Loretta Gallaga to Randy Ryno
- Clayton Greer to Robin Boehnemann
- Billy Shaw to Randy Jones

Guests:

Ashley, Kristy	Exelon Generation
Bogen, David	Oncor
Brown, Jeff	Shell Energy
Bruce, Mark	FPL Energy
Carpenter, Steve	Energy Co.
Cochran, Seth	Sempra Trading
DeTullio, David	Air Liquide
Huerta, Miguel	Chaparral Steel
James, Judith	Texas Regional Entity
Keetch, Rick	Reliant Energy
Klusman, Armin	CenterPoint Energy
Kolodziej, Eddie	Customized Energy Solutions
Kremling, Barry	Guadalupe Valley Electric Coop.
Liang, Congong	Constellation Energy
Marciano, Tony	PUCT
March, Tony	QSE Services/MAMO Enterprises
Owens, Frank	TMPA
Pieniazek, Adrian	NRG Texas

Reid, Walter	Wind Coalition
Rennaker, Guy Phil	DME
Simmons, Walt	Oncor
Tafreshi, Farzaneh	Texas Regional Entity
Thormahlen, Jack	LCRA QSE
Wheeler, Ron	Energy Co.

ERCOT-ISO Staff:
Albracht, Brittney
Blevins, Bill
Brenton, Jim
Frosch, Colleen
Gallo, Andrew
Levine, Jonathan
Huynh, Thuy
McIntyre, Ken
Roark, Dottie
Teixeira, Jay
Villanueva, Leo

Unless otherwise indicated, all Market Segments were present for a vote.

Randy Jones called the meeting to order at 9:33 a.m.

Antitrust Admonition
Mr. R. Jones directed attention to the displayed ERCOT Antitrust Admonition and noted the requirement to comply with the ERCOT Antitrust Guidelines. A copy of the guidelines was available for review.

Agenda Review
There were no changes to the agenda.

Technical Advisory Committee (TAC) Update (see Key Documents)
Mr. R. Jones provided a review of the June 5, 2008 TAC meeting, highlighting TAC recommendation and ERCOT Board of Directors (Board) approval of Protocol Revision Request (PRR) 764, Zonal Congestion and CSCs/CREs, and noting that proposed changes to the Public Appeal for Conservation in the Emergency Electric Curtailment Program (EECP) will require a PRR and Nodal Protocol Revision Request (NPRR).

ROS Voting Items (see Key Documents)[1]
Mr. R. Jones announced Alternate Representatives and assigned proxies.

[1] Key Documents referenced in these minutes may be accessed on the ERCOT website at: http://www.ercot.com/calendar/2008/06/20080612-ROS

Approval of Draft May 15, 2008 Meeting Minutes

Mr. R. Jones requested any revisions to the draft May 15, 2008 ROS minutes. Brittney Albracht noted the addition of Frank Owens to the attendee list. **Mark Garrett moved to approve the May 15, 2008 ROS minutes as amended. Randy Ryno seconded the motion. The motion carried unanimously.**

Delete Media Appeal from EECP Step 2

John Jonte presented proposed changes to the Public Appeal for Conservation in EECP Step 2 for ROS consideration. Market Participants discussed that ERCOT should have flexibility as to when and if a public appeal for conservation is issued; that some EECP events are too brief for an appeal to be effective, or might even pose reliability and over-frequency issues; that local Transmission Operator (TO) may issue an appeal for local congestion without ERCOT approval; and proposed language that ERCOT may issue an ERCOT-wide appeal.

Mr. Jonte moved to recommend that EECP Step 2 language be amended to remove bullet #4 in section 5.6.7, and that the words "ERCOT–wide" be inserted at 5.6.6.1. Dennis Kunkel seconded the motion. The motion carried unanimously.

Nodal Operating Guide Revision Request (NOGRR) 018, Synchronization of OGRR204, Hotline Technology Update

Mr. Jonte presented NOGRR018 for ROS consideration. Market Participants discussed whether proposed language eliminated use of Voice Over Internet Protocol (VOIP) technology; that language did not restrict use of VOIP; and that On Premise Exchange (OPX) systems are analog, but that some Market Participants are changing to VOIP.

Market Participants further discussed that the Wide Area Network (WAN) connection for data and voice is isolated from any system; that Market Participants cannot place the OPX into their switch and communicate with ERCOT; and that ERCOT owns all equipment at both ends.

Mr. Kunkel moved to recommend approval of NOGRR018, and include in the minutes that there was general agreement that future VOIP flexibility is intact. Mr. Ryno seconded the motion. The motion carried unanimously.

NOGRR019, Synchronization of OGRR206, Black Start Satellite Phones

Mr. Jonte presented NOGRR019 for ROS consideration.

Mr. Ryno moved to recommend approval of NOGRR019. Mr. Kunkel seconded the motion. The motion carried unanimously.

Standards Drafting Team (SDT) for SAR-002-TRE-01, Development and Documentation of Regional UFLS Programs

Farzaneh Tafreshi presented SDT volunteers for SAR-002-TRE-01 for ROS consideration. Mr. R. Jones and Mr. Kunkel requested that they be added to the list of volunteers.

Mr. Kunkel moved to approve the presented list of volunteers for the SDT for SAR-002, name Mr. R. Jones as interim chair, and refer the list to the Regional Standards Committee (RSC). Mr. Ryno seconded the motion. Ms. Tafreshi noted that the list constitutes the core group for the SDT, but that participation remains open. **The motion carried unanimously.**

SDT for SAR-003-TRE-01, FERC-Ordered Modification to ERCOT Waiver to R2 of BAL-001-0 CPS2

Ms. Tafreshi presented SDT volunteers for SAR-003-TRE-01for ROS consideration, and noted that more volunteers, possibly from the Performance Disturbance Compliance Working Group (PDCWG) would be preferable. Market Participants discussed that web conferencing for SDT meetings should be considered to enhance participation; that a regional variance would be built around ERCOT's Control Performance Standard 2 (CPS2) waiver; and that Market Participants should be complacent about the CPS2 waiver.

Mr. Kunkel moved to approve the amended list of volunteers for the SDT for SAR-003, name Ananth Palani as interim chair, and refer the list to the RSC. Mr. Ryno seconded the motion. The motion carried unanimously.

Single Entry Model (SEM) Approach Document
Linda Clarke reviewed the SEM go-live procedure and timeline; key issues; and next steps. Market Participants discussed that 75 days is not enough time to validate the model; that ERCOT is obligated to notice activation of the Nodal Protocols, and will also notice the SEM go-live; that ERCOT was requested by the Transition Plan Task Force (TPTF) to present a whitepaper on their validation process; and that ERCOT has two levels of validation and a third level prior to nodal go-live.

Market Participants further discussed that planning cases are on a separate route for impedances; that Stage 2 Validation will take place prior to the 168 Hour Test; and that some changes introduced by Market Participants might invalidate zonal comparisons.

Ms. Clarke reviewed Market Participant comments to the whitepaper distributed to Network Data Support Working Group (NDSWG). Market Participants discussed that some entities are concerned that model validation may require as much as four to six months; that nodal requires that every device on the grid be modeled; and that NDSWG and ERCOT might host a WebEx meeting on SEM validation. Market Participants requested that specific Protocol subsections be listed in future presentations, as well as a link to the most recent versions of the documents for consideration.

Mr. R. Jones requested that the item be brought for a vote at the July 2008 ROS meeting.

Wind Operations Task Force (WOTF) Recommendations (Vote)
Mark Garret presented the Issue 3f "Run multiple CSC limit studies" solution for ROS consideration and requested ROS endorsement, and reported that as of June 10, 2008, ERCOT implemented multiple limit studies for all five Commercial Significant Constraint (CSC) areas. Market Participants discussed that significant changes were seen immediately; that updates should be posted where Transmission Operators may monitor and check against flows; that ERCOT must manually communicate updates at this time; and that the snapshot is off of the State Estimator, but there is not the capability to look ahead to an outage.

Market Participants further discussed that ERCOT is developing an Operations Procedure for posting, and whether currently posted limits may be approached without incurring problems.

Mr. Ryno moved that ROS endorse ERCOT's solution to WOTF Issue #3f. Mr. Garrett seconded the motion. The motion carried unanimously.

<u>EECP 20080226 and Wind Workshop Follow-up (see Key Documents)</u>
WOTF
Mr. Garrett reviewed recent WOTF activities and the statuses of outstanding items for further WOTF consideration. Market Participants discussed that there would be another wind operations workshop for operators to advise ERCOT on equipment, limitations and current operations practices, and that efforts are underway to recruit technology specialists to speak at the workshop.

Market Participants also discussed the feasibility of 5% versus 10% of nameplate capability for a generation ramp rate; that most wind is able to manage to a ramp rate limit; that a hard number for a limit is preferred to a variable; that multiple turbines with fast ramp rates can pose reliability issues; and that ERCOT should determine what ramp rate the system can handle on a normal basis.

Operations Working Group (OWG)
Mr. Jonte reported that ramp rate limitations and changes to the Public Appeal for Conservation in an EECP event were topics of OWG discussion, and that work had not yet been done on Ancillary Services (AS) procurement methodology. ROS requested that WOTF monitor the efforts of the Wholesale Market Subcommittee (WMS) and the Qualified Scheduling Entity (QSE) Managers Working Group (QMWG) on ramp rate limitations from a reliability standpoint.

<u>ERCOT Operations Report (see Key Documents)</u>
May Monthly Report
Thuy Huynh reviewed the May 2008 Operations report.

Unannounced Testing Update
Ms. Huynh reviewed the Unannounced Test Summary for May 2008. Market Participants discussed that ERCOT should ensure that test results are what is entered into resource plans, rather than allowing entities to resubmit High Sustainable Limits (HSLs) which the entity recently failed to demonstrate; that units testing within 3% of their filed HSL should be regarded as passing the unannounced test; and that plus or minus 3% is beyond the current standard and would require a Protocol revision.

Market Participants also discussed that some test failures might be attributable to miscommunication with ERCOT as to the exact testing period; that the Reserve Discount Factor (RDF) will essentially be maintained if a plus or minus 3% is considered passing; and that failing to reach HSL should require a reset, but not necessarily a retest.

<u>Market Participant Identity Management (MPIM) Requirements Update</u>
Jim Brenton announced that Market Participants should have received a Market Notice resolving the issue of MPIM Requirements, and that the ERCOT security group was asked to reconsider whether the requirements for Market Participants as communicated were appropriate; that discussions with other Independent System Operator (ISO) and North American Electric Reliability Corporation (NERC) staff revealed that the intent was not to extend the requirement to Market Participants.

Mr. Brenton reported that by July 2010 ERCOT must show sustained compliance with all Critical Infrastructure Protection (CIP) standards; that ERCOT must report on each standard and requirement through a formal process; and that that the Texas Regional Entity (TRE) has alerted ERCOT to expect increased compliance activity in September 2008.

Mr. Brenton expressed appreciation for Market Participants' patience as ERCOT attends to new compliance requirements, and invited Market Participants to send their representatives to the informal CIP Advisory Group that meets monthly.

<u>ERCOT Updates (see Key Documents)</u>
System Planning

Jay Teixeira answered questions regarding the System Planning report, noting that congestion issues, rather than reliability issues, are anticipated with increased Wind-powered Generation Resources; and that appropriate location of transmission projects is an important consideration for studies.

TPTF
There were no questions of Stacy Bridges regarding the TPTF report.
<u>Texas Regional Entity (TRE) Compliance Report (see Key Documents)</u>
Mark Henry provided the TRE report, audit information and performance highlights, and noted that the first semi-annual Self Assessment would be distributed on June 15, 2008 and would be due one month later.

<u>ROS Working Group Reports (see Key Documents)</u>
Dynamics Working Group (DWG)
Tony Hudson presented the DWG report; there were no questions.

NDSWG
David Bogen reported that NDSWG continues work on the Single Entry Model (SEM); that ERCOT Wholesale Client Relations will meet with NDSWG to discuss communications with ERCOT; and that upcoming discussions will include how to utilize the interface.

OWG
Mr. Jonte reported that three major issues remain to be resolved for Low Voltage Ride Through and will be discussed at the next OWG meeting. Mr. Jonte also reported that OWG will be reviewing critiques of the May 14, 2008 Hurricane Drill, and that the Black Start Task Force is gathering data for a study, per ROS, and will craft a recommendation.

PDCWG
Bob Green reported that CPS1 scores seem to be holding steady, but that the 12-month rolling average continues to decline, and reviewed the Eastern Interconnection probability of frequency within 5 mHz intervals during June 2007 versus June 2005. Mr. Green opined that there is an extra cost associate with oscillation. Market Participants discussed whether the dead band should be reduced by half, or removed entirely; that the Eastern and Western Interconnects do not have governor response; that a 60 GW system should not be compared to a 600 GW system; that older data should be reviewed to determine if this oscillation is a new issue, or truly typical for the ERCOT system; and that perhaps oscillation is more pronounced due to the size of the system.

Steady State Working Group (SSWG)
Walt Simmons presented proposed changes to SSWG Procedures for ROS consideration; Mr. R. Jones noted that the proposed changes would be a voting item on the July 2008 ROS agenda. Mr. Simmons also reported that during the course of a three-day SSWG there is much time lost waiting for ERCOT resources to turn UPLAN dispatches; Mr. Teixeira explained the execution timelines and constraints experience by the three ERCOT resources dedicated to SSWG.

System Protection Working Group (SPWG)
There were no questions of Mark Chronister regarding the SPWG report.

<u>Adjournment</u>
Mr. R. Jones adjourned the meeting at 2:45 p.m.

Attachment 3-002

CPS2 Waiver SDT Meeting Notes

July 10, 2008
9:30am-3:30pm

7620 Metro Center Drive
Austin, Texas 78744

Conference Call Information

Dial-in Number: (512) 225-7282 | **Conference Code:** 0650
WebEx Information: N/A

Administrative

1. Introduction and Attendance

Sydney Niemeyer welcomed the attendees to the meeting.

The attendees are as follows:

Name	Company	Present	Called-In
Ken McIntyre		x	
Ananth Palani		x	
Sydney Niemeyer	NRG Energy	x	
Farzaneh Tafreshi	Texas RE	x	
Nick Henry	FERC		x

Vann Weldon was unable to attend due to prior commitment. .

2. Antitrust Admonition

The Anti-Trust Admonition (Admonition) was displayed for the members. Farzaneh Tafreshi reminded the committee that it is both Texas Regional Entity (RE) and ERCOT policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. The participants were reminded that paper copies of the Admonition are available.

Discussions and Activities

1. Sydney and Ananth were elected Chair and Vice-Chair respectively

2. Farzaneh went over the Texas RE Standard Development Process, roles and responsibilities of the standard drafting team, the regional standards submittal process to NERC and other related subjects.

3. Nick elaborated on the Commission decision on ERCOT waiver for CPS2

4. The team discussed different approaches to address the FERC modification to the waver. The team examined the pro and cons of each option, their impact on market and benefit to grid reliability.

5. The team will discuss the various options with PDCWG during the WG's next meeting.

6. Ken will investigate the purpose of CPS2.

7. Action Items

Action Items	**Status:**	**Assigned To:**
• Contact Stephanie Monzon about possible conflict or restriction on expanding applicable entity on the waiver • UPDATE: Stephanie not aware of such restriction. She will discuss this subject with other NERC Standards Mgrs.and get back with us.	**Completed**	Farzaneh
• Send the team on NERC Generation Verification Standard (Project 2007-9)	**Completed**	Farzaneh

8. Next Meeting: August 14, 2008

More information on meeting will be posted to ERCOT calendar shortly

9. Adjourn

7620 Metro Center Drive
Austin, Texas 78744
Tel: (512) 225-7000
Fax: (512) 225-7165

Fax: (512) 225-7165

Attachment 3-003

BAL-001-TRE

RSC Update
February 5, 2010

Sydney Niemeyer

Drafting Team Members

Sydney Niemeyer	NRG Energy
Ananth Palani	Optim Energy
Pamela Zdenek	BP Alternative Energy
Rick Terrill	Luminant Generation
Kenneth McIntyre	ERCOT
Vann Weldon	ERCOT
Howard Illian	Energy Mark

Assisted by:

Tony Grasso	PUCT
Sarah Hensley	Texas RE
Jagan Mandavilli	Texas RE
Don Jones	Texas RE

Second Draft Completed

- New Glossary Definitions
  - Frequency Measurable Event
  - Governor
  - Primary Frequency Response
- Applicability
  - Balancing Authorities and Generator Owners.
  - Exempted existing Nuclear Generating Facilities.
  - Exempted generating units/generating facilities while operating in synchronous condenser mode.

Balancing Authority Requirements

- R1 BA shall identify and report Frequency Measurable Events (FME).
- R2 BA shall calculate the 12 month rolling average for initial and sustained Primary Frequency Response of each generating unit/generating facility.
  - The 12 month rolling average will contain a minimum of 8 FMEs. If there are less than 8 in a rolling 12 month period, the rolling average will continue until 8 events occur.

Generator Owner Requirements

- R3 Governor Parameters.
  - R3.1 Governor Deadband Settings.
    - Mechanical +/- 0.036 Hz
    - Electronic +/- 0.01666 Hz
    - Digital +/- 0.01666 Hz
  - R3.2 Governor Droop Settings.
    - Combustion Turbine (Combined Cycle) 4%.
    - All other Resource Types set at 5%.

Generator Owner Requirements Droop Implementation

R3 Governor Parameters continued.

- R3.3 For digital and electronic Governors an implementation curve is required.
  - 5% Droop Slope =

    $MW_{GCS} \div (3.0\text{ Hz} - \text{Governor Deadband Hz})$
  - 4% Droop Slope =

    $MW_{GCS} \div (2.4\text{ Hz} - \text{Governor Deadband Hz})$

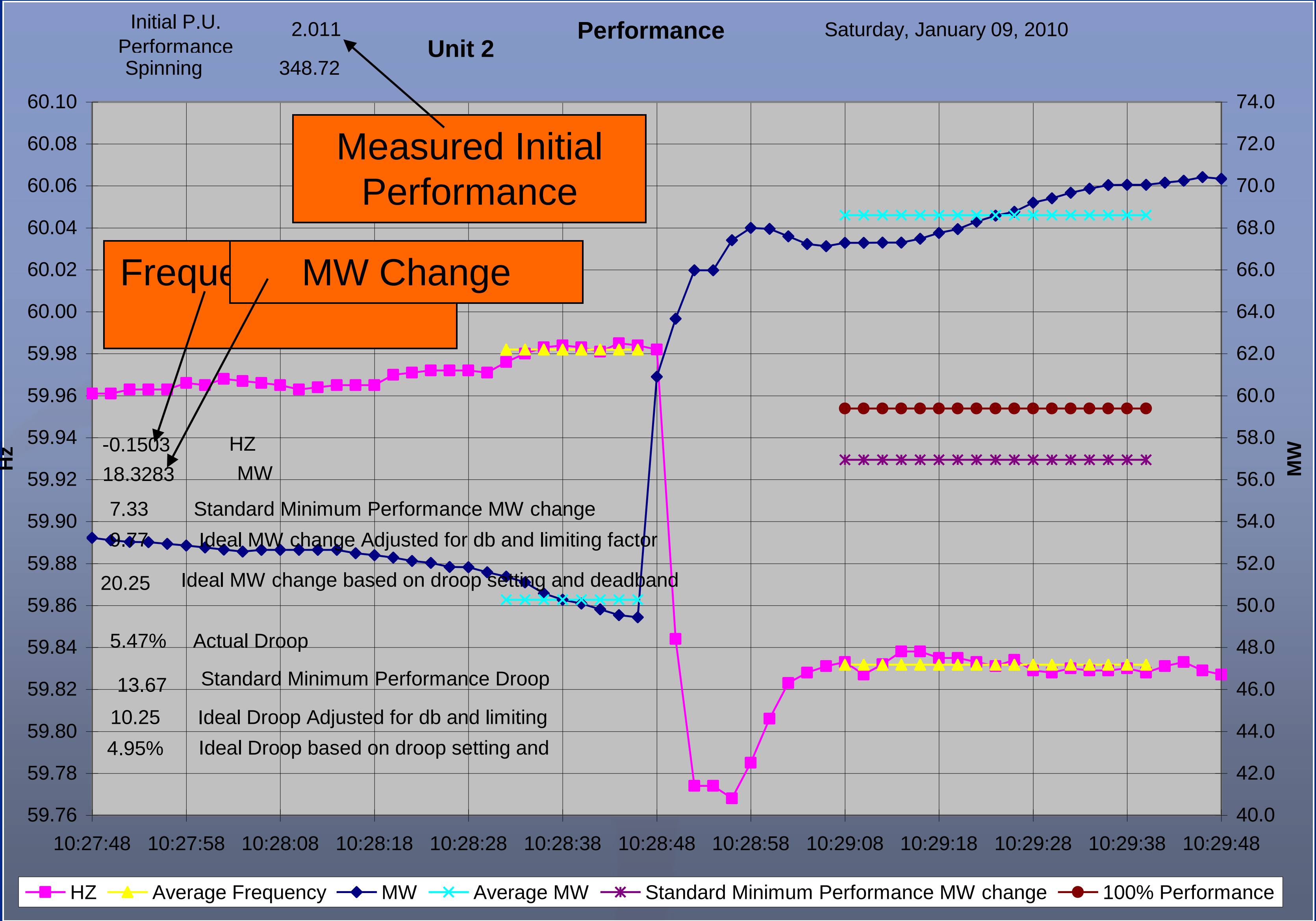
GCS is the maximum megawatt control range of the Governor control system.

Generator Owner Performance Requirements

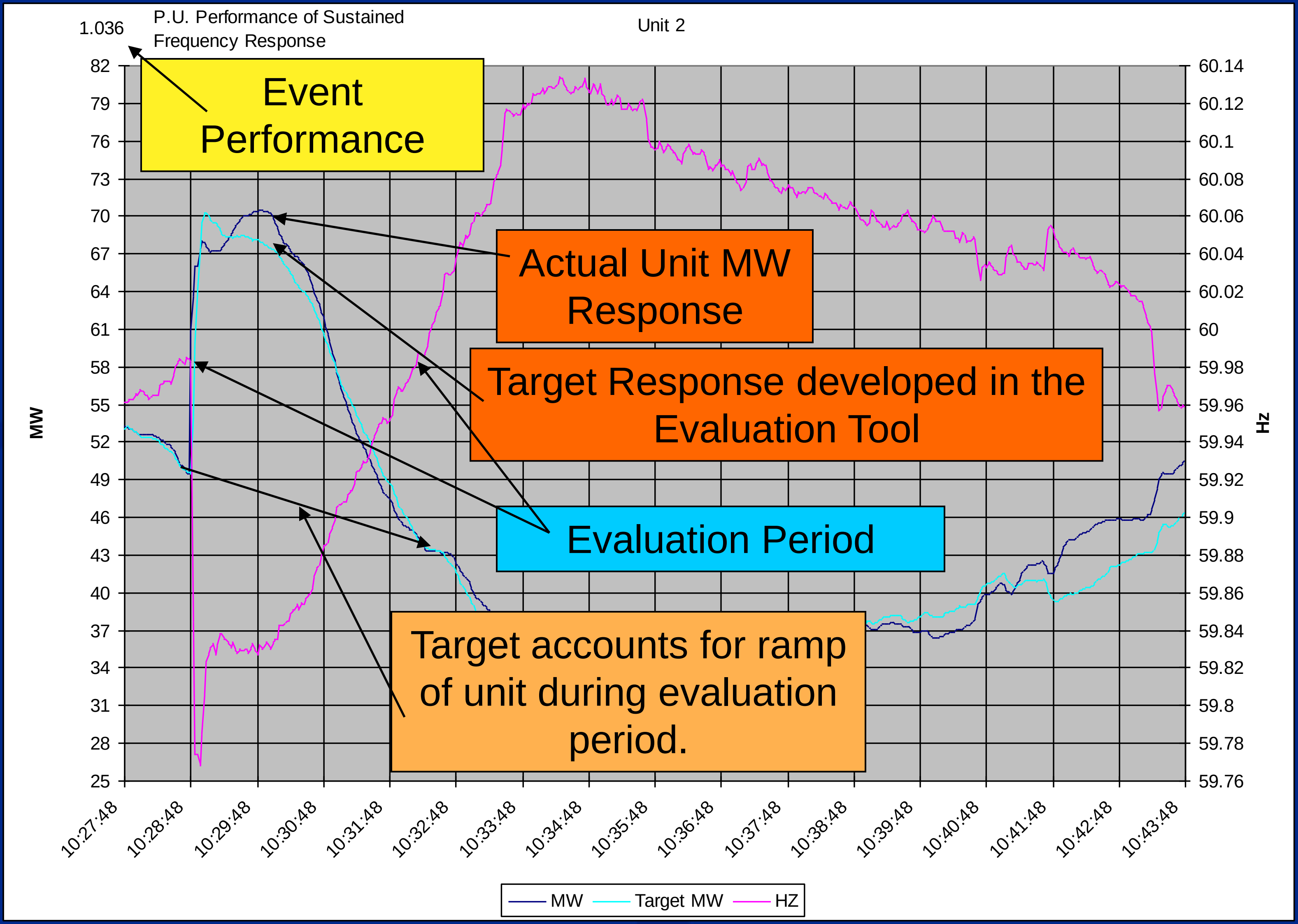
During Frequency Measurable Events:

- R4 GO must meet a minimum “initial” Primary Frequency Response performance.
- R5 GO must meet a minimum “sustained” Primary Frequency Response performance.
- Each measure for, R4 and R5, is a 12 month rolling average with a minimum 8 FME participation.

Measures – GO Initial Performance



Measures – GO Sustained Performance



GO Performance Report Summary

The "Report Summary" worksheet within the Evaluation Tool provides a summary of Individual generating unit/generating facilities initial and sustained performance during the FME being evaluated. These values will be used to develop each one's rolling average.

Date	Saturday, January 09, 2010	
Time of T(0)	10:28:48	
Frequency Before	59.9820	Hz
Frequency After	59.8317	Hz
Frequency Delta	-0.1503	Hz
Event Recovery Time	10:32:12	(sets evaluation period of "Sustained" response.)

No Evaluation = low or no spinning reserve
Low or Withdrawn = fix the governor or outer loop control loop if consistently low.
Marginal = look for reasons of underperformance, governor settings, equipment limits.
Good or Excellent and Sustained = Your doing your share.

Unit	HSL	Spinning	MW Pre event	MW Change	P.U. Perf	Droop	Initial Evaluation	P.U.Perf Sustain	Sustain Evaluation
Unit 1	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**
Unit 2	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**
Unit 3	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**
Unit 4	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**
Unit 5	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**
Unit 6	399	348.72	50.28	18.33	2.000	5.47%	**Excellent**	1.036	**Sustained**

Unit Initial Performance (P.U.) is limited to values between 0.000 and 2.000

Unit Sustained Performance (P.U.) is limited to values between 0.000 and 2.000

GO Governor Parameter Report

The "Governor Parameters" worksheet within the Evaluation Tool provides a summary of Individual generating unit/generating facilities Governor parameters used to evaluate initial and sustained performance.

Unit Name	Turbine Capacity for Droop MW	Gross or Net MW	Droop Setting for Performance Measure	Governor Deadband Hz	Governor Type	Combustion Turbine	Prime Mover Type	Limiting Factor	Limiting Factor Cause	Governor Minimum Load Performance MW	Frequency Response Filter Constant
Unit 1	400	Net	5.00%	0.016667	Electronic	N	Steam	0.4826	Throttle Pressure Change	0	0.250
Unit 2	400	Net	5.00%	0.016667	Electronic	N	Steam	0.4826	Throttle Pressure Change	0	0.250
Unit 3	400	Net	5.00%	0.016667	Electronic	N	Steam	0.4826	Throttle Pressure Change	0	0.250

Governor Droop Setting

rnor
and
ng

rnor
e
(Mechanical, Electronic or Digital)

Steam Turbine, Combustion Turbine (simple or combined cycle), wind, hydro, etc.

imiting
Factor
nsitivity
setting

Limiting Factor contributing cause (Pressure or Mass Flow)

Primary
R
C
f
measure

Minimum operating point of "Sustained" evaluation

Testing New Governor Settings

- Generating units/generating facilities with governors presently set with an intentional deadband less than or equal to +/-0.01666 Hz and droop curve based on this regional standard.
  - 11,607 MW Total Capacity Identified by PDCWG members.
    - 1690 MW Lignite
    - 4139 MW Coal
    - 3620 MW Combustion Turbine Combined Cycle
    - 1519 MW Combustion Turbine Simple Cycle
    - 399 MW Steam Turbine – natural gas fired
    - 240 MW Hydro

Compliance Elements

- Violation Severity levels were assigned per NERC Drafting Team Guidelines and are listed in the Standard.
- Violation Risk Factors and Time Horizons were added to each Requirement in accordance with the NERC Drafting Team Guidelines.

Plan for Next Posting

- Present documents for posting to RSC at February 5th meeting.
  - Second Draft of the standard, clean and redline.
  - Mapping Document.
  - Performance Evaluation Tool for the measure of performance in Requirements R2, R4 and R5 (3 spreadsheets: Steam Turbine, Combustion Turbine and Wind Turbine)
  - Compliance Implementation Schedule.
  - Frequently Asked Questions document.
  - Reference Document (White Paper) of supporting information for the requirements will be available with the posting for comments.
  - Responses to comments from first posting of the draft.
  - Unofficial Comment Form for the second posting.

Future Timeline

- Request Instructions from the RSC
  - Post second draft if instructed on February 12th.
  - Provide an industry workshop on March 3rd following RSC Meeting.
  - Review and respond to comments from second posting week of March 23rd.
  - Drafting Team WebEx March 30th – 2 hour.
  - Earliest recommendation for voting would be at the June RSC meeting.
    - 15 day posting before voting.
    - 15 day balloting.

Questions

?

Attachment 3-004

April 6, 2011

Texas RE Office
805 Las Cimas Blvd.
Austin, TX 78704

Administrative

1. Introduction and Attendance

Rick Keetch welcomed the participants to the meeting. The attendees were as follows:

Name	Company	Sector	Present	Called-in
Steve Myers	ERCOT	System Coord & Planning		
Vann Weldon (Alternate)	ERCOT	System Coord & Planning		X
John Brockhan	CenterPoint Energy Houston Electric	Transmission/ Distribution	X	
Paul Johnson	American Electric Power Service Corp	Transmission/ Distribution	X	
Barry Kremling	Guadalupe Valley Electric Cooperative	Cooperative	X	
Richard McLeon	South Texas Electric Cooperative	Cooperative	X	
David Detelich	CPS Energy	Municipal		
Jose Escamilla (Alternate)	CPS Energy	Municipal	X	
Frank Owens	Texas Municipal Power Agency	Municipal	X	
Marguerite Wagner	PSEG Energy Resources & Trade	Generation	X	
Billy Shaw	IPA Trading	Generation		
Venona Greaff (Alternate)	GDF SUEZ Energy Marketing NA	Generation		
Jeremy Carpenter	Tenaska Power Services	Load Serving & Marketing	X	
Rick Keetch	NRG Power Marketing	Load Serving & Marketing	X	
Tim Soles (Alternate)	Occidental	Load Serving & Marketing	X	
Bruce Wertz	PSEG		X	
Pam Zdenek	BP		X	
Bill Blevins	ERCOT		X	
Brenda Hampton	Luminant		X	
Barb Nutter	NERC			X
Dana Showalter	E.On Renewables			X
Don Jones	Texas Reliability Entity		X	
Natalie Mazey	Texas Reliability Entity		X	

At least one representative from at least four of the six sectors is required to constitute a quorum. At this meeting, a quorum was achieved with at least one representative from 5 of the segments being present. The System Coordinating and Planning segment was not represented at the meeting, but a committee member from that segment participated by phone (non-voting).

Antitrust Admonition & Meeting Minutes

The Texas Reliability Entity (Texas RE) Antitrust Admonition was displayed for the members. Rick Keetch reminded participants that it is Texas RE policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

Approval of February 2, 2011 Meeting Minutes

The meeting minutes were corrected to reflect the appropriate attendance roster. A motion was made by Richard McLeon to approve the minutes as amended. Marguerite Wagner seconded. Motion carried by a voice vote. The February minutes were approved.

3. Announcements

Natalie Mazey informed participants about Texas RE's Spring Standards and Compliance Workshop held on May 17 and 18, at the Texas RE offices. She explained that interested parties may choose which day to attend as both days cover the same agenda. Registration for the workshop will be conducted mid-April via email.

Natalie reminded the group that the NERC Standards Review Subcommittee (NSRS) will have its meeting following the RSC meeting.

Don announced that NERC will hold a webinar on proposed FAC-008 revisions on April 7 at noon, featuring Paul Johnson, who is chair of the NERC SDT.

Discussion and Activities

4. Report from NERC Standards Review Subcommittee (B. Wertz/D. Jones)

Bruce Wertz gave an update on NSRS activities and provided information on the results of recent NERC ballots. He informed the group that the NSRS filed its first comments to the White Paper posted in NERC Project 2010-07, Generator Requirements at the Transmission Interface. The comments focused on proposed revisions to FAC-001 and FAC-003.

Don Jones provided information on the results of recent FERC final orders.

- Order 749 was approved on March 17, 2011 and pertains to standards EOP-001-1, EOP-005-2, and EOP-006-2. Standard EOP-001-1 will become effective on October 1, 2011. Standards EOP-005-2 and EOP-006-2 will become effective July 1, 2013.
- Order 748 was approved on March 17, 2011 and pertains to standards IRO-008-1, IRO-009-1, IRO-010-1a, EOP-001-1, IRO-002-2, IRO-004-2, IRO-005-3, TOP-003-1, TOP-005-2, and TOP-006-2. These reliability standards will become effective October 1, 2011.

Don also informed the group that NERC has prioritized its standard development projects. NERC has identified 12 high priority projects and 20 remaining ongoing projects based on their prioritization tool.

The NSRS group continues to meet every 2-3 weeks to discuss various Standards Under Developments and related issues. The next NSRS teleconference will be on April 18.

5. BAL-001-TRE-1 Status Update (P. Zdenek)

Pam presented proposed changes in the composition of the SAR-003 Standard Drafting Team (SDT). The team proposed removing Rick Terrill and replacing him with Brenda Hampton of Luminant, due to Rick's change in job responsibilities. In addition, the team asked to remove Howard Illian from the SAR-003 SDT as he has not been an active member since 2009. The team noted that both Rick and Howard were instrumental in the development of the BAL-001-TRE-1 standard and their efforts are greatly appreciated.

Frank Owens made a motion to approve the addition of Brenda Hampton to the SAR-003 SDT and the removal of Rick Terrill and Howard Illian. Jose Escamilla seconded. Motion carried by voice vote. The SAR-003 SDT roster changes were approved.

6. Approval to post draft of IRO-006-TRE-1 for ballot (B. Blevins)

Bill Blevins discussed the background and development of the IRO-006-TRE-1 regional standard. Bill asked the RSC for approval to post this standard on the Texas RE Standards Tracking site for a 45-day review and ballot period. Don explained that Texas RE's Standard Development Process requires a 45-day ballot period in which the first 30 days are used to allow entities to review the standard and join the Registered Ballot Pool. Following this reviewing period, a 15-day voting period will commence.

John Brockhan made a motion to approve the IRO-006-TRE-1 standard for ballot. Paul Johnson seconded. Motion carried by voice vote. The IRO-006-TRE-1 was approved to be posted for a 45-day ballot period.

7. SAR-002 – Underfrequency Load Shedding (D. Jones)

Don explained that the SAR-002 SDT was assembled to prepare a regional standard relation to Underfrequency Load Shedding (UFLS), in cooperation with NERC Project 2007-01. The revised NERC standards (PRC-006-1 and EOP-003-2) were approved by the NERC BoT last November and have been submitted to FERC for regulatory approval.

Don reported that the regional SDT chair Brian Bartos recommended that the RSC take no action regarding retiring the SDT in view of the recent filing with FERC. He advised waiting for FERC action on the associated NERC standard before disbanding the team or taking other action.

John Brockhan made a motion to take no action on the SAR-002 SDT roster. Barry Kremling seconded. Motion carried by voice vote.

8. Other Business (R. Keetch)

Don informed the group that the Texas RE Standards Department has set up a "standards issues database" to collect information about problems, concerns, or suggestions regarding NERC standards at the regional level. Market participants are encouraged to forward relevant information to Texas RE for inclusion in this database. To do so, simply email Natalie and she will send you a Standards Issues form to complete.

Natalie encouraged participants to join the Registered Ballot Body (RBB) as the IRO-006-TRE-1 regional standard will be posted for review and ballot in the upcoming week. Each registered entity or interested party may have one representative in the RBB. In order to join the RBB, you must complete a Registered Ballot Body Form and email it as a PDF to the Reliability Standards Manager.. The RBB Form is on the Texas RE Standards Tracking Site (registration required). You do not need to be a Texas RE member to participate in standards development activities, including ballots.

9. Future Agenda Items (R. Keetch)

- Regional Standard BAL-001-TRE-1 will be presented for approval to conduct a ballot period at an upcoming RSC meeting.
- Ballot results from the Regional Standard IRO-006-TRE-1 will be presented to the committee in June.

The meeting adjourned at 11:03 a.m. The next meeting is planned for Wednesday, May 4, 2011 at 9:30 am at the Texas RE Office.

Attachment 4-001

March 4, 2009
9:30 a.m. – 12:00 p.m.

7620 Metro Center Drive
Austin, Texas 78744
Room 168

Conference Call Information

Dial-in Number: 512-225-7282 **|** **Conference Code:** 2162

WebEx Information: N/A

Administrative

1. Introduction and Attendance

Rick Keetch welcomed the attendees to the meeting.

The attendees were as follows:

Name	Company	Segment	Present	Called-In
Nick Fehrenbach	City of Dallas	Cons-Comm.	X	
Paul Gabba	Dow Chemical	Cons-Ind.	X	
Danny Bivens (Proxy) Gary	Office Public Utility Counsel	Cons-Res.	X	
Brian Bartos	Bandera Electric Coop	Coop	X	
Richard McLeon	South Texas Electric Coop	Coop	X	
Darrell Scruggs	Calpine	Ind. Generator	X	
Billy Shaw	International Power America	Ind. Generator		
Jeremy Carpenter	Tenaska Power Services	Ind. PM	X	
Rick Keetch	Reliant Energy	Ind. PM	X	
Joel Firestone	Direct Energy	Ind. REP	X	
Tony Marsh (Proxy) David Chase	Texas Power	Ind. REP		X
Paul Johnson	American Electric Power	IOU	X	
Michael Quinn	Oncor Electric Delivery	IOU		X
Les Barrow	CPS Energy	Municipal		X
Frank Owens	Texas Municipal Power Agency	Municipal	X	
Judith James	Texas RE		X	
Sarah Hensley	Texas RE		X	
Jerry Ward	Luminant	IOU	X	
Tom Burke	Luminant	IOU	X	
Rick Terrill	Reliant	IOU	X	
Doc Kelley	Brazos Electric Coop	Coop	X	
Dana Showalter	ERCOT	ISO	X	
Sydney Niemeyer	NRG	Ind. Generator	X	
Pamela Zdenek	BP Alternative Energy	Ind. Generator	X	
Wayne Bolton	Brazos Electric Coop	Coop		X

John Brockhan	CenterPoint Energy	IOU	X	
Jeanie Doty	Austin Energy		X	
Eric Goff	Reliant	IPM	X	
Steve Myers	ERCOT	ISO	X	
Dave Siebert	ERCOT	ISO	X	
Chuck Manning	ERCOT	ISO	X	
Cesar Seymour	Suez	Ind. Generator	X	
Matt Morais	ERCOT	ISO	X	
Chad Sealy	ERCOT	ISO	X	

At least one representative from five of the seven segments is required to constitute a quorum. At this meeting, a quorum was achieved with a representative from all of the seven segments being present.

Antitrust Admonition

The Texas Regional Entity (Texas RE) Anti-Trust Admonition was displayed for the members. The attendees were reminded that it is both Texas RE and ERCOT policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

Approval of Minutes

The draft minutes from the March RSC meeting were presented. There were no comments or changes suggested.

Joel Firestone moved to approve the draft minutes. The motion was seconded by Frank Owens Motion ***carried*** *by voice vote. The minutes were approved. Nick Fehrenbach abstained.*

RSC Discussions and Activities

2. Presentation of BAL-001-TRE-01 – Sydney Niemeyer

Judith James presented slides on the work product of Standard Drafting Teams in general and the RSC's role reviewing a draft standard. Steve Myers of ERCOT mentioned that there is a NERC SDT provision that allows for a minority team report to be included in a posting.

Sydney Niemeyer, Chair of the SAR-003 SDT presented the draft standard BAL-001-TRE-01 including questions to be included in the posting for comment.

Steve Myers of ERCOT had a concern about BAs not owning resources---as far as automatic response portion, ERCOT cannot do anything about it since they don't own resources. Steve said that he thinks it should be broken into two requirements: what the ISO has to do and then once the instructions are issued, the resource must respond to those instructions correctly.

Sydney said that this had thoroughly been discussed within team. In order to meet the FERC order, the requirement had to be included. Other team members had previously pointed out other standards where ERCOT doesn't have direct control, and yet ERCOT still has to meet BA requirement in those standards.

Pam Zdenek presented the implementation plan for draft BAL-001-TRE-01 and answered questions.

There was a question about whether ERCOT protocol language would change as a result of this standard. Sydney identified those protocols that may be impacted, but the team is not responsible to say how protocols need to be changed. Jerry Ward mentioned that ROS could find a subcommittee to sponsor any PRRs that may be necessary and that any protocol changes wouldn't need to be implemented until the standard is approved by FERC.

There was more discussion among the committee members and guests, but no major issue brought up that would delay the need to post for public comment.

Sydney asked the RSC to vote to move the draft standard to the next step in the process, a 30-day public comment period.

Sydney mentioned that during the comment period the team will schedule a web ex full day workshop to review the standard and answer industry questions on how everything works.

*Nick Fehrenbach moved that BAL-001-TRE-01 be moved to the next step in the process, the 30-day public comment period. Darrell Scruggs seconded the motion. The motion **carried** by voice vote with no abstentions or opposition.*

3. NERC Project 2006-03 System Restoration and Blackstart – Rick Terrill

Rick Keetch introduced Rick Terrill who is a member of the NERC Project 2006-03 System Restoration and Blackstart SDT. Rick reviewed the draft standards, EOP-005 & EOP-006. EOP-007 and EOP-009 will be retired and the requirements have been incorporated into EOP-005 or EOP-006 or are no longer needed. Discussed specific requirements, applicability and how entities could show compliance. The draft standards are about to be posted for comment.

4. SAR-002 UFLS SDT Update – Brian Bartos

Brian Bartos presented history of the NERC UFLS SDT effort. NERC UFLS SDT will post for comment in approx 4-6 weeks. Brian reviewed applicability, the regional UFLS SDT effort and next steps. The next regional UFLS SDT meeting will be scheduled once the NERC UFLS SDT schedule for posting becomes clearer, which is in approximately two months.

5. Texas RE Board Update – Judith James

Rick Keetch asked that there be a monthly Board update to the RSC if there was anything of interest at the Board regarding reliability standards. Judith suggested it be called "RSM Update to RSC" and always include a Board update.

6. Other Updates – Judith James

Due to time constraints, Judith presented only the SAR-001 update and the LSE RWG updated.

NERC is still contemplating whether a comment period is required for SAR-001 since it's not an actual standard. NERC Standards Manager and NERC Legal are reviewing the process to see if they have an obligation to post it for comment.

LSE JRO Update – reviewed actions from February 27 LSERWG meeting. The LSE Standards Applicability Matrix will be sent out and interested parties can respond with comments. Responses are due back to TRE two weeks later. The next LSERWG meeting is March 25.

Brian Bartos suggested putting informational items into a consent agenda to be acted upon at the beginning of the meeting.

7. Meeting adjourned at approximately 12:10 p.m. Next meeting is April 1 at the Met Center in Room 206B.

Attachment 4-002

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.

RSC Accepted May 27, 2008.

Drafting Team was Nominated and Selected in June 2008.

Drafting Team Met July 10, 2008.

Drafting Team Met August 14, 2008.

Drafting Team Met September 2, 2008.

Drafting Team Met September 9-10, 2008, with PDCWG.

Drafting Team Met September 16, 2008.

Drafting Team Met October 3, 2008.

Drafting Team Met October 23, 2008.

Drafting Team Met November 21, 2008.

Drafting Team Met December 5, 2008.

Drafting Team presented initial draft to RSC at December 16, 2008 meeting.

Drafting Team Met February 5, 2009.

Drafting Team Met February 27, 2009.

Final draft accepted by RSC for public posting March 4, 2009.

Description of Current Draft

This drafting team has completed a draft including all requirements, measures, and levels of compliance per the FERC Order associated with this variance and per SAR-003's stated purpose.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
Post for Comment	March 16, 2009

Technical Workshop during comment period	April 2009
Respond to Comments/Revise	April 2009
Present revised draft to RSC	May 2009
Form ballot pool and vote	May/June 2009
TRE Board Adopt (Tentative)	July 2009
NERC Submit (Tentative)	August 2009
FERC Approval (Tentative)	October 2009
Begin Three Year Implementation Plan	November 2009
Be Auditably Compliant	December 2012

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Controllable Load Resource: Load resource capable of providing Regulation Service by controllably reducing or increasing consumption under dispatch control (similar to Automated Generation Control) and that immediately responds proportionally to frequency changes (similar to generator governor action).

Emergency Interruptible Load Service (EILS): A special emergency service used during an Electrical Emergency Alert to reduce Load and assist in maintaining or restoring ERCOT System frequency.

Frequency Responsive Resource: Facility capable of providing electrical energy or Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services (as defined in the current ERCOT Protocols) to the ERCOT System, excluding Underfrequency Relay Load and Emergency Interruptible Loads but not Controllable Load Resources.

Generation Resource: A generator that is capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource.

Interconnection Minimum Frequency Response (IMFR): The minimum frequency response limit for the Interconnection that is initially set at 420 MW/0.1 Hz.

Measurable Event (ME): A sudden change in interconnection frequency that will be evaluated for interconnection frequency response performance and will meet one of the following conditions:

i) a change in interconnection frequency that has a pre-perturbation average frequency to post-perturbation average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year). See Attachment 1 for detailed criteria for this measurement.

or

ii) a change in a Generation Resource, DC tie or firm load pre-perturbation average MW output to post-perturbation average MW output absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year). See Attachment 1 for detailed criteria for this measurement.

Perturbation: Any disturbance of motion, course, arrangement, or state of equilibrium that causes a sudden change in frequency on the Bulk Electric System.

Post–perturbation: The 34-second period of time starting 20 seconds after t(0).

Pre-perturbation: The 16-second period of time before t(0).

Regulation Service: A service that is used to control the power output of Resources in response to a change in system frequency so as to maintain the target system frequency within predetermined limits.

Resource: Facility capable of providing electrical energy or Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System. This includes Generation Resources, Loads acting as Resources and Emergency Interruptible Load Service Resources.

t(0): It is the time of the first observable change in Interconnection frequency at the beginning of a perturbation.

Underfrequency Relay Load: Load that is taken off-line by an underfrequency relay when the frequency goes below a predetermined frequency value for a predetermined number of cycles.

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** **BAL-001-TRE-1 (Regional Variance)**
3. **Purpose:** **To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. This regional variance replaces the CPS2 Waiver that was approved for ERCOT by NERC on November 21, 2002. Specifically, this variance replaces requirement 2 of BAL-001-0a per FERC Order 693.**
4. **Applicability:** **Balancing Authorities (BA), Generator Owners (GO), Generator Operators (GOP)**
5. **Effective Date:** **Within an appropriate time after final regulatory approval and with a three-year implementation plan to allow Generation Resource/Frequency Responsive Resource time to meet the requirements. See outline of implementation plan in Attachment 4.**

B. Requirements

R1. The Balancing Authority for the ERCOT Interconnection shall identify Measurable Events (as defined in this regional standard) for primary governing frequency response measurement of Generation Resources, Frequency Responsive Resources, and firm load.

R2. Within 30 days of a Measurable Event, the Balancing Authority for the ERCOT Interconnection shall submit to the Compliance Enforcement Authority scan rate data necessary to analyze each Measurable Event identified in R1. This data shall include:

(1) Interconnection Frequency;
(2) Interconnection scheduled frequency used in the ACE equation;
(3) Regulation Service deployed;
(4) Responsive Reserve Service deployed;
(5) Available Responsive Reserve Service (Nodal only);
(6) Generation Resource/Frequency Responsive Resource MW value;
(7) Control Error (Schedule CE in Zonal, Generation Resource/Frequency Responsive Resource CE in Nodal);
(8) Generation Resource/Frequency Responsive Resource Expected Frequency Response;
(9) Resource Regulation Service Allocation (Nodal only);
(10) Resource Economic Base Point (Nodal only);
(11) Resource High Operating Limit;
(12) Resource Low Operating Limit;
(13) Load Acting As Resource MW;

(14) Load Acting As Resource deployed;
(15) Resource Responsive Reserve Service Responsibility (Nodal only);
(16) ERCOT Load;
(17) MW value for loss of individual Generation Resource(s) or Load that triggered the Measurable Event;
(18) Emergency Interruptible Load Service deployed;
(19) Time (synchronous time stamp to the nearest second for the data above).

R3. The BA shall analyze frequency and frequency movements and calculate the Interconnection Minimum Frequency Response (MW/0.1Hz) by January 1 of each year.

R4. The BA shall attain a twelve-month rolling average Interconnection Frequency Response, as measured in Attachment 2, greater than or equal to the Interconnection Minimum Frequency Response.

R5. For each Measurable Event, the frequency response performance of each interconnected Generation Resource/Frequency Responsive Resource shall be compiled by the BA as measured in Attachment 3.

R6. The BA shall calculate the twelve-month rolling average frequency response performance of each Generation Resource/Frequency Responsive Resource and report it to the Compliance Enforcement Authority. Generation Resources less than 10 MW each, who at a single point of interconnection sum to an aggregate greater than 10 MW, shall be treated as a single Generation Resource.

R7. The GO shall report to ERCOT the operating range, performance level, and any parameter limiting the frequency response of each Generation Resource/Frequency Responsive Resource. See Attachment 3 for these parameters.

R8. The GO shall ensure that combustion turbines in a combined cycle configuration have a governor droop characteristic of 4%, steam turbines have a governor droop characteristic of 5%, and that all other Generation Resources/Frequency Responsive Resources have a governor droop characteristic of 5% or less. See Attachment 3 for these characteristics.

R9. Each GO shall limit governor deadbands, intentional and unintentional, of turbine governors to those stated in Attachment 3.

R10. Except for protection of equipment or safety, the GO and GOP will sustain its governor response to all frequency deviations that exceed the deadbands stated in Attachment 3.

R11. The GO and GOP will meet a minimum twelve-month rolling average frequency response performance on each Generation Resource/Frequency Responsive Resource as stated in Attachment 3. See chart of Figure 4: Expected Resource Performance and associated spreadsheet.

C. Measures

M1. The BA shall have a procedure in place for identifying Measurable Events.

M2. The BA shall make available for inspection evidence that the data as specified in R2 was submitted to the Compliance Enforcement Authority for evaluation.

M3. The BA shall have available for inspection evidence that the analysis of the IMFR was performed as specified in R3.

M4. The BA shall have evidence it calculated the twelve-month rolling average frequency response performance of the Interconnection of all Measurable Events.

M5. For each Measurable Event, the BA shall have evidence it reported the performance of each interconnected Generation Resource/Frequency Responsive Resource to the Compliance Enforcement Authority.

M6. For each Measurable Event, the BA shall have evidence it reported the twelve- month rolling average performance of each Generation Resource/Frequency Responsive Resource to the Compliance Enforcement Authority.

M7. The GOP shall have evidence it reported to the BA, each Generation Resource/Frequency Responsive Resource's governor operating range and expected frequency response performance for the full output range of each Generation Resource/Frequency Responsive Resource.

M8. The GO shall have evidence its frequency response Generation Resource/Frequency Responsive Resource's governor droop is set in accordance with the settings in Attachment 3.

M9. The GO shall have evidence its frequency response Generation Resource/Frequency Responsive Resource's governor deadband is set in accordance to the limits in Attachment 3.

M10. The GO and GOP shall have evidence that premature frequency response withdrawal by the Generation Resource/Frequency Responsive Resource was not visually observed.

M11. The GO and GOP shall have evidence that within the Measurable Event report, the twelve-month rolling average per unit frequency response performance of each Generation Resource/Frequency Responsive Resource met the minimum performance as stated in Attachment 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Texas Regional Entity

1.2. Compliance Monitoring Period and Reset Time Frame

1.2.1 If a Generation Resource/Frequency Responsive Resource fails any requirement or measure of this standard, the GO and GOP will submit mitigation plans for the failing Generation Resource/Frequency

Responsive Resource with a timeline not to exceed 90 days from the notification of failing performance.

1.2.2 Each Generation Resource/Frequency Responsive Resource will have a rolling event average performance as stated in Attachment 3 of this Standard. If a Generation Resource/Frequency Responsive Resource completes a mitigation plan and implements corrective action that corrects past failing performance as measured by this standard, the rolling event average will be reset on the next successful performance during a measurable event and the Generation Resource/Frequency Responsive Resource will begin a new rolling event average performance. If the Generation Resource/Frequency Responsive Resource fails the next measurable event performance, the GO and GOP will submit a follow-up mitigation plan with a timeline not to exceed 30 days from the notification of failing performance.

1.3. Data Retention

The Balancing Authority, Generator Operator, and Generator Owner shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each BA shall retain a list of identified Measurable Events since the last compliance audit for Requirement 1, Measure 1.
- Each BA shall retain all archived data since the last compliance audit for Requirement 2, Measure 2.
- Each BA shall retain all analysis and calculations since its last compliance audit for Requirement 3, Measure 3.
- Each BA shall retain all comparative calculations since its last compliance audit for Requirement 4, Measure 4.
- Each BA shall retain all calculations and compilations since its last compliance audit for Requirement 5, Measure 5.
- Each BA shall retain all calculations since its last compliance audit for Requirement 6, Measure 6.
- Each GOP shall retain evidence since its last compliance audit for Requirement 7, Measure 7.
- Each GO shall retain evidence since its last compliance audit for Requirement 8, Measure 8.
- Each GO shall retain evidence since its last compliance audit for Requirement 9, Measure 9.

- Each GO and GOP shall retain evidence since its last compliance audit for Requirement 10, Measure 10.
- Each GO and GOP shall retain evidence since its last compliance audit for Requirement 11, Measure 11.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Periodic Data Submittals as required

Exception Reporting as necessary per Attachment 2

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				Did not have a procedure in place to identify Measurable Events.
R2	Submitted data to Compliance Enforcement Authority 45 days after the event.	Submitted data to Compliance Enforcement Authority 60 days after the event.	Submitted data 120 days after the event.	No submission was made to Compliance Enforcement Authority on the identified event.
R3			All changes in Generation Resources greater than 10 MW, either individually or as aggregated behind a single meter, were not included in the IMFR analysis.	No analysis was performed to determine IMFR or there was no record of doing so.
R4	The twelve-month rolling average frequency response is less than 100% but greater than or equal to 90% of the IMFR.	The twelve-month rolling average frequency response is less than 90% but greater than or equal to 80% of the IMFR.	The twelve-month rolling average frequency response is less than 80% but greater than or equal to 70% of the IMFR.	The twelve-month rolling average frequency response is less than 70% of the IMFR.
R5				No evidence of reporting to Compliance Enforcement Authority.
R6				No evidence of reporting to Compliance Enforcement Authority.
R7			The GOP does not have evidence that it reported to the BA most of its Generation Resource/Frequency Responsive Resource's expected frequency response for its normal operating range.	The GOP does not have evidence that it reported to the BA any of its Generation Resource/Frequency Responsive Resource's expected frequency response for its normal operating range.
R8	Completed governor droop test form dated longer than two years.	Completed governor droop test form dated longer than three years.	Completed governor droop test form dated longer than four years.	The GOP does not have evidence that the governor droop characteristics were set per Attachment 3.
R9				The GOP does not have evidence that the governor deadband limits were set per Attachment 3.
R10				The GO or GOP applied control action to reduce or withdraw frequency response of a Generation Resource/Frequency Responsive Resource that exceeded the allowable deadbands as stated in Attachment 3.
R11	The twelve month rolling average frequency response performance of a Generation	The twelve-month rolling average frequency response performance of a Generation	The twelve-month rolling average frequency response performance of a Generation	The twelve-month rolling average frequency response performance of a Generation Resource/Frequency Responsive Resource is less than 0.25 P.U. as measured in Attachment 3.

	Resource/Frequency Responsive Resource is greater than or equal to 0.45 P.U. and less than 0.55 P.U. as measured in Attachment 3.	Resource/Frequency Responsive Resource is greater than or equal to 0.35 P.U. and less than 0.45 P.U. as measured in Attachment 3.	Resource/Frequency Responsive Resource is greater than or equal to 0.25 P.U. and less than 0.35 P.U. as measured in Attachment 3.	

E. Regional Variances

This is a regional variance to NERC Standard BAL-001-0a, specifically replacing R2. Instead of complying with R2 in BAL-001-0a (CPS2), the BA, GO, and GOP in the ERCOT Interconnection maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time by the methods, requirements, and measures described in this regional standard and associated attachments and documents.

F. Associated Documents

Waiver Request – Control Performance Standard 2

Organization

ERCOT

Operating Policy

ERCOT requests a waiver from Policy 1, "Generation Control and Performance," Section E, "Performance Standard" as follows:

Standards

1.2. **Control Performance Standard (CPS2)**. The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}.

Requirements

2. **Control Performance Standard (CPS) Compliance**. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).

Explanation

ERCOT requests a waiver from the CPS2 Standards and Requirements listed above for the following reasons:

1. On July 31, 2001, the ERCOT Interconnection began operating as a single CONTROL AREA, asynchronously connected via two DC ties to the Eastern Interconnection. At that time, ERCOT changed from the traditional tie-line bias generation control algorithms in which ten CONTROL AREAS participated, to a single 15-minute interval competitive balancing energy market and a frequency control system that regulates around the balancing energy schedule on two-to-four second intervals. ERCOT requests that the Operating Committee reconsider CPS2 to ensure it is feasible under this new type of market-based control.

   If the Operating Committee believes that the CPS2 is feasible, then ERCOT would suggest that Policy 1 (or the appropriate Compliance document) provide for a "test period" of six months to allow CONTROL AREAS making such a transition the opportunity to test new control algorithms *provided* they can show that reliability is not degraded during that period. ERCOT also believes that its L_{10} may not be appropriate as it is less than half of the L_{10} of another NERC CONTROL AREA of similar load size.

2. The ERCOT Interconnection is now a single CONTROL AREA asynchronously connected to the Eastern Interconnection, and cannot create inadvertent power flows or frequency errors in other CONTROL AREAS. Therefore, the ISO questions whether the CPS2 Standard is necessary or even beneficial for such asynchronous operation. ERCOT is currently performing a study that compares its single CONTROL AREA performance against that of the former ten CONTROL AREA operations. Initial results of that study show that while the ten CONTROL AREAS *individually* met CPS2 standards, the *aggregate* CPS2 performance of the ten CONTROL AREAS did not, and was actually below that of the current single CONTROL AREA.

Current Operating Reliability

ERCOT does not believe that Frequency control within its new single CONTROL AREA INTERCONNECTION is less reliable as a result of non-compliance with the CPS2 Standard following its conversion. ERCOT Interconnection frequency control has been, and continues to be, very reliable since that conversion.

The table below shows ERCOT's CPS2 performance for August through December 2000 as an INTERCONNECTION with ten Control Areas. The average CPS2 compliance was 74.82%. CPS2 compliance for ERCOT as a single control area for August 2001 was 83.88%, an improvement of approximately nine percentage points.

	% of Frequency Data Available	Supplier Of Frequency Data	Single Control Area CPS1 %	CPS2 %	Average of Absolute1 min Averages Freq Deviation	Average of Absolute10 min Averages Freq Deviation
August-00	79	ERCOT	140.99	76.50	0.011978483	0.008299971
September-00	100	ERCOT	134.89	76.02	0.012366	0.009495
September-00	100	REIT HLP	135.91	77.01	0.012221795	0.008443165
October-00	23	ERCOT	199.68	76.90	0.013910426	0.00857111
October-00	100	REIT HLP	114.01	78.58	0.014621429	0.008120248
November-00	65	ERCOT	105.19	67.20	0.015061531	0.010523159
December-00	60	ERCOT	192.59	72.60	0.013428052	0.009330552
Average	(See Note 1)		134.71	74.82	0.013439915	0.009062032
August-01	None (See Note 2)	None (See Note 2)	127.30	83.88		

Note 1: Weighted Average Based on ERCOT for August, September November and December and REIT for October.

Note 2: From ERCOT CPS report. ERCOT is working on providing frequency data for August 2001.

FERC ORDER 693

FROM FERC ORDER 693, March 16, 2007, Paragraphs 309-315

Regional Difference to BAL-001-0: ERCOT Control Performance Standard 2

309. NERC approved a regional difference for ERCOT by allowing it to be exempt from Requirement R2 in BAL-001-0, which requires that the average area control error (ACE) for each of the six ten-minute periods during the hour must be within specific limits, and that a balancing authority achieves 90 percent compliance. This Requirement is referred to as Control Performance Standard 2 (CPS2).

310. NERC explains that ERCOT requested a waiver of CPS2 because: (1) ERCOT, as a single control area asynchronously connected to the Eastern Interconnection, cannot create inadvertent flows or time errors in other control areas and (2) CPS2 may not be feasible under ERCOT's competitive balancing energy market. In support of this argument, ERCOT cites to a study that it performed showing that, under the new market structure, the ten control areas in its region individually were able to meet CPS2 standards while the aggregate performance of the ten control areas was not in compliance. Since requesting the waiver from CPS2, ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT.

311. In the NOPR, the Commission proposed to approve the ERCOT regional difference and have the ERO submit a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section five of the ERCOT protocols.

312. No comments were filed on this regional difference.

313. The Commission approves the ERCOT regional difference as mandatory and enforceable. Order No. 672 explains that "uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception." However, the Commission has stated that, as a general matter, regional differences are permissible if they are either more stringent than the continent-wide Reliability Standard, or if they are necessitated by a physical difference in the Bulk-Power System. Regional differences must still be just, reasonable, not unduly discriminatory or preferential and in the public interest.

314. The Commission finds that ERCOT's approach under section 5 of the ERCOT protocols appears to be a more stringent practice than Requirement R2 in BAL-001-0 and therefore approves the regional difference.

315. As proposed in the NOPR, the Commission directs the ERO to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols. As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures and Levels of Non-Compliance sections.

ERCOT Protocol 5.9

5.9 Frequency Response Requirements and Monitoring

5.9.1 Generation Resource and QSE Participation

5.9.1.1 Governor in Service

At all times a Generation Resource is on line, its turbine governor shall remain in service and be allowed to respond to all changes in system frequency. Generation Entities shall not reduce governor response on individual Resources during abnormal conditions without ERCOT's consent (conveyed by way of the Generation Entity's QSE) unless equipment damage is imminent.

5.9.1.2 Reporting

Generation Entities shall conduct applicable generating governor speed regulation tests on Resources as specified in the Operating Guides. Test results and/or other relevant information shall be reported to ERCOT and ERCOT shall forward results to the appropriate TSPs.

Resource governor modeling information required in the ERCOT Planning Criteria shall be determined from actual Resource testing described in the Operating Guides. Within thirty (30) days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the connected TSP.

When the governor of a Generation Resource is blocked while the Resource is operating, the QSE shall promptly inform ERCOT. The QSE shall also supply governor status logs to ERCOT upon request.

Any short-term inability of a Generation Resource to supply governor response shall be immediately reported to ERCOT.

If a Generation Resource trips Off-line due to governor response problems, the Generation Entity shall immediately report the change in the status of the Resource to ERCOT and the QSE.

5.9.2 Primary Frequency Control Measurements

For the purposes of this section, the A Point is the last stable frequency value prior to a frequency disturbance. For a decreasing frequency event with the last stable frequency value of 60.000 Hz or below, the actual frequency is used. For a decreasing frequency event with the last stable frequency value between 60.000 and 60.036 Hz, 60.000 Hz will be used. For a decreasing frequency event with the last stable frequency value above 60.036 Hz, actual frequency will be used. For an increasing frequency event with the last stable frequency value of 60.000 or above, the actual frequency is used. For an increasing frequency event with the last stable frequency between 59.964 and 60.000 Hz, 60.000 Hz will be used. For an increasing frequency event with the last stable frequency value of 59.964 or below, the actual frequency is used. ERCOT shall determine the A Point frequency for each event.

For the purposes of this section, the C Point is the lowest frequency value during the first five seconds of the event.

For the purposes of this section, the B Point is the “recovery” frequency value after the C Point. The B Point should occur after full governor response of the turbines has occurred, usually between ten (10) and thirty (30) seconds after the A Point, but not greater than sixty (60) seconds after the A Point. ERCOT shall determine the B Point for each event.

B Point Plus Thirty Seconds: At thirty seconds following the B Point, an analysis will be performed by ERCOT with the assistance of the appropriate ERCOT subcommittee to determine if primary frequency control response is sustained.

For the purposes of this section, a “Measurable Event” is the sudden change in interconnection frequency that will be evaluated for performance compliance will have i) a frequency B Point between 59.700 Hz and 59.900 Hz or between 60.100 Hz and 60.300 Hz, and ii) a difference between the B Point and the A Point greater than or equal to +/- 0.100 Hz.

5.9.2.1 ERCOT Required Primary Frequency Control Response

The combined response of all Generation Resources interconnected in ERCOT to a Measurable Event shall be at least 420 MW / 0.1 Hz. This value should be reviewed on an annual basis by ERCOT and the appropriate ERCOT subcommittee for system interconnect reliability needs.

ERCOT will evaluate, with the assistance of the appropriate ERCOT subcommittee, primary frequency control response during Measurable Events. The actual Generation Resource response will be compiled to determine if adequate primary frequency control participation was available.

ERCOT and the appropriate ERCOT subcommittee will review each Measurable Event, verifying the reasonableness of data. Data that is in question may be requested from the QSE for comparison and/or individual Resource data may be retrieved from ERCOT’s database.

ERCOT’s performance will be averaged using the most recent six (6) Measurable Events to determine its rolling average contribution.

5.9.3 ERCOT Data Collection

5.9.3.1 Data Collection

ERCOT will collect all data necessary to analyze each Measurable Event. This will include the following real-time data:

(1) Interconnection Frequency;
(2) Regulation Service deployed;
(3) Responsive Reserve Service deployed;
(4) QSE available Responsive Reserve Service;
(5) QSE total Generation;
(6) QSE SCE;
(7) QSE Bias;

(8) QSE LaaR MW;
(9) LaaR deployed;
(10)QSE Responsive Reserve Service;
(11)ERCOT Load and individual Resource(s) that contributed to the frequency deviation; and
(12)EILS deployed.

Version History

Version	Date	Action	Change Tracking

Attachment 1

The goal of these criteria is to capture 30 to 40 events each year. These criteria shall be adjusted by the BA to achieve at least the minimum target number of events.

Part 1: Frequency deviation criteria

In the attached Excel spreadsheet "ERCOT Measurable Event Detection.xls" ERCOT scan rate frequency data is collected and automatically analyzed for frequency deviations. The size of the frequency deviation used in the analysis can be controlled in cell C1 of the first worksheet "2secHz" and is presently set at 0.100 Hz (100 mHz). This value in Hz deviation will control how many "events" will be detected from the data set. The data set will collect eleven days of 2-second data and summarize the total number of events detected in the data column. Not all events detected by the spreadsheet will be valid frequency events for performance measurement. Any event detected that results in the "post–perturbation" average frequency ending within the turbine governor deadbands (~60.020 to ~59.980 Hz) should be eliminated. Also, any event that has a median frequency deviation near 60.000 Hz should be eliminated. This would occur when the Pre-perturbation to Post-perturbation frequency is centered around 60.000 Hz. This measurement of Interconnection frequency response would include deadbands in both directions from 60.000 Hz and turbine governor performance will be reduced due to the deadband impact of the non responsive regions. Valid frequency deviations for performance evaluation shall have the Post-perturbation frequency further from 60.000 Hz than the Pre-perturbation frequency.

As the performances of Generation Resource/Frequency Responsive Resources improve as a result of this standard, the Interconnection frequency profile will improve and fewer "false" event detections will be detected by the spreadsheet. It is also likely that with this improved frequency response, the frequency deviation value in cell C1 will have to be decreased to achieve the target number of Measurable Events.

Part 2: MW change causing or contributing to the perturbation

Accurate accounting of the change in megawatts contributing to the perturbation is necessary for proper evaluation of Interconnection frequency response. Most events will be the result of a single Generation Resource or group of Generation Resources (combined cycle plants). However, the Balancing Authority should consider changes in "non-conforming load" during the measurement period and include sympathetic Generation Resource trips that occur during the measurement period. Generation Operators are required to report such trips to the BA. This standard sets 550 MW within 20 seconds as the trigger level to perform an Event analysis. The BA may adjust this value to achieve the targeted number of Measurable Events each year.

Attachment 2

Part 1: Measuring ERCOT Interconnection Frequency Response

The process for measuring Interconnection Frequency Response requires scan rate data of Interconnection frequency and scan rate data of the Generation Resource(s) or Load(s) causing the perturbation. This data must be aligned to eliminate time skew. The steps in the frequency response calculation are: 1) Determine the scan data for t (0), which is the first scan of frequency that frequency deviates from normal. This scan value identifies the beginning of the perturbation; 2) Calculate the average of the Pre and Post perturbation of the Interconnection frequency and megawatt of the Generation Resource(s) or Load(s) causing the perturbation; 3) Take the mathematical differences of each parameter, divide the difference in megawatt change by the difference in frequency change and 4) Divide this quotient by 10 for the standard form in MW per tenth Hz (MW/0.1Hz). An Excel spreadsheet named “Frequency Response data report for Single BA Interconnection 2 second scan.xls” is included in this attachment and performs the frequency response calculation. See Figure 1 below.

Report No. ERCOT20080825 Date : 08/25/08 Time (HHMMSS): 15:14:32
1 Time Standard BA BIAS -660 MW/0.1 Hz
Scan Rate 2 **2 seconds** CDT 55,147 Load @ A

Freq. (before)	Freq. (after)	Freq. Chg.	Sch. Freq.	FR % of Bias		
					54,979	Load @ B
59.9848	59.8592	-0.12557	60.00	95.0%	-627.22	BA MW/0.1 Hz
Average Before	Average After			21.3%	-133.79	BA Load MW/0.1 Hz

Comments File: Load FR % of Total FR -660 Interconnection Total Bias
Interconnection Minimum Freq Response Target. -420 MW/0.1 Hz 65340.22 Interconnection Peak Forecast Load
BA Performance based on Peak Load Ratio 149.34% 65340.22 BA Peak Forecast Load
BA Performance based on Bias Ratio 149.34%
Frequency Response data report for BA: ERCOT

T = Time of Disturbance

	Time	F	Resource Lost	ACE	Index		
T-60 sec	15:13:32	59.982	788.4457	-117.1901	1		
T-58 sec	15:13:34	59.979	788.4457	-136.7094	2		
T-56 sec	15:13:36	59.979	788.4457	-136.7094	3		
T-54 sec	15:13:38	59.978	788.4457	-143.2158	4		
T-52 sec	15:13:40	59.978	788.4457	-143.2158	5		
T-50 sec	15:13:42	59.978	787.2555	-143.2158	6		
T-48 sec	15:13:44	59.978	789.2392	-143.2158	7		
T-46 sec	15:13:46	59.981	789.2392	-123.6966	8		
T-44 sec	15:13:48	59.981	789.2392	-123.6966	9		
T-42 sec	15:13:50	59.981	786.462	-123.6966	10		
T-40 sec	15:13:52	59.982	785.4244	-117.1901	11		
T-38 sec	15:13:54	59.982	785.4244	-117.1901	12		
T-36 sec	15:13:56	59.982	785.4244	-117.1901	13		
T-34 sec	15:13:58	59.985	785.4244	-97.64603	14		
T-32 sec	15:14:00	59.985	790.643	-97.64603	15		
T-30 sec	15:14:02	59.984	790.9482	-104.1525	16		
T-28 sec	15:14:04	59.984	789.7885	-104.1525	17		
T-26 sec	15:14:06	59.981	789.7885	-123.6966	18		
T-24 sec	15:14:08	59.981	789.7885	-123.6966	19		
T-22 sec	15:14:10	59.981	790.3989	-123.6966	20		
T-20 sec	15:14:12	59.981	790.3989	-123.6966	21		
T-18 sec	15:14:14	59.983	787.9269	-110.6589	22		
T-16 sec	15:14:16	59.983	787.9269	-110.6589	23	59.9848	788
T-14 sec	15:14:18	59.985	787.9269	-97.64603	24	59.9848	788
T-12 sec	15:14:20	59.985	788.171	-97.64603	25	59.9848	788
T-10 sec	15:14:22	59.985	788.4457	-97.64603	26	59.9848	788
T-08 sec	15:14:24	59.985	787.1334	-97.64603	27	59.9848	788
T-06 sec	15:14:26	59.985	787.1334	-97.64603	28	59.9848	788
T-04 sec	15:14:28	59.985	787.1334	-97.64603	29	59.9848	788
T-02 sec	15:14:30	59.985	787.1334	-97.64603	30	59.9848	788
T+0 sec	15:14:32	59.831	88.74783	-1100.182	31		
T+02 sec	15:14:34	59.842	88.74783	-1028.586	32		
T+04 sec	15:14:36	59.842	0	-1028.586	33		
T+06 sec	15:14:38	59.867	0	-865.8262	34		
T+08 sec	15:14:40	59.867	0	-865.8262	35		
T+10 sec	15:14:42	59.874	0	-820.2564	36		
T+12 sec	15:14:44	59.874	0	-820.2564	37		
T+14 sec	15:14:46	59.870	0	-846.307	38		
T+16 sec	15:14:48	59.870	0	-846.307	39		
T+18 sec	15:14:50	59.870	0	-846.307	40		
T+20 sec	15:14:52	59.870	0	-846.307	41	59.8592	0
T+22 sec	15:14:54	59.867	0	-865.8262	42	59.8592	0
T+24 sec	15:14:56	59.867	0	-865.8262	43	59.8592	0
T+26 sec	15:14:58	59.866	0	-872.3326	44	59.8592	0
T+28 sec	15:15:00	59.866	0	-872.3326	45	59.8592	0
T+30 sec	15:15:02	59.861	0	-904.8896	46	59.8592	0
T+32 sec	15:15:04	59.861	0	-904.8896	47	59.8592	0
T+34 sec	15:15:06	59.857	0	-930.9401	48	59.8592	0
T+36 sec	15:15:08	59.857	0	-930.9401	49	59.8592	0
T+38 sec	15:15:10	59.857	0	-930.9401	50	59.8592	0
T+40 sec	15:15:12	59.857	0	-930.9401	51	59.8592	0
T+42 sec	15:15:14	59.854	0	-950.4594	52	59.8592	0
T+44 sec	15:15:16	59.854	0	-950.4594	53	59.8592	0
T+46 sec	15:15:18	59.853	0	-956.9658	54	59.8592	0
T+48 sec	15:15:20	59.853	0	-956.9658	55	59.8592	0
T+50 sec	15:15:22	59.853	0	-956.9658	56	59.8592	0
T+52 sec	15:15:24	59.853	0	-956.9658	57	59.8592	0
T+54 sec	15:15:26	59.853	0	-956.9658	58		
T+56 sec	15:15:28	59.853	0	-956.9658	59		
T+58 sec	15:15:30	59.854	0	-950.4594	60		
T+60 sec	15:15:32	59.854	0	-950.4594	61		

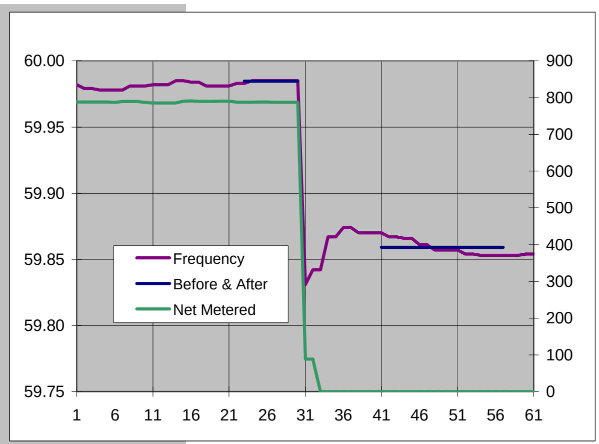


Figure 1: Interconnection frequency response measurement.

Attachment 3

Part 1: Governor deadband and droop settings

Governor Deadbands:

Mechanical governors of steam turbine Generation Resources: Due to gear lash and movement of mechanical parts of a mechanical fly-ball governor on a steam turbine, it is common to observe frequency response deadband for small changes in frequency. This deadband, or range of no frequency response, shall be limited to less than +/- 0.036 Hz (36 mHz).

Electronic and digital governors of Generation Resource/Frequency Responsive Resources: Intentional governor deadbands on electronic and digital governors should be avoided. If intentional frequency response deadband of electronic or digital governors is necessary for Generation Resource/Frequency Responsive Resource stability, it shall be limited to a maximum of +/- 0.01667 Hz (16.67 mHz or one rpm on a two pole generator) as measured from 60.000 Hz. Once frequency deviation has exceeded the governor deadband from 60.000 Hz, the frequency response characteristic shall not "step-into" the 5% droop curve or the 4% droop curve. The droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz or attain the 4% droop curve characteristic when frequency deviation reaches +/-2.4 Hz.

Governor Droop Setting:

Steam Turbine:

Droop settings of steam turbines shall be 5% or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz.

Combustion turbines operating in combined cycle mode, single or multiple shafts:

Combustion turbines, operating in a combined cycle mode, governor shall be set at 4% droop or lower. The 4% droop curve shall linearly add frequency response and attain the 4% droop curve characteristic when frequency deviation reaches +/-2.4 Hz.

Combustion turbines operating in a simple cycle mode:

Combustion turbines, not operating in a combined cycle mode, governor shall be set at 5% droop or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz.

Wind turbine:

Wind turbines that have droop capability shall have a droop setting of 5% or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz.

Other Generation Resource/Frequency Responsive Resources:

Other Generation Resource/Frequency Responsive Resources that have droop capability shall have a droop setting of 5% or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz.

Part 2: Minimum performance of turbine governors during actual grid frequency deviations.

The measurement of frequency response can be challenging. There are conditions when the mathematical calculations that perform the measurement of performance do not account for all control functions of a Generation Resource/Frequency Responsive Resource. The following situations are known to cause measurement techniques to improperly measure performance:

1) Previous AGC or manual control to change the Generation Resource/Frequency Responsive Resources output. If the Generation Resource/Frequency Responsive Resource is ramping from one output level to another during a measurable frequency deviation, frequency response may be difficult to measure. This is true if the ramp direction is in the same direction as the frequency deviation, that is, the Generation Resource/Frequency Responsive Resource is in a down ramp during a low frequency deviation (see Figure 1 below) or up ramp during a high frequency deviation. This is especially true for Generation Resource/Frequency Responsive Resources that have high ramp rates in comparison to their maximum capability. All Generation Resource/Frequency Responsive Resources shall be responsive to all frequency deviations exceeding the governor deadband while ramping. If frequency response is visually apparent during these ramps and the direction of the ramp causes the measurement of the frequency response to be below the minimum performance level, the Event may be removed from the Generation Resource/Frequency Responsive Resources' 12 month rolling average performance measure.
2) Conventional steam driven turbines will have some initial steam pressure drop following large low frequency deviations. This pressure drop should be minimized by the control functions of the steam generator while remaining within the thermal and physical limits of the steam generator. (see Figure 2 below) The same effect is true for high frequency deviations. Steam generator pressure will rise from the frequency response of the turbine thereby reducing the net frequency response of the turbine. The Generator Owner may provide an estimation of this effect in the form of a "parameter" curve to be added to the measurement spreadsheet that accounts for this stored energy limitation.
3) Steam turbines of combined cycle Generation Resources. These turbines depend on the waste heat of combustion turbines to provide additional steam supply for their frequency response. The cycle time of the heat recovery boiler is typically longer

than the performance measure of this standard and performance of these Generation Resources will measure below normal droop characteristic curves.

4) Generation Resource/Frequency Responsive Resources located at the same site as the Generation Resource that causes the perturbation may have a shift in site auxiliary load assignment during the measurement period. This may result in a decrease in "Net" output of the Generation Resource/Frequency Responsive Resource and affect the measurement of frequency response. In this scenario Gross megawatt values for Generation Resource/Frequency Responsive Resource output and Gross High Operating Limit may be used for the evaluation of the frequency response measurement of the Generation Resource/Frequency Responsive Resource.
5) Generation Resource/Frequency Responsive Resources may have auxiliary equipment that must be placed in service throughout the load range of the Generation Resource/Frequency Responsive Resource. If the Generation Resource/Frequency Responsive Resource is operating at an output level that requires placing in service auxiliary equipment, frequency response of the Generation Resource/Frequency Responsive Resource may be limited. This may result in below minimum frequency response performance. The Generation Owner shall document this limitation on each occurrence during a Measurable Event. Once the equipment is placed in service, full frequency response is expected.
6) Generation Resource/Frequency Responsive Resources operating near the High Operating Limit (HOL) of the Generation Resource/Frequency Responsive Resource can measure below the minimum frequency response performance level. The expected performance shall be limited to the HOL of the Generation Resource/Frequency Responsive Resource.
7) Generation Resource/Frequency Responsive Resources operating at extremely low output levels may have limited frequency response. This output level may be defined as the Emergency Low Operating Limit, and responding to frequency deviations may place the Generation Resource/Frequency Responsive Resource at risk. The Generator Owner shall identify and document these operating ranges.
8) Generation Resource/Frequency Responsive Resources operating at extremely high output levels may have limited frequency response. This output level may be defined as the Emergency High Operating Limit, and responding to frequency deviations may place the Generation Resource/Frequency Responsive Resource at risk. The Generator Owner shall identify and document these operating ranges. Generation Resource/Frequency Responsive Resources operating in this range shall not be assigned Responsive Reserve Service since frequency response is not available. This may include these operating conditions:
    a. Over-pressure operation of the steam generator
    b. Duct burner operation of combined cycle Generation Resources
    c. Steam augmentation of combustion turbines and the injection of steam into the turbine combustors.

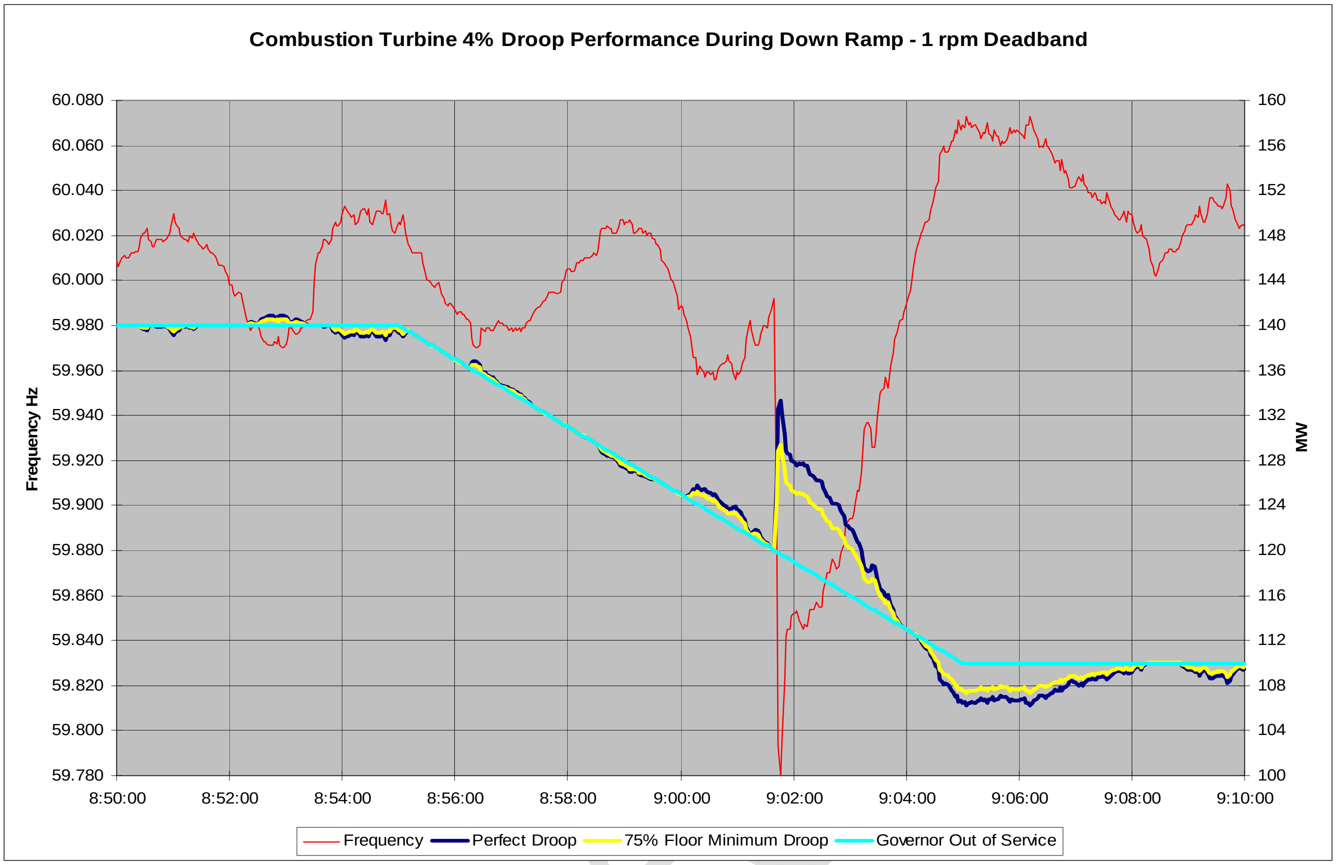


Figure 1: Combustion Turbine – 4% Droop during “Down Ramp”

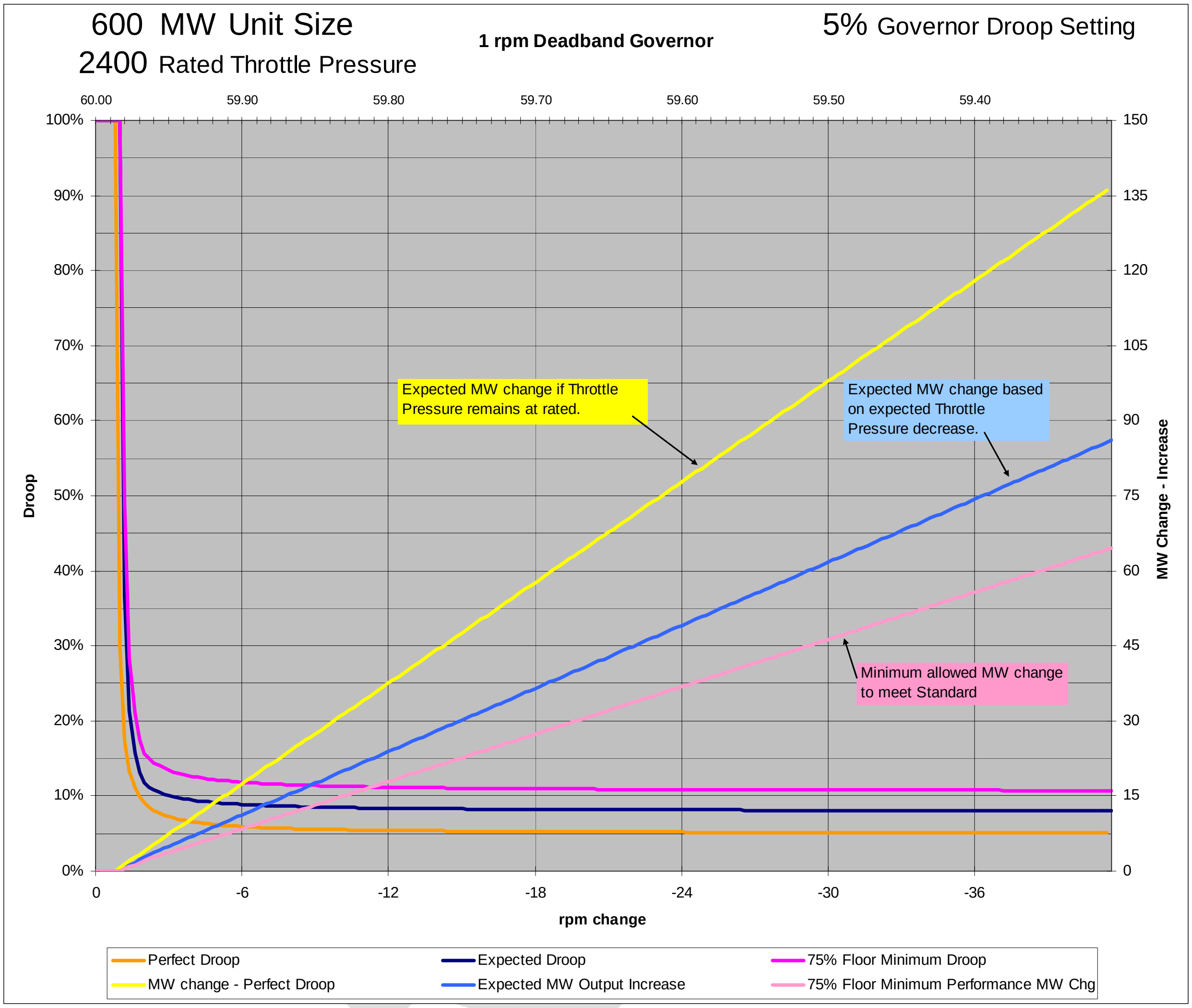


Figure 2: Conventional Steam Turbine @ 5% Droop and Effects of available stored energy.

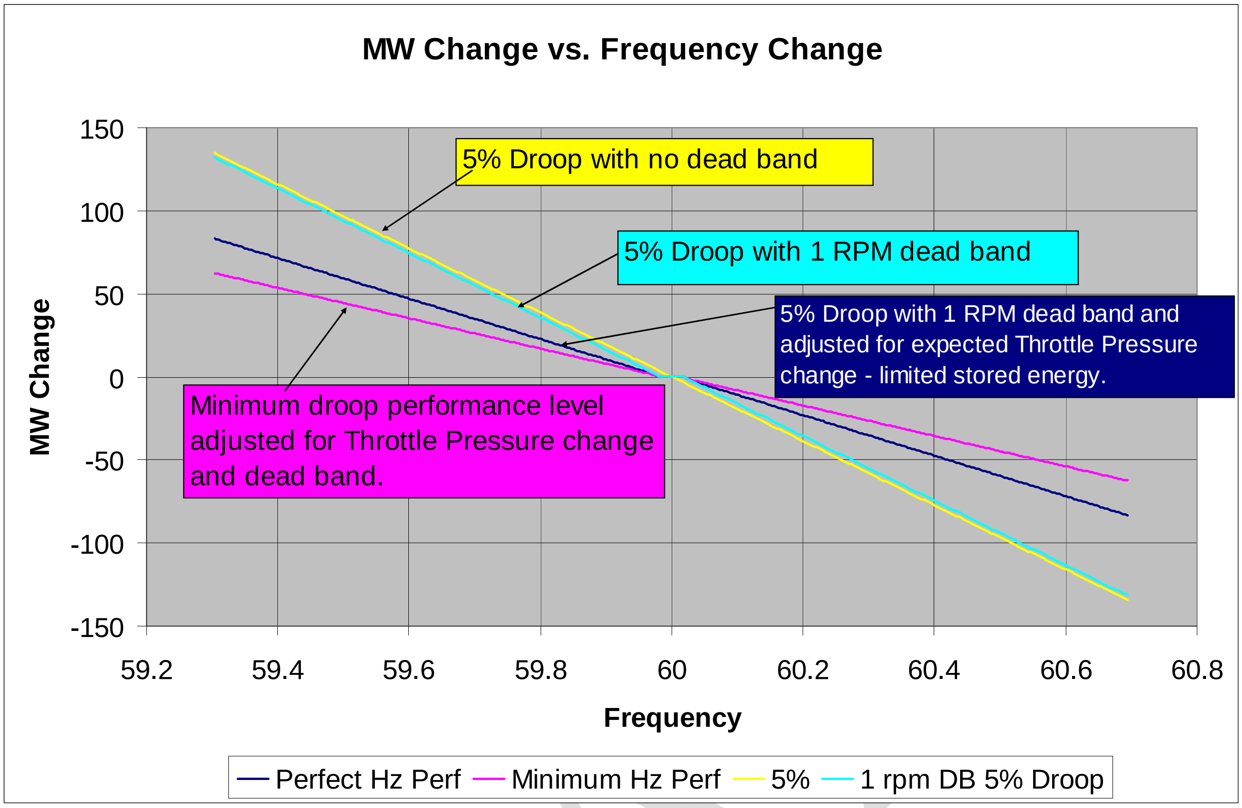


Figure 3. Effects of governor deadband and limited stored energy on frequency response

Measurement of Generation Resource/Frequency Responsive Resource Frequency Response

The method used to calculate Generation Resource/Frequency Responsive Resource frequency response is similar to the method used in calculating the Interconnection frequency response. The same averaging periods of Pre and Post perturbation are used. The output, in megawatts, of the Generation Resource/Frequency Responsive Resource is used in place of the "Resource Lost" data. Additional Generation Resource/Frequency Responsive Resource information is required for the evaluation. These data are HOL, governor droop setting, governor deadband setting and any parameter that reduces Generation Resource/Frequency Responsive Resource performance as in "limited stored energy" or "reduced mass flow" at lower speeds (frequency). An Excel spreadsheet is attached that provides measurement processes of droop performance of steam turbines and combustion turbines. This spreadsheet can be used by combustion turbines operating in combined cycle mode or simple cycle mode. The spreadsheet name is:

Frequency Response and Droop Calculator for Resources.xls

The spreadsheet calculates the "expected MW change" of the Generation Resource/Frequency Responsive Resource and the "minimum expected MW change" for the Generation Resource/Frequency Responsive Resource. (see Figure 4 below) The "expected MW change" is derived from the governor deadband, droop setting and adjusted for "available stored energy" or "reduced mass flow at lower speeds" parameter for the particular Generation Resource/Frequency Responsive Resource. The Generator Owner must develop the "limiting parameter" curve for each Generation Resource/Frequency Responsive Resource. This limiting parameter curve must be technically justifiable. The "actual MW change" of the Generation Resource/Frequency Responsive Resource is compared to the "minimum expected MW change" for this Generation Resource/Frequency Responsive Resource on this event. The value is derived from 75% of the "expected MW change". The performance of the Generation Resource/Frequency Responsive Resource will then be calculated on a per unit (p.u.) measure by dividing the "actual MW change" by the "expected MW change". This value (p.u.) will be used to develop the twelve month rolling average performance of the Generation Resource/Frequency Responsive Resource. The "expected MW change" shall be limited by the HOL and LOL of the Generation Resource/Frequency Responsive Resource.

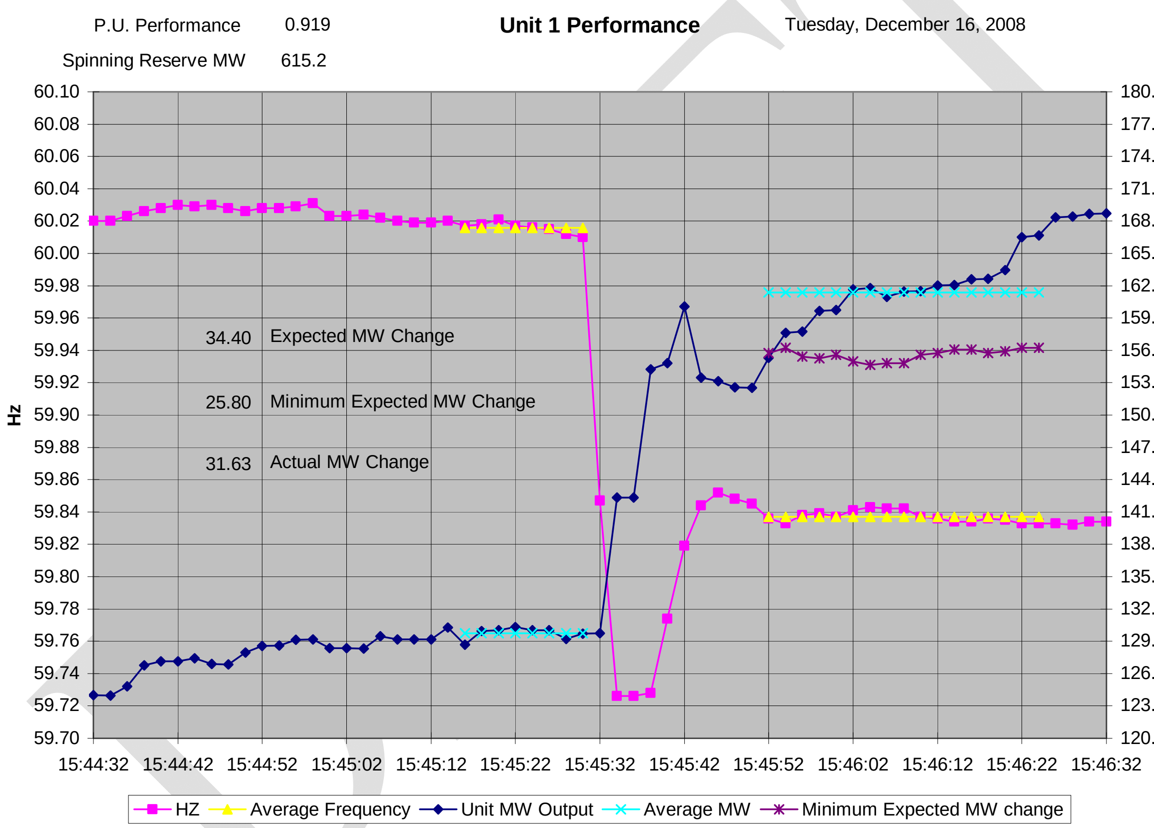


Figure 4: Expected Resource Performance

Attachment 4

Implementation Plan:

Pre-Implementation process:

Post for Comment	March 2009
Technical Workshop during comment period	April 2009
Respond to comments/revise	April 2009
Present revised draft to RSC	May 2009
Form ballot pool and vote	May/June 2009
TRE Board Adoption (Tentative)	July 2009
Submittal to NERC (Tentative)	August 2009
Receive FERC approval (Tentative)	October 2009

Implementation Schedule

Initiation of Three-year Implementation	November 2009
Auditably Compliant	December 1, 2012

The table in the attached Compliance Implementation Schedule spreadsheet identifies when Responsible Entities must Begin Work (BW) to become compliant with a requirement, Substantially Compliant (SC) with a requirement, Compliant (C) with a requirement, and Auditably Compliant (AC) with a requirement.

Begin Work means a Responsible Entity has developed and approved a plan to address the requirements of a standard, has begun to identify and plan for necessary resources, and has begun implementing the requirements.

Substantially Compliant means an entity is well along in its implementation to becoming compliant with a requirement, but is not yet fully compliant.

Compliant means the entity meets the full intent of the requirements and is beginning to maintain required “data,” “documents,” “documentation,” “logs,” and “records.”

Auditably Compliant means the entity meets the full intent of the requirement and can demonstrate compliance to an auditor, including 12-calendar-months of auditable “data,” “documents,” “documentation,” “logs,” and “records.”

Per the standards, each subsequent compliance-monitoring period will require the previous full calendar year of such material.

Attachment 4-003

FERC-Ordered Modification to ERCOT CPS2 Waiver to R2 of BAL-001-0

Question 1	Does this draft variance meet the reliability need addressed in FERC Order 693?

Answers	Frequency
Yes	10 (5 with comments)
No	3 (3 with comments)
No opinion	7 (4 with comments)

ID	Commenter	Answer	Comment	Response
118	Rick Terrill - Luminant	No	Luminant believes that the draft goes beyond that which is required to respond to FERC Order 6937. The nature of a variance is to describe how the existing regional procedures or process (and in ERCOT?s situation, the ERCOT Protocols) meet the intent of a NERC Standard. The draft variance seems to redesign frequency control in the ERCOT Region rather than follow the FERC Order to "include the requirements concerning frequency response contained in section 5 of the ERCOT protocols." Changes to existing ERCOT Protocols should first be vetted through the ERCOT Protocol Revision Request (PRR) process before they are utilized within a variance procedure.	
128	Ronnie Hoeinghaus - Garland Power & Light	No	FERC Order 693 in paragraph 315 orders the ERO to file a modification of the ERCOT Regional Difference to include the requirements concerning frequency response contained in section 5 of the ERCOT Protocols and further states in Paragraph 310 that Section 5 provides the necessary frequency controls needed for reliable operation in ERCOT. This proposed standard does not follow the FERC Order but redesigns what is in the ERCOT Protocols & Operating Guides.	
157	Thad Ness - American Electric Power Service Corp.	No	The best alternative would be to improve control performance and meet the national standard, as other RTOs do, such that a variance is not necessary. Since this alternative provides performance below that of the national standard, we believe that the Standards Development Process would indicate that a regional variance be provided for in the national standard. A regional standard is intended to address the uniqueness of a region that requires differences in performance characteristics, but the regional standard is expected to be no less strict than the national standard. To the extent that Order 693 requires that this regional process be used rather than adapting the national standard, this standard meets the intent, but does not meet the spirit of improvement that the FERC intends. Furthermore, if protocols are permitted to be moved into the standard, then these protocols should be removed. Better to be in one place to	

			avoid maintenance issues that can lead to discrepancies.	
123	Randy Jones - Calpine	No opinion	It appears to exceed the requirements set out in FERC Order 693 in that it exceeds the content of Protocols Section 5 referenced in the order. Specific comments on the Draft Requirements follow: Comment #1: In the Definitions, the passage on Frequency Responsive Resource is confusing in its treatment of Controllable Load Resources: ?Frequency Responsive Resource: Facility capable of providing electrical energy or Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services (as defined in the current ERCOT Protocols) to the ERCOT System, excluding Underfrequency Relay Load and Emergency Interruptible Loads but not Controllable Load Resources.? Is a Controllable Load Resource Frequency Responsive according to this definition excluded? If CLR is excluded the statement should read, ??but not excluding Controllable Load Resources.? Comment #2: R.7, which applies to GOs, calls for the GO to report to ERCOT (the BA) any condition that would limit the generator?s ability to respond to frequency. On what frequency is this reporting to be done and how is the communication carried out? For firms with a large number of units in ERCOT some form of automated interface should also be stipulated. Comment #3: R.8 must be re-written to be more specific. It currently states: ?R8. The GO shall ensure that combustion turbines in a combined cycle configuration have a governor droop characteristic of 4%, steam turbines have a governor droop characteristic of 5%, and that all other Generation Resources/Frequency Responsive Resources have a governor droop characteristic of 5% or less. See Attachment 3 for these characteristics.? We asked in the technical workshop what this requirement meant in application and the answer we received was that combined cycle trains/power blocks would be aggregated and the speed droop for the entire train would be equal to 4% (the ST would be ignored for speed droop since many of them	

			operate with valves wide open and latched up, providing no response). We were also told that the 5% speed droop for steam turbines is intended to be the criteria for other technologies such as gas-steam, PC units, etc. that use a single steam turbine assembly (HP/IP/LP compound on single or multiple shafts for example). This passage appears to be reworded to be clear what the speed droop criteria applies to which technologies. Comment #4: In R.9, the specific governor dead bands found in Attachment #3 should be spelled out clearly in R.9 rather than in the attachment. Also, the qualifying passage about ??intentional and unintentional?.? seems to be superfluous. ?Limiting? unintentional governor dead bands seems contrary to logic. Comment #5: R.10 seems to be unnecessarily open-ended in the definition of ?sustained?. The narrative on page 16 of 29 states that full governor response is to be delivered from 10 seconds to 30 seconds after T0but not greater than sixty (60) seconds after the ?A? point. For this governor response Requirement to have meaning it must be measurable and not refer to an attachment that contains the word ??usually?.? If the intent is for ?sustained? to mean 30 seconds after the ?A? Point then let?s construct R.10 to say just that. Other Questions and Comments Regarding the Draft Regional Standard: a) The move from the current permissive governor dead band of .036 Hz to .01667 will require additional precision in both speed pickups and speed transducers. Have OEMs been consulted on whether this precision is possible? If some deadband of less precision, perhaps .020 Hz, is possible could a GO certify to this ability instead of the value of deadband one firm could achieve in tests on one particular unit (WA Parish #7, as noted in the workshop)? We allow GOs to provide an adjusted Unit Reactive Limit for the use of over and under excitation limiters, can?t this principle also be extended to the setting of deadbands? b) Should this Draft Standard also be accompanied by an ERCOT Region Field Test to see if the benefits asserted by the Drafting Team, based on only four units, actually occur system wide? c) R.2 (6) requires the ?Generation Resource/Frequency Responsive Resource MW value? will be used in the evaluation of performance for each frequency deviation event. This value	

			would be measured at the BES injection point where the EPS metering is read. For cogeneration sites the net increased injection from governor response to frequency is impacted by both the thermal host?s induction load responses to frequency recovery and their steam demands that vary with frequency. Either cogeneration sites should be exempted from this Draft Standard or the total response for them should include the calculation of the parasitic load?s impact on the net injection at the high side of the GSU.	
136	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	
179	Robert Kelly - Brazos Co-op	No opinion	It appears to exceed teh requirements set out in FERC Order 693. The proposed requirements are generally confusing.	
201	Michael Sonnelitter - NextEra Energy Resources	No opinion	The draft variance appears to exceed the CPS2 requirement R2 for GO/GOP.	
111	Jack Thormahlen - Lower Colorado River Authority	Yes	Passage of this regional standard satisfies FERC Order 693, paragraphs 309 through 315 and specifically 314, 315 requiring more stringent practices in ERCOT than other regions.	
141	Ivan Kush - Calpine	Yes	It does meet and exceed Order 693.	
167	Ken McIntyre - ERCOT ISO	Yes	ERCOT ISO believes this draft Regional Variance meets the reliability needs of the FERC Order 693. ERCOT ISO also believes some of the requirements in the current draft exceed what was requested in the FERC Order 693.	
191	Paul Dougherty - Calpine	Yes	The proposed standard is more strigent that the current standard. However, the standard only applies to generators with electronic governors.	

Question 2	Will the requirements for GOs and GOPs in this variance improve Interconnection reliability?

Answers	Frequency
Yes	6 (4 with comments)
No	3 (3 with comments)
No opinion	9 (4 with comments)

ID	Commenter	Answer	Comment	Response
119	Rick Terrill - Luminant	No	To the extent that the requirements go beyond the provisions of the existing ERCOT Protocols, the question concerning improved interconnection reliability is appropriately considered in the ERCOT PRR process. The requirements of R7, R9, and R11 are burdensome on GOs and GOPs and might take away the operators focus of operating the unit in favor of gathering data. Additionally, they are beyond the requirements in the currently approved ERCOT Protocols and any change should be the subject of a PRR.	

129	Ronnie Hoeinghaus - Garland Power & Light	No	Some older, inefficient units that currently provide a stable source of energy may be forced into retirement when faced with expensive governor repairs or governor replacement to remain in compliance with this standard. In addition, there is a heavy, real time analysis & documentation burden placed on the unit operator which potentially could divert his focus from stable operation to data gathering in order to avoid financial penalties.	
192	Paul Dougherty - Calpine	No	With almost half of the online generation excluded from providing governor response (Nucleur, Wind and Base Load Coal) the Balancing Authority may not be able to procure sufficient frequency response to safely and properly operate the ERCOT Grid during an frequency event. This problem could be made worse during the shoulder months as other genrating units are operating at or near their max capability and the percentage of Nuc/Wind/BL Coal and other type of generating units is greater.	
124	Randy Jones - Calpine	No opinion	It would be difficult to determine since both the Region's CPS1 12-month rolling average and its RMS-1 of frequency are already on a steady upward/improving trend for some months now.	
137	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	
144	Clif Lange - South Texas Electric Co-op	No opinion	Tightening the deadband requirements theoretically would improve the statistical distribution of frequency deviations and reduce or eliminate the ?flat top? distribution, but no evidence exists that this would improve Interconnection reliability. The ?outliers? or ?tails? of distribution will still exist and likely with the same magnitude as currently exist. Calpine?s comments regarding the improvement in the CPS-1 12 month rolling average and the RMS-1 are noted as evidence that factors other than the normal distribution of frequency are successfully at work to improve reliability.	
158	Thad Ness - American Electric Power Service Corp.	No opinion	We are very concerned that the TRE is spreading its obligation to meet CPS2 values, by expanding the role of the BA, GO, and GOP to perform frequency regulation service. To the extent that GOs comply with the prescribed requirements to provide frequency regulation through adjustments to dead bands, droop, and governor response, the GO/GOP may be placed in the position of losing revenues or the opportunity for additional revenues with no compensation for providing the ancillary service.	
112	Jack Thormahlen - Lower Colorado River Authority	Yes	With tighter requirements for governor response as outlined in this regional standard, the frequency deviations will be considerably less assuming all gnereators capable of governor	

			response, within the required parameters, participate.	
148	Ivan Kush - Calpine	Yes	It will improve interconnection reliability only in the sense that we're minimizing frequency swings.	
168	Ken McIntyre - ERCOT ISO	Yes	The requirements detailed in this draft Regional Variance for GO and GOPs build on the current ERCOT protocol language, and establishes the necessary information and performance for GOs and GOPs. Improvement is anticipated from increased measurability for those units that may not have adequately aligned their performance with the current Protocols.	
213	Robert Green - Garland Power & Light	Yes	Excellent governor response may prevent the UFR shedding of firm load as a result of a future major measurable event.	

Question 3	The maximum allowable deadband of a turbine governor in the ERCOT Interconnection is +/-0.036 Hz. This regional variance changes the maximum allowable deadband of a turbine electronic or digital governor to +/-0.0166 Hz. Does this change improve Interconnection reliability?

Answers	Frequency
Yes	8 (5 with comments)
No	6 (6 with comments)
No opinion	4 (3 with comments)

ID	Commenter	Answer	Comment	Response
120	Rick Terrill - Luminant	No	To the extent that the tightening of existing ERCOT Protocol and Operating Guide requirements may or may not result in improved interconnection reliability is appropriately considered via the ERCOT PRR or Operating Guide Revision Request (OGRR) process. Although the research done by one company shows it works for them, there are many different boiler/turbine arrangements and without additional research, it is not possible to determine if this works for all units. It is also beyond the scope of the order and should not be included.	
125	Randy Jones - Calpine	No	The change in deadband capping requirements will likely not make a noticable improvement in the interconnect's reliability. Particularly, during shoulder period off-peak hours, when declining amounts of spinning and responsive intertia is available on the system to respond to frequency deviations. This requirement probably has to apply to all generators, on the ground and planned, in order to make a meaningful improvement in system transient stability and longer term reliability.	
130	Ronnie Hoeinghaus - Garland Power & Light	No	This goes beyond the FERC Order 693 and what is in ERCOT Protocol Section 5. The scope of the order was to implement the current protocol, not redesign the protocol.	

			ERCOT has processes and committees in place to identify and handle reliability issues. If it is felt that such an issue for ERCOT may exist, then evidence should be presented to those committees for consideration. If the committees determine that such a reliability condition does exist, then the appropriate Protocol Revision Request or Operating Guide Revision Request will be developed to correct the situation.	
145	Clif Lange - South Texas Electric Co-op	No	Tightening the deadband requirements theoretically would improve the statistical distribution of frequency deviations and reduce or eliminate the ?flat top? distribution, but no evidence exists that this would improve Interconnection reliability. The ?outliers? or ?tails? of distribution will still exist and likely with the same magnitude as currently exist. The greater question is whether the ERCOT interconnect is in greater danger of firm load shed or blackout due to the shape of the statistical distribution? To date the answer has been an overwhelming ?no.?	
193	Paul Dougherty - Calpine	No	ERCOT can achive better frequency control by improving the telemetry of expected frequency response from the QSEs and by writing simple programs on the EMS to address issues related to units operating at max load and units frequency response dead bands. ERCOT can also develop real-time operating procedures to back-off base load units during times of low expected frequency response using the improved telemtry and programs mentioned above.	
203	Michael Sonnelitter - NextEra Energy Resources	No	The standard has several requirements for setting governor deadband and droop and for governor performance. If the turbine manufacturer does not allow operation with these settings, and/or the governor, being in a state of good repair, is not capable of these requirements, then the standard should exempt existing units that have such limitations.	
138	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	
159	Thad Ness - American Electric Power Service Corp.	No opinion	Requirements from referenced attachments should be specifically stated in the standard. Since the attachment contain both technical explanations and requirements, there is room for inadvertent misinterpretations.	
198	Peter So - Calpine	No opinion	Reducing the maximum allowable deadband has effects on our turbines, what effects is tough to quantify or determine without our turbine manufacturer's input. While at first glance, reducing the deadband, one may think that the turbine moves less, when in fact depending on the swing on the grid, the	

			turbine may be moving more to keep within the reduced deadband. If these movements causes reliability issues on our turbines, it can have adverse effect on the interconnect reliability. Our gas turbines are of the latest design for efficiency and especially emissions, small uncontrollable changes can make the combustion unstable and cause the unit to trip or exceed emissions limits. While I can not say for certain the proposed deadband change will cause any issues, I suggest more research and testing needs to be conducted before a standard is adopted.	
113	Jack Thormahlen - Lower Colorado River Authority	Yes	Governors with a maximum deadband of +/- .0166 Hz will be moving earlier and with fewer MW than as current practice using +/- .036 Hz deadband. The smaller deadband may require less maintenance on the machine due to the lessening of the impact of the response, eventhough the unit may be be moving more often.	
149	Ivan Kush - Calpine	Yes	Again I feel this will improve frequency stability. It potentially places other constraints on overall interconnection reliability. For example has GE been approached to determine if their DLN systems can handle this kind of activity? I have spoken with Siemens the OEM itself has never "fully" tested any of their gas turbines with less than .036Hz response. I would propose that the OEM's be officially contacted by the BA or other large organization to ensure that these proposed standards can be met before we look to require GO's to comply. Based on the Siemens response alone, I would recommend that time be allotted prior to submission to NERC for formal testing on a representative subset of GO equipment from the ERCOT region. The work the team has done to date is extremely commendable, but I believe a larger sample of equipment be evaluated ? for example large frame industrial gas turbines 170+ MW machines. If we go forward with this prior to verification we could destabilize the interconnect significantly.	
164	Frank Owens - Texas Municipal Power Agency	Yes	I believe this change can be incorporated into the existing ERCOT Guides.	
169	Ken McIntyre - ERCOT ISO	Yes	Reducing the maximum allowable deadband will result in Resources, which are expected to provide with frequency response, to respond to a frequency deviation sooner. Recent pilot efforts in this area by a market participant in the ERCOT Interconnection seems to indicate that the ERCOT frequency has a better performance around the 60Hz scheduled frequency with the narrower deadband. If Resources are capable of reducing their deadbands and still operate reliably, then it would appear this would help the ERCOT	

			Interconnection frequency response, and reliability.	
214	Robert Green - Garland Power & Light	Yes	The smaller deadband will help minimize sustained operation around 59.964 [at the edge of the lower deadband] which may occassionally prevent shedding of firm load triggered by a low C point. I also believe that hysterisis style production costs will be lowered by eliminating frequent oscillations between the lower deadband and the upper deadband. The smaller deadband will also make it easier to consistently provide a minimum of 420 MW/0.1 HZ of governor response which is the proposed reliability standard.	

Question 4	This variance requires a droop performance that is attainable based on a resource's characteristics and available stored energy in the time period of the measure instead of the normal 5% droop performance. Will this pose a risk to Interconnection reliability?

Answers	Frequency
No	6 (4 with comments)
Yes	5 (5 with comments)
No opinion	7 (3 with comments)

ID	Commenter	Answer	Comment	Response
121	Rick Terrill - Luminant	No	This is added complexity and constitutes a change in the ERCOT Protocols that must first be subject to the PRR process before consideration in developing a variance procedure.	
194	Paul Dougherty - Calpine	No	It is not equitable for a small segment of units (ones with electronic governors) to be expected to provide more droop response when other units like Nucleur, Wind and base load coal have no obligation to provide any droop response.	
210	Rick Vera - Power Consultant	No	It is encouraging that finally the unit capabilities are being considered in the evaluation of its frequency regulation compliance. It has always been believed that calibrating a governor and the unit controls to support a 5% speed regulation would lead to a 5% frequency load regulation. There is a great difference between these two. The unit frequency load regulation (even though perfectly calibrated for a 5% speed regulation) depends on many factors. Among them: 1. Type of unit 2. Type of fuel 3. Boiler energy storage 4. Effect of pressure drop	

			5. Etc. No matter how much fuel is injected into a unit at the time of the frequency event, its initial load response will depend in all the above factors. So developing a standard that can adjust and evaluate the frequency load regulation based on the individual unit capabilities is definitely a step in the right direction. Rick Vera, P.E. Power Consultant	
215	Robert Green - Garland Power & Light	No	Units with a programable droop setting, will still be required by OG 2.2.5 to have a maximum of a 5% droop setting.	
114	Jack Thormahlen - Lower Colorado River Authority	No opinion	Lacking empirical data it is difficult to predict the risk. However, if all generators follow these requiurements we'll have reduced reliability risk.	
139	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	
160	Thad Ness - American Electric Power Service Corp.	No opinion	Requirements from referenced attachments should be specifically stated in the standard. Since the attachment contain both technical explanations and requirements, there is room for inadvertent misinterpretations.	
126	Randy Jones - Calpine	Yes	This approach would seemingly allow a large percentage of the installed ERCOT capacity to avoid making a speed droop contribution during frequency deviations. A solution must be found and incorporated in any CPS-2 performance metric that provides for response attributible to the ERCOT West Congestion Zone. In order to be effective and provide response from the West Zone some form of islanding criteria must be developed, since effective islanding and subsequent control of island frequency is a stated goal of this Standard. As it stands this Standard seems to accept a lack of renewable response as nominal, which can jeopardize the effecting islanding of the West Zone.	
142	Ronnie Hoeinghaus - Garland Power & Light	Yes	This complex portion of the variance is completely outside both the scope of the FERC Order and ERCOT Protocol Section 5. Unnecessary complexity that forces unnecessary expenditures does not enhance the reliability of the Bulk Electric System. Instead, it has the potential of forcing premature retirement of older, inefficient units that currently provide reliable sources of energy.	
150	Ivan Kush - Calpine	Yes	As mentioned previously if we're not 100% certain that all units can handle this pause should be taken until further testing is conducted or information is gathered from OEM's.	

			Also this question is rather ambiguous to me. It implies that we could/should in theory have a droop that is even less than 5%. What is the EXACT time period with which a unit must respond to a given disturbance? While I take no issue with the concept, implementation, verification and regulation will probably require the creation of an entire organization. For large asset owners within the region this could mean a large financial burden on their behalf trying to arrange for resources to communicate this information to the BA. Reporting of any kind requires resources and $$, will larger generators be penalized financially by having to spend increased $$ to meet reporting requirements? How often is reporting required? I also believe that while it means more work - all technologies should be classified separately in terms of their required response times. Combined cycle GT's 4%, ST 5% - a train shall have overall 4%. Simple cycle GT's ? / Large frame GT's ? / Nuclear units ? / Hydro units ? / Peaking gas turbines or small frame GT's ? etc... Attachment 3 p1 discusses intentional dead band. After discussion with at least one OEM dead band is definitely intentional, as a matter of fact it's necessary. I again wish to recommend that this be formally evaluated with some of the major OEMs which are representatives of the population of assets within the region prior to committing to this standard. During peak there will be very little if any frequency response available by some generators it appears that this will be considered, but some OEM's technology may limit response even when the units aren't necessarily at "full load". Temperature controllers are sometimes in effect much earlier than a units "regular or nominal full load condition" how will this be accounted for without huge amounts of digging through historical information?	
170	Ken McIntyre - ERCOT ISO	Yes	Reducing the maximum allowable deadband will result in Resources, which are expected to provide with frequency response, to respond to a frequency deviation sooner. Recent pilot efforts in this area by a market participant in the ERCOT Interconnection seems to indicate that the ERCOT frequency	

			has a better performance around the 60Hz scheduled frequency with the narrower deadband. If Resources are capable of reducing their deadbands and still operate reliably, then it would appear this would help the ERCOT Interconnection frequency response, and reliability.	
182	Robert Kelly - Brazos Co-op	Yes	R7, R8 and Attachment 3 are ambiguous as these pertain to combined-cycle gas turbine ("CCGT") configurations. In the case of CCGT configurations combustion turbines ("CT's") should be required to provide 4% droop characteristic subject to the high emergency limits of the respective generator. However, ERCOT's systems implementations for the Nodal Market are such that the GOP (QSE) representing this generator will not be submitting an accurate limit for each individual CT but rather a plant composite capability. Steam turbines in CCGT configurations in many cases cannot provide any frequency response. Attachment 3, Part 2, Section 8 should be modified to address realistic limitations of CCGT configurations operating in modes where the combustion turbines are at maximum capability. Steam augmentation or duct burners should not be excluded from supplying Responsive Reserve Service ("RRS"). These operating modes can supply limited frequency response. To such degree that this response can be demonstrated, a proportionate amount of this capacity augmentation should be eligible for the supply of RRS.	

Question 5	Can you identify anything that should be incorporated into this regional variance or identify other approaches that could be taken in drafting this variance?

Answers	Frequency
No	3 (1 with comments)
Yes	14 (14 with comments)
No opinion	1 (1 with comments)

ID	Commenter	Answer	Comment	Response
189	Nikolay Moutaftchiev - International Power America Services	No	1. On page 10, Lower VSL for R11 is performance bellow 0.55P.U. and above 0.45P.U. The spreadsheet calculates ?minimum expected MW change? as 0.75 P.U. What if the performance is bellow 0.75 on a certain event? Does it really matter as long as the 12 mo. rolling average is above 0.55? 2. What is the formula for calculating the ?expected MW change?? It can be deduced from the spreadsheet, but it will	

			be better if it is included in the standard. 3. If a resource underperforms due to any legitimate reason, listed on pages 22 and 23, the event should not be included in the calculation of 12 mo. rolling average. This statement should be removed from the last sentence of item 1), page 22 and applied to all the items on pages 22 and 23.	
205	Michael Sonnelitter - NextEra Energy Resources	No opinion	1) The cost of adding capability to existing units, if such added capability is determined and demonstrated to be required for good reliability, should not be imposed on GO/GOPs alone. Existing units were justified and constructed without these requirements, and if added costs are now required to increase capabilities, those costs should be shared by all stakeholders in the Bulk Electric System. 2) It seems like there could be a distinction between (a) having a wind generator move in the proper direction, based on frequency needs (thus performing satisfactorily given available wind resource) and (b) having a large CPS2 due to scheduling error (not enough wind resource).	
115	Jack Thormahlen - Lower Colorado River Authority	Yes	COMMENT #1 (Page 7 Measure 8) Requirement #7 applies to GO. Therefore, change Measure #8 from ?GOP? to ?GO?. Also correct the violation severity table for Requirement #7 on page 10 from ?GOP? to ?GO?. COMMENT #2 (Page 10 Table 2: Violation Severity Levels) Requirements #8 and #9 apply to GO, not GOP. Therefore, change ?Severe VSL? text from ?GOP? to ?GO?. COMMENT #3 (Page 21 Part 1: Governor deadband and droop settings) Hydro units need to be specifically addressed; therefore add changes: Governor Deadbands: Mechanical governors of steam or hydro turbine Generation Resources: Due to gear lash and movement of mechanical parts of a mechanical fly-ball governor on a steam or hydro turbine, it is common to observe frequency response deadband for small changes in frequency. This deadband, or range of no frequency response, shall be limited to less than +/- 0.036 Hz (36 mHz). COMMENT #4 (Page 22 above ?Other Generation Resource?.?)	

			Hydro units need to be specifically addressed; therefore add: Hydro Turbine: Droop settings of hydro turbines shall be 5% or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz. C OMMENT #5 (Page 22-23 ?Part 2: Minimum performance ?..?) Hydro unit performance needs to be addressed; therefore add: 9) Hydro unit frequency response may be affected by changes in lake levels, flood events, or when multiple units are operating simultaneously at one site. HSL may vary during these conditions.	
122	Rick Terrill - Luminant	Yes	Luminant believes the proper approach is to utilize only the exact requirements of approved Protocols, as directed by the FERC Order. Luminant is willing to assist in this effort if desired by the drafting team.	
127	Randy Jones - Calpine	Yes	Effective governor response from all ERCOT generating machines is impossible to achieve due to the current market design. We have no capacity market or mechanism that holds back capacity for delivery under frequency events other than from the fleet providers of RRS and REG. The market design ("Energy-Only") incents all other machines that are in the money to be producing energy at the very top of their capabilities ("baseloaded"). This alignment of incentives is contrarian to the view that all machines should have "room at the top" to provide effective inertia in times of frequency deviation. Essentially, governor response from machines not participating in the provision of RRS or REG is unenforcable since the market needs all their energy and rarely needs capacity held response. In order to further improve the system's frequency response some form of "Governor Response Service" must be instituted. It is not practical and likely not lawful to require individual units that do not get paid for capacity to hold back capacity, particularly during light loading conditions. The concept of a Governor Response Service has been promoted in the past by many market participants and by consultants versed in the ERCOT market design. The proposed tightening of the governor deadband in this Draft Standard is testimony to the fact that a correction in the market's design relative to governor response is needed. A market of the service is the	

			likely solution.	
140	Kenneth Brown - PSEG Texas	Yes	R7: Attachment 3 says a ?limiting curve? shall be required. However this is not specifically stated in R7. Is it required? Can you provide a sample ?limiting curve? with creation methodology? It is our understanding that this shall be created and reported initially, then revised only if a design change which affects the response is implemented. Is that correct? R8: In some units, the droop characteristic is overridden (not active) when the unit is in MW/Load control. Is this condition acceptable when in MW/load control on these units? A 5% droop setting for a combined cycle steam turbine is not feasible. During the 3/31 Technical Workshop, it was stated the 5% only applied to non-combined cycle Steam turbines, and did not apply to combined cycle steam turbines. Will this clarification be incorporated into the standard? R10: It is our assumption that if our unit is operating at full load when there is an event, ERCOT will not penalize us for not being able to pick up additional load. Is that correct? R11: Is the intent here that the ?spreadsheet calculator? shall be used each time there is a ?Measurable Event? and that they should be averaged for a 12-month window? M10: What is meant by ??the GO shall have evidence?was not visually observed.?? What is the intent of this measurement? What type of ?evidence? would satisfy this measurement? Comment on potential conflict ERCOT Protocols Section 5 doesn't allow frequency response to be sustained and until the language in these Protocols is revised to allow for such, Market Participants will find themselves in violation as soon as this new Standard is approved.	
147	Clif Lange - South Texas Electric Co-op	Yes	R6. This requirement refers to an aggregation at a single point of interconnection into a single Generation Resource those Generation Resources whose capacity is less than 10 MW.	

			Q1. Would a combination of online and offline unit capacities skew the expected response measurement? Q2. Would only the aggregate capacity of those units which have an online status be utilized for response measurement? R8. STEC agrees with Calpine?s comments on this requirement that rewording must occur in order to capture the intent stated at the workshop that a steam turbine?s response would be ignored if configured as part of a CC train. R9. & R10. For the sake of clarity, there is no reason to list the deadbands that would be required of the GO in a separate document. Unless the separate document is intended to be a ?living document? where changes can be made readily (we suspect it is not) then the deadband requirements should be listed as sub-requirements (ie. 9.1, 9.2, etc.) for better clarity. R10. This requirement holds the GO and GOP responsible for sustaining governor response to all frequency deviations which exceed a unit?s governor deadband. 1. How much effect does the GOP necessarily have on the sustaining of governor response by a generator? Should the GOP requirement be struck and this requirement is made applicable to the GO only? As written, this could potentially result in an entity being fined twice (double dipped) for the same offense if the entity is both the GO and GOP. Likewise, if contractually a fine levied on a GOP for an offense committed by the GO were passed on to the GO, an offense would presumably result in a double fine to the GO. 2. STEC assumes that this requirement is in place specifically to apply to frequency perturbations and the measurement of such. If this requirement is for perturbations alone then STEC agrees with the Calpine comments that this requirement can not be left open ended and that the language should be modified to reflect some sort of time parameters and that this requirement applies to perturbations. If this requirement is intended to apply to both perturbations and normal intra-hour frequency swings, then a tracking and documentation nightmare is potentially created. If taken to the literal intent, then the GO and GOP would be required to analyze every frequency deviation greater than 60.0167 Hz and less than	

			59.9833 Hz and determine whether each unit responded accordingly, document the findings, and self-report violations to the TRE. This would be a cumbersome process not only for GOs and GOPs but for the TRE as well who would be responsible for sorting through mountains of data as a result of normal ?noise? on the system. R11. This requirement is concerned with the GO and GOP meeting a rolling 12 month average frequency response performance criteria. 1. Should this requirement be applicable to GOPs for the same reasons cited above in R10. 1? 2. Should units with low capacity factors be subject to this requirement or should some threshold be established for a minimum number of events that the unit was online for? Units that are online for only a handful of the targeted 30 ? 40 measurable events per year might not receive a statistically accurate measurement of their response to frequency events. Should a threshold of being online during some number of events be established to provide some meaningful measurement? (ie. 25% of measurable events) Attachment 3. 1. In constructing a limiting parameter curve or a list of limiting parameters, how are limits handled that change on a seasonal, daily, or minute by minute basis handled? For example, chillers, foggers, spray intercooling, etc. are often times temperature dependent and the point at which they are effective or come into service changes with the current weather conditions. 2. In the workshop, it was discussed that post-event defenses could be brought forth to the TRE to explain a lack of response. This concept does not appear to be captured in the Attachment 3. This would seem to be a necessary addition to give GOs and GOPs the opportunity to explain instances where governor response was not at the desired level due to unforeseen events. Ie. unknown mechanical problems, change in fuel, ambient conditions, etc. 3. STEC agrees with LCRA?s comments regarding hydro units and language needed to address their unique characteristics. In addition, provisions need to be put into place to address governor response from hydro units operating in synchronous condensor mode and NOT providing hydro responsive or quick start capability. These units should	

			not be required to provide frequency response in these instances nor should they be measured.	
151	Ivan Kush - Calpine	Yes	As stated by others there are certain generators that not be able to comply fully with these new reccomendations, because of this other generators whose assets can respond will be forced into a continuous supply situation during an event. If these assets are engaged in other supporting roles then those might be affected forcing the operator into other difficulties.	
152	Ronnie Hoeinghaus - Garland Power & Light	Yes	This variance should follow the scope of FERC ORDER 693 which was to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT Protocols. This variance should not redesign protocols or operating guides or impose requirements upon registered entities that are outside of ERCOT Protocol Section 5. Comments on Proposed Standard as written that are outside of the Posted Questions: Note: These comments were written in Word and all formatting was lost when they were transferred to this document - many characters show up as "?" - have attempted to correct & reformat to where they seem somewhat organized ***** Comment on Standard Structure BAL-001-TRE-1 has both attachments and Excel spreadsheets that are intended to be part of the standard (as stated during the BAL-001-TRE-1 Workshop). These attachments are several pages in number and have statements using "shall" or "must" making them a requirement that has to be met. The use of this existing structure or format makes knowing exactly what is an auditable requirement and the extent of that requirement both difficult & confusing. Recommendation - All auditable requirements should be clearly stated in the requirement section. **** Comments on Requirement R7 Requirement Language - The GO shall report to ERCOT the operating range, performance level, and any parameter limiting the frequency response of each Generation Resource/Frequency Responsive Resource. See Attachment 3 for these parameters. ** Comment R7 - #1 The requirement uses the phrase "and any parameter limiting the frequency response..." The word	

			"any" above would have to be interpreted as "all" parameters (based on dictionary definition but more importantly based on Violation Severity Levels which determine penalty amounts). Section 2 (page 10) Violation Severity Levels lists R7 as having the following table selections: High VSL - Penalty range per the NERC Base Matrix Penalty Table is from $3,000 to $625,000 per day depending on the Violation Risk Factor. Reason listed - GOP does not have evidence that it reported to the BA most of its... expected frequency response.. What does "most" mean to an auditor? Also, Please Note: This is a GO requirement, not a GOP - GOP should not be listed Severe VSL - Penalty range per the NERC Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on the Violation Risk Factor. Reason listed - GOP does not have evidence that it reported to the BA any of its... Please Note: This is a GO requirement, not a GOP - GOP should not be listed ** Comment R7 - #2 Frequency Response of a Generation Resource is a combination of boiler control / boiler response and turbine governor response. In real time operation, parameters limiting this response can change minute to minute from changes in fuel quality/supply conditions, ambient temperature, boiler conditions, boiler process equipment condition, and process controls - just to name a few but certainly not a complete list. Even certain parameters that are generally accepted to be fairly stable or constant are required to be telemetered to ERCOT BECAUSE THEY CHANGE. It is impossible to report to ERCOT all the parameters / conditions that can affect frequency response. ** Comment R7- Attachment 3, Part 2, 1) The last sentence states "If frequency response is visually apparent during these ramps and the direction of the ramp causes the measurement of the frequency response to be below the minimum performance level, the Event may be removed from the Generation Resource/Frequency Responsive Resources' 12 month rolling average performance measure." What does the term "visually apparent" mean, to whom is it supposed to be "visually apparent", and how will an auditor interpret "visually apparent"?	

			** Comment R7- Attachment 3, Part 2, 2) Attachment 3, Part 2, 2) discusses initial steam pressure drop following large frequency disturbances and that the GO may provide a parameter curve to be added to the spreadsheet that accounts for this stored energy limitation. In addition, still in attachment 3, on page 26 the phrase "is required for the evaluation" followed by a list of items that includes "limited stored energy". On page 27, it states "The Generator Owner must develop the "limiting parameter" curve for each Generation Resource..." and then states "This limiting parameter curve must be technically justifiable." There are also references to "reduced mass flow" as part of this parameter curve - Comments follow: This information is not common, readily attainable information. It will require an engineering study to be performed either taking up an in-house engineer's time or require hiring a consultant. What possible benefit is there to BES Reliability to require the GO's to spend this money? It appears it's only use is to provide input into a spreadsheet for a calculation - Calculation approach should not require O&M resources to be required to be spent just to support calculation. The manager at one of our generating plants likened this requirement to driving his car down the road. If he takes his foot off the gas, the car does not stop but keeps going because of stored energy. Everyone knows that the car has stored energy but drivers knowing the "technically justifiable" curve representing this stored energy throughout the car's range of speed is another matter. The term "parameter curve" is used to describe this information. Totally agree that it should be a curve because stored energy amounts would changed up and down the unit output range. HOWEVER, in the spreadsheet, I can only find 1 data point for this information - not a curve but one value. Unless I am mistaken and I could be, the spreadsheet is setup for one value only - not a curve. It would seem that "is required" & "must develop" and "technically justifiable" make this an auditable requirement - certainly should show up in the Requirement text - not over 2 or 3 pages in attachment and is also inconsistent with the 1st reference where it states "may" ** Comment R7- Attachment 3, Part 2, 4) Attachment 3, part	

			2, 4) gives a scenario about shifts in site auxiliary load assignment and then states "In this scenario Gross megawatt values for Generation Resource/Frequency Responsive Resource output and Gross High Operating Limit may be used for the evaluation of the frequency response measurement..." To my knowledge, Gross High Operating Limit is not telemetered to ERCOT - Where / how are you going to obtain this scan rate data? ** Comment R7- Attachment 3, Part 2, 5) Attachment 3, part 2, 5) discusses impacts to frequency response due to auxiliary equipment being in or out of service as the unit moves through it's output range. It then states "The Generation Owner shall document this limitation on each occurrence during a Measurable Event." Comments follow: A generating unit operator will not have any idea whether a frequency disturbance has been declared a "Measurable Event" regardless of whether he/she is taking an auxiliary piece of equipment in or out of service or not. In reality, the operator will be focused on getting the equipment in or out of service smoothly and may not even be aware a frequency disturbance has occurred. Auxiliary equipment being place in service or taken out of service is part of the normal operation of the generating unit and will occur every time the unit cycles. In addition, lignite or coal unit have bowl mills & feeders which are smaller auxiliaries than pumps or fans - but still auxiliaries. In real life at the generating unit, the unit operator will have to document every occurrence to be sure that one is not missed? What is the generating unit supposed to do with this documentation? Send it to ERCOT? What is the path to ensure the data is distributed to the BA & the TRE? What possible benefit is there to Bulk Electric System Reliability to require the GO's to spend O&M time and money to document, correlate with frequency disturbances, & maintain documentation for NORMAL, EVERYDAY OPERATIONAL EVENTS - NOTHING BROKEN OR ABNORMAL? "The Generation Owner shall document..." makes this another auditable requirement - should be listed in the Requirement	

			text - not stated in somewhere in an attachment ** Comment R7- Attachment 3, Part 2, 7) & 8) Not entirely sure what this referring to but maybe part of it is sliding pressure on the low operating range for 7) and the upper range for 8) - These comments will apply to sliding pressure operation whether that was the intent of 7) & 8) or not. Sliding pressure is not a constant operational mode - the unit could be operating in a sliding pressure mode part of the day at a given load range and not be in sliding pressure mode at that same load range the rest of the day - it can change intra-day, day to day, week to week. It depends on the GO's fleet operational configuration for it's obligations followed by it's economic loading Units operating in sliding pressure are not going to provide frequency response per a 5% droop curve - nothing is broken or abnormal, it is an economic operation Defining and documenting these ranges and reporting them to ERCOT serves no real purpose for the spreadsheet calculations as the status of sliding pressure operation yes / no will be unknown Both 7) & 8) contain statements "The Generator Owner shall identify and document..." making both auditable requirements. These both should be listed in the Requirement text - not stated in somewhere in an attachment ** Comment R7- Attachment 3 Overall Attachment 3, Part 2 is not an all inclusive list. If the parameter or operating condition is not listed in the list that was reported to the BA (ERCOT) as a reason for reduced frequency response or is not in Attachment 3, Part 2, will an auditor allow that parameter / condition to be used to remove a response from the calculations for a real time event? ** Comment R7 - #3 The requirement says to report the operating range, performance level, and any parameter limiting... What is meant by "performance level"? Operating range is clear and the any parameter limiting is discussed above but what does "performance level" mean? What would it take to demonstrate compliance with an auditor?	

			**** Comments on Requirement R8 Requirement Language - The GO shall ensure that combustion turbines in a combined cycle configuration have a governor droop characteristic of 4%, steam turbines have a governor droop characteristic of 5%, and that all other Generation Resources/Frequency Responsive Resources have a governor droop characteristic of 5% or less. See Attachment 3 for these characteristics. ** Comment R8 - #1 The requirement uses the term "shall ensure" and the terms in Attachment 3 use the terms "shall be" at the 4% or 5% droop requirement or lower. These terms make it clear that a governor cannot have a droop characteristic > than the 4% or 5% without being in violation of this standard. While this may be fairly simple to set with a digital governor control system, it could easily require a very expensive complete governor overhaul (and associated unit outage) for a mechanical governor even if it tests out at 5.5% or 6% or anywhere near but greater than 5%. Violation Severity Level - Severe VSL (page 10) states that you have to evidence that the droop settings were set at 4% or 5% (Base Penalty Matrix shows penalties range from $5,000 to $1,000,000 per day) GOs in this situation with older, low capacity factor units are now potentially faced with the choice of retiring the units if they cannot justify the O&M costs (would take an additional study (costs O&M $) to make the determination) even though the unit provides a stable source of energy to the BES. There are not any Working Group reports before ROS or TAC detailing any reliability issues dealing with governor droop settings. ERCOT Operating Guide Section 2.2.5 states "Every effort should be made to maintain governors droop characteristic not to exceed 5%" and Operating Guide Section 6.2 gives typical examples of tests for both steam & combustion turbines along with droop calculations & answers. Steam Turbine example results are 7.78% and 8.06%. Combustion Turbine examples are 6.25% & 5% (which is adjusted to 4.16%). Please note that none of the typical examples in the Operating Guides for a steam or combustion turbine would pass an audit by this standard & would require O&M expenses or perhaps retirement if an older, low capacity factor unit.	

			If there is not a BES Reliability Issue concerning droop identified and before ROS or TAC, why should there be a requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons? ** Comment R8 - #2 Violation Severity Levels specified for R8 - page 10 The Lower, Moderate, & High VSL set the penalty range based on dated test forms longer than 2, 3, & 4 years. There are no specified time frames for tests or filling out test forms anywhere in this standard - how can there be penalties based on time frames when none are specified in the requirement? Severe VSL (penalty range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor) states "The GOP does not have evidence that the governor droop characteristics were set per Attachment 3" - This is a GO requirement, not a GOP requirement. Also, evidence should be for something stated in requirement - not something stated in an attachment. **** Comments on Requirement R9 Requirement Language - Each GO shall limit governor deadbands, intentional and unintentional, of turbine governors to those stated in Attachment 3. ** Comment R9 - #1 Requirements should be stated in the requirement - not in an attachment. ** Comment R9 - #2 Mechanical Governors Attachment 3 states that mechanical governor's deadbands "shall be limited to less than +/- 0.036 Hz". Measures M9 for compliance evidence states that the "GO shall have evidence..." "governor deadband is set in accordance to the limits in Attachment 3". Violation Severity Levels (Page 10) - Severe Level - "The GOP does not have evidence that the governor deadband limits were set per Attachment 3" (Severe Level penalty range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor)	

			THERE IS NO WAY TO SET a mechanical governor deadband - it is a function of mechanical component movements and wear & tear. By requirement design, a GO with a mechanical governor will be out of compliance. At the workshop when this was brought up, it was stated that the GO could analyze unit response while the unit was on line to determine the deadband. Note: this study may identify where the deadband is but it is not setting the deadband. If by some study the deadband is determined to be +/- 0.036 Hz or greater (attachment 3 says shall be less than +/- 0.036), the GO is now faced with an expensive governor overhaul and associated unit outage or maybe the choice of having to retire the unit if an older, low capacity factor unit. If there is not a Bulk Electric System Reliability Issue concerning these deadbands identified and brought before ROS or TAC, why should there be a requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons. ** Comment R9 - #3 In Attachment 3, it states the frequency response characteristic shall not "step-into" the 5% droop curve or the 4% droop curve. The term "shall not" makes this an auditable requirement. Depending on the governor design, this may or may not be possible to comply with without a major design change on the part of the GO. If there is not a BES Reliability Issue concerning these deadbands identified and brought before ROS or TAC, why should there be a requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons. ** Comment R9 - #4 Violation Severity Levels list GOP as the penalized entity - this is a GO requirement - not a GOP. **** Comments on Requirement R10 Requirement Language - Except for protection of equipment or safety, the GO and GOP will sustain its governor response to all frequency deviations that exceed the deadbands stated	

			in Attachment 3. Note: it says "all frequency deviations that exceed the deadbands..." Violation Severity Levels - Severe VSL Penalty (range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor) based on statement that GO or GOP applied control action to reduce or withdraw frequency response of a Generation Resource / Frequency Responsive Resource that exceeded the allowable deadbands as stated in Attachment 3. It is normal for frequency to move outside the 0.01667 deadband or the "less than" +/- 0.036 Hz deadbands multiple times every hour of everyday! Some examples causing this are from load ramps, schedules being ramped in or out at different times by QSE's, units being brought on or off line, QSE fleet economic dispatch, SCE control, etc. The increment of MW response is very small on a unit when frequency moves outside the deadband due to one of the above reasons. There are a many reasons why a GO unit control action or a GOP EMS control action may be in place that would be larger than this small increment resulting in the control action "overcoming" the frequency response component (not an all inclusive list) - Unit being ramped on or off line, Unit being manually loaded to a different level, QSE SCE control resulting from: Schedules ramping, Economic Dispatch resulting redispatch of fleet for economics, Ramping of balancing deployment Note: During the workshop, ramping was brought up as creating a potential issue for this requirement. The drafting team responded that Attachment 3 provided an exception for ramping. Attachment 3 does not provide an exception for ramping - it states that measurement is more difficult during ramping and then states "All Generation Resource/Frequency Responsive Resources shall be responsive to all frequency deviations exceeding the governor deadband while ramping." Because of the above reasons, this requirement is IMPOSSIBLE TO COMPLY with and can result in multiple	

			self reports DAILY of violations IF an entity was to continually analyze a unit output versus the unit governor's deadband. ** Comments on Measure for M10 Measures M10. "The GO and GOP shall have evidence that premature frequency response withdrawal by the Generation Resource/Frequency Responsive Resource was not visually observed." What does the term "was not visually observed" mean for evidence and audit purposes? ** Comment on Data required for Calculation Requirement R2 states a list of data that will be captured for each Measurable Event and submitted to TRE within 30 days of the event. Where will the TRE get the data to do the calculations for this requirement of monitoring all frequency deviations outside the deadband if they are only given the data captured by requirement R2? When this question was asked at the BAL-001-TRE-1 workshop, it was stated by 2 members of the PDCWG that they can see this data. Is there some plan for the PDCWG to do the compliance monitoring for the BA & TRE? **** Comments on Requirement R11 Requirement Language - The GO and GOP will meet a minimum twelve-month rolling average frequency response performance on each Generation Resource/Frequency Responsive Resource as stated in Attachment 3. See chart of Figure 4: Expected Resource Performance and associated spreadsheet. Meaurement Language - Measures M11. States the GO and GOP shall have evidence that within the Measurable Event report, the twelve-month rolling average per unit frequency response performance of each Generation Resource/Frequency Responsive Resource met the minimum performance as stated in Attachment 3. ** Comment R11 - #1 In addition to gathering evidence for compliance (M11), there are many operational reasons why a unit response may not meet the expected droop response that is required in this	

			document. Because of this, the GO will be required to analyze, document, and maintain the documentation for every individual unit response when a frequency disturbance occurs. Without this analysis and documentation, the GO will not have a means to dispute points that fall below expectation being place into the rolling average calculation. Documentation of every disturbance is required for compliance. The GO will not have knowledge of which disturbances are declared Measurable Events and which are not. Many GO plants are not staffed and have not been staffed for a number of years to be able to perform the analysis and capture the documentation. Staffing to levels to meet this compliance would be a huge O&M costs with little proven benefit to ensuring BES reliability. Very few GO plants are staffed to analyze the boiler process controls and conditions during an event that occurred after hours (1:00 am as example). It is simply impossible to document what happened the next day when the unit operator that was on duty at night is at home asleep. This would possibly require twenty-four seven engineering staffing requirements. ** Comment R11 - #2 Measure M11 states "the GO & GOP shall have evidence... per unit frequency response performance of each Generation Resource..." The performance evidence is all on the GO side - not the GOP side. Without the GOP contacting the GO for every frequency disturbance and requesting a copy of their analysis and documentation, the GOP cannot have such evidence. Why should the GOP have to spend time, money, & manpower to maintain duplicate documentation - this does not enhance Bulk Electric System reliability. Also, the GO & GOP may be entirely different companies and the GO unwilling to share detailed unit operational information with the GOP. If the thought process or intent is centered around the GOP's EMS system pulsing a unit the wrong direction during a frequency disturbance, it would be extremely rare for an EMS system to have historical recording of unit pulses issued. EMS pulses are the result of PID controller outputs that vary in magnitude & time (milliseconds) - they are not database points	

			in the EMS database system that can be historized. This standard should not require GOP's to spend development time & money on their EMS system to come up with a way to historize pulses just for the purpose of additional documentation. This would only apply to units that were on AGC control at the time of the frequency disturbance - not all units on line. If a GO is going to be required to analyze each individual unit's performance as part of their compliance process, AGC pulses received during a disturbance would be one of the parameters captured and analyzed. Therefore, any issues of this nature would be resolved between the GO & GOP to prevent the GO from being penalized. ** Comment R11 - #3 Does your 12 month-rolling average value initialize at the 1st time the unit is on line during a measurable event? If so, what if you did not meet the expected response with that one point? Are you in subject to violation, mitigation plan, & penalty with the 1st point? Peakers or older inefficient low capacity factor units that are frequently not on line will quite likely have very few points in this rolling average. What if there were mixtures of points where some met expected response and some did not? If the average was in compliance, would the unit be considered in violation of the standard if the 12 month old point(s) rolled out of the average dropping the average below expected? Note: If it was the late spring or fall, the unit might not have even been placed in operation for the last month or two. If the average falls below compliance, Section D. Compliance 1.2.2 states "If a Generation Resource/Frequency Responsive Resource completes a mitigation plan and implements corrective action that corrects past failing performance as measured by this standard, the rolling event average will be reset on the next successful performance during a measurable event" The above means that after filing a mitigation plan and doing	

			whatever work that was required, the GO has to place the unit on line, load it to a level for the best chance of response, and wait for a Measurable Event (550 MW unit trip) to occur. This can be an extremely expensive - the reason these units have low capacity factors is that they are inefficient and most of the time cannot be operated at a profit or they would be running - in some cases, retirement of the unit might have to be considered ** Comment R11 - #3 To document compliance and to document legitimate operational reasons for below expected response will result in a huge ongoing cost for the GO. If there is not a BES Reliability Issue concerning individual unit response identified and brought before ROS or TAC, why should there be a requirement forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons. **** Comments on Section D. Compliance Section 1.2.1 If a Generation Resource/Frequency Responsive Resource fails any requirement or measure of this standard, the GO and GOP will submit mitigation plans for the failing Generation Resource/Frequency This says both the GO & GOP are responsible and will have to file a mitigation plan "If a Generation Resoure... fails any requirement or measure.." Why is the GOP being held responsible and being forced to file a mitigation plan if the GO Resource fails a requirement or measure? In response to a question to the TRE if being subject to a mitigation plan meant also being subject to financial penalty, the TRE said "YES". Why should the GOP be penalized for a GO Resource requirement failure? Note: there are only comments concerning GOs & GOPs - no comments about BA compliance **** Comments on Section 1.3 - Data Retention For every requirement and measure, it states that all the documentation will have to be retained from the last compliance audit. The continental-wide BAL-001 requires data to be retained for 1 year. GO & GOP NERC audits are on a six	

			year cycle per a TRE workshop slide (do not know BA cycle). Why does this standard require data to be retained for such a long period of 6 years? **** Comments on Compliance Implementation Schedule Worksheet In 2012, implementation allows only 6 months between becoming Compliant and Auditably Compliant. Compliant means the entity is compliant with the requirements and beginning to maintain documentation. Auditably Compliant requires 12 months of documentation - cannot collect 12 months of data in a 6 month period. **** Conclusion The Commission stated that ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT and that ERCOT's approach under section 5 of the ERCOT protocols appears to be a more stringent practice than Requirement R2 in BAL-001-0 and therefore approves the regional difference. Please note the Commission statement words "reliable operation" and "more stringent" concerning Protocol Section 5. This proposed standard with it's compliance requirements for the GO & GOP goes far beyond both FERC Order 693 & 672 (see everything above). ERCOT has processes and committees in place that continually look at Reliability Issues. (These processes and committees are where the Paragraph 310 which contains the statement: "Since requesting the waiver from CPS2, ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT." that is quoted in the FERC Order 693 came from). Appropriate Protocol revisions or Operating Guide Revisions are made through these processes and committees when such issues are identified. There are no BES Reliability Issues identified before any committees (specifically the Reliability and Operations Subcommittee (ROS) or the Technical Advisory Committee (TAC) that would even remotely suggest the need for the GO & GOP requirements stated in the BAL-001-TRE-1 proposed standard. FERC Order 693 does not require the GO & GOP requirements for the implementation of Protocol Section 5 and they should not be included.	
161	Thad Ness - American Electric Power Service Corp.	Yes	While the SDT has done an excellent job thinking through the technical responses necessary to meet the requirements,	

			there are some higher level questions that should be considered before spelling out the technical details. What can ERCOT do to improve performance and meet the national standard? Should delegation agreements be used to transfer responsibilities to other entities? Should parties be expected to perform frequency regulation services without compensation? Another area not in this question set is the VSLs. R2 focuses on days late, which does not directly impact the reliability of the BES. The intent is more likely be to prevent lateness altogether, by progressively increasing penalties for repeated incidents of lateness. For example, Lower: First Time; Moderate: Second Time in two years; High: Two consecutive late submissions; and Severe: Three or more time. For R4, Lower penalizes everything under 100%, while 90% the national standard? R8 references a form, is it available? R9 and R10 seem to be higher than one would expect	
166	Frank Owens - Texas Municipal Power Agency	Yes	I believe this change can be incorporated into the existing ERCOT Guides.	
174	Ken McIntyre - ERCOT ISO	Yes	1. As applied to Requirement 4, ERCOT ISO is concerned about establishing a requirement on the Balancing Authority (BA) that under the existing Protocols (Protocols Section 5.9 was recommended to be used by FERC Order 693) is on the ERCOT Interconnection, not the BA. The BA in the ERCOT Interconnection does not own Resources and therefore cannot directly control Resource performance as is required with the current wording. ERCOT ISO recommends an approach similar to that of Protocols 5.9 that has the Balancing Authority analyzing and reporting on system performance. Perhaps the Requirement 4 language could be the following: R4. The BA shall calculate monthly a twelve-month rolling average Interconnection Frequency Response, as measured in Attachment 2. If the rolling average is not greater than or equal to the Interconnection Minimum Frequency Response, the BA shall investigate the cause and shall submit the results of their investigation to the Texas RE within 60 calendar days. The measure for R4 would be: The BA provided results of the monthly calculation of the 12 month rolling average of Interconnection Frequency Response. Upon a rolling average Interconnect Frequency Response that was not greater than or equal to the IMFR, the	

			BA conducted an investigation and reported the findings to the TRE. The BA provided the report within 60 calendar days from the detection of failing to meet the IMFR. 2. Requirement 6 stipulates that Generation Resources less than 10 MW each, who at a single point of interconnection sum to an aggregate greater than 10 MW, shall be treated as a single Generation Resource. ERCOT ISO recommends this be removed from the requirement as it is methodology and not a requirement. The language could be moved to Attachment 3, Part 2. 3. ERCOT ISO needs clarification on the method of the delivery of the GO and GOP governor and frequency response information (R7, R8 and R9). Whether it is established through an annual GARF/RARF process, or provided in real time through SCADA telemetry. ERCOT ISO would be supportive of the approach that GOs and GOPs calculate Resource specific governor performance/availability frequency response information and telemeter this in real time to ERCOT ISO. This would include frequency response information such as, governor in service, governor out of service, governor frequency dead band, governor droop setting, frequency response capability etc. 4. ERCOT ISO would suggest the schedule for implementation include a 2 year minimum Field Trial. This would allow time for ERCOT ISO to tune their systems utilizing the GO and GOP data, establish the necessary performance report templates for TRE, GOs and GOPs and allow a period for GOs and GOPs to review their performance as reported by ERCOT ISO as per this Regional Variance.	
183	Robert Kelly - Brazos Co-op	Yes	Reference comments submitted under Question 4.	
195	Paul Dougherty - Calpine	Yes	Given the large volume of Nuclear, Base Load Coal and Wind generation. Having the remaining units with electronic governors reduce their governor dead band setting to the recommended setting will not improve grid reliability. It might help ERCOT ISO improve frequency control; however, ERCOT ISO can improve frequency control by better modeling either the QSE or on a by unit basis expected frequency bias. Given projections of the growth of Nuclear and Wind Generation over the next 10 years, it is conceivable that the ERCOT grid can not provide 660 MW/0.1 HZ bias. It is estimated that when the percent of Nuclear, Wind and Base Load Coal generation hits 50% of the online generation that	

			the current ERCOT Frequency bias will not meet current acceptable levels. Thus, in order to improve the grid more units must provide frequency bias and this includes Nuclear, Wind and Base Load Coals plants. A nuclear plant can easily provide governor response, this is an operational issue for the plant not a systems issues. Base Load Coal plants can also easily provide frequency response by operating at levels that allow a response to be meaning full. Wind unit can also provide frequency response. This is not a technical issue. It makes no long term or short term economic sense to have fewer units carry the frequency burden of the ERCOT grid with no corresponding compensation.	
200	Peter So - Calpine	Yes	I agree with Randy Jones comment on this issue.	
216	Robert Green - Garland Power & Light	Yes	I recommend that R5 thru R11 and M5 thru M11 be deleted from the rext version of the the draft standard. Then the PDCWG should sponsor a PRR to revise protocol section 5.9.2, deleting all of the first paragraph except the first sentence [leaving the A point is the last stable frequency value prior to the frequency disturbance]. Then the PDCWG should sponsor a OGRR to revise OG 2.2.5 to include the deadband section of Attachment 3 Part 1 and delete the maximum intentional deadband of +/- 0.036 HZ requirement. Finally, the PDCWG augmented by an ad hoc group of MP should prepare a NOGRR that adds R5 thru R11 as sections in the new Section 9 that is being created via NOGRR 025.	

Attachment 4-004

BAL-001-TRE-01 Technical Workshop/Web Ex

March 31, 2009

9:00-5:00

ERCOT Met Center, Room 206 B

<u>Agenda</u>

Introduction and Background---This workshop will benefit long term even if there were no standard being developed. – 9:00 – 10:30

> TRE Standards—Judith James—How this variance came about and where we are in the process, where we go from here.
>
> Howard Illian---CPS2 Study and other supporting work in other Interconnections that are helpful.
>
> Reliability Need---Sydney's graphs from RSC meeting presentation justify the need.
>
> Bob Green has a spreadsheet that shows what happens when governor deadband is crossed.

Governors and AGC---Bob Green 10:30

QSE Bias and Frequency Response—how handled in the variance 11:00

Questions and Answers 11:30-12:00

Lunch – 12:00

The Draft Variance 1:00

> BAL-001-TRE-01 Requirements BA—Ken McIntyre

Questions and Answers 1:30

> BAL-001-TRE-01 Requirements GO and GOP--Sydney
>
> > Resource Performance Spreadsheet
> >
> > How to Set Up Limiting Parameter Curve

Questions and Answers 2:30

> Expected Documentation for BAL-001-TRE-01—Sydney and Ananth
>
> Implementation---Pam Zdenek

Questions and Answers 4-5

Attachment 4-005

FERC-Ordered Modification to ERCOT CPS2 Waiver to R2 of BAL-001-0

Question 1	Does this draft variance meet the reliability need addressed in FERC Order 693?

Answers	Frequency
Yes	10 (5 with comments)
No	3 (3 with comments)
No opinion	7 (4 with comments)

ID	Commenter	Answer	Comment	Response
118	Rick Terrill - Luminant	No	Luminant believes that the draft goes beyond that which is required to respond to FERC Order 6937. The nature of a variance is to describe how the existing regional procedures or process (and in ERCOT?s situation, the ERCOT Protocols) meet the intent of a NERC Standard. The draft variance seems to redesign frequency control in the ERCOT Region rather than follow the FERC Order to "include the requirements concerning frequency response contained in section 5 of the ERCOT protocols." Changes to existing ERCOT Protocols should first be vetted through the ERCOT Protocol Revision Request (PRR) process before they are utilized within a variance procedure.	"Regional standards are separate standards that go beyond, add detail to, or implement NERC Reliability Standards; obtain a Regional Variance; or otherwise address issues that are not addressed in NERC Reliability standards." (Appendix to Exhibit C to the Delegation Agreement Between NERC and ERCOT, April 2007, p. 4) A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. (NERC Rules of Procedure, p. 4, Dec. 2008) Texas RE has the authority by delegation to develop both regional standards and regional variances using its FERC and NERC approved standard development process. This process allows for going beyond the national standard and requires that a regional standard be more stringent. (See Appendix to Exhibit C of Delegation Agreement, pp. 3-7.) In the case of the NERC standard BAL-001's stated purpose "to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time," the ERCOT region cannot comply with BAL-001 (CPS2) but does achieve the purpose of BAL-001 through Protocol 5.9. FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a standard. Additionally in FERC Order 693, "As with other new regional differences, the

				Commission expects that the ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections", (P 315), it defines a regional standard, and more specifically, a regional variance, is necessary due to ERCOT's physical difference as a single Balancing Authority Interconnection. Also, by delegation, Texas RE is required to follow all NERC directives and FERC Orders. Both FERC and NERC staff have indicated that a regional standard is the appropriate development path to follow for the ordered and directed modification. Texas RE does <u>not</u> have any authority to develop, modify, or delete ERCOT Protocols. Also, over the past two years, the Performance Disturbance Compliance Working Group (PDCWG) has identified reliability problems associated with the implementation of deadbands in Protocol Section 5.9. In order to meet the performance requirements of 5.9, generating units/generating facilities were encouraged to achieve near 5% droop during measurable events. This requirement resulted in generating units/generating facilities "stepping into" the 5% droop curve once the deadband had been crossed. This resulted in an irregular Interconnection frequency profile that could not achieve a normal probability distribution. This identified additional instability issues that will exist during islanding events. This standard addresses these reliability issues by clearly defining deadband and droop implementation on generating units/generating facilities. This standard also addresses the measurement of frequency response by evaluating performance of generating units/generating facilities using actual deadband and droop settings.
128	Ronnie Hoeinghaus - Garland Power & Light	No	FERC Order 693 in paragraph 315 orders the ERO to file a modification of the ERCOT Regional Difference to include the requirements concerning frequency response contained in section 5 of the ERCOT Protocols and further states in	See response to Rick Terrill, Luminant, on this same question, especially the last paragraph.

			Paragraph 310 that Section 5 provides the necessary frequency controls needed for reliable operation in ERCOT. This proposed standard does not follow the FERC Order but redesigns what is in the ERCOT Protocols & Operating Guides.	
157	Thad Ness - American Electric Power Service Corp.	No	The best alternative would be to improve control performance and meet the national standard, as other RTOs do, such that a variance is not necessary. Since this alternative provides performance below that of the national standard, we believe that the Standards Development Process would indicate that a regional variance be provided for in the national standard. A regional standard is intended to address the uniqueness of a region that requires differences in performance characteristics, but the regional standard is expected to be no less strict than the national standard. To the extent that Order 693 requires that this regional process be used rather than adapting the national standard, this standard meets the intent, but does not meet the spirit of improvement that the FERC intends. Furthermore, if protocols are permitted to be moved into the standard, then these protocols should be removed. Better to be in one place to avoid maintenance issues that can lead to discrepancies.	FERC recognized that ERCOT ISO had a waiver for CPS2----requirement 2 of BAL-001. As with other new regional differences, FERC ordered the development of a regional standard to meet the purpose of BAL-001. FERC also indicated that Protocol 5.9 was the appropriate way to address the purpose of BAL-001 because it appeared to be more stringent than CPS2. Being more stringent is a requirement in order to develop a regional standard. When this standard is approved for the region, then the stakeholders in the region will be responsible to write the protocol revision requests that may be necessary to remove requirements from the Protocols. This team is not responsible for initiating any required Protocol Revision Requests. Please also refer to response to Rick Terrill of Luminant on this same question for definitions of regional standard and variance that this team operates under.
123	Randy Jones - Calpine	No opinion	It appears to exceed the requirements set out in FERC Order 693 in that it exceeds the content of Protocols Section 5 referenced in the order. Specific comments on the Draft Requirements follow: Comment #1: In the Definitions, the passage on Frequency Responsive Resource is confusing in its treatment of Controllable Load Resources: ?Frequency Responsive Resource: Facility capable of providing electrical energy or	This draft standard incorporates improvements to Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9. Response #1. Controllable Load Resource has been removed from the definitions.

			Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services (as defined in the current ERCOT Protocols) to the ERCOT System, excluding Underfrequency Relay Load and Emergency Interruptible Loads but not Controllable Load Resources.? Is a Controllable Load Resource Frequency Responsive according to this definition excluded? If CLR is excluded the statement should read, ??but not excluding Controllable Load Resources.?	
			Comment #2: R.7, which applies to GOs, calls for the GO to report to ERCOT (the BA) any condition that would limit the generator?s ability to respond to frequency. On what frequency is this reporting to be done and how is the communication carried out? For firms with a large number of units in ERCOT some form of automated interface should also be stipulated.	Response #2. R7 has been removed from the revised version of the regional standard.
			Comment #3: R.8 must be re-written to be more specific. It currently states: ?R8. The GO shall ensure that combustion turbines in a combined cycle configuration have a governor droop characteristic of 4%, steam turbines have a governor droop characteristic of 5%, and that all other Generation Resources/Frequency Responsive Resources have a governor droop characteristic of 5% or less. See Attachment 3 for these characteristics.? We asked in the technical workshop what this requirement meant in application and the answer we received was that combined cycle trains/power blocks would be aggregated and the speed droop for the entire train would be equal to 4% (the ST would be ignored for speed droop since many of them operate with valves wide open and latched up, providing no response). We were also told that the 5% speed droop for steam turbines is intended	Response #3: The team agrees and the expected performance of the steam turbine has been addressed in the revised standard in R.3. The performance of a steam turbine of a combined cycle facility will not be evaluated in this standard.

			to be the criteria for other technologies such as gas-steam, PC units, etc. that use a single steam turbine assembly (HP/IP/LP compound on single or multiple shafts for example). This passage appears to be reworded to be clear what the speed droop criteria applies to which technologies. Comment #4: In R.9, the specific governor dead bands found in Attachment #3 should be spelled out clearly in R.9 rather than in the attachment. Also, the qualifying passage about ??intentional and unintentional?.? seems to be superfluous. ?Limiting? unintentional governor dead bands seems contrary to logic. Comment #5: R.10 seems to be unnecessarily open-ended in the definition of ?sustained?. The narrative on page 16 of 29 states that full governor response is to be delivered from 10 seconds to 30 seconds after T0but not greater than sixty (60) seconds after the ?A? point. For this governor response Requirement to have meaning it must be measurable and not refer to an attachment that contains the word ??usually?.? If the intent is for ?sustained? to mean 30 seconds after the ?A? Point then let?s construct R.10 to say just that. Other Questions and Comments Regarding the Draft Regional Standard: a) The move from the current permissive governor dead band of .036 Hz to .01667 will require additional precision in both speed pickups and speed transducers. Have OEMs been consulted on whether this precision is possible? If some deadband of less precision, perhaps .020 Hz, is possible could a GO certify to this ability instead of the value of deadband one firm could achieve in tests on one particular unit (WA	 Response # 4: The terms “intentional and unintentional” have been removed. The new draft of the standard has moved the deadbands into the requirements. Response # 5: This requirement has been removed from the new draft. The twelve-month rolling average performance measure will capture sustainability. The applicability of this standard no longer applies to GOP. Response a): The team picked 0.01667 Hz, which is equivalent to 1 rpm on a two-pole generator. The team feels that the 0.02 Hz does not have added value. If this is not possible on a specific generating unit/generating facility, the generating unit/generating facility would have to set the deadband at its highest value that is below the maximum allowable deadband of this standard.

			Parish #7, as noted in the workshop)? We allow GOs to provide an adjusted Unit Reactive Limit for the use of over and under excitation limiters, can?t this principle also be extended to the setting of deadbands?	The team has not consulted Original Equipment Manufacturers, but based on the implementation so far, the team has not seen a problem. Several market participants have implemented this (in unofficial field trials) on multiple generating unit/generating facility types, not just large steam turbines. The maximum limit on deadband equalizes the obligation of providing Primary Frequency Response from all generating units/generating facilities; therefore, setting larger deadbands cannot be justified.
			b) Should this Draft Standard also be accompanied by an ERCOT Region Field Test to see if the benefits asserted by the Drafting Team, based on only four units, actually occur system wide?	Response b): Currently, multiple units have been tested unofficially, and all have reported improved stability and performance. The members of the PDCWG have tested the Governor droop implementation described in the current draft of the standard on various types of units with success. The team encourages all market participants to test the Governor implementation of this standard on their generating units/generating facilities. Documentation has been supplied with this draft in order to encourage such testing by the industry. Results of such testing could be supplied in future comments on this standard or directly to the PDCWG.
			c) R.2 (6) requires the ?Generation Resource/Frequency Responsive Resource MW value? will be used in the evaluation of performance for each frequency deviation event. This value would be measured at the BES injection point where the EPS metering is read. For cogeneration sites the net increased injection from governor response to frequency is impacted by both the thermal host?s induction load responses to frequency recovery and their steam demands that vary with frequency. Either cogeneration sites should be exempted from this Draft Standard or the total response for them should include the	Response c): The intention of this standard is to measure Primary Frequency Response of generating units/generating facilities. If this requires accounting for changes in a facility's internal load, then that is what should be included. The standard has provisions for using gross data to measure performance. This data would be provided by the generation owner to meet expected performance. The current draft of the standard allows GOs to use gross generation output to measure their frequency responsiveness and thus eliminating the issue with parasitic load. The current sustained measure of Primary Frequency

			calculation of the parasitic load?s impact on the net injection at the high side of the GSU.	Response accounts for generating unit/generating facility ramping during the recovery period. This should address steam demand change by the host during the recovery period.
136	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	Thank you for your comment.
179	Robert Kelly - Brazos Co-op	No opinion	It appears to exceed teh requirements set out in FERC Order 693. The proposed requirements are generally confusing.	This draft standard incorporates improvements to Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9. The team will respond to your general concerns regarding confusion in response to comments that you posted in Question 4 below.
201	Michael Sonnelitter - NextEra Energy Resources	No opinion	The draft variance appears to exceed the CPS2 requirement R2 for GO/GOP.	This draft standard incorporates improvements to Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9.
111	Jack Thormahlen - Lower Colorado River Authority	Yes	Passage of this regional standard satisfies FERC Order 693, paragraphs 309 through 315 and specifically 314, 315 requiring more stringent practices in ERCOT than other regions.	Thank you for your comment.
141	Ivan Kush - Calpine	Yes	It does meet and exceed Order 693.	The team agrees that this draft standard exceeds Order 693 through improved implementation of Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9.
167	Ken McIntyre - ERCOT ISO	Yes	ERCOT ISO believes this draft Regional Variance meets the reliability needs of the FERC Order 693. ERCOT ISO also believes some of the requirements in the current draft exceed what was requested in the FERC Order 693.	The team agrees that this draft standard exceeds Order 693 through improved implementation of Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9.
191	Paul Dougherty - Calpine	Yes	The proposed standard is more strigent that the current standard. However, the standard only applies to generators with electronic governors.	The team agrees that the drafted standard is more stringent than the current Protocols. This draft standard incorporates improvements to Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9. The revised standard has clarified performance requirements for mechanical Governors as well as electronic or digital Governors.

Question 2	Will the requirements for GOs and GOPs in this variance improve Interconnection reliability?

Answers	Frequency
Yes	6 (4 with comments)
No	3 (3 with comments)
No opinion	9 (4 with comments)

ID	Commenter	Answer	Comment	Response
119	Rick Terrill - Luminant	No	To the extent that the requirements go beyond the provisions of the existing ERCOT Protocols, the question concerning improved interconnection reliability is appropriately considered in the ERCOT PRR process. The requirements of R7, R9, and R11 are burdensome on GOs and GOPs and might take away the operators focus of operating the unit in favor of gathering data. Additionally, they are beyond the requirements in the currently approved ERCOT Protocols and any change should be the subject of a PRR.	FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a standard. FERC Order 693 further states: “As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections”. The team agrees that this draft standard exceeds Order 693 through improved implementation of Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9. Changing the Protocols is not part of the regional standard development process. The GOP has been removed from the applicability in the current draft of the standard. The ability to exclude events has been included in the measures of the new draft. The primarily administrative R7 was deleted and pertinent data has been included in the performance evaluation tool. It is the team’s belief that such documentation will be performed once, unless there is a significant design or operating change in the generating unit/generating facility. R9 was combined with R8 and moved to the new R3. The parameters were put into tables and formulas were added for the slope of Governor response. R3 does not require any real time data gathering by the GO. R11 is now contained in the new R4. A minimum participation of 8 events was added. Formulas for calculating the performance were added. The GO can rely on the BA data collection and measurement to meet R4. If the GO disagrees with the BA data, it is free to provide its own data to show performance. In any case, this is

				an automated process that does not shift the operator's focus from real time operations. For a generating unit/generating facility with no data historian, charts can be pulled for manual evaluation of performance if the GO disagrees with the BA's analysis.
129	Ronnie Hoeinghaus - Garland Power & Light	No	Some older, inefficient units that currently provide a stable source of energy may be forced into retirement when faced with expensive governor repairs or governor replacement to remain in compliance with this standard. In addition, there is a heavy, real time analysis & documentation burden placed on the unit operator which potentially could divert his focus from stable operation to data gathering in order to avoid financial penalties.	Existing ERCOT Protocols and Operating Guides already require generating units/generating facilities to have an operating Governor. The Interconnection needs frequency response at all times of the year. When these older inefficient units are online, they are providing this reliability service to the fullest extent that their unit allows. The stability of the unit is of paramount importance to ERCOT and Texas RE. Any extenuating circumstances regarding unit operations and Primary Frequency Response will be mitigated on a case by case basis. Please see response to Rick Terrill, Luminant, Question 2, second paragraph for details on the burden of documentation. Most of the documentation is already available at ERCOT and Texas RE.
192	Paul Dougherty - Calpine	No	With almost half of the online generation excluded from providing governor response (Nucleur, Wind and Base Load Coal) the Balancing Authority may not be able to procure sufficient frequency response to safely and properly operate the ERCOT Grid during an frequency event. This problem could be made worse during the shoulder months as other genrating units are operating at or near their max capability and the percentage of Nuc/Wind/BL Coal and other type of generating units is greater.	The team agrees with your concern about insufficient frequency response. The team feels strongly that base load coal and all wind are not excluded from providing Governor response. Future nuclear generation will be reviewed regarding requirements to provide frequency response as well. This standard will provide ERCOT with a more accurate real time view of available Primary Frequency Response 24 hours per day, 7 days per week. It is the team's belief that ERCOT will make the necessary re-dispatch to ensure that adequate Primary Frequency Response is available.
124	Randy Jones - Calpine	No opinion	It would be difficult to determine since both the Region's CPS1 12-month rolling average and its RMS-1 of frequency are already on a steady upward/improving trend for some months now.	The new deadband settings and droop implementation have been tested on several units since the end of October 2008, resulting in an improved ERCOT frequency reliability profile. The PDCWG through its frequency data analysis believes that these Governor droop characteristics are a contributing factor for this

				improved reliability. The generating units/generating facilities that have tested the setting within this standard are pleased with the resulting unit stability compared to Governor settings per Protocol 5.9.
137	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	Thank you for your comment.
144	Clif Lange - South Texas Electric Co-op	No opinion	Tightening the deadband requirements theoretically would improve the statistical distribution of frequency deviations and reduce or eliminate the ?flat top? distribution, but no evidence exists that this would improve Interconnection reliability. The ?outliers? or ?tails? of distribution will still exist and likely with the same magnitude as currently exist. Calpine?s comments regarding the improvement in the CPS-1 12 month rolling average and the RMS-1 are noted as evidence that factors other than the normal distribution of frequency are successfully at work to improve reliability.	Regarding outliers, the team believes the implementation of Governor droop within this standard will result in more stable generating unit/generating facility operation during steady state conditions and provide a better opportunity for good Primary Frequency Response performance during an event. This will not eliminate the tails, but should reduce the deviation of frequency during an event. This standard will result in stronger participation from all Primary Frequency Responsive generating units/generating facilities through its measures and levels of non-compliance. This in turn will improve frequency response of the Interconnection. The improved statistical distribution of the frequency profile will increase the probability that frequency will be near 60 Hz at the beginning of an event compared to the flat top distribution. This will reduce the magnitude of the frequency deviation during an event.
158	Thad Ness - American Electric Power Service Corp.	No opinion	We are very concerned that the TRE is spreading its obligation to meet CPS2 values, by expanding the role of the BA, GO, and GOP to perform frequency regulation service. To the extent that GOs comply with the prescribed requirements to provide frequency regulation through adjustments to dead bands, droop, and governor response, the GO/GOP may be placed in the position of losing revenues or the opportunity for additional revenues with no compensation for providing the ancillary service.	Texas RE has no obligation to meet CPS2. ERCOT ISO as the BA had the obligation to meet CPS2 before its waiver. Per the FERC Oder 693, a regional standard must now be developed to supplement the waiver, and Texas RE has been delegated authority to develop this regional standard as a variance from the national standard BAL-001. This standard has not changed the requirement in the existing ERCOT Protocols and Operating Guides that all generating units/generating facilities have a Governor in service at all times. This draft standard has only changed how the Governor droop is implemented and performance is measured.
112	Jack Thormahlen - Lower Colorado	Yes	With tighter requirements for governor	Thank you for your comment. The team

	River Authority		response as outlined in this regional standard, the frequency deviations will be considerably less assuming all gnereators capable of governor response, within the required parameters, participate.	believes that this standard will result in stronger participation from all Primary Frequency Responsive generating units/generating facilities through its measures and levels of non-compliance. This will eliminate or mitigate the over-taxing of units which consistently perform in response to frequency deviations.
148	Ivan Kush - Calpine	Yes	It will improve interconnection reliability only in the sense that we're minimizing frequency swings.	Thank you for your comment. The team agrees that frequency swings will be minimized with this standard.
168	Ken McIntyre - ERCOT ISO	Yes	The requirements detailed in this draft Regional Variance for GO and GOPs build on the current ERCOT protocol language, and establishes the necessary information and performance for GOs and GOPs. Improvement is anticipated from increased measurability for those units that may not have adequately aligned their performance with the current Protocols.	Thank you for your comment.
213	Robert Green - Garland Power & Light	Yes	Excellent governor response may prevent the UFR shedding of firm load as a result of a future major measurable event.	Thank you for your comment.

Question 3	The maximum allowable deadband of a turbine governor in the ERCOT Interconnection is +/-0.036 Hz. This regional variance changes the maximum allowable deadband of a turbine electronic or digital governor to +/-0.0166 Hz. Does this change improve Interconnection reliability?

Answers	Frequency
Yes	8 (5 with comments)
No	6 (6 with comments)
No opinion	4 (3 with comments)

ID	Commenter	Answer	Comment	Response
120	Rick Terrill - Luminant	No	To the extent that the tightening of existing ERCOT Protocol and Operating Guide requirements may or may not result in improved interconnection reliability is appropriately considered via the ERCOT PRR or Operating Guide Revision Request (OGRR) process. Although the research done by one company shows it works for them, there are many different boiler/turbine arrangements and without additional research, it is not possible to determine if	Texas RE and this standard drafting team are assigned the task of developing a standard. It is not within the team's purview to change ERCOT Protocols or Operating Guides. The members of the PDCWG have tested this Governor droop implementation on varying types of units with success. The team encourages all market participants to test the Governor implementation of this standard on their generating units/generating facilities.

			this works for all units. It is also beyond the scope of the order and should not be included.	Documentation has been supplied with this draft in order to encourage such testing by the industry. Results of such testing could be supplied in future comments on this standard or directly to the PDCWG. As of October 15, 2009, the PDCWG reported to ROS that 11,107 MW of total capacity now has governor settings that meet this standard. This includes Lignite, Coal, Combustion Turbine Simple and Combined Cycle, conventional steam gas fired and hydro generating units/generating facilities. The team agrees that this draft standard exceeds Order 693 through improved implementation of Protocol 5.9. See response to Rick Terrill and Thad Ness for Question 1 for the reasons for improving upon 5.9.
125	Randy Jones - Calpine	No	The change in deadband capping requirements will likely not make a noticable improvement in the interconnect's reliability. Particularly, during shoulder period off-peak hours, when declining amounts of spinning and responsive intertia is available on the system to respond to frequency deviations. This requirement probably has to apply to all generators, on the ground and planned, in order to make a meaningful improvement in system transient stability and longer term reliability.	This standard will result in stronger participation from all Primary Frequency Responsive generating units/generating facilities through its measures and levels of non-compliance. This in turn will improve frequency response of the Interconnection. The improved statistical distribution of the frequency profile will increase the probability that frequency will be near 60 Hz at the beginning of an event compared to the flat top distribution. This will reduce the magnitude of the frequency deviation during an event.
130	Ronnie Hoeinghaus - Garland Power & Light	No	This goes beyond the FERC Order 693 and what is in ERCOT Protocol Section 5. The scope of the order was to implement the current protocol, not redesign the protocol. ERCOT has processes and committees in place to identify and handle reliability issues. If it is felt that such an issue for ERCOT may exist, then evidence should be presented to those committees for consideration. If the committees determine that such a reliability condition does exist, then the appropriate Protocol Revision Request or Operating Guide Revision Request will be developed to correct the situation.	ERCOT Protocol 5.9 places the frequency response performance requirements on the ERCOT Interconnection. Since the ERCOT Interconnection is not a NERC registered entity, requirements had to be included in the regional standard for existing registered entities i.e. GO/BA. Over the past three years, the Performance Disturbance Compliance Working Group (PDCWG) has identified reliability problems associated with the implementation of deadbands in Protocol Section 5.9. Statistical data has been presented to ROS demonstrating the affects of the present Governor deadband

				and droop requirements in the ERCOT Protocols. A member of the PDCWG has built and published a model that demonstrates the instability of the implementation of the current Protocol deadband and droop characteristics. In order to meet the performance requirements of 5.9, generating units/generating facilities were encouraged to achieve near 5% droop during measurable events. This requirement resulted in generating units/generating facilities "stepping into" the 5% droop curve once the deadband had been crossed. This resulted in an irregular Interconnection frequency profile that could not achieve a normal probability distribution. This work identified additional instability issues that will exist during islanding events. This draft standard addresses these reliability issues by clearly defining deadband and droop implementation on generating units/generating facilities. This draft standard also addresses the measurement of Primary Frequency Response of generating units/generating facilities by accounting for their deadband and droop settings. Texas RE and this standard drafting team are assigned the task of developing a standard. It is not within the team's purview to change ERCOT Protocols or Operating Guides.
145	Clif Lange - South Texas Electric Co-op	No	Tightening the deadband requirements theoretically would improve the statistical distribution of frequency deviations and reduce or eliminate the ?flat top? distribution, but no evidence exists that this would improve Interconnection reliability. The ?outliers? or ?tails? of distribution will still exist and likely with the same magnitude as currently exist. The greater question is whether the ERCOT interconnect is in greater danger of firm load shed or blackout due to the shape of the statistical distribution? To date the answer has been an overwhelming ?no.?	The present implementation of ERCOT Protocol 5.9 and the practice of "stepping into" the droop curve have been demonstrated clearly by PDCWG as causing a potential grid instability situation, especially during islanding events. This regional standard clearly addresses this droop curve and deadband issue. Please refer to the team's response to STEC's comment on Question # 2 and to Garland Power's comment on Question #3 above.
193	Paul Dougherty - Calpine	No	ERCOT can achive better frequency control by improving the telemetry of expected	Implementation of this Regional Standard should improve Primary Frequency Response in

			frequency response from the QSEs and by writing simple programs on the EMS to address issues related to units operating at max load and units frequency response dead bands. ERCOT can also develop real-time operating procedures to back-off base load units during times of low expected frequency response using the improved telemtry and programs mentioned above.	the ERCOT Interconnection since each generating unit/generating facility will have a clear requirement for governor settings. Measurement of each generating unit/generating facility's performance will ensure compliance. ERCOT ISO will be able to manage Interconnection Primary Frequency Response by managing spinning reserve within the ERCOT Interconnection.
203	Michael Sonnelitter - NextEra Energy Resources	No	The standard has several requirements for setting governor deadband and droop and for governor performance. If the turbine manufacturer does not allow operation with these settings, and/or the governor, being in a state of good repair, is not capable of these requirements, then the standard should exempt existing units that have such limitations.	The team is not aware of any turbine manufacturer that does not allow operation within these settings. Current ERCOT Protocols and Operating Guides require that Governors be in service at all times and tested every two years.
138	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	Thank you for your comment.
159	Thad Ness - American Electric Power Service Corp.	No opinion	Requirements from referenced attachments should be specifically stated in the standard. Since the attachment contain both technical explanations and requirements, there is room for inadvertent misinterpretations.	Based on industry comments, the requirements now contain the specific Governor settings. The current draft has been rewritten to clarify the requirements and provide more details within the requirements.
198	Peter So - Calpine	No opinion	Reducing the maximum allowable deadband has effects on our turbines, what effects is tough to quantify or determine without our turbine manufacturer's input. While at first glance, reducing the deadband, one may think that the turbine moves less, when in fact depending on the swing on the grid, the turbine may be moving more to keep within the reduced deadband. If these movements causes reliability issues on our turbines, it can have adverse effect on the interconnect reliability. Our gas turbines are of the latest design for efficiency and especially emissions, small uncontrollable changes can make the combustion unstable and cause the unit to trip or exceed emissions limits. While I can	The team agrees that this deadband setting has not been tested on all types of combustion turbines and manufacturers. We are working with the PDCWG and asking members to test these settings now on their units. A field trial has also been suggested to be used to identify any issues. Anyone who has concerns about this is welcome to participate in the testing. Presently the PDCWG has several members who have set these changes in their generating units/generating facilities with very positive improvement in Primary Frequency Response performance and improved generating unit/generating facility operational stability. This also includes some modern combined cycle generating units/generating facilities. (See response to comments received from Luminant,

			not say for certain the proposed deadband change will cause any issues, I suggest more research and testing needs to be conducted before a standard is adopted.	question 3 above). Depending how current Governor deadbands are implemented on a generating unit/generating facility, decreasing the deadband may or may not cause the generating unit/generating facility to move more. Deadband implementations for some generating units/generating facilities that have “stepped into” the 5% droop curve have resulted in a large step change in generating unit/generating facility output once the deadband is crossed. During an islanding or Blackstart event this will cause more frequency response than the island needs to stabilize frequency, thus causing frequency to be unstable. This standard normalizes the implementation of the droop curve once the deadband is crossed with a straight line proportional change in output of the generating unit/generating facility versus the change in frequency. This will result in movement of the generating unit/generating facility to smaller frequency changes but will eliminate the step change in generating unit/generating facility output once the deadband is crossed. The team agrees that generating units/generating facilities will move more often but the magnitude of the moves will be smaller when all generating units/generating facilities are complying with this standard. Based on results from generating units/generating facilities that have implemented these changes, generating unit/generating facility operational stability has not been compromised and many have seen significant improvement. To date, generating units/generating facilities that have implemented this change have not seen problems with emissions or combustion instability.
113	Jack Thormahlen - Lower Colorado River Authority	Yes	Governors with a maximum deadband of +/- .0166 Hz will be moving earlier and with fewer MW than as current practice using +/-	Thank you for your comment; the team agrees.

			.036 Hz deadband. The smaller deadband may require less maintenance on the machine due to the lessening of the impact of the response, eventhough the unit may be be moving more often.	
149	Ivan Kush - Calpine	Yes	Again I feel this will improve frequency stability. It potentially places other constraints on overall interconnection reliability. For example has GE been approached to determine if their DLN systems can handle this kind of activity? I have spoken with Siemens the OEM itself has never "fully" tested any of their gas turbines with less than .036Hz response. I would propose that the OEM's be officially contacted by the BA or other large organization to ensure that these proposed standards can be met before we look to require GO's to comply. Based on the Siemens response alone, I would recommend that time be allotted prior to submission to NERC for formal testing on a representative subset of GO equipment from the ERCOT region. The work the team has done to date is extremely commendable, but I believe a larger sample of equipment be evaluated ? for example large frame industrial gas turbines 170+ MW machines. If we go forward with this prior to verification we could destabilize the interconnect significantly.	The team encourages people to test their units' capability during the standard development to identify any issues. The team agrees that this deadband setting has not been tested on all types of combustion turbines and manufacturers. We are working with the PDCWG and asking members to test these settings now on their units. A field trial has also been suggested to be used to identify any issues. Anyone who has concerns about this is welcome to participate in the testing. Presently the PDCWG has several members who have set these changes in their generating units/generating facilities with very positive improvement in performance. This also includes some modern combined cycle generating units/generating facilities. As of July 2009, the Governor settings required in this Regional Standard have been used in a newly-commissioned combined cycle facility manufactured by Siemens. These settings are still in place today with no operational issues.
164	Frank Owens - Texas Municipal Power Agency	Yes	I believe this change can be incorporated into the existing ERCOT Guides.	Texas RE and this standard drafting team are assigned the task of developing a standard. It is not within the team's purview to change ERCOT Protocols or Operating Guides. The team agrees that the ERCOT Protocols and Operating Guides will need to be revised once this standard has been approved. The team will have members available for guidance on this effort, and the implementation schedule of this Regional Standard allows adequate time for these activities.
169	Ken McIntyre - ERCOT ISO	Yes	Reducing the maximum allowable deadband will result in Resources, which	Thank you for your comment; the team agrees.

			are expected to provide with frequency response, to respond to a frequency deviation sooner. Recent pilot efforts in this area by a market participant in the ERCOT Interconnection seems to indicate that the ERCOT frequency has a better performance around the 60Hz scheduled frequency with the narrower deadband. If Resources are capable of reducing their deadbands and still operate reliably, then it would appear this would help the ERCOT Interconnection frequency response, and reliability.	
214	Robert Green - Garland Power & Light	Yes	The smaller deadband will help minimize sustained operation around 59.964 [at the edge of the lower deadband] which may occassionally prevent shedding of firm load triggered by a low C point. I also believe that hysterisis style production costs will be lowered by eliminating frequent oscillations between the lower deadband and the upper deadband. The smaller deadband will also make it easier to consistently provide a minimum of 420 MW/0.1 HZ of governor response which is the proposed reliability standard.	Thank you for your comment; the team agrees.

Question 4	This variance requires a droop performance that is attainable based on a resource's characteristics and available stored energy in the time period of the measure instead of the normal 5% droop performance. Will this pose a risk to Interconnection reliability?

Answers	Frequency
No	6 (4 with comments)
Yes	5 (5 with comments)
No opinion	7 (3 with comments)

ID	Commenter	Answer	Comment	Response
121	Rick Terrill - Luminant	No	This is added complexity and constitutes a change in the ERCOT Protocols that must first be subject to the PRR process before consideration in developing a variance procedure.	Texas RE and this standard drafting team are assigned the task of developing a standard. It is not within the team's purview to change ERCOT Protocols or Operating Guides. The revised draft of the standard simplifies and clarifies the requirements and provides a tool for

				GOs to measure Primary Frequency Response.
194	Paul Dougherty - Calpine	No	It is not equitable for a small segment of units (ones with electronic governors) to be expected to provide more droop response when other units like Nucleur, Wind and base load coal have no obligation to provide any droop response.	The team is not stating that nuclear, wind and base load coal have no obligation to provide droop response. Existing base load coal and new wind generation are under the same obligation of complying with the standard as other generating units/generating facilities with electronic and digital Governors. Retrofitting of existing wind units is under current discussion (ERCOT PRR 833). Many base load coal units have electronic and digital Governors and will be required to comply with the standard. Presently, six base load coal units have been operating to the requirements of this standard for over one year and a super-critical lignite base load unit has been tested and found to provide consistent Primary Frequency Response. The team understands that the nuclear generating units/generating facilities presently in ERCOT cannot continuously provide frequency response due to the reactor design. Nuclear generating units/generating facilities currently comprise about 7% of the ERCOT market. Future nuclear generating units/generating facilities may need to provide frequency response as the generation mix evolves over time.
210	Rick Vera - Power Consultant	No	It is encouraging that finally the unit capabilities are being considered in the evaluation of its frequency regulation compliance. It has always been believed that calibrating a governor and the unit controls to support a 5% speed regulation would lead to a 5% frequency load regulation. There is a great difference between these two. The unit frequency load regulation (even though perfectly calibrated for a 5% speed regulation)	Thank you for your comment; the team agrees.

			depends on many factors. Among them: 1. Type of unit 2. Type of fuel 3. Boiler energy storage 4. Effect of pressure drop 5. Etc. No matter how much fuel is injected into a unit at the time of the frequency event, its initial load response will depend in all the above factors. So developing a standard that can adjust and evaluate the frequency load regulation based on the individual unit capabilities is definitely a step in the right direction. Rick Vera, P.E. Power Consultant	
215	Robert Green - Garland Power & Light	No	Units with a programable droop setting, will still be required by OG 2.2.5 to have a maximum of a 5% droop setting.	The team agrees that the droop setting will be a maximum of 5% on any generating unit/generating facility. Please note that the team does not intend for the word "setting" to be synonymous with "performance".
114	Jack Thormahlen - Lower Colorado River Authority	No opinion	Lacking empirical data it is difficult to predict the risk. However, if all generators follow these requiurements we'll have reduced reliability risk.	The team agrees that there is currently no empirical data but based on unofficial field trials, the team has not seen any risk. As more generating units/generating facilities are tested using this standard, frequency response performance of the Interconnection can be evaluated. Existing units currently using the new droop settings within the standard have been more stable and therefore have a higher probability of better performance when an event occurs.
139	Kenneth Brown - PSEG Texas	No opinion	It is our opinion that this question be better answered by the BA or reliability authority.	Thank you for your comment.
160	Thad Ness - American Electric Power Service Corp.	No opinion	Requirements from referenced attachments should be specifically stated in the standard. Since the attachment contain both technical explanations and requirements, there is room for inadvertent misinterpretations.	Thank you for your comment. Please see response to your comment on Question 3.
126	Randy Jones - Calpine	Yes	This approach would seemingly allow a large percentage of the installed ERCOT capacity to avoid making a speed droop contribution during frequency deviations. A solution must be found and incorporated in any CPS-2 performance metric that provides for response attributible to the ERCOT West Congestion Zone. In order to	Attachment 3 of the standard allows the generating unit/generating facility to determine what frequency response is attainable. This determination must be based on sound engineering practices and must be justifiable. The team agrees with your concern. This draft standard is intended to best prepare the system

			be effective and provide response from the West Zone some form of islanding criteria must be developed, since effective islanding and subsequent control of island frequency is a stated goal of this Standard. As it stands this Standard seems to accept a lack of renewable response as nominal, which can jeopardize the effecting islanding of the West Zone.	to survive scenarios such as islanding events. Identifying specific islanding scenarios is not within the scope of this draft standard. Right now, as the Western Congestion Zone exists there is little frequency response available and therefore this zone would have little chance of surviving an islanding event. New wind generation is under the same obligation of complying with the draft standard as other generating units/generating facilities with electronic and digital Governors. Retrofitting of existing wind units is under current discussion (ERCOT PRR 833).
142	Ronnie Hoeinghaus - Garland Power & Light	Yes	This complex portion of the variance is completely outside both the scope of the FERC Order and ERCOT Protocol Section 5. Unnecessary complexity that forces unnecessary expenditures does not enhance the reliability of the Bulk Electric System. Instead, it has the potential of forcing premature retirement of older, inefficient units that currently provide reliable sources of energy.	See response to Rick Terrill, Luminant, on Question 1, especially the last paragraph. Existing ERCOT Protocols and Operating Guides already require generating units/generating facilities to have an operating Governor. The Interconnection needs frequency response at all times of the year. When these older inefficient units are online, they are responsible for providing this reliability service under existing Protocols and under the draft standard.
150	Ivan Kush - Calpine	Yes	As mentioned previously if we're not 100% certain that all units can handle this pause should be taken until further testing is conducted or information is gathered from OEM's. Also this question is rather ambiguous to me. It implies that we could/should in theory have a droop that is even less than 5%. What is the EXACT time period with which a unit must respond to a given disturbance? While I take no issue with the concept, implementation, verification and regulation will probably require the creation of an entire organization. For large asset owners within the region this could mean a large financial burden on their behalf trying to arrange for resources to communicate this	The team agrees that field testing of all types of generating units/generating facilities needs to be done. We are working with the PDCWG and asking members to test these settings now on their units. Field trials will identify underlying issues as they arise. Anyone who has concerns about this is welcome to participate in the testing. Presently the PDCWG has several members who have set these changes in their generating units/generating facilities with very positive improvement in performance. This includes some modern combined cycle generating units/generating facilities. The exact time period of the standard measurement process is clearly identified in the supporting performance evaluation tool and within the attachments of the standard. The

			information to the BA. Reporting of any kind requires resources and $$, will larger generators be penalized financially by having to spend increased $$ to meet reporting requirements?	measurement process compares the pre-perturbation average output of the generating unit/generating facility to its post-perturbation output. The measurement periods are part of the definition for Frequency Measurable Event: post–perturbation: The 34-second period of time starting 20 seconds after t(0). pre-perturbation: The 16-second period of time before t(0). t(0): It is the time of the first observable change in Interconnection frequency at the beginning of a perturbation. The team does not agree that implementation, verification and regulation will require creation of an organization. All of the necessary data to evaluate every generating unit/generating facility's performance (wind resources aggregated) is already available at ERCOT and Texas RE. Once an evaluation process is developed, evaluating performance of each event can and will be automated.
			How often is reporting required?	Regarding how often reporting is required, if your question refers to droop and deadband settings and attainable performance, this information would be reported in the supporting documentation within this standard (performance evaluation tool) and updated only when the characteristics of a generating unit/generating facility have had significant changes.
			I also believe that while it means more work - all technologies should be classified separately in terms of their required response times. Combined cycle GT's 4%, ST 5% - a train shall have overall 4%. Simple cycle GT's ? / Large frame GT's ? / Nuclear units ? / Hydro units ? / Peaking gas turbines or small frame GT's ? etc...	The team believes that the performance evaluation tool, as part of the standard, gives ample opportunity for the generating unit/generating facility owner to identify expected performance for all generating unit/generating facility technologies. The evaluation process will measure performance for each of these types of generating units/generating facilities within the same time frame. The expected performance of each generating unit/generating facility technology can be adjusted based on their capabilities

			  Attachment 3 p1 discusses intentional dead band. After discussion with at least one OEM dead band is definitely intentional, as a matter of fact it's necessary. I again wish to recommend that this be formally evaluated with some of the major OEMs which are representatives of the population of assets within the region prior to committing to this standard. During peak there will be very little if any frequency response available by some generators it appears that this will be considered, but some OEM's technology may limit response even when the units aren't necessarily at "full load". Temperature controllers are sometimes in effect much earlier than a units "regular or nominal full load condition" how will this be accounted for without huge amounts of digging through historical information?	during this same measurement period. In response to the comment regarding Attachment 3, the team agrees that field testing of all types of generating units/generating facilities needs to be done. The team agrees that there is little if any Primary Frequency Response available (for low frequency deviations) for generating units/generating facilities operating at or near their full load. This supports the need to have Primary Frequency Response capability provided to the BA in real time for situational awareness. The BA needs sufficient information of the amount of Primary Frequency Response available to make decisions they deem necessary to maintain reliability. This standard does not require any generating unit/generating facility to provide Primary Frequency Response above its High Operating Limit that is identified by its generator owner/operator (for low frequency deviations). This standard gives the generating unit/ generating facility owner the opportunity to identify operating regions where Primary Frequency Response performance is not feasible. Keeping the High Operating Limit of each generating unit/generating facility accurate is already enforced in the current market through the updating of the resource plan, telemetering of High Operating Limit to ERCOT and submitting seasonal changes to the High Operating Limit through the portal.
170	Ken McIntyre - ERCOT ISO	Yes	Reducing the maximum allowable deadband will result in Resources, which are expected to provide with frequency response, to respond to a frequency	The team agrees with your comment, which shows that you think the draft standard will improve reliability.

			deviation sooner. Recent pilot efforts in this area by a market participant in the ERCOT Interconnection seems to indicate that the ERCOT frequency has a better performance around the 60Hz scheduled frequency with the narrower deadband. If Resources are capable of reducing their deadbands and still operate reliably, then it would appear this would help the ERCOT Interconnection frequency response, and reliability.	
182	Robert Kelly - Brazos Co-op	Yes	R7, R8 and Attachment 3 are ambiguous as these pertain to combined-cycle gas turbine ("CCGT") configurations. In the case of CCGT configurations combustion turbines ("CT's") should be required to provide 4% droop characteristic subject to the high emergency limits of the respective generator. However, ERCOT's systems implementations for the Nodal Market are such that the GOP (QSE) representing this generator will not be submitting an accurate limit for each individual CT but rather a plant composite capability. Steam turbines in CCGT configurations in many cases cannot provide any frequency response. Attachment 3, Part 2, Section 8 should be modified to address realistic limitations of CCGT configurations operating in modes where the combustion turbines are at maximum capability. Steam augmentation or duct burners should not be excluded from supplying Responsive Reserve Service ("RRS"). These operating modes can supply limited frequency response. To such degree that this response can be demonstrated, a proportionate amount of this capacity augmentation should be eligible for the	The team expects the CCGT owner to report a single expected Primary Frequency Response in real time based on the combined capabilities of each component. This aligns with the current Nodal Market design. The team believes that you will be able to use the performance evaluation tool for reporting and measuring Primary Frequency Response for a combined cycle facility and each of its components. Steam turbines in a CCGT configuration typically operate in a valves wide open mode and will not provide Primary Frequency Response to low frequency deviations. However, during severe high frequency situations, the Governor on these units should respond. This standard gives the generating unit/generating facility owner the opportunity to identify operating regions where Primary Frequency Response performance is not feasible.. The team agrees that the current Protocols are clear that RRS must be Primary Frequency Responsive. The generating unit/generating facility owner is required to identify expected frequency response for the full output of the generating unit/generating facility. In the region of duct burner or steam augmentation operation, the reported expected Primary Frequency Response should match expected performance.

			supply of RRS.	

Question 5	Can you identify anything that should be incorporated into this regional variance or identify other approaches that could be taken in drafting this variance?

Answers	Frequency
No	3 (1 with comments)
Yes	14 (14 with comments)
No opinion	1 (1 with comments)

ID	Commenter	Answer	Comment	Response
189	Nikolay Moutaftchiev - International Power America Services	No	1. On page 10, Lower VSL for R11 is performance bellow 0.55P.U. and above 0.45P.U. The spreadsheet calculates ?minimum expected MW change? as 0.75 P.U. What if the performance is bellow 0.75 on a certain event? Does it really matter as long as the 12 mo. rolling average is above 0.55? 2. What is the formula for calculating the ?expected MW change?? It can be deduced from the spreadsheet, but it will be better if it is included in the standard. 3. If a resource underperforms due to any legitimate reason, listed on pages 22 and 23, the event should not be included in the calculation of 12 mo. rolling average. This statement should be removed from the last sentence of item 1), page 22 and applied to all the items on pages 22 and 23.	1. Thank you for pointing out the discrepancy. This has been addressed in the new draft standard. As long as the 12 month rolling average is equal to .75 or above, this is considered meeting the requirement. 2. Based on your comment, the formulas have been moved to the requirements in the new draft of the standard. 3. The ability to exclude events has been included in the measures of the new draft.
205	Michael Sonnelitter - NextEra Energy Resources	No opinion	1) The cost of adding capability to existing units, if such added capability is determined and demonstrated to be required for good reliability, should not be imposed on GO/GOPs alone. Existing units were justified and constructed without these requirements, and if added costs are now required to increase capabilities, those costs should be shared by all stakeholders in the Bulk Electric System. 2) It seems like there could be a distinction	Existing ERCOT Protocols and Operating Guides already require generating units/generating facilities to have an operating Governor. This standard only requires a change in the deadband setting for digital and electronic Governors and the implementation of a straight line droop curve from the deadband. The drafting team is not aware of this being an extremely high cost implementation. If you have information counter to that, you may provide it to the team.

			between (a) having a wind generator move in the proper direction, based on frequency needs (thus performing satisfactorily given available wind resource) and (b) having a large CPS2 due to scheduling error (not enough wind resource).	The team assumes you are referring to SCPS2. The draft standard is targeting frequency response performance during frequency perturbation events on the system, which is distinct from a continuous measure for scheduling such as the SCPS2.
115	Jack Thormahlen - Lower Colorado River Authority	Yes	COMMENT #1 (Page 7 Measure 8) Requirement #7 applies to GO. Therefore, change Measure #8 from ?GOP? to ?GO?. Also correct the violation severity table for Requirement #7 on page 10 from ?GOP? to ?GO?. COMMENT #2 (Page 10 Table 2: Violation Severity Levels) Requirements #8 and #9 apply to GO, not GOP. Therefore, change ?Severe VSL? text from ?GOP? to ?GO?. COMMENT #3 (Page 21 Part 1: Governor deadband and droop settings) Hydro units need to be specifically addressed; therefore add changes: Governor Deadbands: Mechanical governors of steam or hydro turbine Generation Resources: Due to gear lash and movement of mechanical parts of a mechanical fly-ball governor on a steam or hydro turbine, it is common to observe frequency response deadband for small changes in frequency. This deadband, or range of no frequency response, shall be limited to less than +/-0.036 Hz (36 mHz). COMMENT #4 (Page 22 above ?Other Generation Resource?.?) Hydro units need to be specifically addressed; therefore add: Hydro Turbine: Droop settings of hydro turbines shall be 5% or lower. The 5% droop curve shall linearly add frequency response and attain the 5% droop curve characteristic when frequency deviation reaches +/-3.0 Hz. COMMENT #5 (Page 22-23 ?Part 2: Minimum performance ?..?) Hydro unit	1 & 2. Thank you for pointing out these discrepancies. This has been addressed in the current draft standard. 3, 4 & 5. The team agrees with your comments and the changes have been included in the tables of 3.1 and 3.2 in the current draft standard.

			performance needs to be addressed; therefore add: 9) Hydro unit frequency response may be affected by changes in lake levels, flood events, or when multiple units are operating simultaneously at one site. HSL may vary during these conditions.	
122	Rick Terrill - Luminant	Yes	Luminant believes the proper approach is to utilize only the exact requirements of approved Protocols, as directed by the FERC Order. Luminant is willing to assist in this effort if desired by the drafting team.	Please refer to the response to your comment on Question 1. The last paragraph specifically addresses this issue.
127	Randy Jones - Calpine	Yes	Effective governor response from all ERCOT generating machines is impossible to achieve due to the current market design. We have no capacity market or mechanism that holds back capacity for delivery under frequency events other than from the fleet providers of RRS and REG. The market design ("Energy-Only") incents all other machines that are in the money to be producing energy at the very top of their capabilities ("baseloaded"). This alignment of incentives is contrarian to the view that all machines should have "room at the top" to provide effective inertia in times of frequency deviation. Essentially, governor response from machines not participating in the provision of RRS or REG is unenforcable since the market needs all their energy and rarely needs capacity held response. In order to further improve the system's frequency response some form of "Governor Response Service" must be instituted. It is not practical and likely not lawful to require individual units that do not get paid for capacity to hold back capacity, particularly during light loading conditions. The concept of a Governor Response Service has been promoted in the past by many market participants and by consultants versed in the ERCOT market design. The proposed tightening of the governor deadband in this Draft Standard is testimony to the fact that a correction in the market's design relative to governor	This standard does not require a change in market design or for anyone to hold back capacity or “room at the top” for frequency response. It only requires generating units/generating facilities to have an operating Governor within the normal operating range of the generating unit/generating facility and to provide the expected droop performance information to ERCOT. The team disagrees that machines not participating in RRS or REG are not obligated to have Governors in service and that Governor response performance is not enforceable. If your concern is measuring performance when generating units/generating facilities are operating at near-maximum output, it was never the intent of the standard to require you to hold back capacity; the performance evaluation tool uses a 2% minimum spinning reserve for evaluation. Generating units/generating facilities operating above 98% of their HSL will not be evaluated. While the drafting team understands your concerns with the economic issues, it is outside our scope to address these issues in drafting this standard.

			response is needed. A market of the service is the likely solution.	
140	Kenneth Brown - PSEG Texas	Yes	R7: Attachment 3 says a ?limiting curve? shall be required. However this is not specifically stated in R7. Is it required? Can you provide a sample ?limiting curve? with creation methodology? It is our understanding that this shall be created and reported initially, then revised only if a design change which affects the response is implemented. Is that correct? R8: In some units, the droop characteristic is overridden (not active) when the unit is in MW/Load control. Is this condition acceptable when in MW/load control on these units? A 5% droop setting for a combined cycle steam turbine is not feasible. During the 3/31 Technical Workshop, it was stated the 5% only applied to non-combined cycle Steam turbines, and did not apply to combined cycle steam turbines. Will this clarification be incorporated into the standard? R10: It is our assumption that if our unit is operating at full load when there is an event, ERCOT will not penalize us for not being able to pick up additional load. Is that correct? R11: Is the intent here that the ?spreadsheet calculator? shall be used	Response R7: The purpose of the limiting curve is to provide the GO an opportunity to define the expected frequency response performance of his generating unit/generating facility within the measurement period. This limiting curve may be as complex or as simple as necessary to define the expected performance. Sample curves in the spreadsheet attachments are provided for you use. These curves are based on operating experience with the specific generating units/generating facilities in the given examples. The limiting curve is not required in the performance measurement tool and can easily be turned off. With the limiting curve turned off, the performance evaluation tool would use only the droop setting and the deadband setting in calculating the minimum expected performance. Your understanding is correct as to the initial development and revision of this curve. Response R8: No. The MW/Load control function should include the droop characteristic curve. The droop characteristic should <u>not</u> be overridden. The steam turbine of a combined cycle configuration should have a droop setting of 5% and the appropriate deadband; however, performance of this steam turbine will not be evaluated by this standard. Response R10: Yes. No generating unit/generating facility operating at HSL is expected to perform for underfrequency; however, it should perform for overfrequency. Response R11: Yes.

			each time there is a ?Measurable Event? and that they should be averaged for a 12-month window? M10: What is meant by ??the GO shall have evidence?was not visually observed.?? What is the intent of this measurement? What type of ?evidence? would satisfy this measurement? Comment on potential conflict ERCOT Protocols Section 5 doesn't allow frequency response to be sustained and until the language in these Protocols is revised to allow for such, Market Participants will find themselves in violation as soon as this new Standard is approved.	Response M10: During a measureable event, the generating unit/generating facility should sustain its frequency response proportional to the frequency deviation. This includes the period during frequency recovery until frequency returned to the allowable deadband. The performance evaluation tool, in the measurement of sustained response, accounts for pre-event ramping direction and for the ramping during the recovery period. Response to potential conflict: The team disagrees with the suggestion that the Protocols do not allow sustained frequency response. The section of Protocol 5.9.2 regarding "B Point Plus Thirty Seconds" reads: "At thirty seconds following the B Point, an analysis will be performed by ERCOT with the assistance of the appropriate ERCOT subcommittee to determine if primary frequency control response is sustained." For any conflicts that do exist between this standard and the Protocols, the implementation plan associated with this standard allows time for such conflicts to be addressed and aligned.
147	Clif Lange - South Texas Electric Co-op	Yes	R6. This requirement refers to an aggregation at a single point of interconnection into a single Generation Resource those Generation Resources whose capacity is less than 10 MW. Q1. Would a combination of online and offline unit capacities skew the expected response measurement? Q2. Would only the aggregate capacity of those units which have an online status be utilized for response measurement? R8. STEC agrees with Calpine?s	R6 Response Q1: Yes, the combination of online and offline capabilities would skew the expected response measurement. The generation owner should calculate the expected response based on the unit capacities of only the online generating unit/generating facility. R6 Response Q2: Yes, only the capacity of the online generating units/generating facilities should be included in the response measurement. R8 Response: The steam turbine of a combined

			comments on this requirement that rewording must occur in order to capture the intent stated at the workshop that a steam turbine?s response would be ignored if configured as part of a CC train. R9. & R10. For the sake of clarity, there is no reason to list the deadbands that would be required of the GO in a separate document. Unless the separate document is intended to be a ?living document? where changes can be made readily (we suspect it is not) then the deadband requirements should be listed as sub-requirements (ie. 9.1, 9.2, etc.) for better clarity. R10. This requirement holds the GO and GOP responsible for sustaining governor response to all frequency deviations which exceed a unit?s governor deadband. 1. How much effect does the GOP necessarily have on the sustaining of governor response by a generator? Should the GOP requirement be struck and this requirement is made applicable to the GO only? As written, this could potentially result in an entity being fined twice (double dipped) for the same offense if the entity is both the GO and GOP. Likewise, if contractually a fine levied on a GOP for an offense committed by the GO were passed on to the GO, an offense would presumably result in a double fine to the GO. 2. STEC assumes that this requirement is in place specifically to apply to frequency perturbations and the measurement of such. If this requirement is for perturbations alone then STEC agrees with the Calpine comments that this requirement can not be left open ended and that the language should be modified to reflect some sort of time parameters and that this requirement applies to perturbations. If this requirement	cycle configuration should have a droop setting of 5% and the appropriate deadband; however, performance of this steam turbine will not be evaluated by this standard. R9 & R10 – The attachments are part of the standard, but based on other commenters concerns, the team has moved any “must” and “shall” language into the requirements section of the Standard itself for more clarity. R10 #1 – The applicability of this standard no longer applies to GOP. R10 #2 - Except for protection of equipment or safety, the GO will sustain its Governor response to all frequency deviations that exceed the deadbands stated in Table 3.1. The team has defined Frequency Measurable Events in the standard and provided a performance evaluation tool for evaluating performance. The requirement for GOP has been removed from the current draft of the standard. There is no requirement for GOs to

			is intended to apply to both perturbations and normal intra-hour frequency swings, then a tracking and documentation nightmare is potentially created. If taken to the literal intent, then the GO and GOP would be required to analyze every frequency deviation greater than 60.0167 Hz and less than 59.9833 Hz and determine whether each unit responded accordingly, document the findings, and self-report violations to the TRE. This would be a cumbersome process not only for GOs and GOPs but for the TRE as well who would be responsible for sorting through mountains of data as a result of normal ?noise? on the system. R11. This requirement is concerned with the GO and GOP meeting a rolling 12 month average frequency response performance criteria. 1. Should this requirement be applicable to GOPs for the same reasons cited above in R10. 1? 2. Should units with low capacity factors be subject to this requirement or should some threshold be established for a minimum number of events that the unit was online for? Units that are online for only a handful of the targeted 30 ? 40 measurable events per year might not receive a statistically accurate measurement of their response to frequency events. Should a threshold of being online during some number of events be established to provide some meaningful measurement? (ie. 25% of measurable events) Attachment 3. 1. In constructing a limiting parameter curve or a list of limiting parameters, how are limits handled that change on a	analyze every frequency deviation, only identified Frequency Measurable Events will be evaluated. R11 #1 - The applicability to the GOP has been removed from the current draft. R11 #2 – The team agrees and has set a minimum of eight events for evaluation. Att 3 #1 – The limiting factor parameter can be as sophisticated as necessary to properly model the expected frequency response of the

			seasonal, daily, or minute by minute basis handled? For example, chillers, foggers, spray intercooling, etc. are often times temperature dependent and the point at which they are effective or come into service changes with the current weather conditions. 2. In the workshop, it was discussed that post-event defenses could be brought forth to the TRE to explain a lack of response. This concept does not appear to be captured in the Attachment 3. This would seem to be a necessary addition to give GOs and GOPs the opportunity to explain instances where governor response was not at the desired level due to unforeseen events. Ie. unknown mechanical problems, change in fuel, ambient conditions, etc. 3. STEC agrees with LCRA?s comments regarding hydro units and language needed to address their unique characteristics. In addition, provisions need to be put into place to address governor response from hydro units operating in synchronous condensor mode and NOT providing hydro responsive or quick start capability. These units should not be required to provide frequency response in these instances nor should they be measured.	generating unit/generating facility for its full operating range. The standard does not require generating units/generating facilities to perform above their HSL, and as long as the GO communicates that appropriately, these current operating conditions should be accounted for. Att 3 #2 – The SDT agrees and has included exclusion provisions in the Measures section of the standard. Att 3 #3 – Generating units/generating facilities that are operating in synchronous condenser mode (providing reactive power only) are exempt from Standard BAL-001-TRE-01 per the applicability section of the current draft.
151	Ivan Kush - Calpine	Yes	As stated by others there are certain generators that not be able to comply fully with these new reccomendations, because of this other generators whose assets can respond will be forced into a continuous supply situation during an event. If these assets are engaged in other supporting roles then those might be affected forcing the operator into other difficulties.	Generating units/generating facilities that are operating in synchronous condenser mode (providing reactive power only) are exempt from Standard BAL-001-TRE-01 per the applicability section of the current draft.
152	Ronnie Hoeinghaus - Garland Power & Light	Yes	This variance should follow the scope of FERC ORDER 693 which was to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained	FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a standard. FERC Order 693 states: “As with other new regional differences, the Commission expects that the

			in section 5 of the ERCOT Protocols. This variance should not redesign protocols or operating guides or impose requirements upon registered entities that are outside of ERCOT Protocol Section 5. Comments on Proposed Standard as written that are outside of the Posted Questions: Note: These comments were written in Word and all formatting was lost when they were transferred to this document - many characters show up as "?" - have attempted to correct & reformat to where they seem somewhat organized	ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections", (P 315). Order 693 further provides that a regional standard, and more specifically, a regional variance, is necessary due to ERCOT's physical difference as a single Balancing Authority Interconnection. In order to fit Protocol 5.9 into reliability standard format, requirements must be written for registered entities to include Generator Owners and the Balancing Authority. The team agrees that this draft standard exceeds Order 693 through improved implementation of Protocol 5.9. See response to Rick Terrill Thad Ness for Question 1 for the reasons for improving upon 5.9.
			***** Comment on Standard Structure BAL-001-TRE-1 has both attachments and Excel spreadsheets that are intended to be part of the standard (as stated during the BAL-001-TRE-1 Workshop). These attachments are several pages in number and have statements using "shall" or "must" making them a requirement that has to be met. The use of this existing structure or format makes knowing exactly what is an auditable requirement and the extent of that requirement both difficult & confusing. Recommendation - All auditable requirements should be clearly stated in the requirement section. **** Comments on Requirement R7 Requirement Language - The GO shall report to ERCOT the operating range, performance level, and any parameter limiting the frequency response of each Generation Resource/Frequency Responsive Resource. See Attachment 3 for these parameters.	Response on Standard Structure: The attachments define the details of the standard requirements and measures. The current draft standard has been rewritten to clarify the requirements and provide more details within the requirements.
			** Comment R7 - #1 The requirement uses the phrase "and any parameter limiting the	Response on R7, #1: This issue has been addressed in the new draft of the standard. R7

			frequency response..." The word "any" above would have to be interpreted as "all" parameters (based on dictionary definition but more importantly based on Violation Severity Levels which determine penalty amounts). Section 2 (page 10) Violation Severity Levels lists R7 as having the following table selections: High VSL - Penalty range per the NERC Base Matrix Penalty Table is from $3,000 to $625,000 per day depending on the Violation Risk Factor. Reason listed - GOP does not have evidence that it reported to the BA most of its... expected frequency response.. What does "most" mean to an auditor? Also, Please Note: This is a GO requirement, not a GOP - GOP should not be listed Severe VSL - Penalty range per the NERC Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on the Violation Risk Factor. Reason listed - GOP does not have evidence that it reported to the BA any of its... Please Note: This is a GO requirement, not a GOP - GOP should not be listed	has been removed and the requirements are now part of R2. Concerning the dollar penalties you mention, the team assumes you are referring to the NERC Base Matrix Penalty Table in the NERC Rules of Procedure. The matrix gives a range of penalty values, but there are many factors considered before a final penalty is determined. These other factors are also included in the NERC Rules of Procedure. R7 has been removed and the requirements are now part of R2. The term “most” has been removed from the requirement and the GOP applicability has been removed from the standard.
			** Comment R7 - #2 Frequency Response of a Generation Resource is a combination of boiler control / boiler response and turbine governor response. In real time operation, parameters limiting this response can change minute to minute from changes in fuel quality/supply conditions, ambient temperature, boiler conditions, boiler process equipment condition, and process controls - just to name a few but certainly not a complete list. Even certain parameters that are generally accepted to be fairly stable or constant are required to be telemetered to ERCOT BECAUSE THEY CHANGE. It is impossible to report to ERCOT all the parameters / conditions that can affect frequency response.	Response R7, #2: The team understands your concern, but there is a buffer in the standard to account for this and limit the number of parameters. The performance level for each generating unit/generating facility is already adjusted for actual expected performance. The minimum performance level of 75% combined with the 12-month rolling average should minimize the effects of momentary control issues on the generating unit/generating facility. Also included in the measures section of the standard is the ability to provide documented information that would exclude certain events and conditions from the performance measure.

			** Comment R7- Attachment 3, Part 2, 1) The last sentence states "If frequency response is visually apparent during these ramps and the direction of the ramp causes the measurement of the frequency response to be below the minimum performance level, the Event may be removed from the Generation Resource/Frequency Responsive Resources' 12 month rolling average performance measure." What does the term "visually apparent" mean, to whom is it supposed to be "visually apparent", and how will an auditor interpret "visually apparent"? ** Comment R7- Attachment 3, Part 2, 2) Attachment 3, Part 2, 2) discusses initial steam pressure drop following large frequency disturbances and that the GO may provide a parameter curve to be added to the spreadsheet that accounts for this stored energy limitation. In addition, still in attachment 3, on page 26 the phrase "is required for the evaluation" followed by a list of items that includes "limited stored energy". On page 27, it states "The Generator Owner must develop the "limiting parameter" curve for each Generation Resource..." and then states "This limiting parameter curve must be technically justifiable." There are also references to "reduced mass flow" as part of this parameter curve - Comments follow: This information is not common, readily attainable information. It will require an engineering study to be performed either taking up an in-house engineer's time or require hiring a consultant. What possible benefit is there to BES Reliability to require the GO's to spend this money? It appears it's only use is to provide input into a spreadsheet for a calculation - Calculation approach should not require O&M resources to be required to be spent just to	Response R7-Attachment 3, Part 2, 1): The team agrees that the term “visually apparent” is vague and requires clarification. This requirement has been removed from the new draft. The twelve-month rolling average performance measure will capture sustainability. Response R7-Attach. 3, Part 2, 2): The team thinks this is straightforward and will not require an engineering study. Through observation of the generating unit/generating facility’s performance to an actual event, performance can be evaluated. From this performance, a baseline for each generating unit/generating facility can be developed. Indeed, an engineer will need to look at this in order to properly define expected performance. Many companies have similarly designed units, and the study can be done on one unit and applied to other similar units, thus minimizing time and cost. Yes, one value (limiting factor) controls the sensitivity of the affects of throttle pressure variation during the initial moments of a frequency event. However, other factors are included in this calculation: 1) The effects of steam expansion based on the percent the inlet steam valves are open will impact the expected performance. 2) The percent the initial inlet pressure is of rated pressure (for variable pressure units) will impact the expected initial performance. This same parameter is also used for combustion turbine mass flow change due to speed change of the turbine. In this case the limiting factor value is a function of the turbine size so its effect will vary based on the

			support calculation. The manager at one of our generating plants likened this requirement to driving his car down the road. If he takes his foot off the gas, the car does not stop but keeps going because of stored energy. Everyone knows that the car has stored energy but drivers knowing the "technically justifiable" curve representing this stored energy throughout the car's range of speed is another matter. The term "parameter curve" is used to describe this information. Totally agree that it should be a curve because stored energy amounts would changed up and down the unit output range. HOWEVER, in the spreadsheet, I can only find 1 data point for this information - not a curve but one value. Unless I am mistaken and I could be, the spreadsheet is setup for one value only - not a curve. It would seem that "is required" & "must develop" and "technically justifiable" make this an auditable requirement - certainly should show up in the Requirement text - not over 2 or 3 pages in attachment and is also inconsistent with the 1st reference where it states "may"	MW capacity of the generator. Each of these values can be tuned to fit each individual unit. The SDT members have found that one value works for all sizes of combustion turbines since how the value is used in the evaluation is a function of the generator size. The value for steam turbines also has a very small range (0.2 to 0.5) for steam turbines in the range of 120 MW to 900 MW. Once the governor is performing properly during actual frequency events, the “Target Performance” trend can be used to tune these settings to model the performance of the generating unit/generating facility which will result in a baseline for these settings. The GO can make the curve as sophisticated as necessary to model the generating unit/generating facility’s performance. The example in the spreadsheet uses the single linear curve to account for throttle pressure decay during the first few seconds of a Measureable Event. This limiting curve value is further modified by the steam inlet valve position of the turbine, since the inlet valve position impacts the sensitivity of the pressure decay. The expected performance is further adjusted based on the actual throttle pressure at the time of the event as a percent of rated pressure of the turbine. This last factor is simply a “percent of rated pressure” multiplier on the expected performance and will not require an engineering study. The curve that adjusts for the percent inlet valve position is also a fixed curve that should work for all steam turbines. The only need here is to know the approximate turbine valve position at the time of the event. This should be known on most steam turbines where it is a function of throttle pressure and load. A simple curve (IF function) can do this approximation. The spreadsheet does not attempt to calculate “stored energy” of a generating unit. It only attempts to model the delivery of Primary Frequency Response during the first 50 seconds of an event by adjusting the

				expected performance to an achievable value for the unit. The only term that needs adjusting is the single factor that has a typical range of values from 0 (zero) to 0.500. The higher value represents lower stored energy and a reduced expected performance. A frequency response filter constant has been added to the measure of sustained Primary Frequency Response to model the delivery of Primary Frequency Response over time. This constant can be tuned on an individual generating unit/generating facility basis for the normal operating characteristics of the unit. The typical range of values for steam turbines has been found to range from 0.100 to 0.200 and from 0.200 to 0.400 for combustion turbines. By observing the “Target” trend on the “Performance” spreadsheet, one can adjust the filter constant to get the “Target” to have the same sensitivity as the actual generation. Changing the value and observing the effects of the “Target” will result in finding the best value for the “Target” to follow the actual MW output of the unit. This does require that the generating unit not withdraw Primary Frequency Response early. It must be withdrawn proportional to the frequency deviation to meet the standard. The current draft of the standard has been rewritten to clarify the requirements and provide more details within the requirements.
			** Comment R7- Attachment 3, Part 2, 4) Attachment 3, part 2, 4) gives a scenario about shifts in site auxiliary load assignment and then states "In this scenario Gross megawatt values for Generation Resource/Frequency Responsive Resource output and Gross High Operating Limit may be used for the evaluation of the frequency response measurement..." To my knowledge, Gross High Operating Limit is	Response R7, Attach. 3, Part 2, 4): In these special cases, the scan rate data would have to be data that is collected at least every four seconds by the GO and provided to ERCOT and the TRE.

			not telemetered to ERCOT - Where / how are you going to obtain this scan rate data?	
			** Comment R7- Attachment 3, Part 2, 5) Attachment 3, part 2, 5) discusses impacts to frequency response due to auxiliary equipment being in or out of service as the unit moves through it's output range. It then states "The Generation Owner shall document this limitation on each occurrence during a Measurable Event." Comments follow:	Response R7, Attach. 3, Part 2, 5): The team agrees that GOs should keep logs of major pieces of equipment that can limit response during a Frequency Measurable Event. These records should be a part of normal operating logs maintained as a part of daily operations.
			A generating unit operator will not have any idea whether a frequency disturbance has been declared a "Measurable Event" regardless of whether he/she is taking an auxiliary piece of equipment in or out of service or not. In reality, the operator will be focused on getting the equipment in or out of service smoothly and may not even be aware a frequency disturbance has occurred. Auxiliary equipment being place in service or taken out of service is part of the normal operation of the generating unit and will occur every time the unit cycles. In addition, lignite or coal unit have bowl mills & feeders which are smaller auxiliaries than pumps or fans - but still auxiliaries.	Once the standard is approved, a PRR should be initiated to require the BA to post Frequency Measurable Event information for accessibility.
			In real life at the generating unit, the unit operator will have to document every occurrence to be sure that one is not missed? What is the generating unit supposed to do with this documentation? Send it to ERCOT? What is the path to ensure the data is distributed to the BA & the TRE? What possible benefit is there to Bulk	The draft standard has been restructured to provide that the tracking, documentation and communication requirements are the responsibility of the BA. The GO has responsibilities for Governor setting and Primary Frequency Response performance.

			Electric System Reliability to require the GO's to spend O&M time and money to document, correlate with frequency disturbances, & maintain documentation for NORMAL, EVERYDAY OPERATIONAL EVENTS - NOTHING BROKEN OR ABNORMAL? "The Generation Owner shall document..." makes this another auditable requirement - should be listed in the Requirement text - not stated in somewhere in an attachment ** Comment R7- Attachment 3, Part 2, 7) & 8) Not entirely sure what this referring to but maybe part of it is sliding pressure on the low operating range for 7) and the upper range for 8) - These comments will apply to sliding pressure operation whether that was the intent of 7) & 8) or not. Sliding pressure is not a constant operational mode - the unit could be operating in a sliding pressure mode part of the day at a given load range and not be in sliding pressure mode at that same load range the rest of the day - it can change intra-day, day to day, week to week. It depends on the GO's fleet operational configuration for it's obligations followed by it's economic loading Units operating in sliding pressure are not going to provide frequency response per a 5% droop curve - nothing is broken or abnormal, it is an economic operation Defining and documenting these ranges and reporting them to ERCOT serves no real purpose for the spreadsheet calculations as the status of sliding pressure operation yes / no will be unknown Both 7) & 8) contain statements "The Generator Owner shall identify and document..." making both auditable	 The team moved any “must” and “shall” language from the attachments into the requirement section of the Standard itself for more clarity. Response R7, Attach 3, Part 2 7) and 8): R7 has been removed and the requirements are now in R2. The performance evaluation tool (Attachment 2 of current draft) adjusts for variable pressure operation. GOs would need to input appropriate information into the performance evaluation tool. The team moved any “must” and “shall” language from the attachments into the requirement section of the standard itself for

			requirements. These both should be listed in the Requirement text - not stated in somewhere in an attachment ** Comment R7- Attachment 3 Overall Attachment 3, Part 2 is not an all inclusive list. If the parameter or operating condition is not listed in the list that was reported to the BA (ERCOT) as a reason for reduced frequency response or is not in Attachment 3, Part 2, will an auditor allow that parameter / condition to be used to remove a response from the calculations for a real time event? ** Comment R7 - #3 The requirement says to report the operating range, performance level, and any parameter limiting... What is meant by "performance level"? Operating range is clear and the any parameter limiting is discussed above but what does "performance level" mean? What would it take to demonstrate compliance with an auditor? **** Comments on Requirement R8 Requirement Language - The GO shall ensure that combustion turbines in a combined cycle configuration have a governor droop characteristic of 4%, steam turbines have a governor droop characteristic of 5%, and that all other Generation Resources/Frequency Responsive Resources have a governor droop characteristic of 5% or less. See Attachment 3 for these characteristics. ** Comment R8 - #1 The requirement uses the term "shall ensure" and the terms in Attachment 3 use the terms "shall be" at the 4% or 5% droop requirement or lower. These terms make it clear that a governor cannot have a droop characteristic > than the 4% or 5% without being in violation of this standard. While this may be fairly	more clarity. Response R7, Attach. 3, Overall: If the limiting parameter can be identified, justified and reported, then that parameter will be allowed. Response R7, #3: The term “performance level” has been removed from the requirement. The performance evaluation tool defines the expected performance level for specific Frequency Measurable Events. The measures identify methods for demonstrating compliance. Response R8, #1: R8 has been removed from the current draft and the settings requirements are now in R3. In the current draft, some flexibility has been given to droop and deadband settings. The Lower VSL for R3 states, “Any Governor parameter setting >10% and ≤20% outside setting range specified in R3”.

			simple to set with a digital governor control system, it could easily require a very expensive complete governor overhaul (and associated unit outage) for a mechanical governor even if it tests out at 5.5% or 6% or anywhere near but greater than 5%. Violation Severity Level - Severe VSL (page 10) states that you have to evidence that the droop settings were set at 4% or 5% (Base Penalty Matrix shows penalties range from $5,000 to $1,000,000 per day) GOs in this situation with older, low capacity factor units are now potentially faced with the choice of retiring the units if they cannot justify the O&M costs (would take an additional study (costs O&M $) to make the determination) even though the unit provides a stable source of energy to the BES. There are not any Working Group reports before ROS or TAC detailing any reliability issues dealing with governor droop settings. ERCOT Operating Guide Section 2.2.5 states "Every effort should be made to maintain governors droop characteristic not to exceed 5%" and Operating Guide Section 6.2 gives typical examples of tests for both steam & combustion turbines along with droop calculations & answers. Steam Turbine example results are 7.78% and 8.06%. Combustion Turbine examples are 6.25% & 5% (which is adjusted to 4.16%). Please note that none of the typical examples in the Operating Guides for a steam or combustion turbine would pass an audit by this standard & would require O&M expenses or perhaps retirement if an older, low capacity factor unit. If there is not a BES Reliability Issue concerning droop identified and before ROS or TAC, why should there be a requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for	As you point out, mechanical Governors that test at droop performance at higher than 5% are not presently meeting current ERCOT Protocol requirements. This standard will not require any additional Governor overhaul. This standard makes it more clear when an adjustment to a mechanical Governor will be necessary, thus improving BES reliability overall. It is the team's belief that this is an adjustment to the Governor, not necessarily an overhaul. The Interconnection needs frequency response 24/7 for reliable operation of the BES. Over the past two years, the Performance Disturbance Compliance Working Group (PDCWG) has identified reliability issues associated with the implementation of deadbands pursuant to Protocol Section 5.9. In order to meet the performance requirements of 5.9, generating units/generating facilities were encouraged to achieve near 5% droop during measurable events. This requirement resulted in generating units/generating facilities "stepping into" the 5% droop curve once the deadband had been crossed. This resulted in an irregular Interconnection frequency profile that could not achieve a normal probability distribution. This identified additional instability issues that will exist during islanding events. This standard addresses these reliability issues by clearly defining deadband and droop implementation on generating units/generating facilities. This standard also addresses the measurement of frequency response of generating units/generating facilities by accounting for their deadband and droop settings. The team would also like to point out that the examples in the

			compliance reasons?	ERCOT Operating Guides are just examples and may not represent actual compliant performance.
			** Comment R8 - #2 Violation Severity Levels specified for R8 - page 10 The Lower, Moderate, & High VSL set the penalty range based on dated test forms longer than 2, 3, & 4 years. There are no specified time frames for tests or filling out test forms anywhere in this standard - how can there be penalties based on time frames when none are specified in the requirement? Severe VSL (penalty range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor) states "The GOP does not have evidence that the governor droop characteristics were set per Attachment 3" - This is a GO requirement, not a GOP requirement. Also, evidence should be for something stated in requirement - not something stated in an attachment.	Response R8 - #2: R8 has been removed from the current draft and the settings requirements are now in R3. The testing interval as stated in the current ERCOT Operating Guide (every two years) is adequate proof for this requirement. The VSL issue has been corrected in the current draft standard. GOP has been removed from the applicability.
			**** Comments on Requirement R9 Requirement Language - Each GO shall limit governor deadbands, intentional and unintentional, of turbine governors to those stated in Attachment 3.	
			** Comment R9 - #1 Requirements should be stated in the requirement - not in an attachment.	Response R9 #1 – R9 has been deleted and requirements are in R3 in the current draft standard. The team moved any "must" and "shall" language from the attachments into the requirement section of the standard itself for more clarity.
			** Comment R9 - #2 Mechanical Governors Attachment 3 states that mechanical governor's deadbands "shall be limited to less than +/- 0.036 Hz". Measures M9 for compliance evidence states that the "GO shall have evidence..." "governor deadband is set in accordance to the limits in Attachment 3". Violation Severity Levels (Page 10) - Severe Level - "The GOP does	Response R9 #2 – The GOP has been removed from the applicability in the current draft standard. Mechanical Governors can be maintained to respond to frequency deviations well below +/- 0.036 Hz as required by the standard. It is the team's belief that this is an adjustment to the Governor, not necessarily an

			not have evidence that the governor deadband limits were set per Attachment 3" (Severe Level penalty range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor) THERE IS NO WAY TO SET a mechanical governor deadband - it is a function of mechanical component movements and wear & tear. By requirement design, a GO with a mechanical governor will be out of compliance. At the workshop when this was brought up, it was stated that the GO could analyze unit response while the unit was on line to determine the deadband. Note: this study may identify where the deadband is but it is not setting the deadband. If by some study the deadband is determined to be +/- 0.036 Hz or greater (attachment 3 says shall be less than +/- 0.036), the GO is now faced with an expensive governor overhaul and associated unit outage or maybe the choice of having to retire the unit if an older, low capacity factor unit. If there is not a Bulk Electric System Reliability Issue concerning these deadbands identified and brought before ROS or TAC, why should there be a requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons.	overhaul. The drafting team does not expect that this standard will have an extremely high implementation cost.
			** Comment R9 - #3 In Attachment 3, it states the frequency response characteristic shall not "step-into" the 5% droop curve or the 4% droop curve. The term "shall not" makes this an auditable requirement. Depending on the governor design, this may or may not be possible to comply with without a major design change on the part of the GO. If there is not a BES Reliability Issue concerning these deadbands identified and brought before ROS or TAC, why should there be a	Response R9 #3 - Over the past two years, the Performance Disturbance Compliance Working Group (PDCWG) has identified reliability issues associated with the implementation of deadbands in Protocol Section 5.9. In order to meet the performance requirements of 5.9, generating units/generating facilities were encouraged to achieve near 5% droop during measurable events. This requirement resulted in generating units/generating facilities "stepping into" the 5% droop curve once the deadband had been crossed. This practice resulted in an

			requirement potentially forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons.	irregular Interconnection frequency profile that could not achieve a normal probability distribution. PDCWG identified additional instability issues that will exist during islanding events. This draft standard addresses these reliability issues by clearly defining deadband and droop implementation on generating units/generating facilities. This standard also addresses the measurement of frequency response of generating units/generating facilities by accounting for their deadband and droop settings.
			** Comment R9 - #4 Violation Severity Levels list GOP as the penalized entity - this is a GO requirement - not a GOP.	Response R9 #4 - This issue has been corrected as GOP has been removed from the applicability of this standard.
			**** Comments on Requirement R10 Requirement Language - Except for protection of equipment or safety, the GO and GOP will sustain its governor response to all frequency deviations that exceed the deadbands stated in Attachment 3. Note: it says "all frequency deviations that exceed the deadbands..." Violation Severity Levels - Severe VSL Penalty (range per the Base Matrix Penalty Table is from $5,000 to $1,000,000 per day depending on Violation Risk Factor) based on statement that GO or GOP applied control action to reduce or withdraw frequency response of a Generation Resource / Frequency Responsive Resource that exceeded the allowable deadbands as stated in Attachment 3. It is normal for frequency to move outside the 0.01667 deadband or the "less than" +/- 0.036 Hz deadbands multiple times every hour of everyday! Some examples causing this are from load ramps, schedules being ramped in or out at different times by QSE's, units being brought on or off line, QSE fleet economic dispatch, SCE control, etc. The increment of MW response is very small on a unit when frequency moves outside the	Response R10 – Generating unit/generating facilities will be evaluated on measurable events based on expected frequency response performance defined by the GO. The performance evaluation tool accounts for the deadband of the generating unit/generating facility. If improperly set, the unit will have difficulty meeting the standard through the measures. The twelve-month rolling average performance measure will capture sustainability. The sustainability measure accounts for pre-event and post-event ramping. Requirements that were in Attachment 3 have been moved into the current draft of the standard, and the measures describe how to provide evidence for meeting compliance.

			deadband due to one of the above reasons. There are a many reasons why a GO unit control action or a GOP EMS control action may be in place that would be larger than this small increment resulting in the control action "overcoming" the frequency response component (not an all inclusive list) - Unit being ramped on or off line, Unit being manually loaded to a different level, QSE SCE control resulting from: Schedules ramping, Economic Dispatch resulting redispatch of fleet for economics, Ramping of balancing deployment Note: During the workshop, ramping was brought up as creating a potential issue for this requirement. The drafting team responded that Attachment 3 provided an exception for ramping. Attachment 3 does not provide an exception for ramping - it states that measurement is more difficult during ramping and then states "All Generation Resource/Frequency Responsive Resources shall be responsive to all frequency deviations exceeding the governor deadband while ramping." Because of the above reasons, this requirement is IMPOSSIBLE TO COMPLY with and can result in multiple self reports DAILY of violations IF an entity was to continually analyze a unit output versus the unit governor's deadband. ** Comments on Measure for M10 Measures M10. "The GO and GOP shall have evidence that premature frequency response withdrawal by the Generation Resource/Frequency Responsive Resource was not visually observed." What does the term "was not visually observed" mean for evidence and audit purposes? ** Comment on Data required for Calculation Requirement R2 states a list of data that will be captured for each	 Response M10 – This measure has been removed from the new draft. The team agrees that the term "not visually observed" is vague and has developed a different measure to address performance expectations during ramping. The twelve-month rolling average performance measure will assess sustainability. Response Data for R2: Requirements R1 and R2 in the current draft of the standard describe how the data is collected and communicated to

			Measurable Event and submitted to TRE within 30 days of the event. Where will the TRE get the data to do the calculations for this requirement of monitoring all frequency deviations outside the deadband if they are only given the data captured by requirement R2? When this question was asked at the BAL-001-TRE-1 workshop, it was stated by 2 members of the PDCWG that they can see this data. Is there some plan for the PDCWG to do the compliance monitoring for the BA & TRE? **** Comments on Requirement R11 Requirement Language - The GO and GOP will meet a minimum twelve-month rolling average frequency response performance on each Generation Resource/Frequency Responsive Resource as stated in Attachment 3. See chart of Figure 4: Expected Resource Performance and associated spreadsheet. Meaurement Language - Measures M11. States the GO and GOP shall have evidence that within the Measurable Event report, the twelve-month rolling average per unit frequency response performance of each Generation Resource/Frequency Responsive Resource met the minimum performance as stated in Attachment 3.	Texas RE. Texas RE has the resources available to evaluate this measure and Texas RE is the compliance monitor.
			** Comment R11 - #1 In addition to gathering evidence for compliance (M11), there are many operational reasons why a unit response may not meet the expected droop response that is required in this document. Because of this, the GO will be required to analyze, document, and maintain the documentation for every individual unit response when a frequency disturbance occurs. Without this analysis and documentation, the GO will not have a means to dispute points that fall below expectation being place into the rolling average calculation. Documentation of	Response R11 #1 - The Interconnection needs frequency response 24/7 for reliable operation of the BES. Plants that are not staffed are running automatically, and as long as they are set up properly with frequency response support, they should be able to meet this standard easily. Situation awareness of a plant operator to grid perturbations is important. If the generating unit/generating facility is unable to perform properly due to a limiting factor, the operator should be trained to document it. The BA will perform initial performance analysis. The compliance analysis will be managed by Texas RE.

			every disturbance is required for compliance. The GO will not have knowledge of which disturbances are declared Measurable Events and which are not. Many GO plants are not staffed and have not been staffed for a number of years to be able to perform the analysis and capture the documentation. Staffing to levels to meet this compliance would be a huge O&M costs with little proven benefit to ensuring BES reliability. Very few GO plants are staffed to analyze the boiler process controls and conditions during an event that occurred after hours (1:00 am as example). It is simply impossible to document what happened the next day when the unit operator that was on duty at night is at home asleep. This would possibly require twenty-four seven engineering staffing requirements. ** Comment R11 - #2 Measure M11 states "the GO & GOP shall have evidence... per unit frequency response performance of each Generation Resource..." The performance evidence is all on the GO side - not the GOP side. Without the GOP contacting the GO for every frequency disturbance and requesting a copy of their analysis and documentation, the GOP cannot have such evidence. Why should the GOP have to spend time, money, & manpower to maintain duplicate documentation - this does not enhance Bulk Electric System reliability. Also, the GO & GOP may be entirely different companies and the GO unwilling to share detailed unit operational information with the GOP. If the thought process or intent is centered around the GOP's EMS system pulsing a unit the wrong direction during a frequency disturbance, it would be extremely rare for an EMS system to have historical recording of unit pulses issued. EMS pulses are the result of PID controller outputs that vary in	 Response R11 #2 – The measures in the current draft describe how the GO can provide evidence for meeting compliance. The GOP has been removed from the applicability.

			magnitude & time (milliseconds) - they are not database points in the EMS database system that can be historized. This standard should not require GOP's to spend development time & money on their EMS system to come up with a way to historize pulses just for the purpose of additional documentation. This would only apply to units that were on AGC control at the time of the frequency disturbance - not all units on line. If a GO is going to be required to analyze each individual unit's performance as part of their compliance process, AGC pulses received during a disturbance would be one of the parameters captured and analyzed. Therefore, any issues of this nature would be resolved between the GO & GOP to prevent the GO from being penalized. ** Comment R11 - #3 Does your 12 month-rolling average value initialize at the 1st time the unit is on line during a measurable event? If so, what if you did not meet the expected response with that one point? Are you in subject to violation, mitigation plan, & penalty with the 1st point? Peakers or older inefficient low capacity factor units that are frequently not on line will quite likely have very few points in this rolling average. What if there were mixtures of points where some met expected response and some did not? If the average was in compliance, would the unit be considered in violation of the standard if the 12 month old point(s) rolled out of the average dropping the average below expected? Note: If it was the late spring or fall, the unit might not have even been placed in operation for the last month or two. If the average falls below compliance, Section D. Compliance 1.2.2 states "If a Generation Resource/Frequency Responsive Resource completes a mitigation plan and implements corrective action that corrects past failing	 Response R11 #3 – No, compliance is determined by a 12-month rolling average which initiates upon collection of 12 months of data containing a minimum of eight events. If the minimum number of events is not attained within a 12-month period, the 12-month rolling average is extended until the minimum number of events occurs. Following implementation of a mitigation plan, the generating unit/generating facility would not have to be brought online just to prove performance. Regarding the comment on past failing performance affecting current performance following implementation of a mitigation plan, this is addressed in Section D.1.2 of the current draft of the standard.

			performance as measured by this standard, the rolling event average will be reset on the next successful performance during a measurable event" The above means that after filing a mitigation plan and doing whatever work that was required, the GO has to place the unit on line, load it to a level for the best chance of response, and wait for a Measurable Event (550 MW unit trip) to occur. This can be an extremely expensive - the reason these units have low capacity factors is that they are inefficient and most of the time cannot be operated at a profit or they would be running - in some cases, retirement of the unit might have to be considered	
			** Comment R11 - #3 To document compliance and to document legitimate operational reasons for below expected response will result in a huge ongoing cost for the GO. If there is not a BES Reliability Issue concerning individual unit response identified and brought before ROS or TAC, why should there be a requirement forcing GO's to spend large sums of money or perhaps in some cases retire a unit for compliance reasons.	Response R11 #3 - The Interconnection needs frequency response 24/7 for reliable operation of the BES. Situation awareness of a plant operator to grid perturbations is important. If the generating unit/generating facility is unable to perform properly due to a limiting factor concerning the generating unit/generating facility, the operator should be trained to document it. Regarding your concern about the cost, please refer to Response R9 #3.
			**** Comments on Section D. Compliance Section 1.2.1 If a Generation Resource/Frequency Responsive Resource fails any requirement or measure of this standard, the GO and GOP will submit mitigation plans for the failing Generation Resource/Frequency This says both the GO & GOP are responsible and will have to file a mitigation plan "If a Generation Resoure... fails any requirement or measure.." Why is the GOP being held responsible and being forced to file a mitigation plan if the GO Resource fails a requirement or measure? In response to a question to the TRE if being subject to a mitigation plan meant also being subject to	Response Section D –The GOP has been removed from the applicability in the current draft of the standard.

			financial penalty, the TRE said "YES". Why should the GOP be penalized for a GO Resource requirement failure? Note: there are only comments concerning GOs & GOPs - no comments about BA compliance	
			**** Comments on Section 1.3 - Data Retention For every requirement and measure, it states that all the documentation will have to be retained from the last compliance audit. The continental-wide BAL-001 requires data to be retained for 1 year. GO & GOP NERC audits are on a six year cycle per a TRE workshop slide (do not know BA cycle). Why does this standard require data to be retained for such a long period of 6 years?	Response Section 1.3 – GOs are already retaining data for six years as required by other standards.
			**** Comments on Compliance Implementation Schedule Worksheet In 2012, implementation allows only 6 months between becoming Compliant and Auditably Compliant. Compliant means the entity is compliant with the requirements and beginning to maintain documentation. Auditably Compliant requires 12 months of documentation - cannot collect 12 months of data in a 6 month period.	Response Implementation Worksheet – The Implementation Plan has been changed to have the GO be fully compliant with R3 at 18 months after the effective date, which is the first day of the first calendar quarter after applicable regulatory approval. GOs have to be fully compliant with R4 and R5 30 months after the effective date.
			**** Conclusion The Commission stated that ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT and that ERCOT's approach under section 5 of the ERCOT protocols appears to be a more stringent practice than Requirement R2 in BAL-001-0 and therefore approves the regional difference. Please note the Commission statement words "reliable operation" and "more stringent" concerning Protocol Section 5. This proposed standard with it's compliance requirements for the GO & GOP goes far beyond both FERC Order 693 & 672 (see everything above).	Response Conclusion - Texas RE has the authority by delegation to develop both regional standards and regional variances using its FERC and NERC approved standard development process. This process allows for going beyond the national standard and requires that a regional standard be more stringent. (See Appendix to Exhibit C of Delegation Agreement, pp. 3-7.) NERC standard BAL-001's stated purpose is "to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time." The ERCOT region cannot comply with BAL-001 R2 (CPS2), but the region does achieve the purpose of BAL-001 R2 through Protocol 5.9.

			ERCOT has processes and committees in place that continually look at Reliability Issues. (These processes and committees are where the Paragraph 310 which contains the statement: "Since requesting the waiver from CPS2, ERCOT has adopted section 5 of the ERCOT protocols which identify the necessary frequency controls needed for reliable operation in ERCOT." that is quoted in the FERC Order 693 came from). Appropriate Protocol revisions or Operating Guide Revisions are made through these processes and committees when such issues are identified. There are no BES Reliability Issues identified before any committees (specifically the Reliability and Operations Subcommittee (ROS) or the Technical Advisory Committee (TAC) that would even remotely suggest the need for the GO & GOP requirements stated in the BAL-001-TRE-1 proposed standard. FERC Order 693 does not require the GO & GOP requirements for the implementation of Protocol Section 5 and they should not be included.	FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a standard. Additionally, Order 693 states: "As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections", (P 315). Order 693 provides that a regional standard, and more specifically a regional variance, is necessary due to ERCOT's physical difference as a single Balancing Authority Interconnection. Also, by delegation, Texas RE is required to follow all NERC directives and FERC Orders. Both FERC and NERC staff have indicated that a regional standard is the appropriate development path to follow for the ordered and directed modification. Texas RE does <u>not</u> have any authority to develop, modify, or delete ERCOT Protocols. Also, over the past two years, the Performance Disturbance Compliance Working Group (PDCWG) has identified reliability problems associated with the implementation of deadbands in Protocol Section 5.9. In order to meet the performance requirements of section 5.9, generating units/generating facilities were encouraged to achieve near 5% droop during measurable events. This requirement resulted in generating units/generating facilities "stepping into" the 5% droop curve once the deadband had been crossed. This resulted in an irregular Interconnection frequency profile that could not achieve a normal probability distribution. PDCWG identified additional instability issues that will exist during islanding events. This draft standard addresses these reliability issues by clearly defining deadband and droop implementation on generating units/generating facilities. This standard also addresses the measurement of frequency response of generating units/generating facilities by accounting for the deadband and droop setting

				of each generating unit/generating facility.
161	Thad Ness - American Electric Power Service Corp.	Yes	While the SDT has done an excellent job thinking through the technical responses necessary to meet the requirements, there are some higher level questions that should be considered before spelling out the technical details. What can ERCOT do to improve performance and meet the national standard? Should delegation agreements be used to transfer responsibilities to other entities? Should parties be expected to perform frequency regulation services without compensation? Another area not in this question set is the VSLs. R2 focuses on days late, which does not directly impact the reliability of the BES. The intent is more likely be to prevent lateness altogether, by progressively increasing penalties for repeated incidents of lateness. For example, Lower: First Time; Moderate: Second Time in two years; High: Two consecutive late submissions; and Severe: Three or more time. For R4, Lower penalizes everything under 100%, while 90% the national standard? R8 references a form, is it available? R9 and R10 seem to be higher than one would expect	ERCOT has a waiver for BAL-001 R2 because it cannot meet CPS2. This draft regional standard is the variance required to satisfy FERC Order 693, which directs the development of a standard that contains requirements, measures, and levels of non-compliance associated with the original purpose of BAL-001---- To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. Regarding delegation agreements, the FERC Order requires development of a regional standard. While delegation agreements may be appropriate in some circumstances, it is not within the standard drafting team's scope to specify how organizations should share responsibility to achieve compliance. Current ERCOT Protocols already require frequency regulation services without compensation, and this standard builds upon existing Protocols, but does not materially change the Protocol requirement. The team has revised the VSLs in accordance with the current draft standard and guidance from NERC.
166	Frank Owens - Texas Municipal Power Agency	Yes	I believe this change can be incorporated into the existing ERCOT Guides.	FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a regional standard---FERC Order 693 states: "As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures, and Levels of Non-Compliance sections".
174	Ken McIntyre - ERCOT ISO	Yes	1. As applied to Requirement 4, ERCOT ISO is concerned about establishing a requirement on the Balancing Authority (BA)	Response R4: The team has modified the approach in the current draft standard.

			that under the existing Protocols (Protocols Section 5.9 was recommended to be used by FERC Order 693) is on the ERCOT Interconnection, not the BA. The BA in the ERCOT Interconnection does not own Resources and therefore cannot directly control Resource performance as is required with the current wording. ERCOT ISO recommends an approach similar to that of Protocols 5.9 that has the Balancing Authority analyzing and reporting on system performance. Perhaps the Requirement 4 language could be the following: R4. The BA shall calculate monthly a twelve-month rolling average Interconnection Frequency Response, as measured in Attachment 2. If the rolling average is not greater than or equal to the Interconnection Minimum Frequency Response, the BA shall investigate the cause and shall submit the results of their investigation to the Texas RE within 60 calendar days. The measure for R4 would be: The BA provided results of the monthly calculation of the 12 month rolling average of Interconnection Frequency Response. Upon a rolling average Interconnect Frequency Response that was not greater than or equal to the IMFR, the BA conducted an investigation and reported the findings to the TRE. The BA provided the report within 60 calendar days from the detection of failing to meet the IMFR.	
			2. Requirement 6 stipulates that Generation Resources less than 10 MW each, who at a single point of interconnection sum to an aggregate greater than 10 MW, shall be treated as a single Generation Resource. ERCOT ISO recommends this be removed from the requirement as it is methodology and not a requirement. The language could be moved to Attachment 3, Part 2.	Response R6: This methodology has been removed from the current draft standard.

			3. ERCOT ISO needs clarification on the method of the delivery of the GO and GOP governor and frequency response information (R7, R8 and R9). Whether it is established through an annual GARF/RARF process, or provided in real time through SCADA telemetry. ERCOT ISO would be supportive of the approach that GOs and GOPs calculate Resource specific governor performance/availability frequency response information and telemeter this in real time to ERCOT ISO. This would include frequency response information such as, governor in service, governor out of service, governor frequency dead band, governor droop setting, frequency response capability etc. 4. ERCOT ISO would suggest the schedule for implementation include a 2 year minimum Field Trial. This would allow time for ERCOT ISO to tune their systems utilizing the GO and GOP data, establish the necessary performance report templates for TRE, GOs and GOPs and allow a period for GOs and GOPs to review their performance as reported by ERCOT ISO as per this Regional Variance.	Response R7, R8, R9: The performance evaluation tool contains a form for GOs to provide their parameters to ERCOT and Texas RE. R7 was deleted, and the requirements of R8 and R9 were moved to R3. Per the implementation plan, the BA will have to be compliant with R1 12 months after the effective date which is defined as the first day of the first calendar quarter after final applicable regulatory approval. The BA will have to be compliant with R2 18 months after the effective date.
183	Robert Kelly - Brazos Co-op	Yes	Reference comments submitted under Question 4.	See the response to Robert Kelly's comment in Question 4.
195	Paul Dougherty - Calpine	Yes	Given the large volume of Nuclear, Base Load Coal and Wind generation. Having the remaining units with electronic governors reduce their governor dead band setting to the recommended setting will not improve grid reliability. It might help ERCOT ISO improve frequency control; however, ERCOT ISO can improve frequency control by better modeling either the QSE or on a by unit basis expected frequency bias. Given projections of the growth of Nuclear and Wind Generation over the next 10 years, it is conceivable that the ERCOT grid can not provide 660 MW/0.1 HZ bias. It is	This draft standard requires ERCOT to evaluate the minimum allowable frequency response of the Interconnection on an annual basis. Future wind and nuclear generating units/generating facilities may need to be required to provide frequency response in order to keep the Interconnection reliable. The team agrees that better modeling of expected frequency response can improve frequency control by enabling improved ERCOT re-dispatching when available frequency response is below minimum required levels. Future nuclear generation should expect to be required to provide frequency response. All

			estimated that when the percent of Nuclear, Wind and Base Load Coal generation hits 50% of the online generation that the current ERCOT Frequency bias will not meet current acceptable levels. Thus, in order to improve the grid more units must provide frequency bias and this includes Nuclear, Wind and Base Load Coals plants. A nuclear plant can easily provide governor response, this is an operational issue for the plant not a systems issues. Base Load Coal plants can also easily provide frequency response by operating at levels that allow a response to be meaning full. Wind unit can also provide frequency response. This is not a technical issue. It makes no long term or short term economic sense to have fewer units carry the frequency burden of the ERCOT grid with no corresponding compensation.	existing wind generation that can provide frequency response, and all future wind generation and other renewable resources, should also expect to provide frequency response. Presently there are no exclusions for base load coal units to provide frequency response. Reliability standards are not the venue to address economic issues associated with a market. In the current draft of the standard, existing nuclear generating units regulated by the U.S. Nuclear Regulatory Commission have been exempted from the applicability.
200	Peter So - Calpine	Yes	I agree with Randy Jones comment on this issue.	Please see response to Randy Jones comment on this question.
216	Robert Green - Garland Power & Light	Yes	I recommend that R5 thru R11 and M5 thru M11 be deleted from the rext version of the the draft standard. Then the PDCWG should sponsor a PRR to revise protocol section 5.9.2, deleting all of the first paragraph except the first sentence [leaving the A point is the last stable frequency value prior to the frequency disturbance]. Then the PDCWG should sponsor a OGRR to revise OG 2.2.5 to include the deadband section of Attachment 3 Part 1 and delete the maximum intentional deadband of +/- 0.036 HZ requirement. Finally, the PDCWG augmented by an ad hoc group of MP should prepare a NOGRR that adds R5 thru R11 as sections in the new Section 9 that is being created via NOGRR 025.	FERC Order 693 directs that the regional difference that ERCOT currently has (Protocol 5.9) be put in the form of a standard. The current draft standard has been rewritten to address several concerns from commenters.

Attachment 5-001

February 5, 2010
9:30 a.m. – 12:30 p.m.

7620 Metro Center Drive
Austin, Texas 78744
Room 206B

Administrative

1. Introduction and Attendance

Chairman Rick Keetch welcomed the attendees to the meeting.

The attendees were as follows:

Name	Company	Segment	Present	Called-In
Nick Fehrenbach	City of Dallas	Cons-Comm.	X	
Paul Gabba	Dow Chemical	Cons-Ind.	X	
Danny Bivens	Office Public Utility Counsel	Cons-Res.	X	
Brian Bartos	Bandera Electric Coop	Coop	X	
Richard McLeon	South Texas Electric Coop	Coop	X	
Lane Robinson	Sweetwater Wind	Ind. Generator	X	
Billy Shaw (Cesar Seymour proxy)	International Power America	Ind. Generator		
Jeremy Carpenter	Tenaska Power Services	Ind. PM	X	
Rick Keetch	Reliant Energy	Ind. PM	X	
Joel Firestone	Direct Energy	Ind. REP		
Tony Marsh	Texas Power	Ind. REP	X	
Paul Johnson	American Electric Power	IOU	X	
John Brockhan	CenterPoint Energy	IOU	X	
Les Barrow	CPS Energy	Municipal		
Frank Owens	Texas Municipal Power Agency	Municipal	X	
Steve Myers	ERCOT ISO	ERCOT ISO	X	
Sarah Hensley	Texas RE	RE	X	
Don Jones	Texas RE	RE	X	
Sydney Niemeyer	NRG Energy		X	
Jack Thormahlen	LCRA		X	
Scott Etnoyer	FERC		X	
Tom Burke	Luminant		X	
Jimmy Sikes	City of Georgetown		X	
Gerry Nunan	Schneider Engineering		X	
Phillip Amaya	Magic Valley Electric Coop		X	
Pam Zdenek	BP		X	
Jeanie Doty	Austin Energy		X	
Julius Horvath	WETT		X	
Antonio Ansede	WETT		X	
Sie Cheung	WETT		X	
Matt Pawlowski	NextEra			X

Bruce Wertz	PSEG			X

At least one representative from five of the seven segments is required to constitute a quorum. At this meeting, a quorum was achieved with a representative from each of the seven segments being present.

Antitrust Admonition

The Texas Regional Entity (Texas RE) Anti-Trust Admonition was displayed for the members. The attendees were reminded that it is both Texas RE and ERCOT policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

Approval of Minutes

The draft minutes from the January RSC meeting were presented. There were no comments or changes suggested.

Paul Johnson moved to approve the draft minutes. The motion was seconded by John Brockhan. Motion ***carried*** *by voice vote. The minutes were approved.*

RSC Discussions and Activities

2. Texas RE Separation – Update – Sarah Hensley

Sarah Hensley presented the status of the Texas RE separation from ERCOT. Membership vote on bylaws is in progress, closes at midnight tonight. Tony Marsh asked if the RSC members would remain the same. Sarah said there would be a new election since the sectors will be changing. The Members Representative Committee will begin elections around March, and the RSC will begin elections closer to the time of separation.

3. SAR-003 BAL-001-TRE-01 Presentation to Post for comment – Sydney Niemeyer

Sydney Niemeyer, chair of the BAL-001-TRE-01 drafting team, presented the changes made to the BAL-001 standard since the last posting. He also demonstrated how the performance evaluation tools work for measuring unit performance.

Steve Myers asked if there was a maximum expected duration for event recovery. Sydney said no, it is set at frequency recovery point which is the pre-event level or 60 Hz.

Sydney said two drafts of the standard are very different. The new version is much more professional, easy to read and understand, and concise. There were three performance evaluation tools posted with the meeting materials: one each for wind, steam and combustion. Additional materials included the mapping document from the first to the current draft, implementation schedule, a list of frequently asked questions, the responses to the first round of comments and the list of questions for the second comment period.

Sydney then asked for permission from RSC to post the second draft for comment If approved, the timeline is to post Feb 12, hold a half-day workshop on March 3 following the RSC meeting. Assuming there are not many changes requested by the comments, the earliest possible posting for vote would be in June.

Don Jones asked if Sydney could explain further about the volunteer market participants who have tested the settings in the standard and had excellent results. Sydney said the biggest advantage seen is the frequency response to the small frequency deviations. With the generators responding to frequency deviation, frequency does not even get to 0.036.

Don asked about the possible exclusions mentioned in M4 and M5 if generators provide documented evidence of certain factors and what kind of situations would justify an exclusion. Sydney used the example of two 50% boiler feed pumps. On an 800 MW Unit with output at 390 Mw, the GO has to decide when to turn the next pump. With one pump on, the GO makes the decision to start the steam feed pump which may take up to 10 minutes to get it in service. Before the second pump is placed in service the unit may have some frequency response but not much. Other examples were pulverizers on coal units and condensate pumps that may take 30 seconds to start.

Don asked for clarification on R3 that states deadband and droop settings. He said it appears that R3 is not requiring that the unit actually operate at those levels, but it does require that unit be set with those settings, which Sydney confirmed. Don also noted that in the VSL table, there is a 10% buffer built-in, so that in case the governor drifts a little, it would not automatically be a violation.

Jack Thormahlen asked what kind of leeway is there on combined cycle units with issues with flameouts due to 4% droop vs. 5% droop. Sydney said that in this situation, the GO should document that and prove that the unit trips and there is nothing they can do due to mechanical limitation. They should also contact Texas RE to discuss a modification. Sydney said he would be surprised if the units could not be tuned not to trip at the 4% droop. His units have been operating at 0 deadband and 4% droop for years and have not had problems.

Scott Etnoyer asked if the lengthy, phased implementation period could be justified. Specifically, why is the three-year period more beneficial than an 18-month or two-year period, and how can we assure reliability during that implementation time? Sydney said that in the ERCOT region there are already requirements in Protocols for deadband and droop settings, but no measure to make sure every generator is performing. During the implementation period, there will be no less stringent rules in place than what is in place now. The three-year plan is to allow entities to budget and hit a two-year inspection/maintenance cycle on turbines. It will give them time to engineer the implementation, buy the parts, get them installed and test before having to be compliant.

Lane Robinson asked how this standard relates to PRR 833 that is in the works for primary frequency response for wind. Sydney said the only thing that is different is the deadband, the PRR states the same deadband as in current Protocols. The standard also says if a unit is within 2% of HSL or pmax (maximum production potential), it will not be measured. Wind turbines are at pmax 90% or more of the time. The standard does not distinguish between existing and future units. Anything that has storage capability would be expected to provide frequency response.

After the discussion, Rick reminded the RSC that the SDT has asked for a vote to post for comment. Frank Owens made the motion to approve posting of BAL-001 second draft, Steve Myers seconded. No further discussion. The motion was approved by voice vote, no abstentions or opposition. The standard will be posted for a 30-day comment period beginning February 12, 2010.

4. NERC SDT Update – Matt Pawlowski

Matt Pawlowski provided an update on NERC projects that are currently posted for comment or pre-ballot review.

5. 2006-02 Assess Transmission Future Needs – TPL-001 – Julius Horvath

Julius Horvath, the ERCOT representative member of the NERC standard drafting team, made a presentation to the committee on Project 2006-02, Assess Transmission Future Needs, which includes TPL-001. If anyone had questions, Julius provided his email address: Julius.horvath@windenergyoftexas.com.

6. Prioritize and Discuss NERC Projects – Don Jones/Group

Don Jones reviewed five NERC projects that the committee had previously indicated interest in. Steve Myers made the comment that Laura Zotter of ERCOT is on the Project 2007-02 Operating Personnel Communications standard drafting team. They are currently working on responding to comments and there will be extensive revisions before the second posting. Brian Bartos made one clarification on the UFLS project that the third posting should be out in March or April. Steve Myers noted that he serves on many drafting teams, Reliability Coordination SDT, Functional Model Working Group, Disturbance Monitoring and several interpretation drafting teams. Steve also said that Jim Brenton from ERCOT is on the Order 706 Cyber Security drafting team. Don noted that there have been many interpretations going through the interpretations process recently, and that the results of those interpretations may influence the number of future interpretations requested.

Don suggested that in order for the RSC to get involved in any particular NERC project as a group commenter, an individual member of the RSC will need to champion the project of their interest, and that Texas RE will facilitate such activity and assist as needed.

Rick asked the committee look at the distributed list of NERC active standards projects and to consider how to prioritize those standards for further RSC consideration.

7. Discussion on CIP-001 Applicability – Brian Bartos/Group

Brian Bartos said the issue of CIP-001 applicability came up in the last few days and he wanted to bring it to the table. He noted that Texas RE has suggested that certain TOs that do not operate LCCs (local control centers) should be registered as TOPs for the purposed of compliance with CIP-001. Brian said that while he agrees with the direction Texas RE wants to go, he feels strongly that we should not attempt to fix a reliability gap caused by a poorly drafted standard with the registration process, but should instead use the standard development process. He wants to make sure a precedent is not being set by registering entities for functions that they should not be registered for. Brian feels like now is the time to propose a regional standard revision to include TO, GO, and DP as applicable functional entities in CIP-001, and that it would probably be better received than first SAR that was submitted on this subject.

Don said he intends to submit a CIP-001 regional SAR for RSC consideration next month. Don noted that it will take at least a year to get a regional standard to NERC. Texas RE is concerned about the existence of a reliability gap during that time and is looking for a stopgap measure to make sure all relevant parties are complying with CIP-001 until a regional standard is in place.

Brian responded that his company, like others who received the letter, is already on the hook for the standard because it is already registered as an LSE.

There was further discussion regarding the NERC standard revision project that is addressing a similar problem, and regarding whether this issue should be addressed through a regional standard or a variance. The RSC also discussed whether this issue can be addressed through agreements among the parties rather than through a registration-based solution.

8. Closing Notes

Sarah will send email to call for interested parties to join the tracking site. Also, it was announced that the BAL-001 technical workshop will take place in the afternoon after the March RSC meeting.

9. Meeting adjourned at approximately 12:30 p.m.

Next meeting is March 3, 2010 at ERCOT Austin in Room 206B.

Attachment 5-002

Frequency Measurable Event (FME): Frequency Deviation used to evaluate generating unit/generating facility Primary Frequency Response performance and that meets one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 34-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year). See Attachment 1 for detailed criteria for this measurement.

or

ii) a change in a generating unit/generating facility, DC tie or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year). See Attachment 1 for detailed criteria for this measurement.

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response: The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Real Power Balancing Control Performance

2. **Number:** BAL-001-TRE-1

3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. This regional standard supplements the CPS2 Waiver that was approved for ERCOT by NERC on November 21, 2002. Specifically, this standard replaces requirement 2 of BAL-001-0a per FERC Order 693.

4. **Applicability:**

   4.1. Balancing Authorities (BA), Generator Owners (GO)

   4.2. Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from Standard BAL-001-TRE-01.

   4.3. Generating units/generating facilities while operating in synchronous condenser mode (providing reactive power only) are exempt from Standard BAL-001-TRE-01.

5. (**Proposed) Effective Date:** After final regulatory approval and with the three-year implementation plan to allow generating unit/generating facility time to meet the requirements. See outline of implementation plan in Attachment 3.

B. Requirements

R1. The BA shall identify Frequency Measurable Events and submit a report to the Compliance Enforcement Authority for each Frequency Measurable Event identified. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

R2. The BA shall calculate the 12-month rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility using the Primary Frequency Response Evaluation Tool (Attachment 2). If the generating unit/generating facility has not participated in a minimum of (8) eight Frequency Measurable Events in a 12-month period, performance shall be based on a rolling eight Frequency Measurable Event average response. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

R3. Each GO shall set the Governor parameters as follows: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

3.1. Limit Governor deadbands within those listed in Table 3.1.

Table 3.1 Governor Deadband Settings

Governor Type	Max. Deadband
Mechanical	+/- 0.036 Hz
Electronic	+/- 0.01666 Hz
Digital	+/- 0.01666 Hz

3.2. Ensure that Governor droop settings do not exceed those listed in Table 3.2.

Table 3.2 Governor Droop Settings

Resource Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)	5%
Diesel	5%
Wind Turbine	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

3.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, ensure that the resource Governor follows the slope derived from the formula below.

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

Where: MW_{GCS} is the maximum megawatt control range of the Governor control system.

R4. The GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance on each generating unit/generating facility based on an eight (8) Frequency Measurable Event minimum participation. If the generating unit/generating facility has not participated in a minimum of eight Frequency Measurable Events in a 12-month period, performance shall be based on a rolling eight Frequency Measurable Event average response. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

$$Avg_{Period}[P.U.\ PFR_{Resource}] \geq 0.75$$

Where: P.U. $PFR_{Resource}$ is the per unit measure of the Primary Frequency Response of a Resource during identified Frequency Measurable Events.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response}{Expected\ Primary\ Frequency\ Response}$$

Expected Primary Frequency Response (EPFR): This is calculated when the frequency deviation exceeds the deadband.

$$Expected\ MW\ Change = \left[\frac{(HZ_{actual} -\ 60.0 + deadband_{max})}{(60 * droop_{max} - deadband_{max})} \times (-1) \times (Capacity)\right]$$

EPFR for Combustion Turbine

$$Expected\ MW\ Change +\ (HZ_{actual} - 60.0) \times 10 \times 0.00276 \times Generation\ Resource\ Capacity$$

EPFR for Steam Turbine

$$(Expected\ MW\ Change + Stored\ EnergyLoss + Steam\ Expansion\ Loss) \times \frac{Actual\ Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

$$Stored\ Energy\ Loss = \left[Expected\ MW\ Change \times K \times \left(\frac{Capacity}{PSIG_{Rated}}\right)\right]$$

$$Where\ K = \frac{Change\ in\ Pressure\ (\Delta PSIG)}{Change\ in\ MW\ (\Delta MW)}\ is\ in\ the\ range\ of\ 0.0 \rightarrow 0.5$$

$$Steam\ Expansion\ Loss = \left[Expected\ MW\ Change \times 2 \times MW_{post-perturbation} \times \left(\frac{K}{PSIG_{Rated}}\right)\right]$$

Actual Primary Frequency Response (APFR): This is the difference between Pre-perturbation Average MW and Post-perturbation Average MW.

$$Actual\ Primary\ Frequency\ Response = MW_{pre-perturbation} - MW_{post-perturbation}$$

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{8}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(52)}^{t(20)} MW}{17}$$

R5. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance on each generating unit/generating facility based on an eight (8) Frequency Measurable Event minimum participation. If the generating unit/generating facility has not participated in a minimum of eight Frequency Measurable Events in a 12-month period, performance shall be based on a rolling eight Frequency Measurable Event average response. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

Event Recovery Time (ERT): Time at which frequency returns to pre-perturbation frequency or Scheduled Frequency, whichever occurs first.

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{8}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(52)}^{t(20)} MW}{17}$$

MW $_{\mathbf{ERT}}$ = Instantaneous MW at ERT

$$\Delta MW = MW_{pre-perturbation} - MW_{ERT}$$

$$\#Scans = ERT - t(0) - 2$$

$$Expected\ 60\ Hz\ MW_t = \left(\frac{t}{2}\right)\left(\frac{\Delta MW}{\#Scans}\right) + MW_{pre-perturbation}$$

Initial Primary Frequency Response in P.U. (IPFR$_{\mathbf{p.u}}$)

$$IPFR_{p.u.} = \frac{\left(MW_{post-perturbation} - MW_{pre-perturbation}\right)}{EPFR}$$

$$If\left(IPFR_{p.u.} > 1.0\right)\ then\ IPFR_{p.u.} = 1.0$$

$$If\left(IPFR_{p.u.} < 0.15\right)\ then\ IPFR_{p.u.} = 0.0\ (No\ evaluation\ is\ required)$$

Event Average Expected MW

$$MW_{EAE} = \frac{\sum_{t(-2)}^{t(ERT)} \left(Expected\ 60\ Hz\ MW_t + EPFR_t \times IPFR_{p.u.}\right)}{\#Scans}$$

Event Average Actual MW

$$MW_{EAA} = \frac{\sum_{t(-2)}^{t(ERT)} (MW_t)}{\#Scans}$$

$$P.U.PFR_{Resource} = \frac{MW_{EAA}}{MW_{EAE}}$$

$$\mathrm{Avg}_{\mathrm{Period}}[\mathrm{P.U.\ PFR}_{\mathrm{Resource}}] \geq 0.75$$

C. Measures

M1. The BA shall have evidence it reported each Frequency Measurable Event to the Compliance Enforcement Authority within 30 days of the FME as required in R1. The data provided to the Compliance Enforcement Authority may include but is not limited to that listed in Attachment 1.

M2. The BA shall have evidence it reported the rolling average Primary Frequency Response performance of each generating unit/generating facility monthly to the Compliance Enforcement Authority as required in R2.

M3. The GO shall have evidence that it set the Governor parameters in accordance with R3. Examples of evidence include but are not limited to:

- Governor test reports,
- Governor setting sheets,
- performance monitoring reports.

M3.1 The GO shall have evidence that it set the Governor deadbands as required in Table 3.1 in Requirement R.3.

M3.2 The GO shall have evidence that the accepted Governor droop characteristics did not exceed the settings in Table 3.2 in Requirement R3.

M3.3 The GO shall have evidence that when frequency deviation has exceeded the Governor deadband from 60.00 Hz the Governor follows the approved slopes derived from the prescribed formulas for 4% droop and 5% droop.

M4. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum performance level of 0.75 P.U. $\mathrm{PFR}_{\mathrm{Resource}}$ per R4 and documented evidence of any Frequency Measurable Events where generating unit performance should be excluded.

M5. Each GO shall have evidence that each of its generating units/generating facilities sustained a minimum performance level of 0.75 P.U. $PFR_{Resource}$ per R5 and documented evidence of any Frequency Measurable Events where generating unit performance should be excluded. On a single event, if M4 is <0.15 P.U. $PFR_{Resource}$, then M5 is not measured.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Texas Regional Entity

1.2. Compliance Monitoring Period and Reset Time Frame

1.2.1 Each generating unit/generating facility will have a rolling event average performance as stated in R4 and R5 of this standard.

If a generating unit/generating facility fails any requirement or measure of this standard, the GO will submit mitigation plans for the failing generating unit/generating facility with a timeline not to exceed 90 days from the notification of failing performance.

1.2.2 If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R4 and R5 of the standard, then the generating unit/generating facility will begin a new rolling event average performance on the next successful performance during a Frequency Measurable Event. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R4 and R5.

1.2.3 If the generating unit/generating facility fails the next Frequency Measurable Event performance after completing its mitigation plan, the GO will submit a follow-up mitigation plan with a timeline not to exceed 30 days from the notification of failing performance.

1.3. Data Retention

The Balancing Authority and Generator Owner shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each BA shall retain a list of identified Frequency Measurable Events since its last compliance audit for R1, M1.
- Each BA shall retain all monthly reports since its last compliance audit for R2, M2.
- Each GO shall retain evidence since last compliance audit for R3, M3.
- Each GO shall retain evidence since last compliance audit for R4, M4.

- Each GO shall retain evidence since last compliance audit for R5, M5.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Periodic Data Submittals as required

Exception Reporting as necessary

1.5. Additional Compliance Information

N/A at this time

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	A Frequency Measurable Event is not reported >30 days but ≤50 days of identification of the event	A Frequency Measurable Event is not reported >50 days but ≤70 days of identification of the event	A Frequency Measurable Event is not reported >70 days but ≤90 days of identification of the event	A Frequency Measurable Event is not reported >90 days identification of the event
R2	Monthly reports submitted >30 days but ≤50 days from the end of the reporting month	Monthly reports submitted >50 days but ≤70 days from the end of the reporting month	Monthly reports submitted >70 days but ≤90 days from the end of the reporting month	Monthly reports submitted >90 days from the end of the reporting month
R3	Any Governor parameter setting >10% and ≤20% outside setting range specified in R3	Any Governor parameter setting >20% and ≤30% outside setting range specified in R3	Any Governor parameter setting >30% and ≤40% outside setting range specified in R3	Any Governor parameter setting >40% outside setting range specified in R3 – OR – the electronic or digital Governor was set to step into the curve
R4	Rolling average per R4 is <0.75 and ≥0.65	Rolling average per R4 is <0.65 and ≥0.55	Rolling average per R4 is <0.55 and ≥0.45	Rolling average per R4 is <0.45
R5	Rolling average per R5 is <0.75 and ≥0.65	Rolling average per R5 is <0.65 and ≥0.55	Rolling average per R5 is <0.55 and ≥0.45	Rolling average per R5 is <0.45

E. Regional Variances

This is a regional variance to NERC Standard BAL-001-0a, specifically replacing R2. Instead of complying with R2 in BAL-001-0a (CPS2), the BA and GO in the ERCOT Interconnection maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time by the methods, requirements, and measures described in this regional standard and associated attachments and documents.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking

Attachment 1

The type of data provided to the Compliance Enforcement Authority for analyzing each Frequency Measurable Event that has been identified by the BA may include but not limited to that listed below:

(1) Interconnection Frequency;
(2) Interconnection scheduled frequency used in the ACE equation;
(3) Regulation Service deployed;
(4) Responsive Reserve Service deployed;
(5) Available Responsive Reserve Service (Nodal only);
(6) Generating unit/generating facility megawatt value;
(7) Control Error (Schedule CE in Zonal, Generation Resource Energy Deployment Performance (GREDP) in Nodal);
(8) Generating unit/generating facility expected Primary Frequency Response;
(9) Resource Regulation Service Allocation (Nodal only);
(10) Resource Economic Base Point (Nodal only);
(11) Resource High Operating Limit;
(12) Resource Low Operating Limit;
(13) Load Acting As Resource megawatt;
(14) Load Acting As Resource deployed;
(15) Resource Responsive Reserve Service Responsibility (Nodal only);
(16) ERCOT Load;
(17) Megawatt value for loss of individual generating unit/generating facility(s) or Load that triggered the Frequency Measurable Event;
(18) Emergency Interruptible Load Service Deployed;
(19) Time (synchronous time stamp to the nearest second for the data above).

Attachment 5-003a

TEXAS REGIONAL ENTITY
An Independent Division of ERCOT

BAL-001-TRE-1 Technical Workshop for Comment Period on Second Draft

March 3, 2010, 1:00 p.m. to 5:00 p.m.

ERCOT Austin, Room 206B, 7620 Metro Center Drive, Austin, Texas
Web Ex: https://ercot.webex.com
Dial-In: 866-469-3239 Meeting # 353 176 509 Password Tre123!!

Item	Topic	Presenter	Time
1.	Introduction & Background	D. Jones	1:00 p.m.
2.	Governors and AGC	B. Green	1:20 p.m.
3.	Comparison of Governor Deadband Settings	S. Niemeyer	1:40 p.m.
4.	Requirements • BA Requirements (R1 & R2) • GO Requirements (R3, R4 & R5)	 K. McIntyre A. Palani	2:00 p.m.
5.	Mapping Document	P. Zdenek	2:30 p.m.
6.	Performance Evaluation Tool Demonstration	S. Niemeyer	3:00 p.m.
7.	Implementation Plan	P. Zdenek	3:30 p.m.
8.	FAQ Document	A. Palani	3:50 p.m.
9.	Q & A	Team	4:20 p.m.
	Adjourn		5:00 p.m.

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Attachment 5-003b

BAL-001-TRE-1 Workshop Notes
March 3, 2010

Item	Topic	Presenter	Time
1.	Introduction & Background	D. Jones	1:00 p.m.
2.	Governors and AGC	B. Green	1:20 p.m.
3.	Comparison of Governor Deadband Settings	S. Niemeyer	1:40 p.m.
4.	Requirements • BA Requirements (R1 & R2) • GO Requirements (R3, R4 & R5)	 K. McIntyre A. Palani	2:00 p.m.
5.	Mapping Document	P. Zdenek	2:30 p.m.
6.	Performance Evaluation Tool Demonstration	S. Niemeyer	3:00 p.m.
7.	Implementation Plan	P. Zdenek	3:30 p.m.
8.	FAQ Document	A. Palani	3:50 p.m.
9.	Q & A	Team	4:20 p.m.
	Adjourn		5:00 p.m.

Don – Intro – Agenda & Background

Bob Green – background on governors and AGC. presented powerpoint, no questions

Sydney – Comparison of Governor Deadband Settings

- (.0166 with straight line droop curve and .036 with step droop curve) –
- presented how the different deadband settings compare, and effects on the grid and on individual units. Better unit and frequency stability, as more units implement lower deadband the frequency profile improves and everyone will all save money.
- Robert Kelly – appreciation for team's work. To get the increased stability, reduction in movement, on units tested, were there any modifications to equipment or just change settings?
- Sydney – only changes were deadband setting and droop curve. Second question, if this is adopted as standard, do you foresee having to install equipment to monitor what we're doing to demonstrate compliance?
- Sydney – have posted three performance evaluation tool spreadsheets, on website to download, plug data from disturbance into spreadsheet. Will demonstrate this later in the workshop.

Ken McIntyre – BA Requirements – presented BA requirements –

- reduction of BA requirements since last posting, more of a reporting role now.
- Question – Jack Thormahlen – if a unit that runs all the time (combined cycle) In 30-40 events, ratio of bad events to good events could be 1/40 whereas a unit that isn't on all the time and has a minimum of 8 has a larger ratio, has the team discussed that and the fairness?
- Ananth – yes, if you look at the units online year round, those are more important than peakers. The duration for which the peaker stays is less, it compensates for the ration discrepancy.
- Ken – lot of discussion around this, trying to be as fair as possible, is a rolling average. Units are supposed to have governors in service and perform.
- Robert Kelly – has there been discussion about how the BA will get the GO information? Protocols? Standards?

- Ken – needs to be discussed, at the most it would be part of the Operating Guides and Protocols.
- Jim Sorrels – added definition for Frequency Measurable Events – identified two conditions, but within that gave room adjusting for number of events per year, curious why elected to add parentheticals?
- Sydney – NERC resources subcommittee has always recommended to do bias calculation to use 30 events, went on same premise to look for 30-40 to give a big enough sample size to calculate the unit's performance. With settings in there, will be easy enough to achieve those numbers. If the standard improves performance, might have to decrease the 100mhz.
- Thad Ness – applicability – any thought to what units would be excluded?
- Ken – yes, Nuclear units, hydro and synchronous condenser are excluded. R3 details the resources that should have droop and governor in service.
- Sydney – did discuss that. Rick Terrill contacted solar generation people, depending on type, if solar has storage capability they do have the capability of providing frequency response. If not, it would be a unit operating at pmax. Non-storage solar units will always be at pmax. Performance will not be evaluated in the evaluation tool if it is operating at pmax.

Ananth Palani – GO Requirements –

- R3 is for setting governor parameters, R4 & 5 are performance.
- Jack – if unit apparently failed but have very good reason why, it can be excluded from average correct? The exemption has to be applied for and approved.
- Jagan – report from ERCOT and event happens on monthly basis, could we get a report from ERCOT at an audit for same month, report should match.
- Ananth will go over who is responsible for what in the FAQ.
- Jagan – how is TRE communicating and coordinating with ERCOT on a regular basis.
- Jack – known areas that you know you cannot meet the standard.
- Sarah – will have to self report the non-compliance and TRE will work with them on mitigating that.
- Randy G – valves wide open at 98% at HSL, spreadsheet will not evaluate that.
- Randy – where is the 98% mentioned specifically?
- Sydney – it is built into the evaluation tool. The only data that is required is the MW of the unit and pmax or HSL.
- John Werner – is there a correlation between that and wind?
- Sydney – yes, if wind is not curtailed and operating at pmax, will not be evaluated.
- Randy – concern is that the pmax that is in the spreadsheet is not verbalized in the standard itself.
- Ananth – should be included in formulas, will verify and get back to him. Ananth checked, it is not included in the formulas. The team will add that into the standard, asked that they would submit that as a comment.

Pam Zdenek – Mapping Document –presented the mapping document

Sydney Niemeyer – Performance Evaluation Tool Demonstration –

- Encouraged people to try the spreadsheets for their units and let us know if there is anything about the spreadsheets that doesn't work.
- Jagan – who is going to validate the numbers in the spreadsheet and approve them?
- Sydney – the numbers to be used in the spreadsheets are pretty typical of all units. The pressure curve on the steam generator that would be the issue, most steam generators have a constant curve they always operate under. A simple IF statement, ex. IF mw is less than 100, use 1000 lbs pressure.
- Jagan – agrees, but for verification purpose, once the spreadsheet is finalized, it has to be validated and approved by someone. Any verification the auditors are doing is on the assumption that the spreadsheet is correct. Is ERCOT verifying with the GOs?
- Sydney – will have to be done.
- Sandip – using pressure numbers, how much of expected primary frequency response changes if we use them and if not using them?

- Sydney – for variable pressure unit, it's pretty dramatic. As pressure is reduced on the unit, you can see it takes into account the limited factor, so you can see the impact expected pressure has on the unit.
- Sandip – is it going to be a static table?
- Sydney – yes, as far as ERCOT is concerned, it has to be an IF statement or a static table that will be provided.
- Jagan – has to be static table, people can change IF statements and mess up whole spreadsheet.
- Sydney – ERCOT doesn't have throttle pressure available, has to be either IF statement or static table.
- Sandip – can lock down cells where if they receive a change from GO they have procedure to change the data and lock the cells again.
- Jagan – should be part of RARF, people can change it if something changes. Said there needs to be some sort of approved set of data that can be used in an audit to compare.
- Mike Grimes asked if Sydney would walk through the wind spreadsheet.
- Sydney – yes, set up the same but no throttle pressure adjustment.
- Sydney – each unit has 4 spreadsheets: Frequency Response sets up the Governor, Performance-initial and sustained, hour Chart and Performance graph.
- Sydney – maybe a suggestion for a wind farm is to change the 2% of pmax to 5%. What we need to do is get someone with a wind farm to get frequency response working to see what works.

Pam Zdenek – Implementation Plan –

- reviewed the implementation plan and required compliance times for each requirement.
- Question – what is the official measure of compliance? Is it the calculation in R2 by the BA?
- Sydney – want the BA to be able to deliver the spreadsheets with the performance. GO's will not be measured for compliance at that time.
- Will GO's be required to provide spreadsheets for each unit?
- Sydney- no, droop setting, limiting factors.
- Sandip – for R2, the BA has to calculate initial and sustained but GO only has to calculate only one.
- Sydney – no, they do both. The GO is not required to calculate them.
- Sydney –needs ERCOT to start calculating data using the spreadsheets to see if it works.
- Sandip – ERCOT cannot calculate the 650 units using the spreadsheets, will have to do it another way.

- Robert Kelly – what is the rest of the country doing?
- Sydney – right now the Eastern Interconnect realized they have a frequency response problem.
- Robert – suggestion – at some point in the process, it would be good to target the spreadsheets as a separate workshop. Get the people who would actually use them together.
- Sydney – would like to remind every market participant that ERCOT has a group called the PDCWG that does this every month. There is a confidentiality agreement to sign to join the group, but if you want to come learn about the spreadsheet, they discuss it.

Ananth Palani – FAQ document –

- Frank – GO requirement is in Section 5.9, will there be a PRR to remove that?
- Ananth – 5.9 requires all governors to be in service, no settings in protocols but is in operating guides.
- Les – will have to circle back to Protocols and operating guides to remove duplicative requirements.
- Frank Owens – asked if the BA will let the QSEs know if a FME has occurred?
- Ananth – hasn't been determined how it will happen, but QSEs are not responsible for the standard. Recommend that ERCOT uses email or xml notification.
- Pam – understand the market needs these notices but haven't determined how it will happen yet.
- Jack – when and if the BA accepts ownership and maintains the spreadsheet and there are multiple versions out there, who is going to make sure a notification that a change has been made to the spreadsheet.

- Ananth – spreadsheet/tool must comply with the standard. If they use the spreadsheet and make a change, expect them to put it out for public use. If they build a tool that can't be shared with public, still expect them to comply with the standard.

- Robert Kelly – if there's a problem with the spreadsheet, will there have to be a SAR to correct that?
- Don – enough comments that there will probably be another draft. Encourages everyone to go try the spreadsheet on their units. Sounds like ERCOT won't be using the spreadsheet, will probably need to redraft the standard to not specify the use of the performance evaluation tool.
- Pam – clarified that the spreadsheets have been posted for a while now and have been and still encourage companies to test out the spreadsheet and let us know if there are any issues so that we can refine and improve them.
- Robert – what would they be audited on if they're not using the spreadsheets?
- Sydney – would think they would have the spreadsheet available for their performance to question the difference between ERCOT's measures and their own. Would think that ERCOT would have a process to communicate performance on a monthly basis or so.
- Scott Etnoyer – comment period, not a ballot, can go through as many comments periods as necessary until the draft is ready.
- Robert Kelly – is not generation, is transmission, could he call Sydney to help with his people?
- Sydney – yes.
- Frank – if this got approved in the next 7 months, the auditable timeline.

Attendees:
Webex:
Marshall Adair– PUC
Lewis De La Rosa – PUC
Bruce Wertz – PSEG
Dan Makelki – AEP
Kevin Carter – Duke
Roy Blackshear – AEP/Desert Sky
John Werner - ?
David Daniels – AEP
Richard Ross – AEP
Kevin Patten – AEP
Ben Givens – AEP
Vance Beauregard – AEP
Ibrahim Abdur-Rahman – NRG
Jim Sorrels – AEP
John Wester - ?
Tony Kroskey – Brazos Electric Coop
Percy Galliguez – Brazos Electric Coop
Tom Paff - ?
Thad Ness – AEP
Mike Grimes - ?
Diana Leese – PUC
D. Sculley -?

In person:
Les Barrow – CPS
Frank Owens – TMPA
Paul Johnson – AEP
Pam Zdenek – BP

Sydney Niemeyer – NRG
Ananth Palani – Optim Energy
Bob Green – Garland Power & Light
Jack Thormahlen – LCRA
Sandip Sharma – ERCOT
Ken McIntyre – ERCOT
Scott Etnoyer – FERC
Jeremy Carpenter – Tenaska
Randy Gilleland – TMPA
Jagan Mandavilli – Texas RE
Sarah Hensley – Texas RE
Don Jones – Texas RE
Sean Wasko – Dow Chemical
Robert Kelly – Brazos Electric Coop
Tony Grasso – PUC
Jeannie Doty – Austin Energy
Les Barrow – CPS Energy

Attachment 5-004

Reliability Standards Tracking
Comments & Responses

SAR-003-TRE-1 FERC-Ordered Modification to ERCOT CPS2 Waiver to R2 of BAL-001-0

02/12/2010 **through** 03/13/2010

1. The first posted draft applied to the Balancing Authority (BA), Generator Owner (GO), and Generator Operator (GOP). The applicability has changed in this version: the GOP has been removed and existing facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from BAL-001-TRE. Do you agree with these changes? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**

Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **Yes**

Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Name: **Zotter, Laura**
Phone: **512.248.3884**

Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Answer: **Yes**

Comment

Comment	Response
Consideration should be given to addressing generation resources that either lack or can provide only minimal frequency response, and are rarely on-line during FMEs.	1. No Generation Resources should by design lack Primary Frequency Response (PFR) characteristic or not have a Governor. If the unit is at the top of its capacity with no-room to move upward then PFR for low frequency event will not be evaluated but the generation resource should provide rated PFR if the frequency is higher than maximum allowable deadband. 2. No PFR is expected of the off-line generation resources. Performance of GOs is measured based on a 12-month rolling average based on an eight FME minimum participation. If the generating unit/generating facility has not participated in a minimum of eight FMEs in 12 months, performance will be based on an eight FME average response. The current draft of the standard also exempts generating units/generating facilities while operating in synchronous condenser mode (providing reactive power only). M8 also includes examples of operating conditions that may support the exclusion of performance during FMEs.

Name: **Kelly, Robert M**
Organization: **Brazos Co-op**
Phone: **254-744-1463**
Department: **Transmission**
Segment: **Cooperative**
Answer: **Yes**

Comment

None

Name: **Owens, Frank J**
Organization: **Texas Municipal Power Agency**
Phone: **936-873-1120**
Department: **Transmission**
Segment: **Municipally Owned Utility**
Answer: **Yes**

2. The BA requirement in the first posting for maintaining minimum interconnection frequency response was eliminated. The BA requirements in R1 and R2 of the current draft are for monitoring and reporting on Frequency Measurable Events. Do you agree with these revised BA responsibilities? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**
Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **No**
Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Comment	Response
During the recent Workshop for this Regional Standard, it was stated that ERCOT would not use the proposed analysis spread sheet due to the enormity of the spread sheet for a system of more than 600 generators. If ERCOT develops its own tool to analyze events per this Standard, I recommend that, at the very least, the PDCWG review and analyze the ERCOT tool prior attempting to any event analysis. R2 should be revised to state that the attached tool will / will not be the tool used by ERCOT and describe how the actual tool is to be evaluated.	The current draft of the standard does not specify use of a specific tool, but rather a methodology by which to measure performance of each generating unit/generating facility. The methodology is included in R8 and R9 and Attachment 1 (flowchart). GOs can still use the performance evaluation tool spreadsheet to track their own performance, but it is not required.

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Name: **Zotter, Laura**
Phone: **512.248.3884**
Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Comment	Response
ERCOT ISO suggests removing the phrase in R2, "?using the Primary Frequency Response Evaluation Tool (Attachment 2)." As with other NERC Reliability Standards, the requirements should focus on what is required, not how the goal is met. ERCOT ISO needs to be able to develop whatever tool it needs and incorporate the formulas for performance as detailed in this standard.	The current draft of the standard does not specify use of a specific tool, but rather a methodology by which to measure performance of each generating unit/generating facility. The methodology is included in R8, R9 and Attachment 1 (flowcharts).

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**
Answer: **Yes**

Comment	Response
AEP does agree with the change, but the BA should be required to provide the information to the Generation Owner. Otherwise, unless the GO elects to monitor Frequency Measurable Events, the GO may not be aware that a violation has occurred. Additionally, the Requirements 1 & 2 should stipulate that Frequency Measurable Events be reported in less than 30 days to be consistent with Violation Severity Levels.	R1 of the current draft requires the BA to identify FMEs and notify the Compliance Enforcement Authority and within 14 calendar days after each FME make FME information (time of FME [t(0)], pre-perturbation average frequency, post-perturbation average frequency) publicly available.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Organization: **Brazos Co-op**
Department: **Transmission**
Answer: **No**

Comment	Response
It could be argued that the BA may have some requirement for maintaining minimum interconnection frequency response because depending on how well the BA manages its operations for BAL-001 compliance it could be possible that there may not be adequate reserve capability on units that would ensure primary frequency response compliance. A sub-requirement should be considered under R1 for the BA to establish what the triggers of an Event will be rather than the definition. R1 should state that the report should be submitted by the BA within 30 days of the Event. The requirement should specifically identify what minimum information will be reported. M1 says it "may include" it should say "will include" or "must include". Another consideration is whether the report is a preliminary or a final report. R2 should state that the BA shall submit the monthly report within 30 days after the month. A suggested sub-requirement for R2 is for the BA to request from each GO with a unit that has a failing score for an Event to provide a reason for possibly excluding the unit from the Event measurement.	R3 of the current draft requires the BA to calculate the Interconnection minimum Frequency Response (IMFR) each year. The BA must also make the IMFR, the methodology for calculation and criteria for determination of the IMFR publicly available. R4. The BA shall determine and make publicly available the Interconnection?s combined Frequency Response performance for a rolling average of the last six (6) FME?s by the end of the following month. R4.1 Following any FME that causes the Interconnection?s six-FME rolling average combined Frequency response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response. Regarding your suggestion for exclusions, M8 includes examples of operating conditions that may support the exclusion of performance during FMEs.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Organization: **Texas Municipal Power Agency**
Department: **Transmission**
Answer: **Yes**

3. In R4, the formulas for calculating the expected initial response have been modified to reflect the ramp direction of resource in the minute before the Frequency Measurable Event to adjust expected response based on that direction. Do you agree with this adjustment? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**

Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **No**

Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Comment	Response
In the equation for Expected MW Change the term capacity needs to be better defined as to what capacity is to be used, i.e. HSL, LSL, HASL, nameplate, max gross output or any other interpretation. The term capacity needs to be defined for each equation used in R4.	The formulas have been modified to use HSL and LSL as telemetered by the GO to the BA in real time. R8 of the current draft states that the term ? capacity? as used in this standard will be the high sustained limit as telemetered in real-time by the GO to the BA.

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Comment	Response
The formula only accounts for pre event ramp and removes the pre event frequency response of the unit. I believe any movement of the unit prior to the event should be accounted for whether it be from ramping or from pre event frequency. The effects on the generator are the same. For example, the unit may not be ramping at all, but a momentary pre event high frequency change will cause the unit to decrease generation (and cut fuel) only to have this action be reversed at the beginning of the measurable event. In this scenario the expected primary frequency response of the resource should be reduced since it will have to reverse direction. Also, the value in cell F8 on the "Perf" worksheet includes two values, one is the expected frequency response that is limited by the normal HSL and low operating point of the governor and the second value, the ramp of the unit prior to the event. The results of the sum of these two values in cell F8 should also be limited to HSL and the low operating point of the generator since it is possible that a ramp in the same direction as the frequency response will exceed the HSL of the unit or the low operating point of the governor for a high frequency event. The sum of these two values should not be larger than the margin remaining on the unit	Both items have been fixed in the current draft of the standard.

Name: **Zotter, Laura**
Phone: **512.248.3884**

Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Comment	Response
The set of equations for performance evaluation under both R4 and R5 are referred only for sustained performance, in reference to R4 the performance is called initial Primary Frequency Response performance (no performance equation present) while for R5 it s referred to as sustained Primary Frequency Response performance. ERCOT ISO suggests some additional language for clarification of what equations are to be used for which measure for its responsibilities under R1 and R2.	The formulas for each type of calculation have been clarified in the new R8 and R9 (formerly R4 and R5). We have also added an informational text box for each requirement for extra clarity as to which requirement measures initial or sustained performance.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **Yes**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
AEP does agree with the SDT's approach and would request the following text change to add further clarity: "R4. The GO . . . on each on-line sychronized generating unit/generating facility based on Frequency Measurable Events with a minimum participation of eight (8) events."	This has been addressed in the new R6: ?Each GO shall operate each generating unit/generating facility connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GOP has been notified.? R2 includes the required minimum of 8-FME participation.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Answer: **Yes**

Organization: **Brazos Co-op**
Department: **Transmission**

Comment	Response
Suggest that "The GO" be changed to ""Each GO" at the beginning of the requirement. See other comment for R4 in response to Question #8.	This change has been made in the current draft.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Answer: **Yes**

Organization: **Texas Municipal Power Agency**
Department: **Transmission**

4. In R5, the SDT has added formulas for calculation of sustained performance during the frequency recovery period to replace the ?visually apparent? performance and clarify the requirement. These calculations have been added to the Performance Measurement Tool. Do you agree with these changes? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **No**
Organization: **POWER CONSULTANT**
Department:

Comment	Response
There is an additional item that I think needs to be considered. The frequency response of a boiler-turbine plant has three distinctive regions. The first one is the MW surge in response to the turbine valve opening accompanied by the corresponding throttle pressure drop (the magnitude depending on the available stored energy). The second is a MW hold period as the response of the boiler to the injection of fuel takes effect, and the third one is the restoration of the MW increase as the pressure is restored. The duration of the hold prior appears to be a function of the magnitude of the frequency change, the availability of stored energy and the boiler response to the injection of fuel. Therefore I suggest that the calculations should include a variable time constant based on these characteristics.	The team agrees with your comment, the evaluation tool has been modified to model stored energy limitations of steam boilers during severe frequency deviations. This has been accomplished using the frequency response filter constants. The drafting team believes that during very large frequency deviations that Load acting as a Resource will be activated, and will limit the frequency deviation to a normal magnitude and not exhaust stored energy in the unit. Extraordinary events will be treated on an exception basis.

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **Yes**
Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Comment	Response
The measurement of sustained response seems to work very well as long as the stored energy of the unit is not exhausted. I have measured performance on very large frequency deviation events where the controls at the unit must limit the response inorder not to risk tripping the unit. If the filter constant was allowed to change value and be a smaller number for events that exceed the stored energy of the unit, this could help measure performance more accurately for each unit. For example, on a steam generator/steam turbine unit with limited stored energy, the value of the filter constant could be the normal 0.15 value for frequency deviations between zero and -0.100 Hz and then switch to a much smaller value (0.003) for deviations greater than -0.100 Hz. I do not believe that this adjustment would be necessary for high frequency deviations.	The drafting team believes that during very large frequency deviations that Load acting as a Resource will be activated, and will limit the frequency deviation to a normal magnitude and not exhaust stored energy in the unit.

Name: **Zotter, Laura**
Phone: **512.248.3884**

Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Comment	Response
ERCOT ISO agrees with replacing "visually apparent", but the existing formulas require more detail, and all the limitations, exemptions, parameters used in the "Tool" need to be extracted and then detailed in the standard. Also, the set of equations for performance evaluation under both R4 and R5 are referred only for sustained performance, in reference to R4 the performance is called initial Primary Frequency Response performance (no performance equation present) while for R5 it s referred to as sustained Primary Frequency Response performance. ERCOT ISO suggests some additional language for clarification of what equations are to be used for which measure for its responsibilities under R1 and R2. ERCOT ISO suggests that the Attachment 2 should be used to provide the detailed method of calculating average initial and sustained Primary Frequency Response performance. Also all parameters, limitations and exemptions that are currently imbedded in the Primary Frequency Response Evaluation Tool should be clearly stated in the standard, either in the formulas/equations, or in the Attachment 2. This will ensure consistency for all concerned when measuring performance. Then based on the measures, parameters, limitations, exemptions defined (perhaps in Attachment 2), the BA shall evaluate the performance of individual units. We proposed the following language for R2: ?The BA shall calculate the 12-month rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility using the measure as defined in Attachment 2. If the generating unit/generating facility has not participated in a minimum of (8) eight Frequency Measurable Events in a 12-month period, performance shall be based on a rolling eight Frequency Measurable Event average response. [Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]?	The current draft of the standard does not specify use of a specific tool, but rather a methodology by which to measure performance of each generating unit/generating facility. The methodology is included in R8 and R9 and Attachment 1 (flowchart). GOs can still use the performance evaluation tool spreadsheet to track their own performance, but it is not required. Examples of exceptions that may be allowed are listed in M8.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**
Answer: **Yes**

Comment	Response
AEP does agree with the SDT's approach and would request the following text change to add further clarity: "R5. The GO . . . on each on-line sychronized generating unit/generating facility based on Frequency Measurable Events with a minimum participation of eight (8) events."	Please see response to your comment on Question 3.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Organization: **Brazos Co-op**
Department: **Transmission**

Answer: **No**

Comment	Response
During the Workshop on March 3, 2010, the SDT presented Performance Measurement Tools that could be used to determine governor speed droop response during Frequency Measurable Events. ERCOT ISO indicated during the workshop that they may not use the proposed Performance Measurement Tools. It appears beneficial, if not essential, for the BA and GO entities to utilize consistent measurement tools. Otherwise, without the implementation of clear and well defined measurement tools, we risk uncertainty in providing sound evidence to demonstrate performance during compliance audits.	The current draft of the standard does not specify use of a specific tool, but rather a methodology by which to measure performance of each generating unit/generating facility. The methodology is included in R8 and R9 and Attachment 1 (flowchart). GOs can still use the performance evaluation tool spreadsheet to track their own performance, but it is not required.
If and once preliminary Performance Measurement Tools are universally adopted by applicable entities and approved by RSC, a verification program would be advantageous to evaluate the completeness of these tools before they are finalized. Subsequently, ERCOT ISO acting as the BA and GO entities could have an evaluation period to flush out any potential issues regarding the application and implementation of the Performance Measurement Tools. The evaluation period could involve educational workshops catering to an audience of personnel that would be responsible for applying the measurements tools for audits.	The team has held a workshop on August 6 to address the performance evaluation methodology, inform entities of what information the BA will require and provide training on the evaluation tool (spreadsheet) to interested parties. Market participants also have the opportunity to join the PDCWG that will provide additional opportunities to evaluate the standard and measures in the standard.
Simply stated, the proposed BAL-001 Regional Reliability Standards would serve the interest of all applicable parties if these standards, or supporting document, include universally applied performance measure tools with well defined implementation guidelines. In order to accomplish this objective, it is suggested that an educational program and an evaluation period be developed and implemented as part of these standards. Hopefully, such measures will eliminate uncertainty in providing sound evidence to demonstrate performance during compliance audits.	The next posting and comment period provides time for the GOs and BA to identify any issues.
In addition, some of the formulas in the standard assume no missing scans occurred for calculations such as Pre-perturbation and Post-perturbation Average MW with divisors of 8 and 17, respectively. The standard needs to address missing scanned data, minimum number of acceptable scans or guidance on what is acceptable to replace in lieu of such missing data.	Missing data is covered under exceptions. Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute. What does TRE do with missing data for SCPS?

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Organization: **Texas Municipal Power Agency**
Department: **Transmission**

Answer: **Yes**

5. Violation Risk Factors (VRFs) and Time Horizons were not included in the first posted draft and have been added to the current draft. Do you agree with the VRFs and Time Horizons assigned to each requirement? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**
Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **Yes**
Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Name: **Zotter, Laura**
Phone: **512.248.3884**
Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **No**

Comment	Response
The VRF for R1 seems to be incorrect. "A FME is NOT reported > 30 days but <= 50 days of the identification of the event". ERCOT ISO suggests removing the language "NOT" so the intent of the R1 VSL aligns more closely with that of the R2 VSL.	The SDT has modified the VSL for R1 in accordance with your comment.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **No**
Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
The draft standard has not developed far enough for this assessment to be properly conducted.	Thank you for your comment.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Answer: **Yes**

Organization: **Brazos Co-op**
Department: **Transmission**

Comment	Response
None	Thank you.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Answer: **Yes**

Organization: **Texas Municipal Power Agency**
Department: **Transmission**

6. The compliance measures were revised to reflect the timelines for reporting and provide clarification. Do you agree with these changes? If not, please comment and suggest alternative measures.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**
Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **Yes**
Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Name: **Zotter, Laura**
Phone: **512.248.3884**
Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **No**

Comment	Response
M1: The Measure for this R1 goes beyond the time-line set by the Drafting Team. Requirement 1 requires ERCOT to identify each measurable event but the measure for this requirement requires ERCOT to provide data related to both R1 and R2, the data list under Attachment 1. Attachment 1 is very comprehensive and some of the data may not contribute to analyzing or measuring performance evaluation required by the standard. The measure should simply state as; ?The BA shall have evidence it reported each Frequency Measurable Event to the Compliance Enforcement Authority within 30 days of the FME as required in R1.? M2: M2 only refers to reporting rolling average Primary Frequency response performance. This does not clearly align with the R2 of initial and sustained reports. Needs to be more specific to the R2 language. M5: Regarding the sentence, "On a single event, if M4 is <0.15 P.U. PFRResource, then M5 is not measured." Does this mean if the Resource scored less than 0.15 P.U, it has to be excluded?	The requirements and measures for the BA have been modified in the current draft. R1 requires the BA to identify FMEs, and within 14 calendar days of the FME, report the Compliance Enforcement Authority and make FME information publicly available. M1 is aligned with R1. The former Attachment 1 (list of data) has also been removed from the standard. R2 requires the BA to calculate the 12-month rolling average initial and sustained Primary Frequency Response and submit them to the Compliance Enforcement Authority, M2 is aligned with R2. Regarding M5: The current draft does not exclude events where M8 <0.15 P.U. PFR Resource from the rolling average (M9). Each measure (M8 & M9) of frequency response is independent of each other.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **No**
Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
Measures 1 & 2 do not appear to be in alignment with Requirements 1 & 2. Conforming language changes for M4 & M5 would be required when the language suggested for R4 & R5 (Question Responses 4 and 5) is adopted.	The team believes the changes to the current draft address your concerns.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Answer: **No**
Organization: **Brazos Co-op**
Department: **Transmission**

Comment	Response
It is unclear in Measure M3.2 what the word "accepted" means. There appears to be requirements within the compliance section that need to be specifically shown in R1 (see response to Question #2).	Regarding M3.2 (M5 in the current draft), the SDT has removed the word ?accepted? from the measure.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Answer: **Yes**
Organization: **Texas Municipal Power Agency**
Department: **Transmission**

7. The Violation Severity Levels (VSLs) were modified to reflect changes in the requirements per NERC Drafting Team Guidelines. Do you agree with these VSLs? If not, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **International Power America Services**
Department: **Engineering**

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**

Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **Yes**

Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Name: **Zotter, Laura**
Phone: **512.248.3884**

Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Comment	Response
ERCOT ISO suggests the drafting team look into the NERC Performance Based Standards work where NERC is recognizing that administrative/reporting type requirements may not be Reliability requirements. NERC SDT for FAC-003 have used this method successfully. R1 and R2 may be considered as administrative/reporting type requirements?	The team has moved in the direction of the Performance Based Standards with this draft. However R1 and R2 are not purely administrative reporting requirements, they are an integral part of the overall frequency response performance evaluation and are necessary for the rest of the standard.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **No**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
The draft standard has not developed far enough for this assessment to be properly conducted.	Thank you for your comment.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Answer: **No**

Organization: **Brazos Co-op**
Department: **Transmission**

Comment	Response
Separate VSLs for R3.1 and R3.2 should be considered as the percentage for each parameter that could be defined as bad performance could be different. Please explain justification for the proposed values.	The SDT thanks you for your comment. However, the SDT believes the VSL as written applies equitably to both 3.1 and 3.2 (5.1 and 5.2 in the current draft). The team felt that using percentages was the most equitable approach. Both settings are equally important for proper operation of a Governor. Having the VSLs the same emphasizes this importance.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Answer: **Yes**

Organization: **Texas Municipal Power Agency**
Department: **Transmission**

8. Do you have any other comments to improve the draft standard? If so, please explain in the comment area.

Name: **Moutaftchiev, Nikolay**
Phone: **972-923-7473**
Segment: **Independent Generator**
Answer: **Yes**
Organization: **International Power America Services**
Department: **Engineering**

Comment	Response
1. R3.2 requires that CCGT governor is set at 4% and the associated ST governor is set at 5%. It is my understanding that the only reason to require GT governor to be set lower is to compensate for the steam turbine being operated with valves wide open. If the GT governor is to be set at 4%, then there should not be a requirement for ST governor in combine cycle mode, especially for ST in single shaft combine cycle arrangement. In this arrangemet GT governor set at 4% will fully compensate for the ST (up and down) and the generator output will vary with 5% droop. For single shaft steam turbine measures M3, M4 and M5 are not applicable as there is on way to measure separate MW output of the ST. I suggest that the requirement for Steam Turbine (Combined Cycle) in table 3.2 Governor droop settings is removed. 2. An observation on how the evaluation tool works with single shaft combine cycle data. For these units MW measurement includes both GT and ST output. This creates lower performance evaluation, as the whole unit capacity is used in the calculations, while the frequency response is proportional only to the GT capability. For fair evaluation, droop in the spreadsheet should be set at 5% for calculation of the expected response. This expectation should be compared with the unit MW change. With GT operating at 4% droop, the produced MW change will meet the requirement for a unit with 5% droop. In this way single shaft combine cycle unit will be fairly compared to the other resources.	On single shaft combined cycle units, the normal HSL of the combustion turbine will have to be provided to the BA. The expected primary frequency response will utilize the capacity of the combustion turbine?s contribution only and not include the capacity of the steam turbine output on the generator. This HSL could be represented by a % of the telemetered HSL of the combined cycle resource. The combustion turbine share can be submitted to the BA as part of the list of constraints. When the steam turbine is offline the multiplier doesn?t apply. Table 5.2 has been modified to reflect steam turbine operating under combustion cycle mode being required to set their Governor settings per R5, but are not expected to comply with R8 and R9. The team agrees that we should only use the gas turbine portion of capacity as explained above. A multiplier can be used to determine the GT HSL.

Name: **VERA, RICK**
Phone: **281-343-2266**
Segment:
Answer: **Yes**
Organization: **POWER CONSULTANT**
Department:

Name: **Thormahlen, Jack**
Phone: **512-473-3200**
Segment: **Cooperative**
Answer: **No**
Organization: **Lower Colorado River Authority**
Department: **WholeSale Power Services**

Comment	Response
R3.3 equations using the term MWgcs defined as maximum megawatt control range of the governor control system needs to better define the phrase maximum megawatt control range due to the phrase being interpreted in many different ways. In addition, the workshop presenters stated that certain data will be required to be sent to ERCOT in order for them to perform the evaluations. There is nothing in this BAL that requires data submission, when and how to submit the data, and by what means to submit the data. There are other statements, definitions and requirements in the spreadsheet (tool) that are not specified in this BAL. If these are pertinent data, statements, definitions or requirements, they need to be stated in this BAL. One last issue. This is a very complicated spreadsheet (tool). I recommend that several training sessions be provided to the MPs to gain certain knowledge of the complexities of this spreadsheet (tool). This will at least make the MPs aware that help is available.	The current draft of the standard uses HSL. Parameters will be sent to the BA in the format requested by the BA. The current draft of the standard does not specify use of a specific tool, but rather a methodology by which to measure performance of each generating unit/generating facility. The methodology is included in R8 and R9 and Attachment 1 (flowchart). GOs can still use the performance evaluation tool spreadsheet to track their own performance, but it is not required. The team has held a workshop on August 6 to address the performance evaluation methodology, inform entities of what information the BA will require and provide training on the evaluation tool (spreadsheet) to interested parties. The PDCWG will provide additional opportunities to evaluate the standard and measures in the standard.

Name: **Niemeyer, Sydney L**
Phone: **713-795-6108**
Segment: **Independent Generator**
Answer: **Yes**

Organization: **NRG Texas**
Department: **Asset Desk - Real Time Op**

Comment	Response
On the "Report Summary" sheet of the evaluation tool, in column "J", the P.U. Perf Sustain should be blank when the Sustain Evaluation column "K" indicates "No Evaluation". This is just a cosmetic change.	This has been fixed, thank you.

Name: **Zotter, Laura**
Phone: **512.248.3884**

Organization: **ERCOT ISO**
Department: **Operating Standards**

Group Members

Name	Organization
Ken McIntyre	ERCOT ISO
Sandip Sharma	ERCOT ISO

Segment: **ERCOT ISO**
Answer: **Yes**

Comment	Response
1. In the Applicability section, the standard should exempt any individual Unit or aggregated Units with the physical capacity less than 10 MWs at the point of interconnection. 2. In the Apllicability section, Requirement 4.2, for exempted generating facilities, ERCOT ISO suggests some clarifying language other than "Existing". ERCOT ISO suggest language such as "Existing prior to the effective date of this standard", or "Connected to the ERCOT Interconnection (BES) prior to the effective date of this standard". 3. In Attachment 1: #8 should be removed. This is the measure for R2 and has a different implementation date. 4. ERCOT ISO suggests that all necessary measures, parameters, limitations, exemptions in the current Performance tool should be extracted and detailed in the standard. 5. ERCOT ISO requests clarification on who is responsible for determining unit/resource exemptions if it is not clearly detailed in this standard. Will it be the BA or the Compliance Enforement Authority? If the standard does not cleary detail the exemptions and the qualifying criteria for exemptions, then a registered entity must have the responsibilty to develop such criteria. The existing performance 'Tool' may already contain the criteria and as such again nees to be extracted and detailed in the standard.	1. Based on the NERC compliance registry, Individual generating units less than 20 MVA (gross nameplate rating) are excluded from registering as a GO/GOP, unless it is a blackstart unit or is material to the reliability of the bulk power system. 2. This has been addressed in the current version of the standard. 3. Attachment 1 (list of data) has been removed from the standard. 4. The methodology for performance evaluation is included in the flowchart (current Attachment 1), and the formulas are included in R8 and R9. 5. Application of exceptions occurs during the enforcement process, and will be done by the Compliance Enforcement Authority.

Name: **Ness, Thad K**
Phone: **614-716-2053**
Segment: **Investor-Owned Utility**
Answer: **Yes**

Organization: **American Electric Power Service Corp.**
Department: **Regulatory Services**

Comment	Response
In response to the provided definition of Frequency Measurable Event (FME), AEP is concerned with the paranthetical phases added to conditions (i) and (ii), that include "(the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year)" and "(the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year)," respectively. While this is useful information for performing analysis, it is not appropriate to weaken the standard's requirements in this manner. Conditions under which a unit's frequency response is not required to be evaluated need to be included within the proposed standard. For example valves wide open (over 98% PMax), operation at dead points in ramp curve, unit in startup mode and below stated minimum load point. On the 3/3/10 TRE webinar it was stated that some of this is built into the frequency response evaluation spreadsheets.	The drafting team does not feel that changing the criteria for defining an FME will weaken the standard?s requirements. It provides flexibility for obtaining a statistically valid sample size of events for evaluating Interconnection performance and generator performance. The drafting team does not consider it appropriate to try to identify every possible limitation where an exception could be warranted. Exceptions will be considered on a case by case basis by the Compliance Enforcement Authority. Identified limitations in the evaluation methodology have formulas added to the requirements of the standard.

Name: **Kelly, Robert M**
Phone: **254-744-1463**
Segment: **Cooperative**
Answer: **Yes**

Organization: **Brazos Co-op**
Department: **Transmission**

Comment	Response
Definitions: Should the definition of Primary Frequency Response be expanded to define what is meant by "initial" and "sustained" response in place of the last sentence that says it is "in the direction that stabilizes frequency". R3 comment: Consider clarifying the wording of R3 with the following: "Each GO shall ensure that Governor parameters for each of its generating unit/generating facility are set to provide the following perfomance characteristics:". R4 comment: Should there be a requirement for the GO to inform the BA what the values to use in each of the equations for each of its generating unit/generating facility. Are there default values if the GO so chooses?	The formulas within the requirements define the time periods for ?initial? and ? sustained?. ?Initial? uses t(20) through t(52). The ?sustained? uses t(0) to event recovery time. The requirements of R5 (formerly R3) are directed to settings, not performance. Performance is measured in R8 and R9. The limiting factor parameters provide the GO an opportunity to communicate limits to the Compliance Enforcement Authority and the BA that can be used to modify expected performance. If the GO chooses not to provide this information, default values will be utilized. The default values will not incorporate unique unit characteristics or reduce the expected primary frequency response value.

Name: **Owens, Frank J**
Phone: **936-873-1120**
Segment: **Municipally Owned Utility**
Answer: **Yes**

Organization: **Texas Municipal Power Agency**
Department: **Transmission**

Comment	Response
We recommend add 4.4 under section A that reads as follows: 4.4 Generating units/generating facilities while operating in valves wide open (VWO) mode are exempt from Standard BAL-001-TRE-1.	This has been included as an example of a legitimate operating condition that may support the exclusion of FMEs under M8.

Attachment 6-001

September 1, 2010
9:30 a.m. – 11:00 a.m.

7620 Metro Center Drive
Austin, TX 78744
Room 206

Administrative

1. Introduction and Attendance

Rick Keetch welcomed the attendees to the meeting. The attendees were as follows:

Name	Company	Sector	Present	Called-in
Steve Myers	ERCOT	System Coord & Planning		
Laura Zotter (Alternate)	ERCOT	System Coord & Planning	X	
John Brockhan	CenterPoint Energy Houston Electric	Transmission/ Distribution	X	
Paul Johnson	American Electric Power Service Corp	Transmission/ Distribution	X	
Barry Kremling	Guadalupe Valley Electric Cooperative	Cooperative	X	
Richard McLeon (proxy - Barry Kremling)	South Texas Electric Cooperative	Cooperative		
David Detelich	CPS Energy	Municipal	X	
Frank Owens	Texas Municipal Power Agency	Municipal		
Marguerite Wagner	PSEG Energy Resources & Trade	Generation	X	
Billy Shaw	IPA Trading	Generation	X	
Venona Greaff (Alternate)	GDF SUEZ Energy Marketing NA	Generation	X	
Jeremy Carpenter	Tenaska Power Services	Load Serving & Marketing	X	
Rick Keetch	NRG Power Marketing	Load Serving & Marketing	X	
Lindley Ellisor	Texas Reliability Entity		X	
Don Jones	Texas Reliability Entity		X	
Tim Soles	Occidental	Load Serving & Marketing	X	
Sydney Niemeyer	NRG Texas	Generation	X	
Andrew Gallo	Austin Energy	Municipal	X	
Jose Escamilla	CPS Energy	Generation	X	
Bruce Wertz	PSEG	Generation		X

At least one representative from at least four of the six sectors is required to constitute a quorum. At this meeting, a quorum was achieved with at least one representative from all six segments being present.

Antitrust Admonition & Meeting Minutes

The Texas Reliability Entity (Texas RE) Antitrust Admonition was displayed for the members. The attendees were reminded that it is Texas RE policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

The draft minutes from the August RSC meeting were presented. There were no comments or changes suggested.

*A motion was made and seconded to approve the draft minutes. Motion **carried** by voice vote. The minutes were approved.*

Discussions and Activities

2. BAL-001 TRE-1 – Approval to Post for Comment (D. Jones and S. Niemeyer)

Don Jones asked the RSC to approve the Third Draft of Regional Standard BAL-001-TRE-1 to be posted for comment. Don outlined the revisions that were made in the Third Draft. Sydney Niemeyer answered several questions regarding the drafting process. Don noted that the Tracking Site will be ready to accept comments on or about October 4 (see below). *Billy Shaw made a motion to approve posting the draft for comments. Jeremy Carpenter seconded the motion. The motion **carried** with none opposed and no abstentions.*

Sydney also informed the RSC of the recently completed CERTS study of frequency response in the North American interconnections. He also noted that FERC will conduct a technical workshop on Frequency Response on September 23, where he will be on the expert panel.

3. Other Regional Standards Activity (D. Jones)

Don Jones reported that the CIP-001 Regional Variance (SAR-008) was approved by the Texas RE Board and submitted to NERC for informal review. The Variance will be formally submitted to NERC after an informal review is completed.

Don reported that the SAR-009 SDT met on August 17 and elected Jerry Ward as Chair and Marguerite Wagner as Vice Chair. Future SDT meetings are scheduled for September 20 and October 11. Don requested the RSC to approve a Milestone Date of February 1, 2011 for this Regional Standard Project, which is the SDT's deadline for presenting a first draft of the standard to the RSC to be posted for comments. *David Detelich made a motion to set a Milestone Date of February 1, 2011. Paul Johnson seconded the motion. The motion **carried** with none opposed and no abstentions.*

4. NERC Standards Under Development (D. Jones)

Don provided a brief overview of NERC Standards Under Development, including a list of the NERC Standards Projects that are open for ballot or comment at this time. He presented additional information on NERC's proposed Reliability Standards Development Plan, which is open for comment through September 16. It was noted that the NERC Standards/NSS presentation will be made by the NSS Chair (or his designee) in the future.

5. Status of Standards Tracking Site Development (D. Jones)

Don notified the RSC that the Texas RE Standards Tracking Site revisions related to separation from ERCOT have been substantially delayed due to vendor personnel problems. The vendor has committed to having sufficient revisions completed to allow a comment period to open on October 4. Texas RE is continuing to work with the vendor to expedite completion of this project.

6. NSS Formation Update (D. Jones)

Don reported that the first meeting of the NERC Standards Subcommittee (NSS) of the RSC was held by teleconference on August 30, 2010. Bruce Wertz was elected Chair and Pam Zdenek was elected Vice Chair. There are presently 11 volunteers on the NSS roster, representing 9 organizations. Don noted that the Transmission Sector is not currently represented on the NSS. He reported that a small team of NSS volunteers is drafting Procedures for the NSS, which will be presented to the RSC for approval when they are completed.

The NSS has scheduled additional teleconference meetings on September 13 and 20, and plans to have a face-to-face meeting in Austin following the November 3 RSC meeting.

7. Standards-Related Procedures (Ad hoc team)

Billy Shaw presented the Ad Hoc Team's revised draft Procedures for RSC, SDT and RBB. A number of issues were discussed, including the role of Sector Alternates and voting requirements. Texas RE will post the latest versions of the Procedures (red-line and final versions) for further consideration, comment and discussion at the next RSC meeting.

8. Texas RE Board and MRC Update (D. Jones)

Don reported that the August 24 MRC and Board meetings were attended by Gerry Cauley (NERC CEO), and by John Anderson and Paul Barber (NERC Board members). He also reported on the following actions of the Texas RE Board:

- The Board approved the CIP-001 Regional Variance for submission to NERC.
- The MRC recommended, and the Board decided, that Texas RE will not respond to the PUC's RFP for Reliability Monitor services after January 1, 2011. Texas RE plans to continue serving in that role through the end of 2010.

9. The meeting adjourned at 10:53 am. The next meeting is planned for Wednesday, October 6, 2010 at 9:30 am at the ERCOT Met Center.

Attachment 6-002a

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.

SAR posted for comment on April 24, 2008.

SAR approved May 27, 2008.

Drafting Team nominated and selected in June 2008.

First posting of standard on March 16, 2009.

Drafting Team held technical workshop on March 31, 2009.

Second posting of standard on February 12, 2010.

Drafting Team held technical workshop on March 3, 2010.

Drafting Team held a performance evaluation workshop on August 6, 2010.

Third posting requested at RSC Meeting September 1, 2010.

Description of Current Draft

This drafting team is currently working on revising the draft based on comments received during the second comment period and guidance from FERC staff. This draft will likely be posted for a third comment period in September 2010 and ballot in December 2010.

Future Development Plan:

Anticipated Actions	Anticipated Date
Present final draft to RSC to accept for public posting	September 2010
Workshop on Performance Evaluation	September 2010
Post for Comment	September 2010
Respond to Comments/Revise	October/November 2010
Present revised draft to RSC	December 2010
Form ballot pool and vote	December 2010
TRE Board Adopt (Tentative)	January 2011
NERC Submit (Tentative)	January 2011
FERC Approval (Tentative)	June 2011
Begin Implementation Plan	July 2011
All Applicable Entities Fully Compliant	January 2014

Definitions of Terms Used in Standard

Frequency Measurable Event (FME): Frequency Deviation used to evaluate generating unit/generating facility Primary Frequency Response performance, which will be identified by the BA at the BA's sole discretion, if it meets one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 34-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

or

ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Real Power Balancing Control Performance

2. **Number:** BAL-001-TRE-1

3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. This regional standard supplements the CPS2 Waiver that was approved for ERCOT by NERC on November 21, 2002. Specifically, this standard replaces requirement 2 of BAL-001-0a per FERC Order 693.

4. **Applicability:**

   4.1. Functional Entities:

   1. Balancing Authority (BA)
   2. Generator Owners (GO)
   3. Generator Operators (GOP)

   4.2. Exemptions:

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode (providing reactive power only) are exempt from Standard BAL-001-TRE-01.

5. (**Proposed) Effective Date:** After final regulatory approval and in accordance with the 30-month Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements. See attached Implementation Plan (Attachment 1).

B. Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M1. The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in R1.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard. This calculation shall be a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. The calculation results shall be submitted to the Compliance

Enforcement Authority by the end of the month in which they were completed. If the generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M2. The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in R2.

R3. The BA shall calculate the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, and the methodology for calculation and criteria for determination of the IMFR publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

M3. The BA shall demonstrate that the IMFR was calculated in December of each year. The BA shall demonstrate that the IMFR and the methodology for calculation, and the criteria for determination of the IMFR is publicly available.

R4. The BA shall determine and make publicly available the Interconnection’s combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following month. Following any FME that causes the Interconnection’s six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M4. The BA shall provide evidence that the rolling average of the Interconnection’s combined Frequency Response performance for the last six (6) FMEs was calculated and made public. If the Interconnection’s six-FME rolling average combined Frequency Response performance was less than the IMFR, the BA shall provide evidence that actions were taken to improve Frequency Response.

R5. Each GO shall set its Governor parameters as follows:

5.1. Limit Governor deadbands within those listed in Table 5.1, unless directed otherwise by the BA.

Table 5.1 Governor Deadband Settings

Governor Type	Max. Deadband
Mechanical	+/- 0.034 Hz
Electronic	+/- 0.01666 Hz
Digital	+/- 0.01666 Hz

5.2. Ensure that Governor droop settings do not exceed those listed in Table 5.2, unless directed otherwise by the BA.

Table 5.2 Governor Droop Settings

Resource Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Turbine	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of a Combined Cycle Resource are required to comply with 5.1, 5.2 and 5.3, but are not expected to comply with R8 and R9.

5.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, ensure that the resource Governor setting follows the slope derived from the formula below.

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

where MW_{GCS} is the maximum megawatt control range of the Governor control system.

[Violation Risk Factor = High] [Time Horizon = Operations Planning]

M5. Each GO shall have evidence that it set its Governor parameters in accordance with R5. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

M5.1 The GO shall have evidence that it set the Governor deadbands as required in Table 5.1 in Requirement R5.

M5.2 The GO shall have evidence that the Governor droop characteristics did not exceed the settings in Table 5.2 in Requirement R5.

M5.3 The GO shall have evidence that when frequency deviation has exceeded the Governor deadband from 60.00 Hz, the Governor setting follows the approved slopes derived from the prescribed formulas for 4% droop and 5% droop.

R6. Each GO shall operate each generating unit/generating facility connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GOP has been notified.

[Violation Risk Factor = High] [Time Horizon = Real-time Operations]

M6. Each GO shall have evidence that each generating unit/generating facility had its Governor in service when the generating unit/generating facility was online and released for dispatch as described in R6.

R7. Each GOP shall notify the BA within 30 minutes of a status or capability change of a Governor.

[Violation Risk Factor = High] [Time Horizon = Real-time Operations]

M7. Each GOP shall have evidence that it notified the BA within 30 minutes of each status or capability change of a Governor.

R8. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 P.U. $PFR_{Resource}$ on each generating unit/generating facility based on an eight (8) FME minimum participation, using the methodology described in the following calculations and in Attachment 2. If the generating unit/generating facility has not participated in a

R8 measures *initial* unit FR performance (A-point to B-point). This requirement specifies a certain level of measured performance over a 12-month rolling average.

minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

Each GO may submit to the BA unit-specific information used by the BA in this requirement to calculate initial PFR performance for each generating unit/generating facility.

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

where P.U. $PFR_{Resource}$ is the per unit measure of the Primary Frequency Response of a Resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response}{Expected\ Primary\ Frequency\ Response}$$

Ideal Expected Primary Frequency Response ($EPFR_{ideal}$): This is the unadjusted expected MW change calculated when the frequency deviation exceeds the deadband.

$$EPFR_{ideal} = \left[\frac{(HZ_{actual} - 60.0 \pm deadband_{max})}{(60 * droop_{max} - deadband_{max})} \times (-1) \times (Capacity)\right]$$

Capacity as used in this standard will be the high sustained limit (HSL) as telemetered in real-time by the GO to the BA.

For normal, released for dispatch operation, the maximum and minimum operating level of a Resource's Governor must be identified by the GO and provided to the BA.

For negative frequency deviations, if

$$MW_{Pre-perturbation} \geq (maximum\ operating\ level\ x\ 0.98)$$

then Primary Frequency Response is not evaluated for this FME.

For positive frequency deviations, if

$$MW_{Pre-perturbation} \leq [minimum\ operating\ level + (Capacity\ x\ 0.02)]$$

then Primary Frequency Response is not evaluated for this FME.

EPFR for Combustion Turbine

$$EPFR_{CT} = EPFR_{ideal} + (HZ_{actual} - 60.0) \times 10 \times 0.00276 \times Generation\ Resource\ Capacity$$

EPFR for Steam Turbine

$$\% \, Steam \; Flow = \frac{Post - perturbation \; Average \; MW_{Actual}}{HSL}$$

$$Steam \; Flow \; \mathrm{Pr}essure \, Change \; Factor = \frac{\% \, Steam \; Flow}{0.5}$$

$$MW_{Adjustment} = EPFR_{ideal} * \frac{K}{Rated \; Throttle \; \mathrm{Pr}essure} * HSL * Steam \; Flow \; \mathrm{Pr}essure \, Change \; Factor$$

where K is a frequency response filter constant measured at 50% output of the steam turbine.

$$EPFR_{ST} = \left(EPFR_{ideal} + MW_{Asjustment}\right) * \frac{Throttle \; \mathrm{Pr}essure}{Rated \; Throttle \; \mathrm{Pr}essure}$$

where Throttle Pressure = Interpolation of Pressure curve at MW_{Actual}.

Actual Primary Frequency Response (APFR): This is the difference between Pre-perturbation Average MW and Post-perturbation Average MW.

$$Actual \; Primary \; Frequency \; Response = MW_{pre-perturbation} - MW_{post-perturbation}$$

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{8}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(52)}^{t(20)} MW}{17}$$

8.1. A generating unit/generating facility’s Frequency Response performance during a FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Frequency Response performance.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M8. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum performance level of 0.75 P.U. $PFR_{Resource}$ as described in R8. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at maximum unit output (low-frequency events) or minimum unit output (high-frequency events);
- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

R9 measures *sustained* unit FR performance (frequency recovery period). This requirement specifies a certain level of measured performance over a 12-month rolling average.

R9. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 P.U. $PFR_{Resource}$ on each generating unit/generating facility based on an eight (8) FME minimum participation, using the methodology described in the following calculations and in Attachment 2. If the generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

Each GO may submit to the BA any information used by the BA in this requirement to calculate sustained PFR performance for each generating unit/generating facility.

Event Recovery Time (ERT): For low frequency events, the time at which frequency returns to pre-perturbation frequency or 59.984 Hz, whichever occurs first. For high frequency events, the time at which frequency returns to pre-perturbation frequency or 60.016 Hz, whichever occurs first.

MW_{ERT} = Instantaneous MW at ERT

Event Average Ramp MW

$$MW_{EAR} = \frac{MW_{t-2} + MW_{ERT}}{2}$$

Event Average Expected MW

$$MW_{EAE} = \frac{\sum_{t(-2)}^{t(ERT)}(EPFR_t)}{\#Scans}$$

Where EPFR (Expected Primary Frequency Response) is:

$$Expected\ MW\ Change = \left[\frac{(HZ_{actual} -\ 60.0 \pm deadband_{max})}{(60 * droop_{max} - deadband_{max})} \times (-1) \times (Capacity)\right]$$

Event Average Actual MW

$$MW_{EAA} = \frac{\sum_{t(-2)}^{t(ERT)} (MW_t)}{\#Scans}$$

$$P.U.PFR_{Resource} = \frac{MW_{EAA} - MW_{EAR}}{MW_{EAE} - MW_{EAR}}$$

$$\mathrm{Avg}_{\mathrm{Period}}[\mathrm{P.U.\ PFR}_{\mathrm{Resource}}] \geq 0.75$$

9.1 A generating unit/generating facility's Frequency Response performance during a FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Frequency Response performance.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained performance that is at least 0.75 P.U. $\mathrm{PFR}_{\mathrm{Resource}}$ as described in R9, and documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation.

C. Compliance

1. Compliance Enforcement Authority

Texas Reliability Entity

2. Compliance Monitoring Period and Reset Time Frame

2.1. Each generating unit/generating facility will have a rolling event average performance as stated in R8 and R9 of this standard.

If a generating unit/generating facility fails any requirement or measure of this standard, the GO will submit mitigation plans for the failing generating unit/generating facility with a timeline not to exceed 90 days from the notification of failing performance.

2.2. If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R8 and R9 of the standard, then the generating unit/generating facility will begin a new rolling event average performance on the next successful performance during a FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R8 and R9.

2.3. If the generating unit/generating facility fails the next FME performance after completing its mitigation plan, the GO will submit a follow-up mitigation plan with a timeline not to exceed 30 days from the notification of failing performance.

3. Data Retention

3.1. The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain a list of identified Frequency Measurable Events and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The BA shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The BA shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The BA shall retain all data and calculations relating to the Interconnection's Frequency Response, and all evidence of actions taken to increase the Interconnection's Frequency Response, since its last compliance audit for Requirement R4, Measure M4.
- Each GOP shall retain evidence since its last compliance audit for Requirement R7, Measure M7.
- Each GO shall retain evidence since its last compliance audit for Requirements R5, R6, R8 and R9, Measures M5, M6, M8 and M9.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Periodic Data Submittals as required

Exception Reporting as necessary

D. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	An FME is not reported >14 days but ≤ 30 days of identification of the event	An FME is not reported >30 days but ≤50 days of identification of the event	An FME is not reported >50 days but ≤70 days of identification of the event	An FME is not reported >70 days identification of the event
R2	Monthly reports submitted >30 days but ≤50 days from the end of the reporting month	Monthly reports submitted >50 days but ≤70 days from the end of the reporting month	Monthly reports submitted >70 days but ≤90 days from the end of the reporting month	Monthly reports submitted >90 days from the end of the reporting month
R3	The BA did not make the calculation and criteria for determination for the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR in December.	The BA did not calculate the IMFR.
R4	N/A	The BA did not make the six FME rolling average public.	The BA did not calculate the six FME rolling average.	The BA did not take necessary actions for an FME where the Interconnection's combined performance was less than the IMFR.
R5	Any Governor parameter setting >10% and ≤20% outside setting range specified in R5	Any Governor parameter setting >20% and ≤30% outside setting range specified in R5	Any Governor parameter setting >30% and ≤40% outside setting range specified in R5	Any Governor parameter setting >40% outside setting range specified in R5 – OR – the electronic or digital Governor was set to step into the curve
R6	N/A	N/A	N/A	GO operated with its Governor out of service and did not notify the GOP.
R7	The GOP notified the BA of a change in Governor status or capability between 30 minutes and one hour.	The GOP notified the BA of a change in Governor status or capability within 1-4 hours.	The GOP notified the BA of a change in Governor status or capability after 4 hours.	The GOP failed to notify BA of a change in Governor status or capability.
R8	Rolling average per R8 is <0.75 and ≥0.65	Rolling average per R8 is <0.65 and ≥0.55	Rolling average per R8 is <0.55 and ≥0.45	Rolling average per R8 is <0.45
R9	Rolling average per R9 is <0.75 and	Rolling average per R9 is <0.65 and	Rolling average per R9 is <0.55 and	Rolling average per

	≥0.65	≥0.55	≥0.45	R9 is <0.45

E. Regional Variances

This is a regional variance to NERC Standard BAL-001-0a, specifically replacing Requirement R2 in the ERCOT Region. Instead of complying with R2 in BAL-001-0a (CPS2), the BA, GO, and GOP functional entities in the ERCOT Interconnection maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time by the methods, requirements, and measures described in this regional standard and associated attachments and documents.

F. Associated Documents

1. Attachment 1 - Implementation Plan.
2. Attachment 2 - Flowchart illustrating computations used to determine Primary Frequency Response performance as described in R8 and R9.

Version History

Version	Date	Action	Change Tracking

Attachment 6-002b

Attachment 1

Implementation Plan FOR BAL-001

Compliance Schedule for Requirements R1- R9 for BAL-001-TRE-01

Effective Date: After final regulatory approval and in accordance with the three-year Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements.

REQUIREMENT	Months after Effective Date / Responsible Party	12 mos.	18 mos.	24 mos.	30 mos.	Measurement definition for responsible party:
R1	BA	Compliant				**M1.** The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in R1.
R2	BA		Compliant			**M2.** The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in R2.
R3	BA		Compliant			**M3.** The BA shall demonstrate that the IMFR was calculated in December of each year. The BA shall demonstrate that the IMFR and the methodology for calculation, and the criteria for determination of the IMFR is publicly available.
R4	BA		Compliant			**M4.** The BA shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public. If the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, the BA shall provide evidence that actions were taken to improve Frequency Response.
R5	GO	50% of GO's units Compliant (if >1 unit)	100% of GO's units Compliant			**M5.** Each GO shall have evidence that it set its Governor parameters in accordance with R5. Examples of evidence include but are not limited to: • Governor test reports • Governor setting sheets • Performance monitoring reports M5.1 The GO shall have evidence that it set the Governor deadbands as required in Table 5.1 in Requirement R.5. M5.2 The GO shall have evidence that the Governor droop characteristics did not exceed the settings in Table 5.2 in Requirement R5. M5.3 The GO shall have evidence that when frequency deviation has exceeded the Governor deadband from 60.00 Hz, the Governor setting follows the approved slopes derived from the prescribed formulas for 4% droop and 5% droop.
R6	GO	50% of GO's units Compliant (if >1 unit)	100% of GO's units Compliant			**M6.** Each GO shall have evidence that each generating unit/generating facility had its Governor in service when the generating unit/generating facility was online and released for dispatch as described in R6.
R7	GOP	50% of GO's units Compliant (if >1 unit)	100% of GO's units Compliant			**M7.** Each GOP shall have evidence that it notified the BA within 30 minutes of each status or capability change of a Governor.
R8	GO			50% of GO's units Compliant (if >1 unit)	100% of GO's units Compliant	**M8.** Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum performance level of 0.75 P.U. PFRResource as described in R8. Each GO shall have documented evidence of any FMEswhere the generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include: • Operation at maximum unit output (low-frequency events) or minimum unit output (high-frequency events); • Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans). • Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute
R9	GO			50% of GO's units Compliant (if >1 unit)	100% of GO's units Compliant	**M9.** Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained performance that is at least 0.75 P.U. PFRResource as described in R9, and documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation.

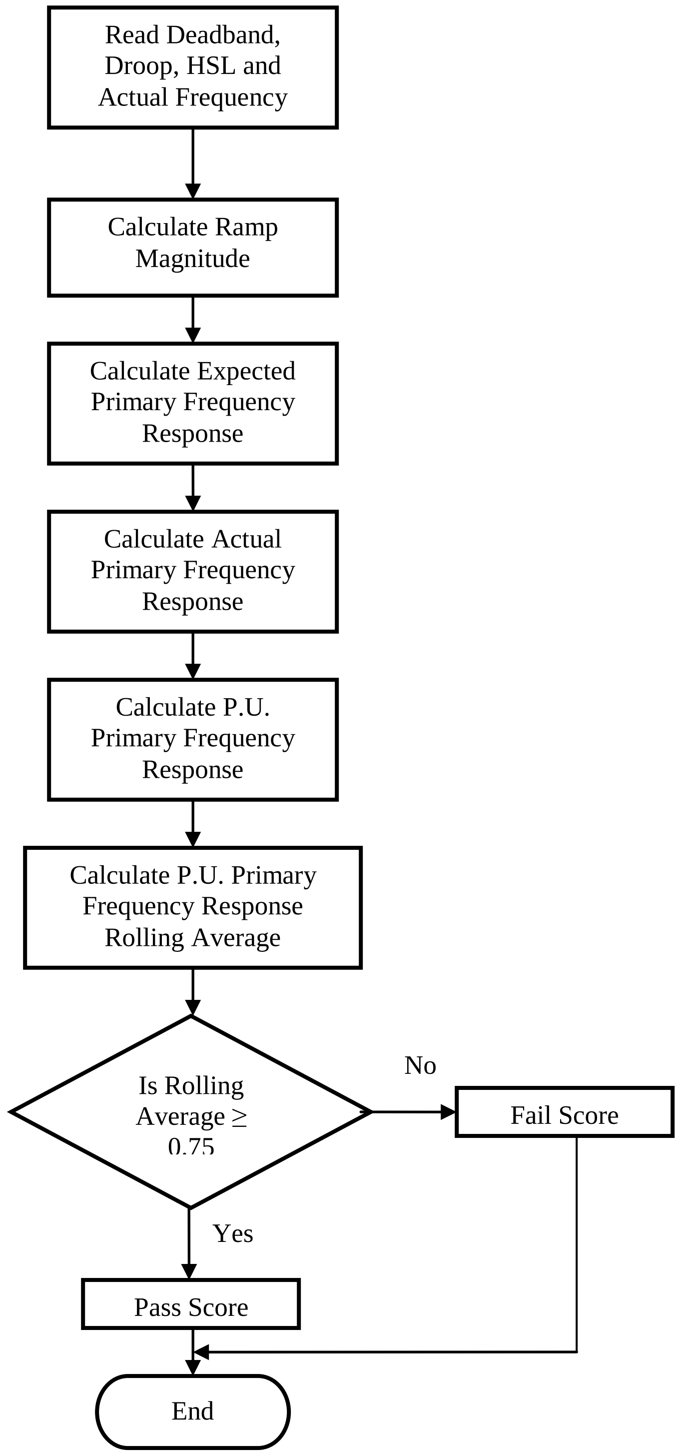
Attachment 6-002c

ATTACHMENT 2:

Primary Frequency Response Methodology for BAL-001-TRE-1

Initial Primary Frequency Response Methodology (R8)

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response



Initial Primary Frequency Response Methodology (R8)

Ramp Magnitude Calculation

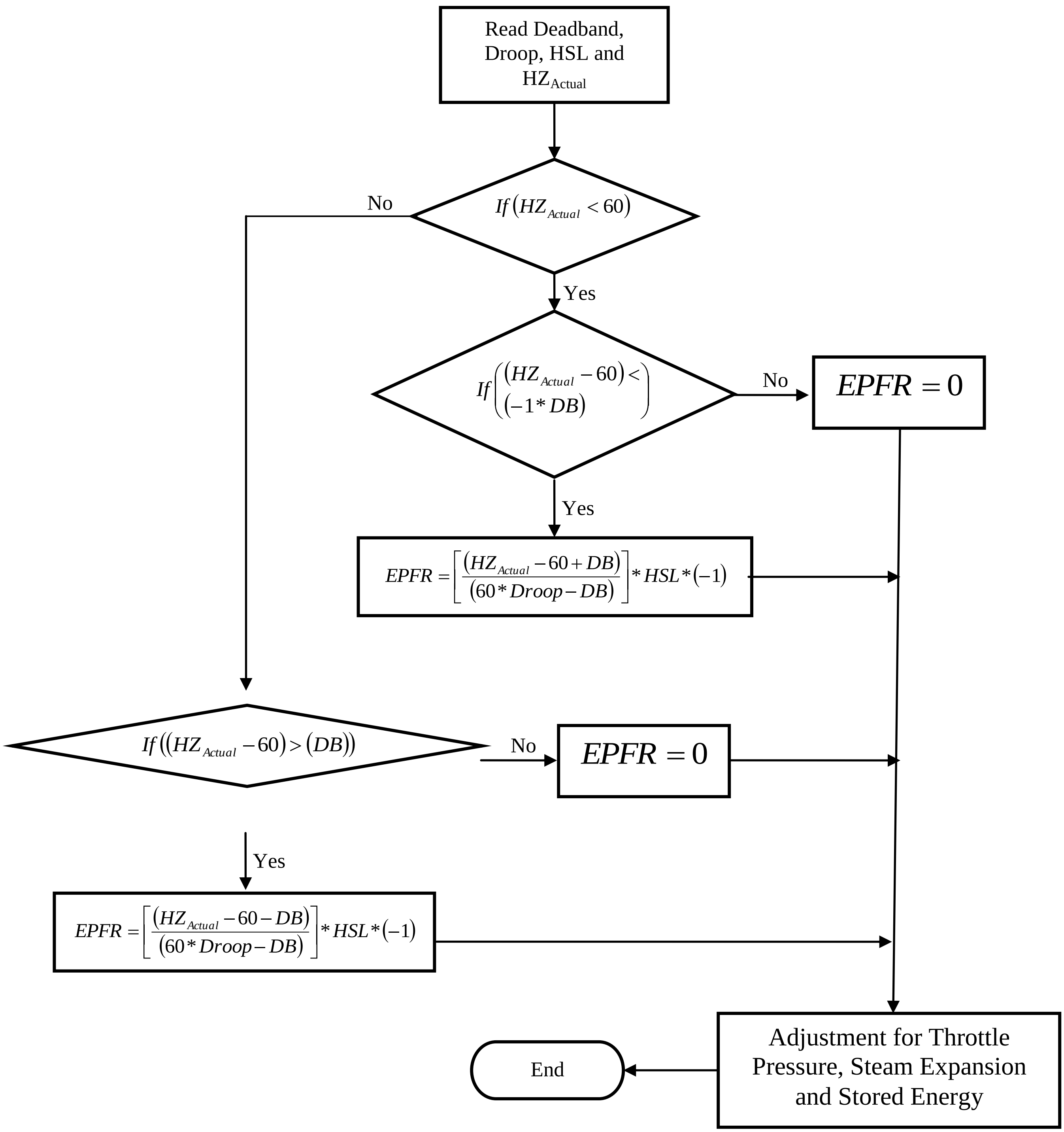
Ramp Magnitude = $MW_{T-4} - MW_{T-60}$

↓

End

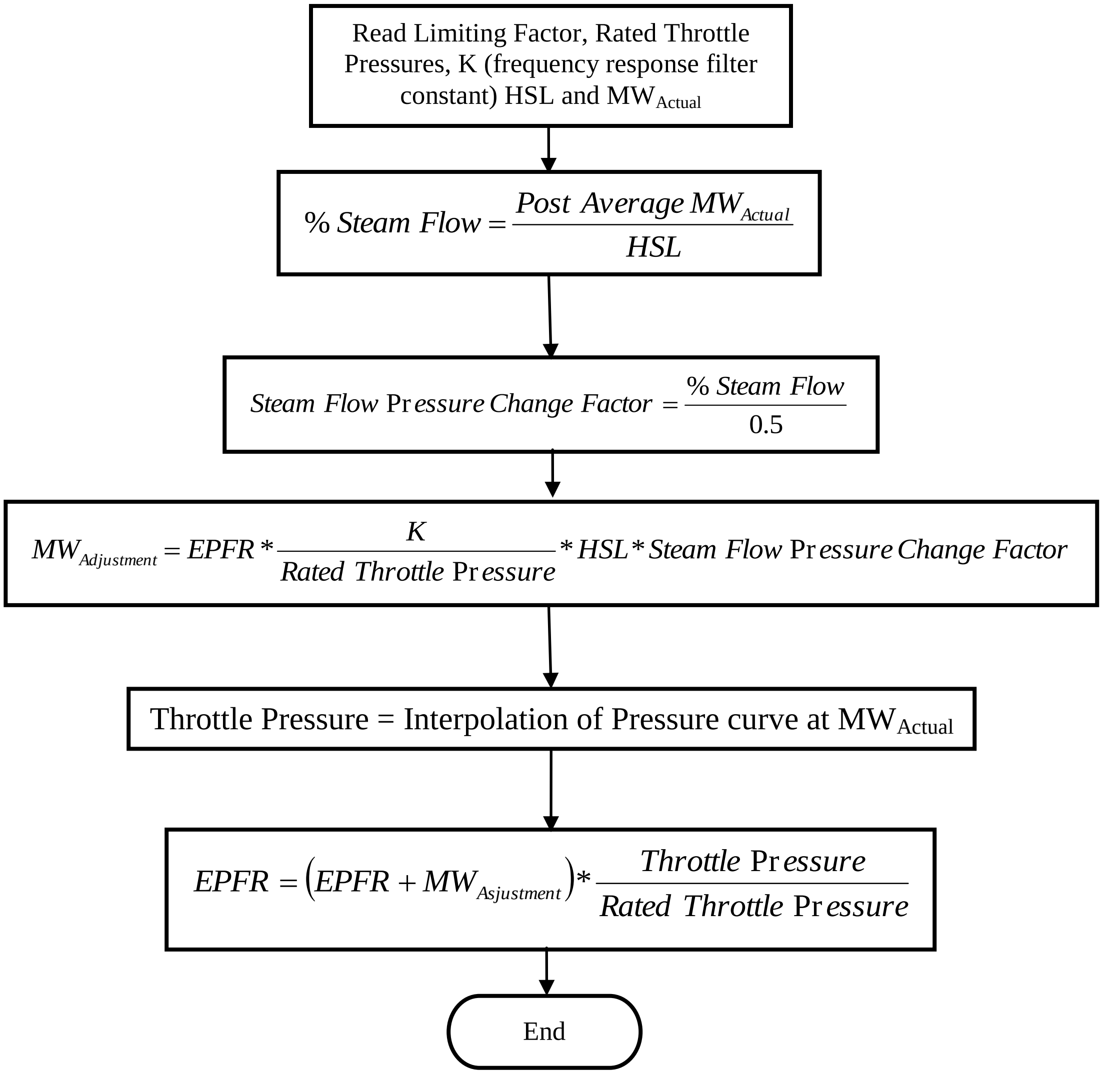
Initial Primary Frequency Response Methodology (R8)

Expected Primary Frequency Response Calculation



Initial Primary Frequency Response Methodology (R8)

Adjustment for Throttle Pressure, Steam Expansion and Stored Energy



Initial Primary Frequency Response Methodology (R8)

Actual Primary Frequency Response Calculation

Read Deadband, Droop, Capacity and Actual Frequency

Calculate Pre-Perturbation average for MW and Frequency

$$\frac{\sum_{T-16}^{T-2} MW_{Actual}}{\#\ of\ Scans}, \frac{\sum_{T-16}^{T-2} HZ_{Actual}}{\#\ of\ Scans}$$

Calculate Post-Perturbation average for MW and Frequency

$$\frac{\sum_{T+20}^{T+52} MW_{Actual}}{\#\ of\ Scans}, \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

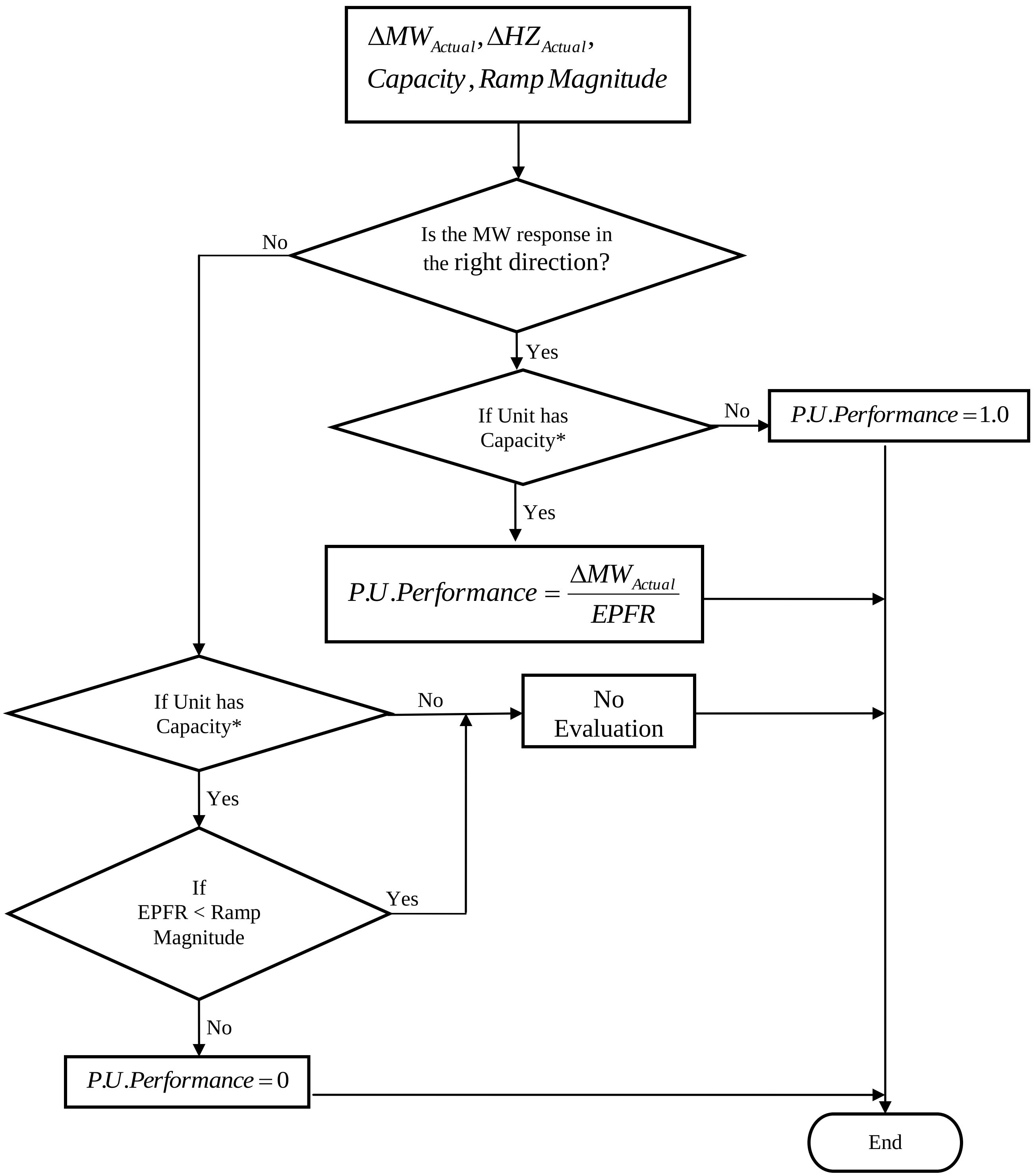
Calculate Post-Perturbation average for MW and Frequency

$$\Delta MW_{Actual} = Post - perturbation\ MW - \Pr e - perturbation\ MW$$
$$\Delta HZ_{Actual} = Post - perturbation\ HZ - \Pr e - perturbation\ HZ$$

End

Initial Primary Frequency Response Methodology (R8)

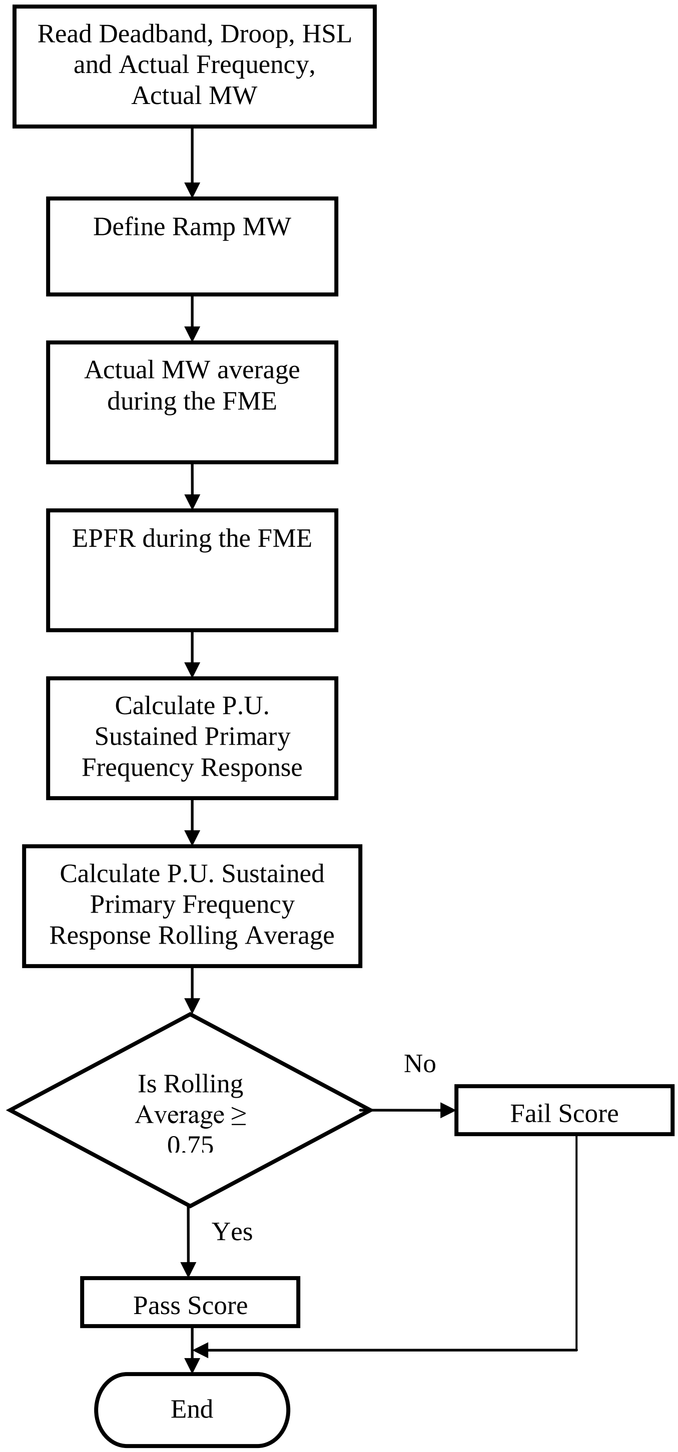
P.U. Primary Frequency Response Calculation



*check for 2% Margin. If a unit has only 2% of HSL or less as available capacity, the unit is considered operating at full capacity and will not be evaluated for low frequency. If a unit has only 2% HSL as down margin it is considered operating at Low Capacity and will not be evaluated for high frequency.

Sustained Primary Frequency Response Methodology (R9)

Primary Frequency Response Measurement and Rolling Average Calculation – Sustained Response



Sustained Primary Frequency Response Methodology (R9)

Calculate Ramp MW

Read Actual MW

$$\downarrow$$

$$\boxed{Ramp\ MW = MW_{at\ start\ of\ the\ event}}$$

Actual MW average during the FME

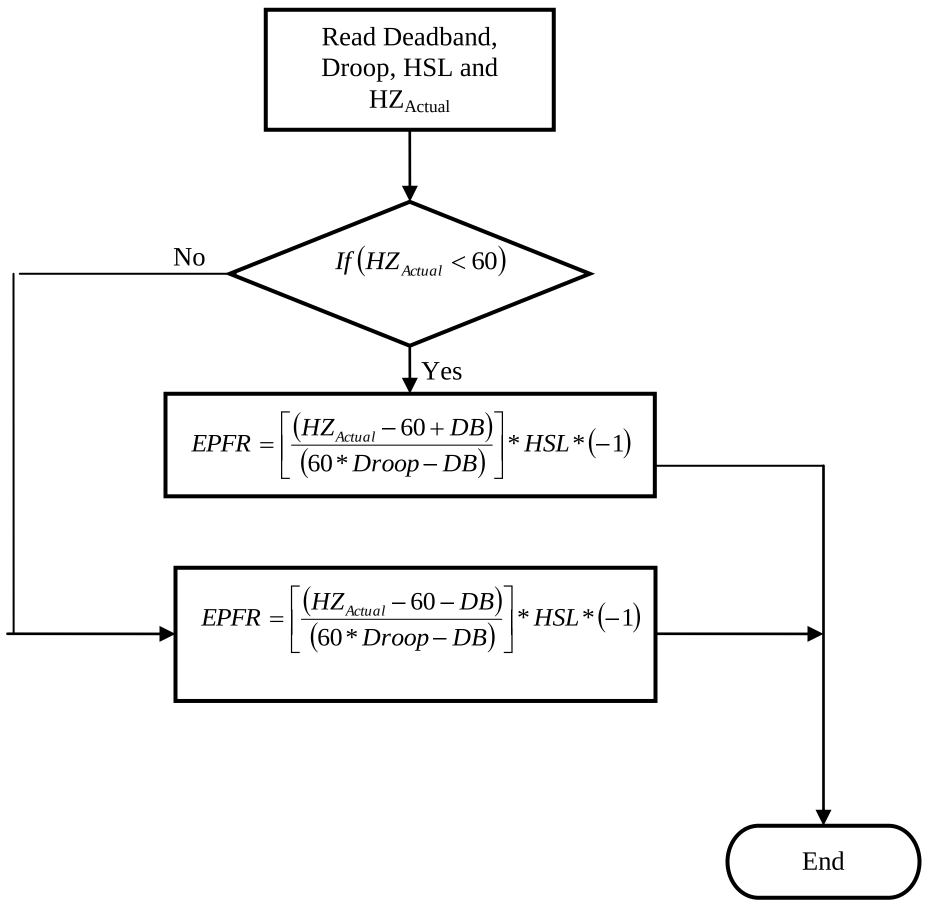
Read Actual MW

$$\downarrow$$

$$\boxed{Actual\ \ MW_{average\,during\,FME} = \frac{\sum_{start\ of\ the\ event}^{Recovery\ Time} MW_{actual}}{\#of\ \ scans}}$$

Sustained Primary Frequency Response Methodology (R9)

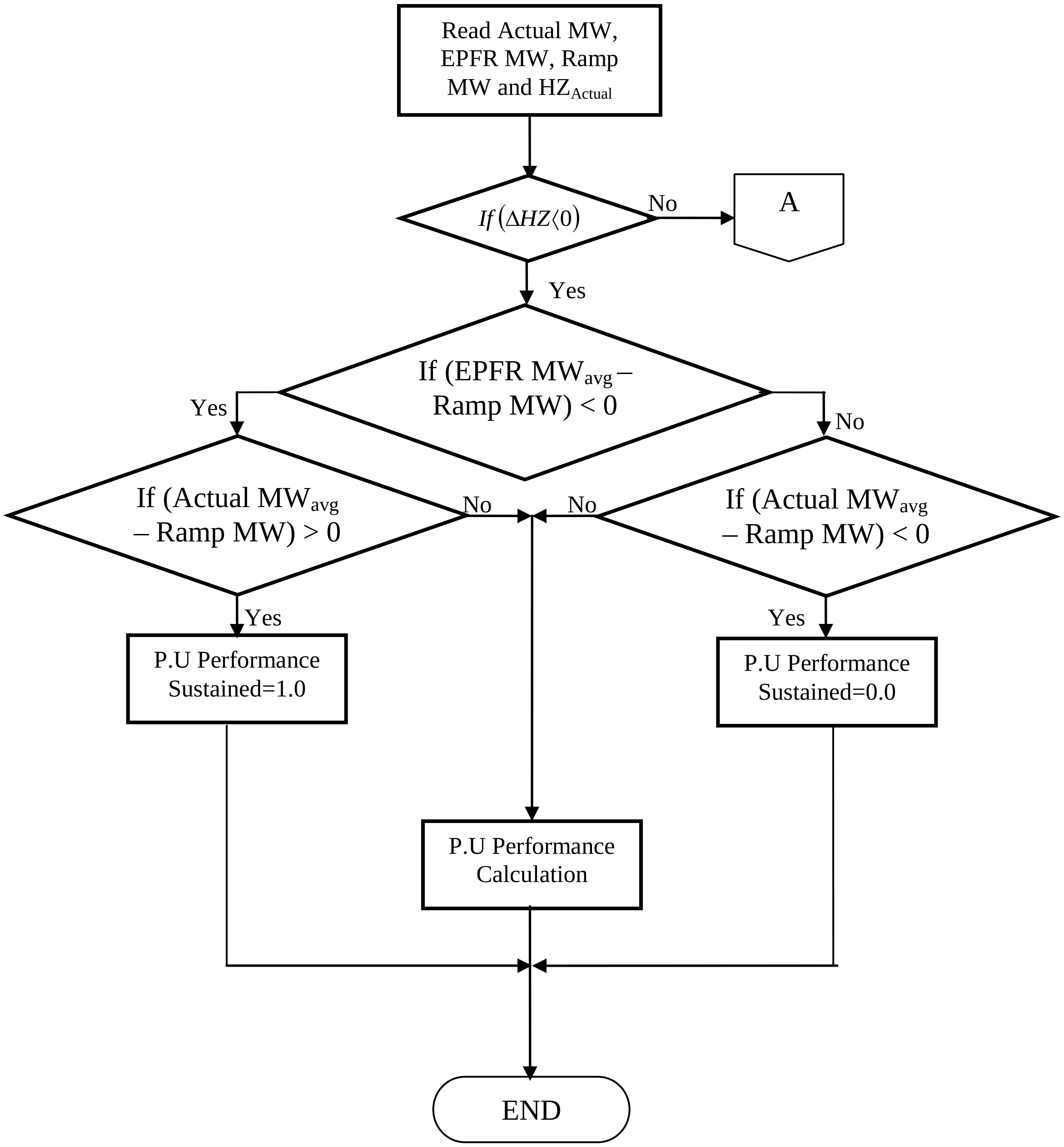
Expected Primary Frequency Response MW Average



$$EPFR\ MW_{averageduringFME} = \frac{\sum_{start\,of\ the\,event}^{Recovery\,Time} MW_{EPFR}}{\#of\ \ scans}$$

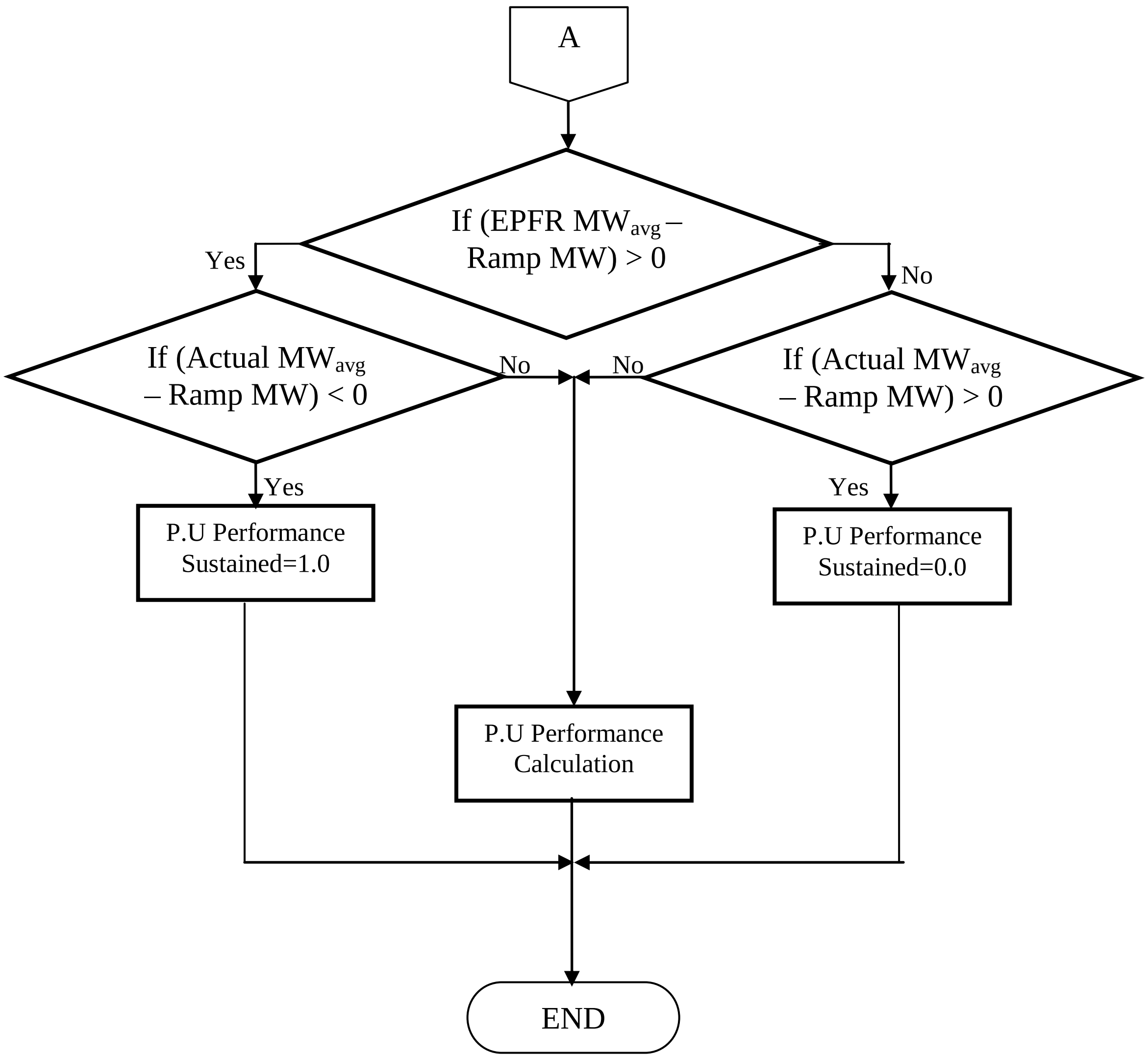
Sustained Primary Frequency Response Methodology (R9)

P.U. Performance Calculation



Sustained Primary Frequency Response Methodology (R9)

P.U. Performance Calculation



Sustained Primary Frequency Response Methodology (R9)

P.U. Performance Calculation

$$P.U.Performance_{sustained} = \frac{Actual\ MW_{averageduringFME} - Ramp\ MW}{EPFR\ MW_{averageduringFME} - Ramp\ MW}$$

Attachment 6-003

Real Power Balancing Control Performance

Question 1	The posted draft has introduced a requirement that each GOP shall notify the BA of a status or capability change of a governor (R. 7). Do you agree with this change? If not, please explain in the comment area, and address how the reliability objective can be achieved without involving the GOP.

Answers	Frequency
Yes	5 (1 with comments)
No	1 (1 with comments)

ID	Commenter	Answer	Comment	Response
309	Thad Ness - AEPSC: AEP Tex Nrth & Cen, PS of Ok-4006	No	It is unclear what real-time reliability objective would be met if the GOP indicated to the BA that the governor is out of service? What is expected that the BA would do with the information? Submitting unsolicited information that is disregarded by the receiver is not beneficial for reliability purposes.	It is envisioned that the BA will be monitoring available frequency response from on-line frequency responsive resources. This has significant importance as grids integrate additional non-frequency responsive resources and non-conforming loads. ERCOT presently collects all governor settings on frequency responsive resources to estimate grid frequency response in real-time to both high and low frequency deviations. Knowing when a governor is out of service will give the ERCOT operator situation awareness of expected Interconnection frequency response.
329	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	Yes	BA needs to know how long a governor is expected to be out of service.	Thank you for your comment. The drafting team agrees.

Question 2	The posted draft includes a requirement for the BA to calculate the Interconnection Minimum Frequency Response (IMFR) and to direct actions to improve the Frequency Response if necessary (R. 3 and 4). Do you agree with these requirements? If not, please explain in the comment area.

Answers	Frequency
Yes	6 (2 with comments)
No	0

ID	Commenter	Answer	Comment	Response
323	WALTER REID - CONSULTANT	Yes	1. In R4 change “shall calculate the Interconnection minimum Frequency Response (IMFR)” to read “shall calculate an Interconnection minimum Frequency	1. We presume you intended to refer to R3 rather than R4 and R5 in this comment. The BA must consider both high and low frequency deviations when setting IMFR and there is

			Response (IMFR) for high frequency events and an Interconnection minimum Frequency Response (IMFR) for low frequency events." In R5 add "The BA shall estimate the Interconnection Frequency Response to high frequency events above 60.1 Hz using procedures that do not depend upon FMEs." This is one of the most critical components of the standard. The BA should be required to calculate the IMFR for both low frequencies as well as high frequencies. 2. The posting of the assumptions and the basis for the calculation establishing these minimums is strongly supported. The second most critical component of the standard is the requirement of the BA to measure and report the actual Interconnection Frequency Response. 3.While FMEs are very unlikely for high frequency events, R4 should include a requirement for the BA to develop mechanisms to estimate the Interconnection Frequency Response to high frequencies of more than 60.1 Hz.	nothing preventing these values from being different. All NERC standards are calculated based on the concept of symmetrical frequency response from 60 Hz. 2. We agree that the BA should measure and report the actual Interconnection Frequency Response, including assumptions and the basis for the calculation. 3. See response to number 1 above.
330	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	Yes	1. Should there be a requirement that specifies that the GOs and GOPs have to do what the BA says? Similar to language in TOP001 R3 and IRO001 R8. EOP002 says the BA shall have the authority to direct, but there is no requirement directing the GO/GOP to comply. 2. Does the information need to be publicly available? Are there any confidentiality/sabotage-related concerns with making this information publicly available? Texas laws may prohibit ERCOT, as the only BA, from making publicly available market sensitive	1. The drafting team agrees that GOs and GOPs must follow directions from the BA, but no specific language is required in this standard. It is envisioned by the drafting team that following an FME that causes the metric to go below the minimum, the BA would respond to this occurrence through normal operational processes. 2. Yes, information needs to be published for ease of access by all interested parties to provide transparency for this process. No, there are no sabotage-related or legal concerns because the public information is system-wide aggregated information, and it is not resource-specific nor market sensitive information.

			information.	

Question 3	Will this standard accomplish the reliability objective of ensuring sufficient Frequency Response from generators in the ERCOT Region? If not, please explain in the comment area.

Answers	Frequency
Yes	4 (0 with comments)
No	2 (2 with comments)

ID	Commenter	Answer	Comment	Response
311	Thad Ness - AEPSC: AEP Tex Nrth & Cen, PS of Ok-4006	No	This standard will not "ensure" sufficient Frequency Response, but by tracking the metrics, it might improve the situation.	Thank you for your comment. The drafting team believes that R4 will ensure sufficient Frequency Response and agrees that tracking the metrics will improve frequency response performance.
331	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	No	1. We are concerned that with this Standard as written, can motivate governor response to a lower level and still pass compliance. The Standard appears to consider the worst case limitation of each type of generator, then establish a lowest common denominator approach to governor performance. Would the system be better served if specific criteria were established within the capabilities of a generator by type (CTG, Combined Cycle, Fuel Oil/Diesel, Lignite or other unique coal unit)? 2. As is, there appears to be three abatement options provided, creating a synergistic allowance that could result in a less desirable system droop. No one wants	1. The drafting team agrees with your concern but also believes that requirement R5 is clear and concise enough to protect against a GO targeting a performance level of 0.75 P.U. The only way a GO could consistently perform at this level would be to not meet R5. The 0.75 P.U. was set to allow for the normal everyday problems that machines and equipment encounter. The Limiting Factors built into the measures are intended to do exactly as you are suggesting and identify the capabilities of each generator type. The drafting team agrees with your concern about over-compensation and diluted performance requirements and has agreed to limit the range of each of the limiting factors of steam turbines. The drafting team has been using FME analysis by this measure for the past two years on generators that have been set to the requirements of R5. We believe that the 0.75 P.U. measure is appropriate and that the 12 month rolling average will provide the GO ample opportunity to address problems before failure. 2. The team believes that the exclusion language in the standard (Measures 8 and 9) is appropriate. It would be impossible to create a list of exceptions that cover all types of

			to punish a solid performing unit that gets caught in unavoidable circumstances, but allowing post-event reporting of governor limitation, in addition to 12 month averaging, in addition to .75PU performance allowance, appears to not only allow units to avoid achieving a level of performance that should be expected, but possibly incentivize them to perform more profitably at a level below their capability. Exceptions should be pre-event notifications to be allowed. 3. Governor Deadband for Wind Resources that do not have conventional governor but governor like control setting should also be spelled in table 5.1. 4. The performance index for generators not having enough room to provide PFR are awarded with 100% performance. This should be set at minimum level of 75% (page 7 of the flow chart). 5. The Requirement for the performance measurement should not be less than 5% droop characteristics for each resource. For the adjustment to reflect the real-time condition of the unit it should have already been accounted for under the 75% passing rate.	resources. It is not feasible to notify the BA of all exceptions ahead of time. 3. This issue has been addressed. The Governor deadband for wind resources would fall in the "All Other" category in revised table 5.1. 4. The team agrees, and it revised R8 to provide that, for a generator that does not have enough operating margin to provide full response, but which responds in the proper direction, the initial PFR will be the calculated PFR or 0.75, whichever is greater. 5. See number 1 above.

Question 4	Violation Risk Factors (VRFs), Violation Severity Levels (VSLs) and Time Horizons were added in connection with new requirements in the current draft. Do you agree with the VRFs, VSLs, and Time Horizons assigned to those requirements? If not, please explain in the comment area.

Answers	Frequency
Yes	4 (0 with comments)
No	2 (2 with comments)

ID	Commenter	Answer	Comment	Response

312	Thad Ness - AEPSC: AEP Tex Nrth & Cen, PS of Ok-4006	No	AEP has comments regarding some of the specific requirement that would need to be addressed before we can agree to all the VRF, VSL and other requirement based attributes.	Thank you for your comments.
332	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	No	VRF on R1 and R2 is excessive.	The drafting team agrees and revised the VRF to “Lower” on Requirements R1 and R2.

Question 5	Some measures have been revised, and new measures were added in connection with new requirements in the current draft. Do you agree with the measures contained in the current draft? If not, please explain in the comment area.

Answers	Frequency
Yes	4 (1 with comments)
No	2 (2 with comments)

ID	Commenter	Answer	Comment	Response
313	Thad Ness - AEPSC: AEP Tex Nrth & Cen, PS of Ok-4006	No	AEP has comments regarding some of the specific requirements that would need to be addressed before we can agree to all the measures. We suggest that some of the elements in the measures be included in the associated requirement(s). For example, M8 has exclusions that are not contained in the requirement. Today, Registered Entities are audited primarily on the requirements and not the measures.	Requirements in standards must have associated measures. The exclusions contained in M8 (and M9) were added based on industry comment to previous postings of the standard, and the drafting team agrees with these exclusions. In the Requirements, parts 8.1 and 9.1 were added to ensure that the exclusions are in the Requirements, not just in the Measures.
319	Nikolay Moutaftchiev - ANP Funding I, LLC-4007	No	Table 5.2 "Governor Droop Settings" does not address the specifics of the gas turbine - steam turbine single shaft unit. This type of unit has a single MW output that is the sum of the GT and ST MW output. Single shaft units should be expected to respond to frequency deviations by varying this combined MW output at 5% droop. This can be achieved by decreasing the GT droop so that it compensates for the ST part of the power train that is not responding. There should not be a requirement for governor setting of the steam turbine in single shaft combine cycle arrangement. I propose that line 5 of table 5.2 is revised to read Combustion Turbine (Combined Cycle and	The drafting team assumes that you meant to combine the single-shaft combined-cycle generator with the simple-cycle combustion turbine for droop settings. The single-shaft combined-cycle resource type has been added to Table 5.2 with the 5% droop setting. The total capacity of the combustion turbine and the steam turbine of the single-shaft generator will be used in calculating expected primary frequency response at a 5% droop.

			Single Shaft Combined Cycle units)	
333	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	Yes	We like having the measures (M1, M2, etc.) embedded within the requirements so they can be easily associated with the related requirement.	Thank you for your comments.

Question 6	Do you agree with the Implementation Plan (Attachment 1) as included in the current draft? If not, please explain in the comment area.

Answers	Frequency
Yes	5 (0 with comments)
No	0

ID	Commenter	Answer	Comment	Response

Question 7	Do you have any other comments to improve the draft standard? If so, please explain in the comment area.

Answers	Frequency
Yes	5 (5 with comments)
No	1 (0 with comments)

ID	Commenter	Answer	Comment	Response
301	Jack Thormahlen - Lower Colorado River Authority-4093	Yes	In the 4.0 Applicability; 4.2 Exemptions; 4.2.2 generating units/ generating facilities while operating in synchronous condenser mode (providing reactive power only) are exempt from Standard BAL-001-TRE-01. The LCRA units when in synchronous condenser mode for use as RRS does not produce any reactive power. If we were to produce reactive power while in synchronous condenser mode, the hydro units would not pass the current ERCOT requirements of 10 seconds to full load after relay triggered rollout of 59.90 Hz. Therefore, LCRA requests that the requirement for "providing reactive power only" be deleted in its entirety or a statement that "operating in synchronous condenser mode" with or without providing	The team agrees and has removed the language as requested.

			reactive power "are exempt from Standard BAL-001-TRE-01." I recommend that the phrase "providing reactive power only" be deleted.	
308	Eric Armke - Interested Third Party	Yes	1. My comments are primarily intended to help clarify the proposed Standard for a reader who is not well versed in the principles of Control Performance. The term "initial" and "sustained" PFR are first mentioned in R2 but are not discussed in detail (using equations, etc.) until R8 and R9. I think the Standard would be easier for an unschooled reader to understand if each term was conceptually explained in the "Definitions of Terms" section. 2. I also think the proposed Standard would be clearer if the requirement for mechanical Governors was also mentioned in 5.3 or a sentence was added explaining why mechanical Governors are not referenced.	1. The team agrees and has added an explanation of the "initial" and "sustained" response concepts under the Background section of the standard. 2. The team agrees and incorporated the relevant wording into the standard.
314	Thad Ness - AEPSC: AEP Tex Nrth & Cen, PS of Ok-4006	Yes	1. Are wind farms without governors exempt from the metrics or is this covered under measure 8? 2. The document fails to address any type of special consideration or exemption for units operating in sliding pressure mode. Even though the unit may not be at 98% of full load, the valves may be wide open and the governor unable to respond to a low frequency disturbance. Do Requirements 8.1 or 9.1 account for this operating condition?	1. No, wind farms are not exempt unless the BA has specifically exempted them from the selected metrics. The team has modified R8 to address other generation types, including wind-powered facilities, including a limiting factor (LF) that can be adjusted by the BA to account for the frequency response performance capability of specific generators. 2. A generator operating in full sliding pressure mode will not meet R8 and R9. Operating in this mode is unacceptable to the team. A GO that makes the decision to operate in full sliding pressure mode, understanding the reliability impact on the interconnection, is at risk of failing this standard. The exclusions in 8.1 and 9.1 are not intended to include intentional operation in a mode that does not provide sufficient PFR. Operation in a partial sliding pressure mode by operating at a valve point that is significantly less than 100% open can meet R8 and R9. This discussion does not apply to steam

				turbines of combined cycle facilities. The combustion turbine providing energy to this steam turbine has additional performance requirements to achieve a combined equivalent performance level.
			3. The document fails to address any type of special consideration or exemption for combustion turbines operating in a thermal limiting mode. Even though the unit may not be at 98% of full load, the thermal limitation of the exhaust temperature will prevent the governor from responding to a low frequency disturbance. Do Requirements 8.1 or 9.1 account for this operating condition?	3. Yes, the Standard does account for combustion turbines operating in a thermal limiting mode. If a combustion turbine is thermally limited by the exhaust temperature, the turbine is at HSL. The 98% limit will apply and no evaluation of frequency response will be performed.
			4. The governor deadband settings in Table 5.1 for Electronic and Digital control systems are very tight at +/- 0.01666 Hz or 1 rpm on a 3600 rpm machine. What is the reliability basis for such tight deadbands?	4. The basis for the required deadbands is improved system frequency performance in combination with elimination of the step response at the edge of the deadband. Droop implementation in the past has included a step response at the edge of the deadband in order to achieve 5% droop performance. Research has demonstrated that this implementation leads to generator and grid instability, especially during islanding and black start conditions. In order to eliminate this instability, the step response was eliminated and a proportional droop curve from the edge of the deadband is now being applied. Using this implementation at the higher deadbands (0.036 Hz) causes frequency response performance to be significantly higher than 5% droop. By decreasing the deadbands (0.016 Hz) near 5% droop is restored.
			5. Units close to wind or solar farms will constantly be swinging the main turbine valves and the boiler firing to control frequency. This equates to higher heat rate, increased emissions and increased wear to	5. The drafting team disagrees. Since frequency response from generators is delivered in seconds, frequency across the grid is virtually the same no matter how far a generator is from a variable generator or load. Each generator

			mechanical components. 6. What is the reliability basis for having the maximum droop setting for simple cycle combustion turbines at 5% when most simple cycle combustion turbines come from the OEMs with 4% droop? Why would the combined cycle combustion turbines be held to a 4% droop when the simple cycle units are held to 5%? 7. What is the expected number of MW data points used in calculating the pre-perturbation average MW and post-perturbation average MW for Requirement? We would like to understand how the denominator numbers were determined. 8. Does the 90 days listed in Compliance Section 2.1 refer to the allowable time to submit a mitigation plan or the time for the plan to be implemented?	with this setting will respond proportionally regardless of their location on the grid. Generators have been using these settings for over two years and have experienced significantly less governor movement than when the larger deadband with step implementation was used. 6. In the drafting team's experience, and consistent with industry practice, a 5% droop setting provides sufficient Primary Frequency Response. You can operate at 4% droop, which is within the scope of the requirement and not considered an exceedance. Combined-cycle combustion turbines are held to a maximum 4% droop to compensate for the associated steam turbine that provides little or no frequency response. 7. The APFR calculation in R8 assumes a 2-second scan rate, so 8 data points are averaged for the pre-perturbation average MW, and 17 data points are averaged for the post-perturbation average MW. The denominator will be different for different scan rates. The denominator has been revised to refer to the number of scans. 8. The 90 day reference has been removed from the standard. Mitigation plans will have to be submitted according to normal enforcement processes.
328	WALTER REID - CONSULTANT	Yes	There are three additional comments presented below: A. Allow for exemptions of certain wind-powered generation; B. Allow for future specification of wind-powered generation technical limits; and C. Technical Comments.	

			A. Allow for exemption of certain wind-powered generation Insert new section: “4.2.3 Certain wind-powered generating facilities with Standard Generation Interconnection Agreements executed on or prior to January 1, 2010 may be exempted by the BA from Standard BAL-001-TRE-01.” There must be a clear exemption for certain wind-powered generation with a Standard Generation Interconnect Agreement signed before January 1, 2010. The exemption should provide the authority for the BA to allow such an exemption. The ERCOT Board has already acted to exempt certain wind-powered generating facilities from providing Primary Frequency Response. For reference, the wording approved by the ERCOT Board of Directors is provided below: "Wind-powered Generation Resources (WGRs) with Standard Generation Interconnection Agreements (SGIAs) signed after January 1, 2010 shall provide Primary Frequency Response to frequency deviations from 60.000 Hz. The WGR automatic control system design shall have an adjustable dead band that can be set as specified in the ERCOT Operating Guides. The Primary Frequency Response shall be similar to the droop characteristic of five-percent (5%) used by conventional steam generators. For WGRs with Standard Generation Interconnection Agreements executed on or prior to January 1, 2010, those not already equipped with Primary Frequency Response shall by December 1, 2011 acquire that capability. Those WGRs that cannot technically be retrofitted with Primary Frequency Response capability shall submit an attestation to ERCOT by June 1, 2010	A. The drafting team declines to exempt certain wind-powered generation from the performance requirements. ERCOT’s disposition of this issue is irrelevant in this context. However, the BA may grant an exemption to specific metrics. A wind powered generating facility may seek to have an event excluded from the rolling average calculations pursuant to 8.1 and 9.1, just like any other generator. In R8, the team added a new “EPFR for Other Generating Units/Generating Facilities” that includes an adjustable, facility-specific “limiting factor” that can be used to reduce the expected response from units that are not capable of providing the ideal expected response, including some wind-powered facilities.

			explaining the technical infeasibility. At ERCOT” sole discretion, those WGRs for which Primary Frequency Response is technically infeasible may be granted a permanent exemption from the requirement. ERCOT shall make a determination within one hundred eighty (180) days of receipt of the attestation. If ERCOT does not grant an exemption, the WGR shall acquire the capability to provide Primary Frequency Response within twenty-four (24) months of being notified of that determination. If ERCOT grants the exemption, then ERCOT may require the WGR to install alternate measures, such as over-frequency relays, that are technically feasible and would approximate Primary Frequency Response to Measurable Events." B. Allow for future specification of wind-powered generation technical limits Insert new wording in R8: " EPFR for wind-powered generators The BA shall have the authority to establish temporary adjustments to the required EPFR for wind-powered generation pending amendments to this standard.” In the Wind Coalition's comments to the previous draft of BAL-001-TRE, the main focus was the recognition that there is no experience with Primary Frequency Response for wind-powered generation. This new version now includes explicit formulas allowing for reduced performance for all existing generation technologies except wind-powered generation. This is quite understandable given the lack of empirical data for wind-powered generation. However, no provision has been made to allow inclusion of such adjustments to wind-powered generation performance once actual experience is gained. This exposes wind-powered	B. The drafting team agrees that the expected response of wind-powered generators may need to be adjusted based on technical capabilities. The team added in R8 the capability of implementing a limiting factor that will adjust expected response based on knowledge gained through operational experience. The limiting factor may be adjusted by the BA.

			generation to potentially large penalties for performance issues due to the limitations of the wind-powered turbine technology and/or control system. Had these limitations been known now, they could be included. The BA should be given the authority to provide temporary modifications to the performance requirements for wind-powered generation pending revision of this standard. C. Technical Comments 1. In R8 change: "Capacity as used in this standard will be the high sustained limit (HSL) as telemetered in real-time by the GO to the BA by adding and maximum operating level" so that it now reads "Capacity and maximum operating level as used in this standard will be the high sustained limit (HSL) as telemetered in real-time by the GO to the BA." It should be made clear that "maximum operating level" is the Real Time Telemetered HSL. Use of any other value would not make sense if the intent is to exclude from evaluation those generators that have no room to move. The "minimum operating level" is more stable, but there does not seem to be a reason why the Real Time Telemetered value of LSL should not be used. The drafting team may wish to evaluate the need for using different terms to say the same thing. The use of "Real Time Telemetered HSL" and "Real Time Telemetered LSL" may be the terms of preference unless some other capacity value such as "Rated Maximum Capacity" is intended. 2. In the wind-power spread-sheet there is	C. 1. The team agrees that the use of real-time HSL as a capacity measure was confusing, and has revised R8 to use the "officially reported seasonal capacity" instead. For wind-powered generators, the capacity is the cumulative nameplate capacity of all units that were online when the FME occurred. 2. For wind-powered facilities, expected

			the statement "If the Farm is being curtailed, Production Potential plus actual generation would be HSL." This is incorrect. The definition of Renewable Production Potential is equal to the total possible production given the current wind conditions and turbine availability. That is to say, it already includes any actual generation for the curtailed facility. Per Nodal Protocol Section 6.5.5.2 (3) WGRs will telemeter their Production Potential as their HSL when curtailed so, in all cases, a WGRs telemetered HSL is the appropriate value.	performance will be based on the installed capacity of the wind-powered facility adjusted for any outages on individual turbines.
			3. The standard uses the term wind turbine where the performance requirements and measures are applicable to the whole wind-powered generator. The term "wind-powered generator" should be used unless there is some specific reason to refer to an individual wind-powered turbine.	3. The team agrees and the standard has been revised to eliminate references to “wind turbine” except when referring to an individual wind-powered generating unit.
			4. In 5.2 change “Steam Turbines of a Combined Cycle Resource are required to comply with 5.1, 5.2 and 5.3, but are not expected to comply with R8 and R9 by adding for low frequency events” to now read “Steam Turbines of a Combined Cycle Resource are required to comply with 5.1, 5.2 and 5.3, but are not expected to comply with R8 and R9 for low frequency events.” Steam turbines that are fully loaded for the steam conditions cannot increase output, but they can decrease output.	4. The drafting team disagrees. The requirement for the combustion turbine of a combined cycle facility to operate at a 4% droop fully compensates for the lack of frequency response of the associated steam turbine. Since the steam turbine operates at valves wide open, response to small high frequency deviations will not reduce steam flow into the turbine and produce frequency response.
			5. In R8 the formula for EPFR ideal should be modified to make it clear that it is limited by the amount of capacity available to respond ((Real Time Telemetered HSL MW pre-perturbation) or (MW pre-perturbation Real Time Telemetered LSL))	5. The “capacity” used in EPFR calculations determines the expected frequency response of the generating unit/generating facility. The maximum operating level (HSL) or minimum operating level (LSL) determines if there is an available margin for the expected response. A provision has been added to R8 to address when the available margin is less than the

			  6. There is no mention of solar generation or generation from batteries. What are the plans for including requirements for these new technologies? Absent any requirements these facilities, like wind-power generation, will not be designing their facilities to provide primary frequency response. Is it planned that they will be required to retrofit their facilities once there are requirements for them to provide primary frequency response?	expected response. 6. This standard is intended to apply to all types of generating facilities that are subject to the NERC Reliability Standards. An EPFR for "Other Generating Units/Generating Facilities" has been added in R8.
335	Halmer Weldon - Elec Reliab. Council of Texas, Inc.-4056	Yes	1. In R6, GOs don't operate the generating units, as the language implies. 2. For the EPFR ideal equation on page 7 (and a few other equations), what determines the sign that is used for the +/- factor in the numerator? Does this decision determine if the "(-1)" value is used? If you want this to be an absolute value, then perhaps you should put absolute value symbols around the numerator or the quantity "HZactual" "60.0" and remove the "(-1)" factor. 3. In the equations, "x", "X" and "*" are used interchangeably. Suggest using one symbol. 4. For the post-perturbation average MW equation, it appears the "20" and "52" in the summation symbol (Sigma symbol) indices should be swapped to be consistent with the formula above it. 5. There are some italicized fonts intermingled with non-italicized fonts that look funny in the EPFRST equation on page 8Looks like the word "Pressure" has the same problem in many of the formulas.	1. The language has been changed to address this comment. 2. The team has reviewed the equations and believes they should remain as is. The flow chart clearly demonstrates the proper use of the +/- in the equations, which depends on the direction of the frequency excursion. (There is no absolute value used in this equation.) 3. Thank you. The team agrees and this has been addressed. 4. Thank you. The team agrees and this has been addressed. 5. Thank you. The team agrees and this has been addressed.

Attachment 7-001

BAL-001-TRE-1
Performance Metric Calculations
Technical Reference Document

I. Introduction

This Technical Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities in accordance with Requirements R8 and R9. Flowcharts A (Initial PFR) and B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Technical Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available for reference and use in performing these calculations.

This Technical Reference Document is not considered to be a part of the regional standard. This Technical Reference Document will be maintained by Texas RE and will be subject to modification as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process. Technical Reference Document revision requests will be accepted by the Reliability Standards Manager, who will present the request to the Texas RE Reliability Standards Committee (RSC) for consideration. The RSC will make a recommendation to the Board of Directors, which shall adopt the revision request, reject it, or adopt it with modifications. Any modifications to the Technical Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

High Sustained Limit (HSL) for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility.

Low Sustained Limit (LSL) for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy production capability of a generating unit/generating facility.

II. Initial Primary Frequency Response Calculations

Requirement 8

R8. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

> R8 measures *initial* unit FR performance (A-point to B-point). This requirement specifies a certain level of measured performance over a 12-month rolling average.

8.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME. The initial Primary Frequency Response performance for each FME shall be between zero and 2.0.

8.2. Each BA shall compute the initial Primary Frequency Response performance for each FME and the rolling average, for each generating unit/generating facility, using the methodology described in the Technical Reference Document.

8.3. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

8.4. A generating unit/generating facility's Frequency Response performance during a FME may be excluded from the rolling average calculation by the Compliance Enforcement Authority due to a legitimate operating condition that prevented normal Frequency Response performance.

Initial Primary Frequency Response Performance Calculation Methodology

Each GO may submit to the BA unit-specific information used by the BA in this requirement to calculate initial PFR performance for each generating unit/generating facility.

,

where P.U. $PFR_{Resource}$ is the per unit measure of the Primary Frequency Response of a Resource during identified FMEs.

where P.U. $PFR_{Resource}$ for each FME is between zero and 2.0.

The Actual Primary Frequency Response and the Expected Primary Frequency Response$_{Final}$ ($EPFR_{Final}$) are calculated as described below:

Ideal Expected Primary Frequency Response ($EPFR_{ideal}$): This is the unadjusted expected MW change calculated when the frequency deviation exceeds the deadband for all generator types.

Capacity and NDC are used interchangeably and the term Capacity will be used in this document. They are the official reported seasonal capacity of the generating unit/generating facility. The capacity for wind-powered generators is the cumulative nameplate capacity of all wind turbines in that facility that were on-line when the FME occurred.

For normal, released for dispatch operation, the maximum and minimum operating level of a Resource's Governor must be identified by the GO and provided to the BA.

For combined cycle facilities, ERCOT will calculate each generator's HSL using the submitted seasonal ratings, the telemetered individual net MW, and telemetered combined cycle HSL. As an alternative the GO/GOP may telemeter HSL values for each generator of the combined cycle facility.

In the numerator, the "+" is used for positive frequency excursions and the "–" is used for negative frequency excursions.

$EPFR_{final}$ for Combustion Turbine

First calculate the Adjusted EPFR:

where

$$HZ_{Actual} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

Note: The 0.00276 constant is MW/0.1 Hz change / MW Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Then add a ramp factor to determine $EPFR_{final}$:

$$EPFR_{final} = EPFR_{adj} + RampMagnitude$$

where

$$RampMagnitude = (MW_{T-4} - MW_{T-60}) * 0.59$$

Note: $(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

$EPFR_{final}$ for Steam Turbine

First calculate the adjusted EPFR:

where:

where:

and where K is a frequency response filter constant between 0.0 and 0.6 psig/MW, measured at 50% output of the steam turbine. The GO should determine the fixed K factor for each steam turbine that generally results in the best match between EPFR and APFR (and the highest P.U. $PFR_{Resource}$). K will not change unless a steam turbine is significantly reconfigured.

Throttle Pressure = Interpolation of Pressure curve at Post-perturbation Average MW_{Actual}.

Then add a ramp factor to determine $EPFR_{final}$:

$EPFR_{final} = EPFR_{adj} + RampMagnitude$

EPFR$_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{Adj} = EPFR_{ideal} + (HZ_{Actual} - 60) * 10 * LF * Capacity$$

$EPFR_{Final} = EPFR_{Adj} + RampMagnitude$

where LF is a limiting factor that may be applied to other types of generators. LF is initially 1.0, and it may be adjusted by the BA in the range 0.5 to 1.0. LF may be variable across the operating range of a generator and it may be generator-specific.

Ramp Adjustment: The Final Expected Primary Frequency Response number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is added to $EPFR_{Adj}$.

Ramp Magnitude = $(MW_{T-4} – MW_{T-60})*0.59$

$(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency $Response_{Final} = EPFR_{Adj}$ + Ramp Magnitude

Actual Primary Frequency Response (APFR): This is the difference between Post-perturbation Average MW and Pre-perturbation Average MW.

where

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

Limits on Calculation of initial Primary Frequency Response performance:

If the generating unit/generating facility is operating within 2% of its operating limits at the time an FME occurs (pre-perturbation), then that unit/facility's Primary Frequency Response performance is not evaluated for that FME.

For negative frequency deviations, if

then Primary Frequency Response is not evaluated for this FME.

For positive frequency deviations, if

then Primary Frequency Response is not evaluated for this FME.

Expected PFR greater than Operating Margin: When a generating unit/generating facility has greater than 2% pre-perturbation operating margin, but where the Expected Primary Frequency Response is greater than the available operating margin, if the generating unit/generating facility's actual $PFR_{Initial}$ response is in the correct direction the P.U. $PFR_{Resource}$ will be 0.75 or the calculated P.U. $PFR_{Resource}$, whichever is greater.

III. Sustained Primary Frequency Response Calculations

Requirement 9

R9. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement following the FME.

9.2. Each BA shall compute the sustained Primary Frequency Response performance for each FME and the rolling average, for each generating unit/generating facility, using the methodology described in the Technical Reference Document.

9.3. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

9.4. A generating unit/generating facility's Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Frequency Response performance.

Sustained Primary Frequency Response Performance Calculation Methodology

Event Recovery Time (ERT): For low frequency events, the time at which frequency returns to pre-perturbation frequency or 59.984 Hz, whichever occurs first. For high frequency events, the time at which frequency returns to pre-perturbation frequency or 60.016 Hz, whichever occurs first.

Event Recovery Period (ERP): The period from T=0 to ERT expressed in seconds.

Each GO may submit to the BA any information used by the BA in this requirement to calculate sustained PFR performance for each generating unit/generating facility.

RampMW Calculation (MW/scan)

Note: There are 29 two-second scans between t-2 and t-60. The terminology "$MW_{(t-2)}$" refers to MW output at 2 seconds before the Frequency Measurable Event (FME) occurs at t(0).

$EPFR_{ideal}$ Calculation

When the frequency is within the Governor deadband:

$EPFR_{ideal} = 0$

When the frequency is outside the Governor deadband and above 60 Hz:

When the frequency is outside the Governor deadband and below 60 Hz:

$EPFR_{delayed}$ Calculation

For every scan *i* from 70 seconds prior to the FME (t-70) to ERT:

Where *Time Constant* is a value in the range 0.05 to 1.0. This value is provided by the GO for each generating unit/generating facility. The GO should determine (and provide to the BA) the Time Constant for each unit or facility that generally results in the best match between sustained EPFR and sustained APFR (and the highest sustained P.U. $PFR_{Resource}$). The Time Constant will not change unless the unit or facility is significantly reconfigured.

TargetMW Calculation

TargetMW[i] at t = -2:

Pre-Event TargetMW[i] for every scan *i* from t-4 to t-60 (between 4 and 60 seconds before the FME):

Recovery TargetMW[i] for every scan from t(0) to Event Recovery Time:

Note: If TargetMW[i] exceeds HSL or is less than LSL it is limited to the corresponding HSL or LSL.

TargetMW$_{avg}$

ActualMW$_{avg}$

P.U. Calculation (Ramp Up)

For generating unit/generating facility whose MW output value at ERT is higher than MW output at t-4.

P.U. Calculation (Ramp Down / No Ramp)

For generating unit/generating facility whose MW output value at ERT is lower than or equal to MW output at t-4.

Sustained Primary Frequency Response performance requirement:

Attachment 8-001

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BAL-001-TRE-1

Primary Frequency Response in the ERCOT Region

Sydney Niemeyer
SDT Chair

SAR-003 Standard Drafting Team

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Vann Weldon	ERCOT
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Purpose

- **The purpose of this standard will be to address FERC-directed modification to the ERCOT regional difference to include requirements concerning frequency response contained in the ERCOT Protocols, Section 5.**

Development History

A SAR (SAR-003) was submitted by Farzaneh Tafreshi of Texas Regional Entity.

SAR-003 was presented to the RSC and approved for further development. The RSC approved an SDT composed of individuals from seven different entities.

Second posting of BAL-001-TRE-1 for comments.

Drafting Team met to review and revise standard

SDT held Techincal Workshop on March 31, 2009

April 15, 2008	April 24- May 16, 2008	May 27, 2008	March 16, 2009	February 12, 2010	September 1, 2010	May 5-6, 2011

SAR-003 was posted for a 20-day comment period on the Texas RE Tracking Site.

First posting of BAL-001-TRE-1 for comments.

SDT held Techincal Workshop on March 3, 2010 and a Performance Evaluation workshop on August 6, 2010.

Third posting of BAL-001-TRE-1 for comments.

Requirements Overview

- **Applies to BA, GO and GOP function**
- **Provides requirements for:**
  - Identifying Frequency Measureable Events (FME)
  - Calculating the Primary Frequency Response (PFR) of each resource in the Region
  - Calculating the Interconnection minimum Frequency Response
  - Monitoring the actual Frequency Response of the Interconnection
  - Setting Governor deadband and droop parameters
  - Providing Primary Frequency Response performance requirements.
- **Importantly, the standard narrows the governor deadband and requires the droop curve to begin at the edge of the deadband with no step function.**

Measures

- Under this standard, two Primary Frequency Response performance measures are calculated: “initial” and “sustained.”

- The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts.

- The sustained PFR performance (R10) measures the actual response compared to the expected response at the Event Recovery Time, when the frequency returns to normal.

Requirements and Measures

R1.

The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

M1.

The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

Requirements and Measures

R2.

The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Technical Reference Document. This calculation shall be a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. The calculation results shall be submitted to the Compliance Enforcement Authority by the end of the month in which they were completed. If the generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

M2.

The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in Requirement R2.

Requirements and Measures

R3.

The BA shall calculate the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, and the methodology for calculation and criteria for determination of the IMFR publicly available.

M3.

The BA shall demonstrate that the IMFR was calculated in December of each year per Requirement R3. The BA shall demonstrate that the IMFR and the methodology for calculation and the criteria for determination of the IMFR are publicly available.

Requirements and Measures

R4.

The BA shall determine and make publicly available the Interconnection’s combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following month.

M4.

The BA shall provide evidence that the rolling average of the Interconnection’s combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

Requirements and Measures

R5.

Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

M5.

The BA shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

Requirements and Measures

R6.

Each GO shall set its Governor parameters as follows:

R6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.01666 Hz

M6. Each GO shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

M6.1 The GO shall have evidence that it set the Governor deadbands as required in Table 6.1 in Requirement R6.

Requirements and Measures

R6. (cont.)

Each GO shall set its Governor parameters as follows:

R6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of a Combined Cycle Resource are required to comply with Requirements R6.1, R6.2 and R6.3, but are not expected to comply with Requirements R9 and R10.

M6.2 The GO shall have evidence that the Governor droop characteristics did not exceed the settings in Table6.2 in Requirement R6.

Requirements and Measures

R6. **(cont.)**

Each GO shall set its Governor parameters as follows:

R6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

For 5% Droop: Slope = $\frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$

For 4% Droop: Slope = $\frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

M6.3 The GO shall have evidence that when frequency deviation has exceeded the Governor deadband from 60.00 Hz, the Governor setting follows the approved slopes derived from the prescribed formulas for 4% droop and 5% droop.

Requirements and Measures

R7.

Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GOP has been notified that the Governor is not in service.

M7.

Each GO shall have evidence that each generating unit/generating facility had its Governor in service when the generating unit/generating facility was online and released for dispatch as described in Requirement R7.

R8.

Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status or capability change of a Governor.

M8.

Each GOP shall have evidence that it notified the BA within 30 minutes of each discovery of a status or capability change of a Governor.

Requirements and Measures

R9.

Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, except steam turbines in combined-cycle facilities, based on participation in at least eight FMEs.

R9.1.

The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME. The initial Primary Frequency Response performance for each FME shall be between 0.0 and 2.0.

R9.2.

If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

R9.3.

A generating unit/generating facility's Frequency Response performance during an FME may be excluded from the rolling average calculation by the Compliance Enforcement Authority due to a legitimate operating condition that prevented normal Frequency Response performance.

Requirements and Measures

M9.

Each GO shall have evidence that each of its generating units/generating facilities achieved an average initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

Requirements and Measures

R10.

Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, except steam turbines in combined-cycle facilities, based on participation in at least eight FMEs.

R10.1.

The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the event recovery period following the FME.

R10.2.

If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

R10.3.

A generating unit/generating facility's Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Frequency Response performance.

Requirements and Measures

M10.

Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each GO shall have documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

VSLs

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The BA reported an FME more than14 days but less than 31 days after identification of the event	The BA reported an FME more than 30 days but less than 51 days after identification of the event	The BA reported an FME more than 50 days but less than 71 days after identification of the event	The BA reported an FME more than 70 days after identification of the event
R2	The BA submitted a monthly report more than one month but less than 51 days after the end of the reporting month	The BA submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month	The BA submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month	The BA failed to submit a monthly report within 90 days after the end of the reporting month
R3	The BA did not make the calculation and criteria for determination of the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR for the following year in December.	The BA did not calculate the IMFR.
R4	N/A	The BA did not make public the six-FME rolling average. Interconnection combined Frequency Response by the end of the following month	The BA did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month.	N/A

VSLs

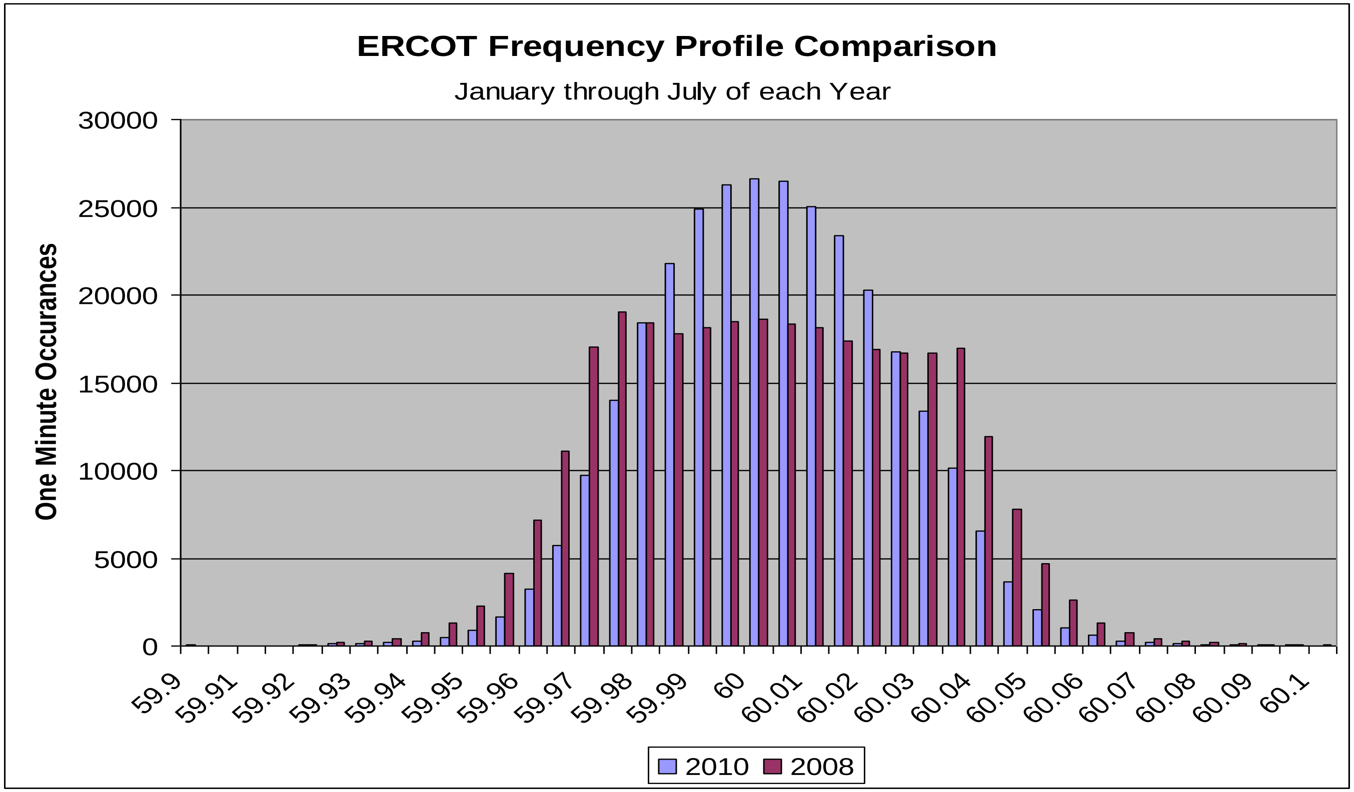
R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The BA did not take action to improve Frequency Response when the Interconnection’s rolling-average combined Frequency Response performance was less than the IMFR.
R6	Any Governor parameter setting > 10% and ≤ 20% outside setting range specified in R6	Any Governor parameter setting > 20% and ≤ 30% outside setting range specified in R6	Any Governor parameter setting > 30% and ≤ 40% outside setting range specified in R6	Any Governor parameter setting > 40% outside setting range specified in R6 – OR – the electronic or digital Governor was set to step into the droop curve
R7	N/A	N/A	N/A	GO operated with its Governor out of service and did not notify the GOP.
R8	The GOP notified the BA of a change in Governor status or capability between 31 minutes and one hour after discovery of the change.	The GOP notified the BA of a change in Governor status or capability more than 1 hour but within 4 hours after discovery of the change.	The GOP notified the BA of a change in Governor status or capability more than 4 hours after discovery of the change.	The GOP failed to notify BA of a change in Governor status or capability after discovery of the change.

VSLs

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R9	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45	A GO's rolling average initial Primary Frequency Response performance per R9was < 0.45
R10	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.45

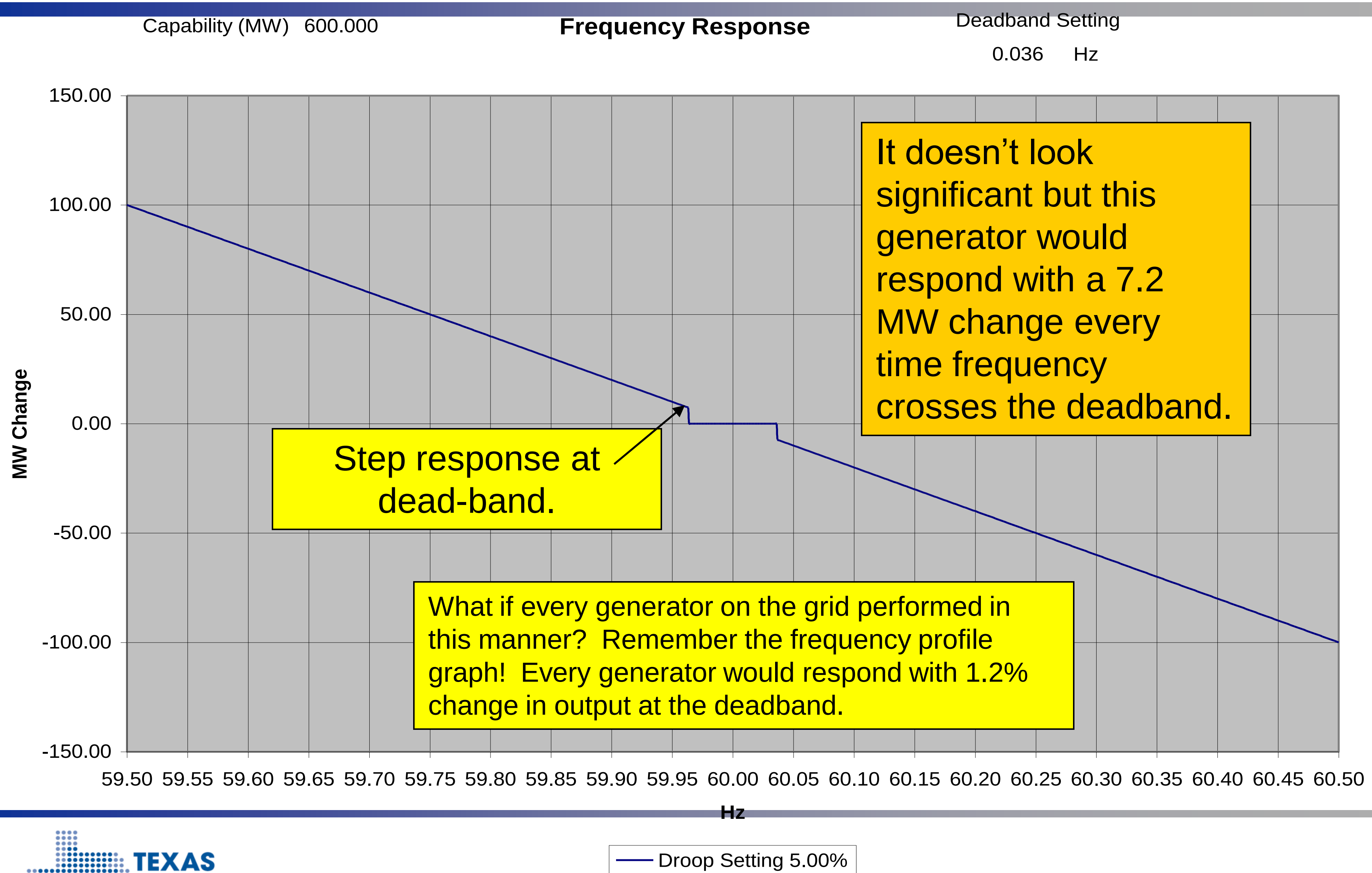
Generating units in ERCOT with the proposed deadband/droop settings in 2009 and 2010

The purple bars represent the measured frequency profile in 2008, when the system frequency was just as likely to be 59.97 or 60.03 as it was to be 60 Hz. The blue bars represent the measured frequency profile in 2010, when only about 14,000 MW of generation was set to the narrower deadband without a step function. This demonstrates that the system frequency is much more likely to be at or near the desired level when the new deadband and droop settings are used.

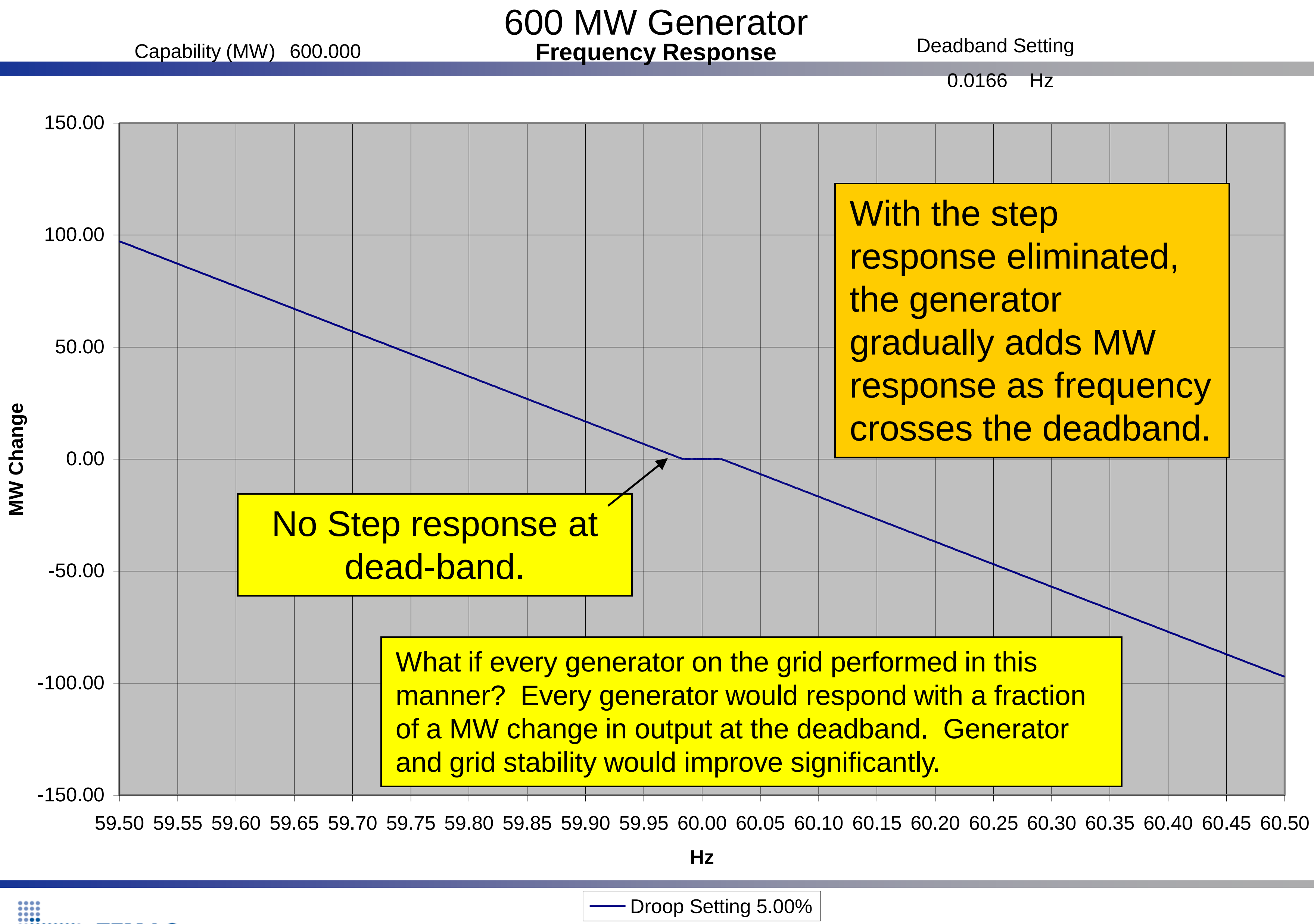


Close up look at +/-0.036 Hz Dead Band with Step Implementation

600 MW Generator



Close up look at +/-0.0166 Hz Dead Band with No Step Implementation



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Benefits

- **Implementation of this regional standard will provide a number of benefits to the system and to individual generators, including the following:**
  - Generators were observed to move 24.38% less when using the lower deadband setting, compared to larger deadband and poorer frequency control.
  - Less maintenance is required on generators, due to fewer and smaller MW output changes.
  - Generators are more stable due to fewer and smaller MW fluctuations.
  - Grid is more reliable due to higher probability that frequency will be near 60 Hz at the time of a major event.
  - Generators perform better since they are more stable and waste less fuel.

EPFR: Expected Primary Frequency Response - MW

When the frequency is outside the Governor deadband and above 60 Hz

$$EPFR_{ideal}[i] = \left[\frac{(HZ_{actual}[i] - 60.0 - deadband)}{(60 \times droop - deadband)} \times (NDC) \times (-1)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$EPFR_{ideal}[i] = \left[\frac{(HZ_{actual}[i] - 60.0 + deadband)}{(60 \times droop - deadband)} \times (NDCCapacity) \times (-1)\right]$$

Droop = 5% or 0.05

Deadband = 0.01666 Hz

NDC = Capacity of Generator (MW)

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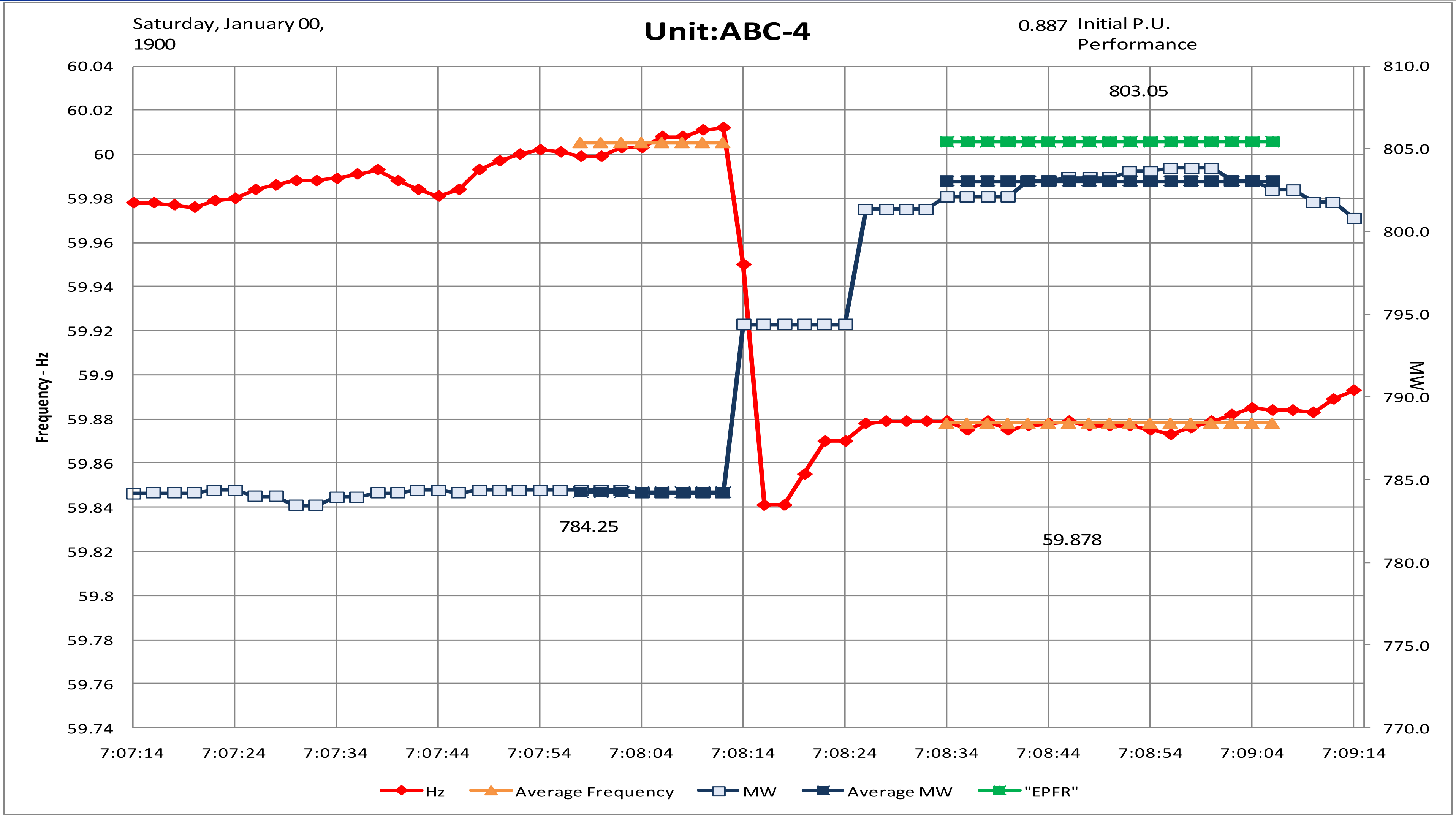
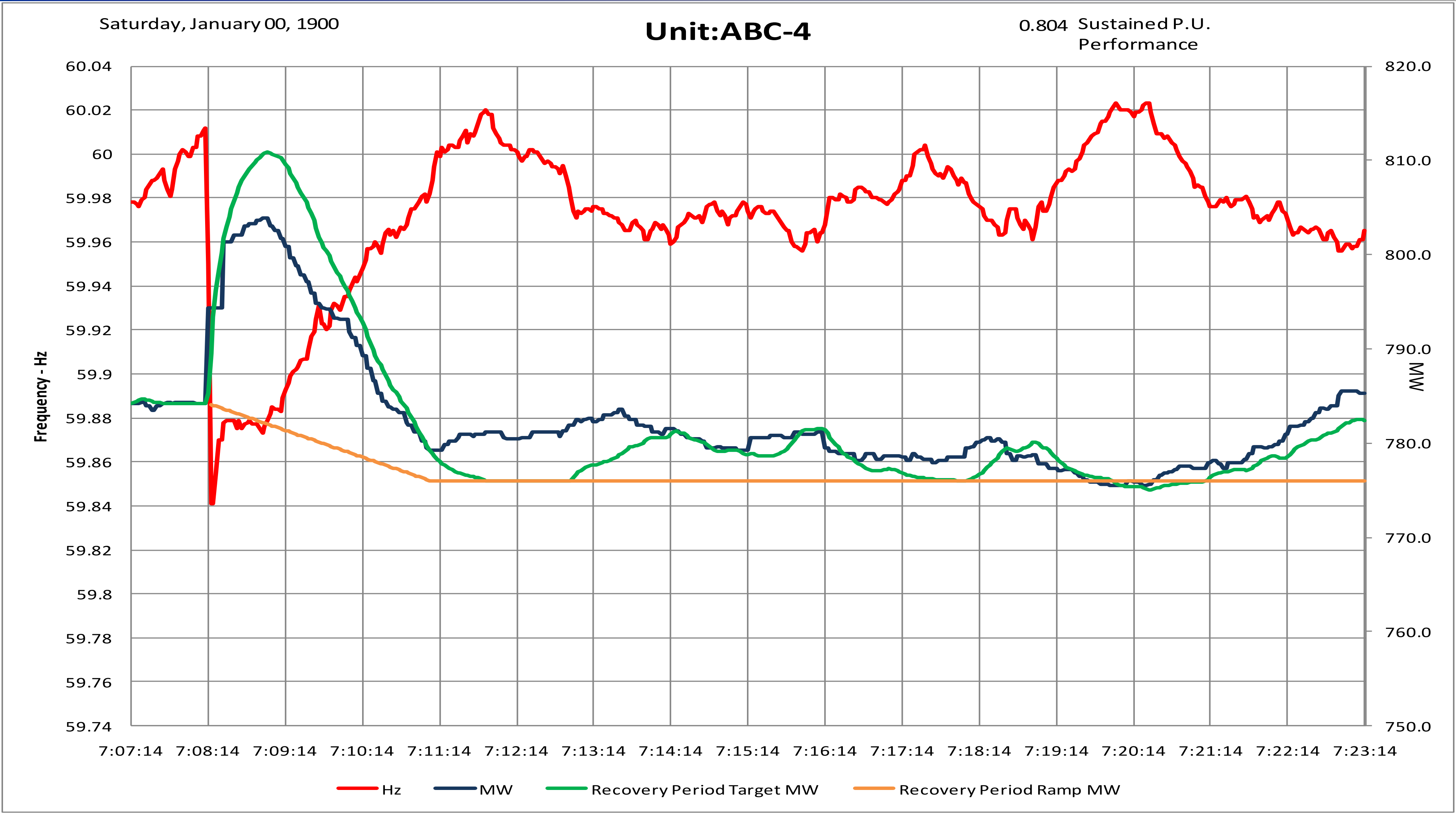
EPFR Adjustments

- **Steam Turbine Expected Performance Adjustments**
  - Steam Pressure at the time of the event.
  - Stored Energy in the steam generator
  - Steam Expansion
- **Combustion Turbine Expected Performance Adjustments**
  - Mass flow change due to turbine speed change.

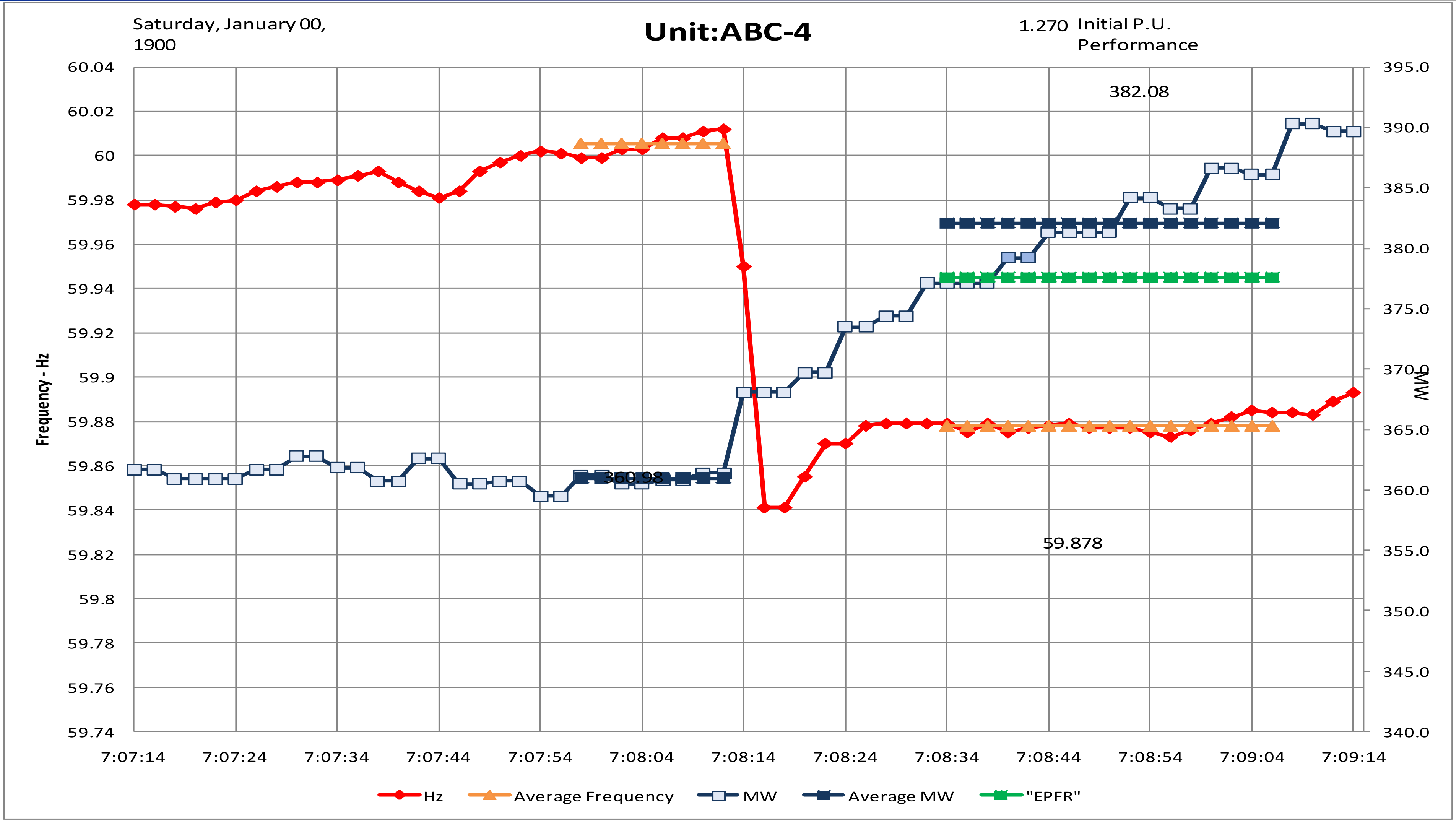
R9: Initial Response Performance - Steam Turbine



R10: Sustained Response Performance - Steam Turbine



R9: Initial Response Performance - Steam Turbine



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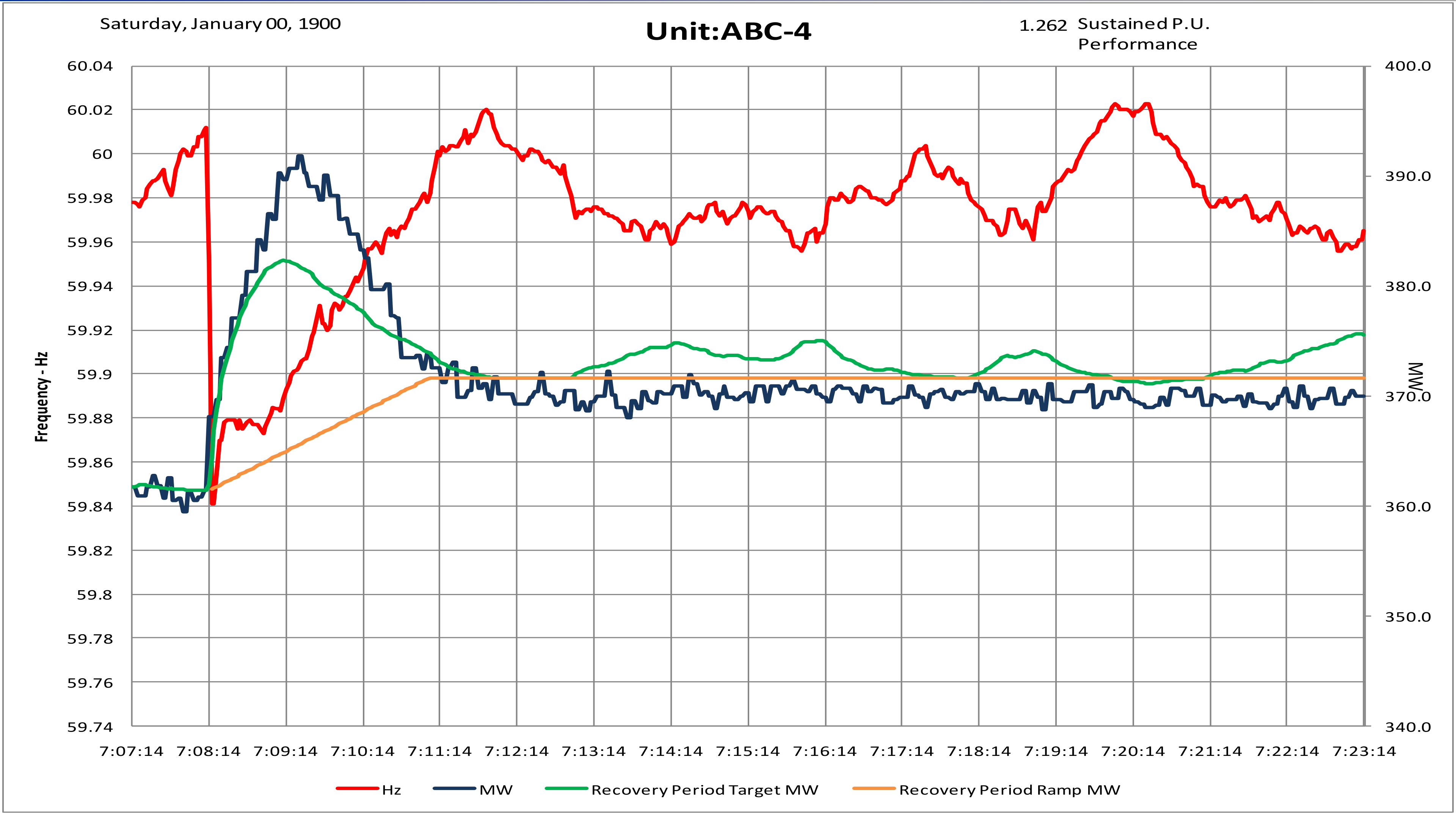
R10: Sustained Response Performance - Steam Turbine



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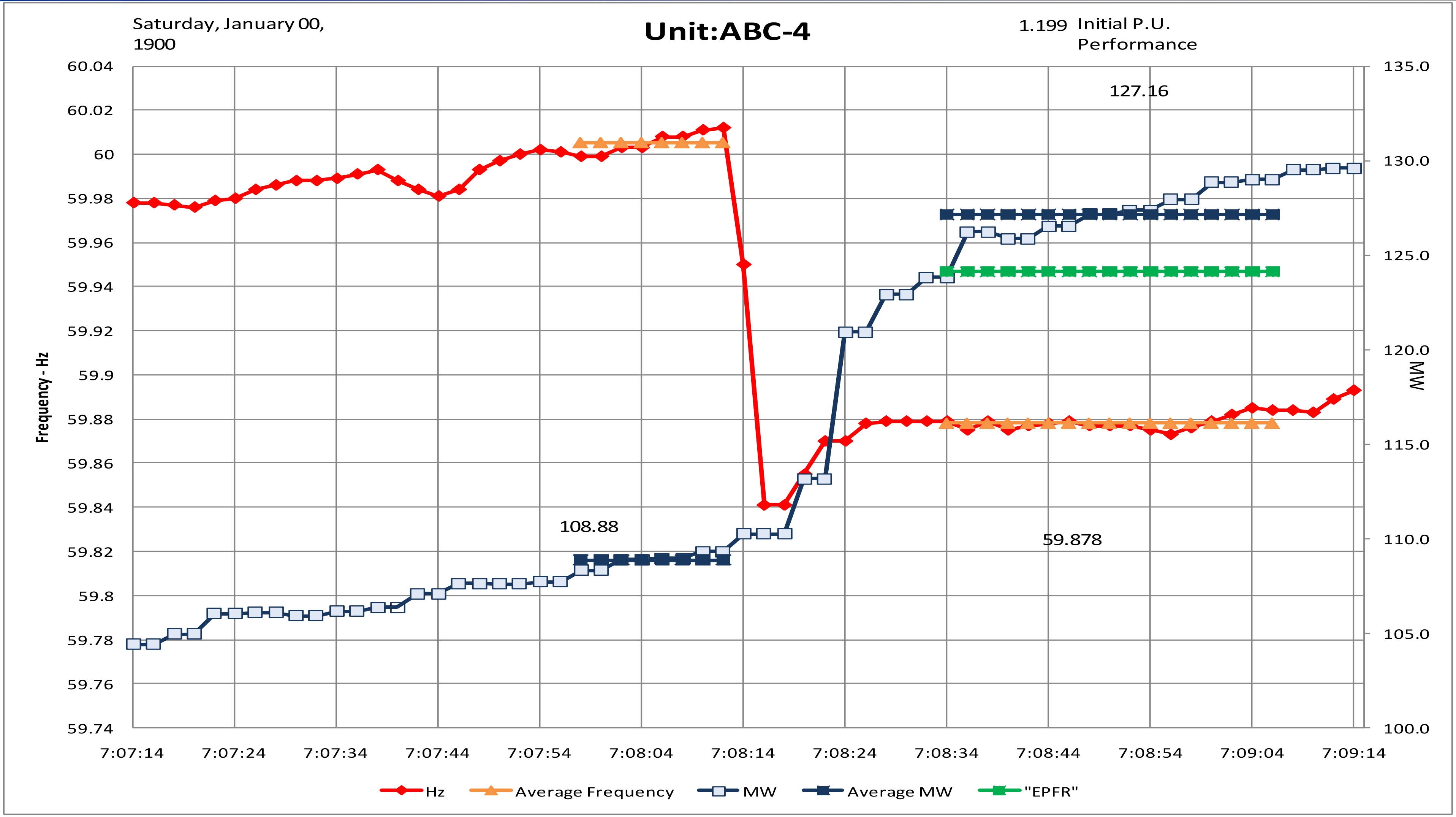
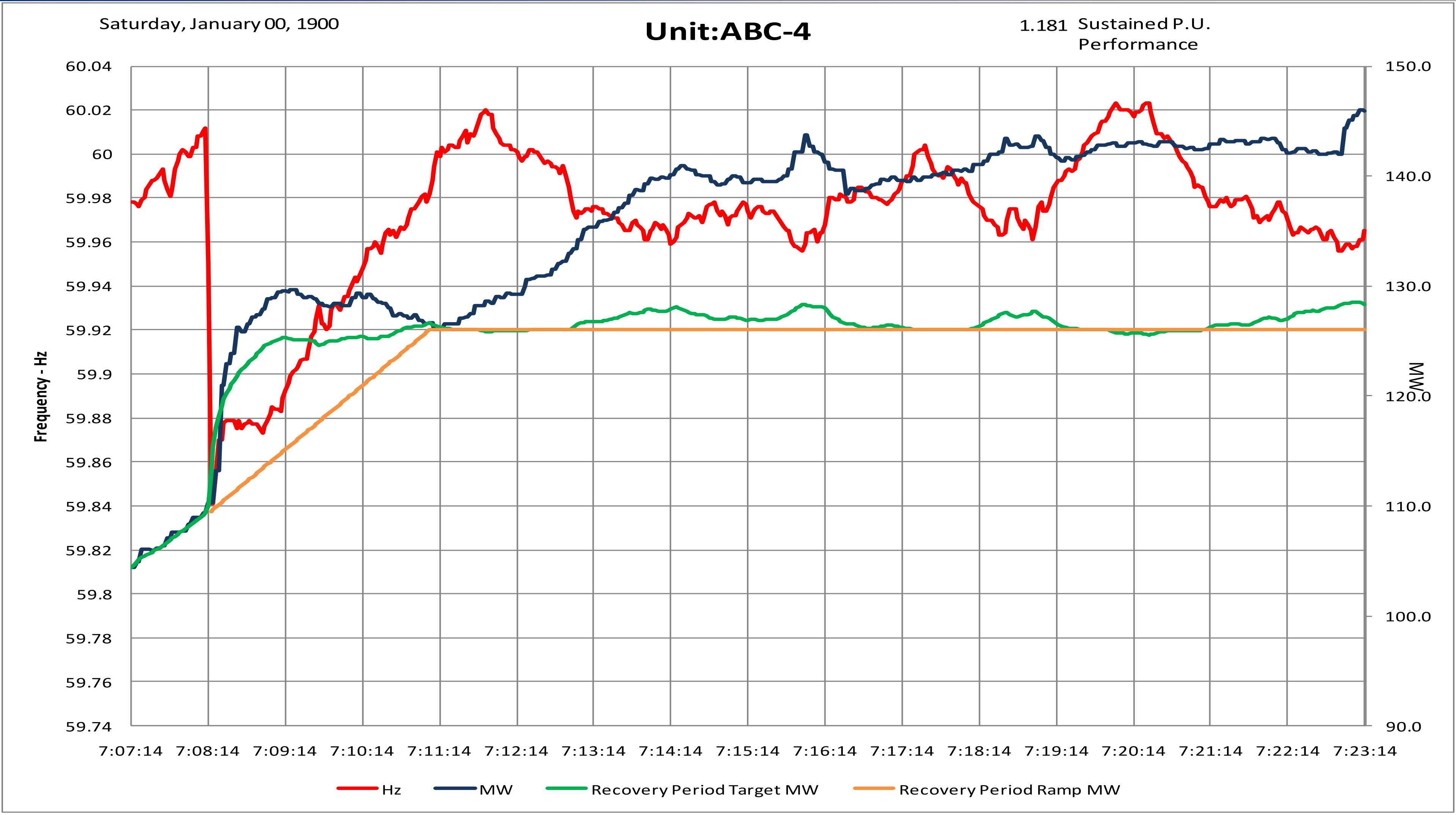
R9: Initial Response Performance - Steam Turbine



R10: Sustained Response Performance - Steam Turbine while Ramping up before and during event



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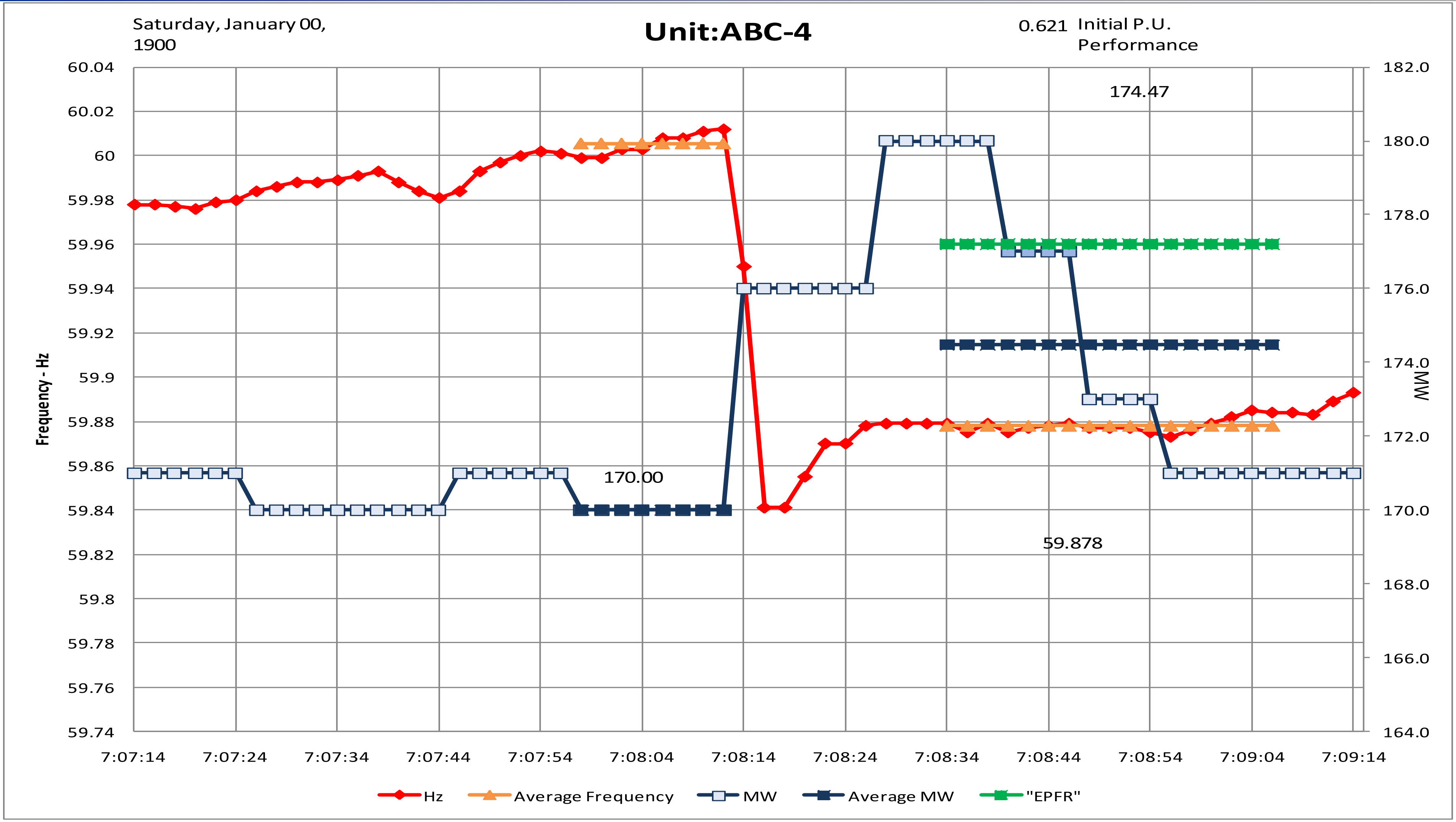
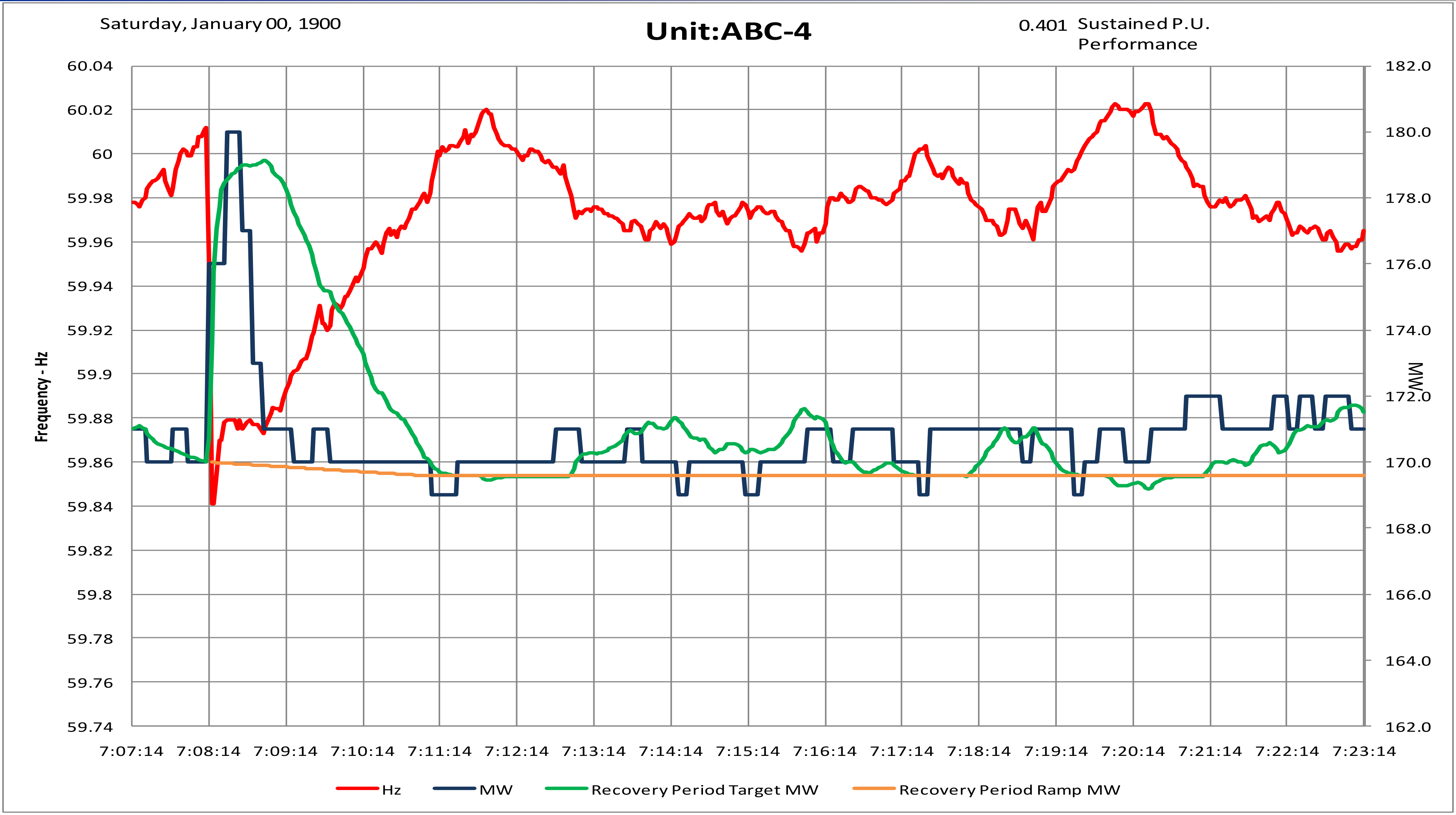
R9: Initial Response Performance - Combustion Turbine with below standard performance

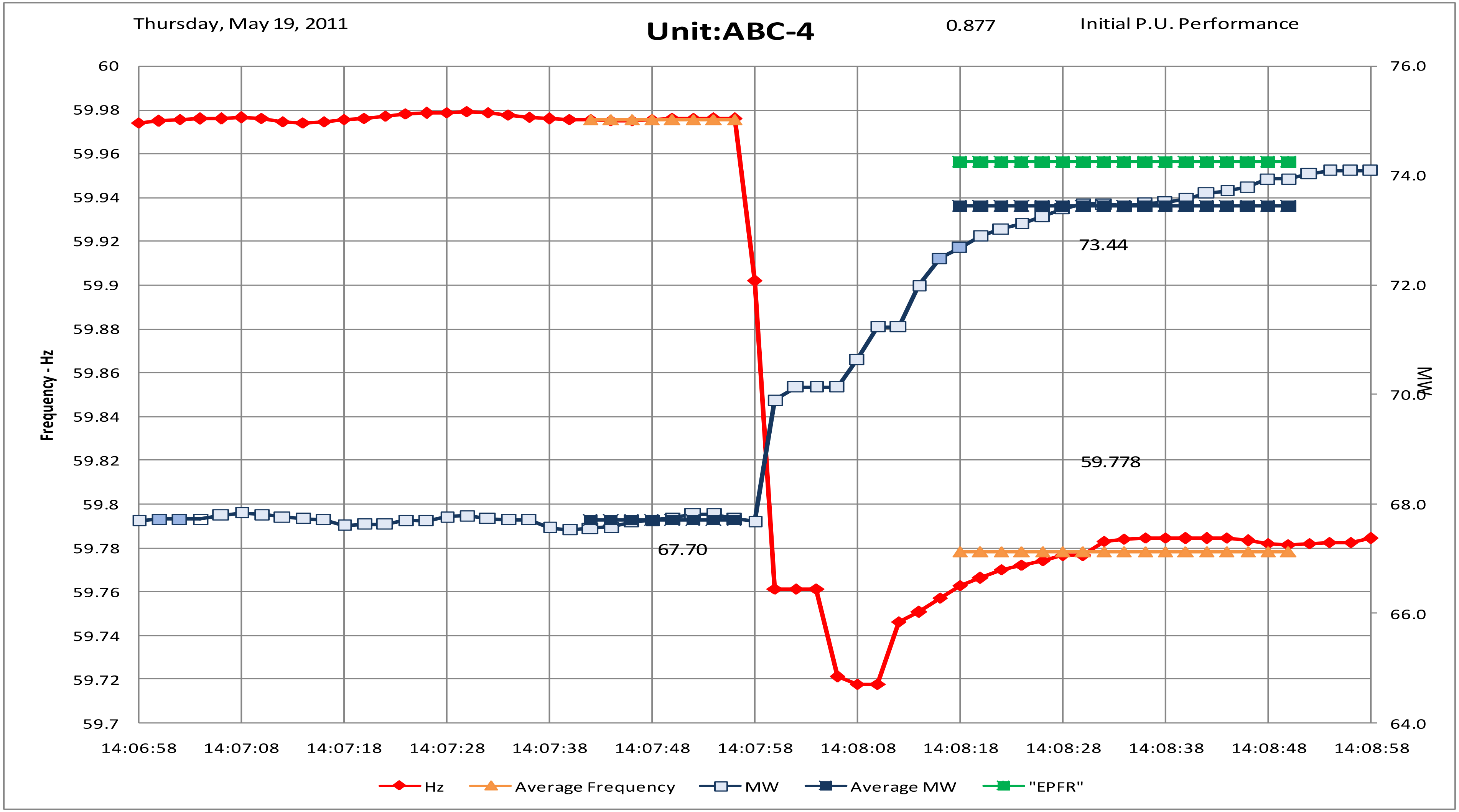


R10: Sustained Response Performance – Combustion Turbine with below standard performance



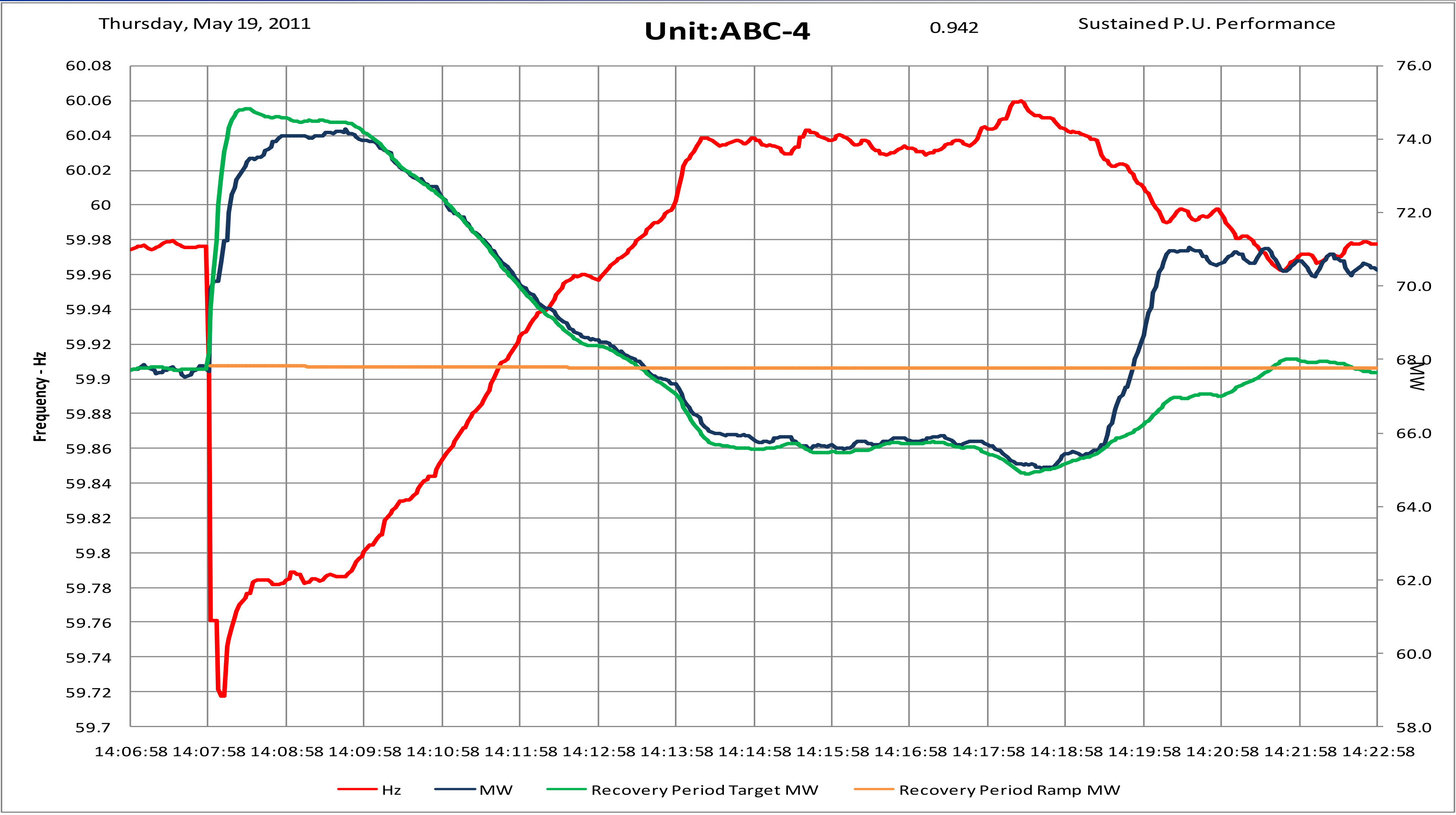
TEXAS RELIABILITY ENTITY

R9: Initial Response Performance - Combustion Turbine



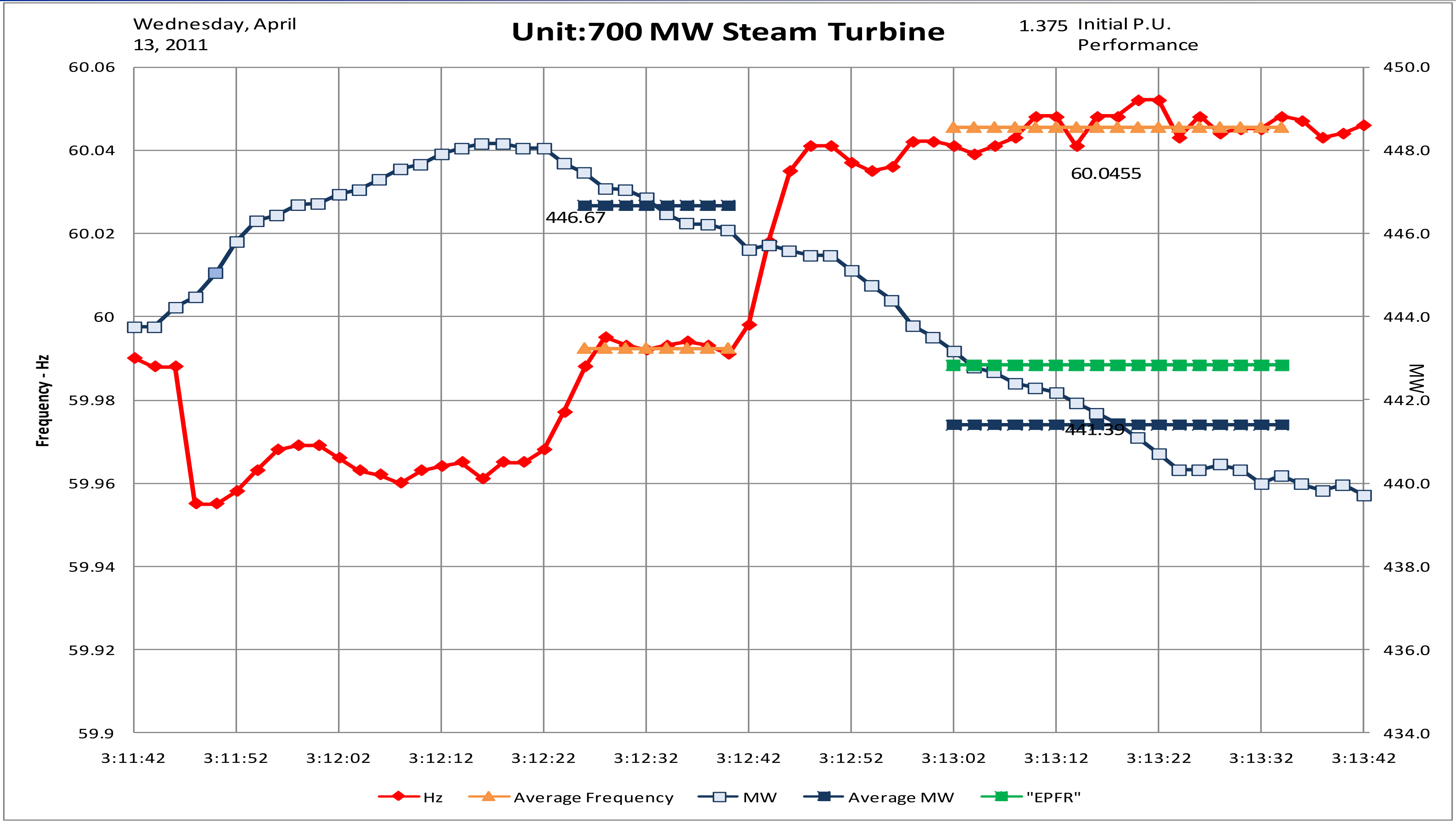
TEXAS RELIABILITY ENTITY

R10: Sustained Response Performance – Combustion Turbine



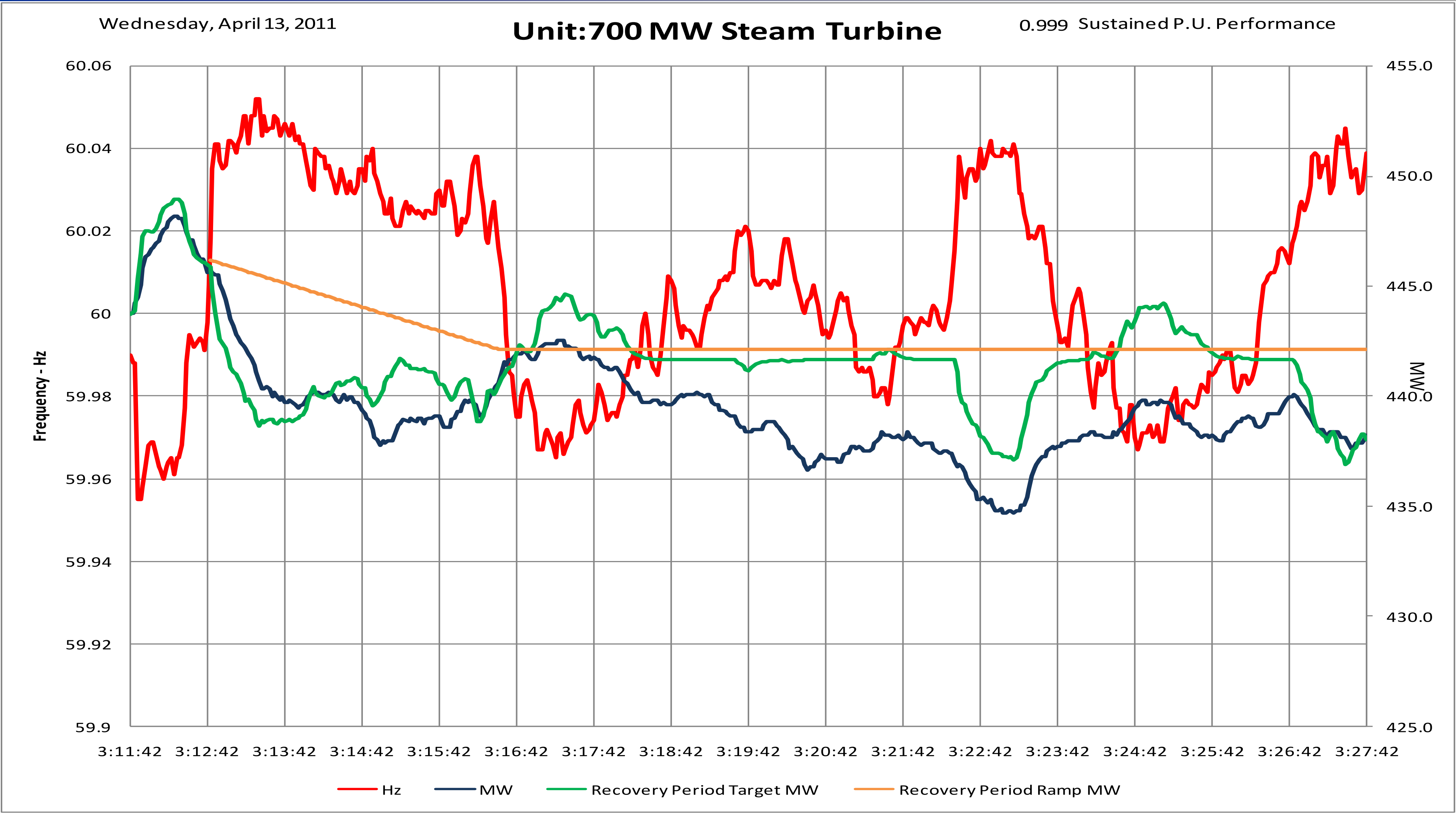
TEXAS RELIABILITY ENTITY

R9: Initial Response Performance - Steam Turbine High Frequency Event



TEXAS RELIABILITY ENTITY

R10: Sustained Response Performance – Steam Turbine High Frequency Event



TEXAS RELIABILITY ENTITY

Questions?

Attachment 8-002

August 5, 2011
Texas RE Office
805 Las Cimas Blvd.
Austin, TX 78746

Administrative

1. Introduction and Attendance

Rick Keetch welcomed the participants to the meeting. The attendees were as follows (RSC members shown in bold font):

Name	Company	Sector	Present	Called-in
Rick Keetch (Chair)	NRG Power Marketing	Load Serving & Marketing	X	
Marguerite Wagner (Vice Chair)	Edison Mission Marketing & Trading	Generation	X	
Steve Myers	ERCOT	System Coord & Planning	X	
Vann Weldon (Alternate)	ERCOT	System Coord & Planning		
John Brockhan	CenterPoint Energy Houston Electric	Transmission/ Distribution	X	
Paul Johnson	American Electric Power Service Corp	Transmission/ Distribution	X	
Barry Kremling	Guadalupe Valley Electric Cooperative	Cooperative	X	
Richard McLeon	South Texas Electric Cooperative	Cooperative	X	
David Detelich	CPS Energy	Municipal	X	
Jose Escamilla (Alternate)	CPS Energy	Municipal		
Frank Owens	Texas Municipal Power Agency	Municipal	X	
Billy Shaw	IPA Trading	Generation		
Venona Greaff (Alternate)	GDF SUEZ Energy Marketing NA	Generation		
Jeremy Carpenter	Tenaska Power Services	Load Serving & Marketing		X
Tim Soles (Alternate)	Occidental	Load Serving & Marketing	X	
Brenda Hampton	Luminant		X	
Sydney Niemeyer	NRG		X	
Phillip Amaya	Magic Valley Electric Cooperative		X	
Hugo Mena	Electric Power Engineers, Inc.		X	
Bradley Schwarz	E.ON Climate & Renewables		X	
Kevin Carter	Duke Energy			X
Alton Aars	TNMP			X
Barb Nutter	NERC			X
Mark Pavelka	Brazos Electric Cooperative			X
Pam Zdenek	BP			X
Don Jones	Texas Reliability Entity		X	
Natalie Mazey	Texas Reliability Entity		X	

At least one representative from four of the six sectors is required to constitute a quorum. At this meeting, a quorum was achieved with at least one representative from all six segments being present.

Antitrust Admonition & Meeting Minutes

The Texas Reliability Entity (Texas RE) Antitrust Admonition was displayed for the members. Don Jones reminded participants that it is Texas RE policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

2. Approval of June 8, 2011 Meeting Minutes

The meeting minutes were presented for committee members. There were no comments or changes suggested. A motion was made by John Brockhan to approve the minutes. Frank Owens seconded. Motion carried by a voice vote. The June 2011 minutes were approved.

3. Announcements

Texas RE staff made several announcements about upcoming Texas RE and NERC activities.

Discussion and Activities

4. Report from NERC Standards Review Subcommittee (N.Mazey)

Natalie Mazey gave an update on NSRS activities and provided information on the results of recent NERC ballots.

- <u>Project 2006-06 Reliability Coordination</u> – Recirculation ballots on revisions to IRO-002-3 – Reliability Coordination – Analysis Tools; IRO-005-4 – Reliability Coordination – Current Day Operations; and IRO-014-2 – Coordination Among Reliability Coordinators concluded with all three standards being approved by the associated ballot pool.

- <u>Project 2007-17 Protection System Maintenance and Testing</u> – Recirculation ballot on revisions to PRC-005-02 – Protection System Maintenance failed with a 64.76% segment vote. The drafting team will review comments submitted with the recirculation ballot as well as comments submitted during the formal comment period and successive ballot that concluded May 13, 2011 to determine whether to revise the standard. A new initial ballot will be conducted.

- <u>Project 2007-09 Generation Verification</u> – Initial ballots of two standards, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and PRC-024-1– Generator Frequency and Voltage Protective Relay Settings, concluded with both standards receiving a failing segment vote. The drafting team will review and revise the standard based on comments submitted with the initial ballot and proceed with a successive ballot.

- <u>Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans</u> – A recirculation ballot on revisions to TPL-001-2 — Transmission System Planning Performance Requirements concluded on Friday, July 22, 2011. The revised standard, TPL-001-2, was approved by the associated ballot pool.

- <u>Project 2007-03 Real-time Transmission Operations</u> – An initial ballot of three standards, TOP-001-2 Coordination of Transmission Operations, TOP-002-2

Operations Planning, and TOP-003-2 Operational Reliability Data, concluded with all three standards receiving a failing segment vote. The drafting team will review and revise the standard based on comments submitted with the initial ballot and proceed with a successive ballot.

The NSRS group continues to meet every 2-3 weeks to discuss various Standards Under Development and related issues. The next NSRS teleconferences will be held on August 22 and September 12.

5. BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region (D.Jones/S. Niemeyer)

This regional standard was presented to the RSC for approval to post on the Texas RE Tracking Site for a regional stakeholder ballot. Don Jones gave a brief overview on the requirements and measures of Regional Standard BAL-001-TRE-1. He explained that the drafting team plans to conduct another technical workshop to ensure that stakeholders understand what the new standard requires and how it is to be implemented. This workshop will be held on August 24, 2011 at the ERCOT Met Center.

Several issues were discussed, including whether primary frequency control should be required from resources that are not financially compensated for providing that service, and whether wind generation resources are treated appropriately in the standard, given the current state of available control technology for WGRs.

Frank Owens made a motion to approve regional standard BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region to be posted for a 30-day pre-ballot review period, followed by a 15-day ballot period, on the Texas RE Standards Tracking Site. The motion included a provision to allow Texas RE staff to make non-substantive editorial changes to documents associated with this regional standard. David Detelich seconded the motion. All segments participated in the vote, and the motion carried by voice vote with no negative votes. Marguerite Wagner (Generation) abstained. The BAL-001-TRE-1 was approved to be posted for a 45-day review/ballot period.

6. Report from Reliability Standards Manager (D. Jones)

Don Jones gave a presentation on recent issues addressed at the NERC Standards Committee on July 13-14. He provided information on five high priority projects were discussed at the NERC meeting including: Vegetation Management (2007-07), CIP (2008-06), GRTI (2010-07), BES Definition, and PRC-005-2.

Don also gave an update on Texas RE Regional Standards that are under development:

- FERC approved CIP-001-2a – Sabotage Reporting with a regional variance for Texas RE on August 2, 2011. This standard requires all TOs and GOs to be in compliance on October 1, 2011.
- Regional standard IRO-006-TRE-1—IROL and SOL Mitigation in the ERCOT Region is now within NERC's 45-day comment period ending August 22. Following the comment period, this regional standard will be forwarded to the NERC Board of Trustees.
- The SAR-003 Standard Drafting Team has completed its work on regional standard BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region,

which the RSC approved for ballot at this meeting. The Standard Drafting Team will conduct a Technical Workshop on August 24 to present the team's final draft and to answer technical questions related to this regional standard. The workshop will be held at ERCOT Austin Met Center, Room 206 B from 9:00 a.m. to 1:00 p.m.

7. Other Business (R. Keetch)

Don informed the committee that the next NERC Standards Committee will be held on September 7.

9. Future Agenda Items (R. Keetch)

- Consider whether RSC Charter revisions are needed (consider the role of the RSC in the BAL-001-TRE-1 reference document revision process).
- Consider whether the Texas RE Standard Development Process should be revised, in view of the changes made to the corresponding NERC process.

The meeting adjourned at 11:03 a.m. The next meeting is planned for Friday, September 7, 2011 at 9:30 am at the Texas RE Office.

Attachment 8-003

Company	Sector	Name	Standard Vote	VRFs/VSLs vote		BALLOT RESULTS	VRFs/VSLs RESULTS
South Texas Electric Coop, Inc.	Cooperative	Richard McLeon	NO			YES- 1 (.333) NO-2 (.667)	YES- 1 (.5) NO-1 (.5)
Brazos Electric Power Co Op, Inc.	Cooperative	Shari Heino	NO	NO			
Guadalupe Valley Electric Co Op Inc	Cooperative	Barry Kremling	YES	YES			
Sand Bluff Wind Farm LLC	Generation	Dana Showalter	NO	ABSTAIN		YES-7 (.259) NO-20 (.741)	YES-6 (.75) NO-2 (.25) ABSTAIN- 11
Scurry County Wind LP	Generation	Mark Soutter	NO				
Silver Star I Power Partners, LLC	Generation	Carla Bayer					
South Trent Wind, LLC	Generation	Scott Gowder	YES	YES			
Buffalo Gap Wind Farm, LLC	Generation	Tracy Jarvis	NO	NO			
Calpine Corporation	Generation	Randy Jones	NO				
Champion Wind Farm	Generation	Dana Showalter	NO	ABSTAIN			
EC&R Panther Crk WF I & II, LLC	Generation	Dana Showalter	NO	ABSTAIN			
EC&R Panther Crk WF III, LLC	Generation	Dana Showalter	NO	ABSTAIN			
EC&R Papalote Creek I, LLC	Generation	Dana Showalter	NO	ABSTAIN			
EC&R Papalote Creek II	Generation	Dana Showalter	NO	ABSTAIN			
Elbow Creek Wind Project	Generation	Kevin Matt	YES	YES			
Forest Creek Wind Farm, LLC	Generation	Dana Showalter	NO	ABSTAIN			
Inadale Wind Farm, LLC	Generation	Dana Showalter	NO	ABSTAIN			
Ingleside Cogeneration, LP	Generation	Michelle D'Antuono	NO				
Kiowa Power Partners, LLC	Generation	Robert Bell	NO				
Langford Wind Power, LLC	Generation	Rick Keetch	YES	YES			
Lower Colorado River Authority	Generation	Tom Foreman	YES	YES			
Luminant Generation Company, LLC	Generation	Brenda Hampton	NO	YES			
Mesquite Wind LLC	Generation	Mike Grimes	NO				
Notrees Windpower, LP	Generation	Kevin Carter	NO	NO			
NRG Cedar Bayou Dev Co, LLC	Generation	John Palen	YES				
NRG Texas Power, LLC	Generation	Robert Bailey	YES				
Optim Energy Marketing, LLC	Generation	Steven Moss	YES	YES			
Pattern Gulf Wind LLC	Generation	Grit Schmieder-Copeland	NO	ABSTAIN			
Post Oak Wind, LLC	Generation	Mike Grimes	NO				
Pyron Wind Farm, LLC	Generation	Dana Showalter	NO	ABSTAIN			
Roscoe Wind Farm, LLC	Generation	Dana Showalter	NO	ABSTAIN			
Sherbino I Wind Farm, LLC	Generation	Carla Bayer					
Tenaska Power Services Co.	Load Serving and Marketing	Brad Cox	YES			YES-2 (.667) NO-1 (.333)	YES-1 (1) NO-0
Constellation Enrgy Commod Grp Inc.	Load Serving and Marketing	Brenda Powell	NO				
NRG Power Marketing, LLC	Load Serving and Marketing	Rick Keetch	YES	YES			
Texas Municipal Power Agency	Municipal Utility	Frank Owens				YES- 1 (.5) NO-1 (.5)	YES-1 (.5) NO-1 (.5)
City of Austin dba Austin Energy	Municipal Utility	Andrew Gallo	NO	NO			
CPS Energy	Municipal Utility	Jose Escamilla	YES	YES			
Elec Reliab. Council of Texas, Inc.	System Coordination and Planning	H. Steven Myers	YES	YES		YES-1 (1)	YES-1 (1)
CenterPoint Enrgy Houston Elec, LLC	Transmission and Distrubition	John Brockhan	YES	ABSTAIN		YES- 1 (1) ABSTAIN- 1	ABSTAIN-1
Oncor Electric Delivery Company LLC	Transmission and Distrubition	Alan Bern	ABSTAIN				
					TOTAL	YES - 3.759 NO- 2.241	YES- 3.75 NO- 1.25
						FAILED	**PASSED**

Attachment 8-004a

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.
SAR posted for comment on April 24, 2008.
SAR approved May 27, 2008.
Drafting Team nominated and selected in June 2008.
First posting of standard on March 16, 2009.
Drafting Team held technical workshop on March 31, 2009.
Second posting of standard on February 12, 2010.
Drafting Team held technical workshop on March 3, 2010.
Drafting Team held a performance evaluation workshop on August 6, 2010.
Third posting requested at RSC Meeting September 1, 2010.
Third posting ended on November 11, 2010.
Drafting Team reviewed and revised the Standard on May 5-6, 2011.
Texas RE staff received comments from NERC Staff review and revised standard draft to address comments (5/24/11).
Drafting Team finalized Standard and approved final version on July 25, 2011.
RSC approved the Standard for ballot on August 5, 2011.
[TBA: Ballot results, Board approval, etc.]

Description of Current Draft

This drafting team has revised the draft based on comments received during the third comment period, further consideration of the performance metric calculations, and guidance from FERC staff and NERC staff. This draft will likely be posted for ballot in August 2011.

Future Development Plan:

Anticipated Actions	Anticipated Date
Respond to comments/revise draft	Nov. 2010 to May 2011
Present revised draft to RSC	August 2011
Form ballot pool and vote	August-September 2011
TRE Board Adopt (Tentative)	October 2011
NERC Submit (Tentative)	November 2011
FERC Approval (Tentative)	??

Definitions of Terms Used in Standard

Frequency Measurable Event (FME): An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

or

ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region

2. **Number:** BAL-001-TRE-1

3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. This regional standard supplements the CPS2 Waiver that was approved for ERCOT by NERC on November 21, 2002. Specifically, this standard replaces requirement 2 of BAL-001-0a in the ERCOT Region per FERC Order 693.

4. **Applicability:**

   4.1. **Functional Entities:**

      1. Balancing Authority (BA)
      2. Generator Owners (GO)
      3. Generator Operators (GOP)

   4.2. **Exemptions:**

      4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

      4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.

      4.2.3 Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

5. **Background:**

   The ERCOT Interconnection was initially given a waiver of BAL-001 R2. In FERC Order 693 the NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event.

   This regional standard provides requirements related to identifying Frequency Measureable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

   Under this standard, two Primary Frequency Response performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the actual response compared to the expected response during the event recovery period, when the frequency returns to normal.

In this regional standard the term “resource” is synonymous with “generating unit/generating facility”.

6. (**Proposed) Effective Date:**

After final regulatory approval and in accordance with the 30-month Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements. See attached Implementation Plan (Attachment 1).

B. Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M1. The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall be a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. The calculation results shall be submitted to the Compliance Enforcement Authority by the end of the month in which they were completed. If the generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M2. The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in Requirement R2.

R3. The BA shall calculate the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available.

[1] The Primary Frequency Response Reference Document contains the calculations that the BA will use to determine Primary Frequency Response performance of generating units/generating facilities. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

M3. The BA shall demonstrate that the IMFR was calculated in December of each year per Requirement R3. The BA shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. The BA shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following month.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M4. The BA shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M5. The BA shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each GO shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.01666 Hz

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of a combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M6. Each GO shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets

- Performance monitoring reports

M6.1 The GO shall have evidence that it set the Governor deadbands as required in Table 6.1 in Requirement R6.

M6.2 The GO shall have evidence that the Governor droop characteristics did not exceed the settings in Table6.2 in Requirement R6.

M6.3 The GO shall have evidence that when frequency deviation has exceeded the Governor deadband from 60.00 Hz, the Governor setting follows the approved slopes derived from the prescribed formulas for 4% droop and 5% droop.

R7. Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GOP has been notified that the Governor is not in service.

[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]

M7. Each GO shall have evidence that each generating unit/generating facility had its Governor in service when the generating unit/generating facility was online and released for dispatch as described in Requirement R7, and evidence of a valid reason if it was not in service.

R8. Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status or capability change of a Governor.

[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]

M8. Each GOP shall have evidence that it notified the BA within 30 minutes of each discovery of a status or capability change of a Governor.

R9 measures *initial* unit PFR performance (A-value to B-value). This requirement specifies a certain level of average measured performance over a 12-month period.

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined-cycle facility will be determined using an expected performance droop of 5.78%.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME. The initial Primary Frequency Response performance for each FME shall be between 0.0 and 2.0.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Compliance Enforcement Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each GO shall have evidence that each of its generating units/generating facilities achieved an average initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

R10. Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

R10 measures *sustained* unit PFR performance (frequency recovery period). This requirement specifies a certain level of average measured performance over

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the event recovery period following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M10. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each GO shall have documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

C. Compliance

1. Compliance Enforcement Authority

Texas Reliability Entity

2. Compliance Monitoring Period and Reset Time Frame

2.1. If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

3. Data Retention

3.1. The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain a list of identified Frequency Measurable Events and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The BA shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The BA shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The BA shall retain all data and calculations relating to the Interconnection's Frequency Response, and all evidence of actions taken

to increase the Interconnection's Frequency Response, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.

- Each GOP shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each GO shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

D. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The BA reported an FME more than 14 days but less than 31 days after identification of the event.	The BA reported an FME more than 30 days but less than 51 days after identification of the event.	The BA reported an FME more than 50 days but less than 71 days after identification of the event.	The BA reported an FME more than 70 days after identification of the event.
R2	The BA submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The BA submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The BA submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The BA failed to submit a monthly report within 90 days after the end of the reporting month.
R3	The BA did not make the calculation and criteria for determination of the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR for the following year in December.	The BA did not calculate the IMFR.

R4	N/A		The BA did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The BA did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month.
R5	N/A	N/A	N/A	The BA did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7	N/A	N/A	N/A	The GO operated with its Governor out of service and did not notify the GOP.
R8	The GOP notified the BA of a change in Governor status or capability between 31 minutes and one hour after discovery of the change.	The GOP notified the BA of a change in Governor status or capability more than 1 hour but within 4 hours after discovery of the change.	The GOP notified the BA of a change in Governor status or capability more than 4 hours after discovery of the change.	The GOP failed to notify the BA of a change in Governor status or capability after discovery of the change.
R9	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A GO's rolling average sustained Primary Frequency Response	A GO's rolling average sustained Primary Frequency Response	A GO's rolling average sustained Primary Frequency Response	A GO's rolling average sustained Primary Frequency Response

	performance per R10 was < 0.75 and ≥ 0.65.	performance per R10 was < 0.65 and ≥ 0.55.	performance per R10 was < 0.55 and ≥ 0.45.	performance per R10 was < 0.45.

E. Associated Documents

1. Attachment 1 – Implementation Plan.
2. Attachment 2 – Primary Frequency Response Reference Document, including Flow Charts A and B.
    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9 and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.
    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	

Attachment 8-004b

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-1
Performance Metric Calculations

I. Introduction

This Primary Frequency Response Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities in accordance with Requirements R9 and R10. Flowcharts A (Initial PFR) and B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Primary Frequency Response Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available for reference and use in understanding and performing these calculations.

This Primary Frequency Response Reference Document is not considered to be a part of the regional standard. This document will be maintained by Texas RE and will be subject to modification as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.

The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

High Sustained Limit (HSL) for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility.

Low Sustained Limit (LSL) for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy production capability of a generating unit/generating facility.

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined-cycle facility will be determined using an expected performance droop of 5.78%.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME. The initial Primary Frequency Response performance for each FME shall be between 0.0 and 2.0.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

9.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Compliance Enforcement Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance.

Initial Primary Frequency Response Performance Calculation Methodology

Initial Primary Frequency Response performance requirement:

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

where P.U. $PFR_{Resource}$ is the per unit measure of the Primary Frequency Response of a Resource during identified FMEs.

Each GO may submit to the BA unit-specific information used by the BA in this requirement to calculate initial PFR performance for each generating unit/generating facility.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response\ (APFR)}{Expected\ Primary\ Frequency\ Response_{Final}}$$

where P.U. $PFR_{Resource}$ for each FME is between zero and 2.0.

The Actual Primary Frequency Response and the Expected Primary Frequency $Response_{Final}$ ($EPFR_{Final}$) are calculated as described below:

EPFR Calculations use droop and deadband values as stated in R6 with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of the steam turbine generator is included in the evaluation) where the evaluation droop will be 5.78%.[1]

Ideal Expected Primary Frequency Response ($EPFR_{ideal}$)

The unadjusted expected MW change calculated when the frequency deviation exceeds the deadband for all generator types.

$$EPFR_{ideal} = \left[\frac{(HZ_{actual} - 60.0 \pm deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (Capacity)\right]$$

Capacity and NDC are used interchangeably and the term Capacity will be used in this document. They are the official reported seasonal capacity of the generating unit/generating facility. The capacity for wind-powered generators is the cumulative nameplate capacity of all wind turbines in that facility that were on-line when the FME occurred.

For combined cycle facilities, ERCOT will calculate each generator's HSL using the submitted seasonal ratings, the telemetered individual net MW, and telemetered combined cycle HSL. As an alternative the GO/GOP may telemeter HSL values for each generator of the combined cycle facility.

In the numerator, the "+" is used for positive (above 60.000 Hz) frequency excursions and the "–" is used for negative (below 60.000 Hz) frequency excursions.

$EPFR_{final}$ for Combustion Turbine

First calculate the Adjusted EPFR:

$$EPFR_{Adj} = EPFR_{ideal} + (HZ_{actual} - 60.0) \times 10 \times 0.00276 \times Capacity$$

where

$$HZ_{Actual} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

Note: The 0.00276 constant is MW/0.1 Hz change / MW Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

[1] The effective droop of a typical combined-cycle facility with governor settings per Requirement R6 is 5.78%, assuming a 2-to-1 ratio between combustion turbine capacity and steam turbine capacity.

Then add a ramp adjustment to determine $EPFR_{final}$:

$EPFR_{final} = EPFR_{adj} + RampMagnitude$

where

$RampMagnitude = (MW_{T-4} – MW_{T-60}) * 0.59$

Note: $(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility during the full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

<u>$EPFR_{final}$ for Steam Turbine</u>

First calculate the adjusted EPFR:

$$EPFR_{Adj} = \left(EPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{Adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times HSL \times Steam\ Flow\ Pressure\ Change\ Factor$$

where:

$$\%Steam\ Flow = \frac{Post - perturbation\ Average\ MW_{actual}}{HSL}$$

$$Steam\ Flow\ Pressure\ Cha\overset{x}{n}ge\ Factor = \frac{\%Steam\ Flow}{0.5}$$

and where K is used to model the stored energy available to the resource and ranges between 0.0 and 0.6 psig/MW, measured at 50% output of the steam turbine. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, based on resource loading (% steam flow) further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between EPFR and APFR (resulting in the highest P.U. $PFR_{Resource}$). K will not change unless the steam generator is significantly reconfigured.

Throttle Pressure = Interpolation of Pressure curve at Post-perturbation Average MW_{Actual}.

Then add a ramp factor to determine $EPFR_{final}$:

$EPFR_{final} = EPFR_{adj} + RampMagnitude$

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{Adj} = EPFR_{ideal} + X * LF$$

$$EPFR_{Final} = EPFR_{Adj} + RampMagnitude$$

where X and LF are the adjustment methods that properly model the delivery of PFR due to known and approved technical or physical limitations of the resource. X and LF may be adjusted by the BA and may be variable across the operating range of a resource.

Ramp Adjustment: The Final Expected Primary Frequency Response number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is added to $EPFR_{Adj}$.

$$\text{Ramp Magnitude} = (MW_{T-4} - MW_{T-60})*0.59$$

$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

$$\text{Expected Primary Frequency Response}_{Final} = EPFR_{Adj} + \text{Ramp Magnitude}$$

Actual Primary Frequency Response (APFR)

This is the difference between Post-perturbation Average MW and Pre-perturbation Average MW.

$$Actual\ Primary\ Frequency\ Response = MW_{post-perturbation} - MW_{pre-perturbation}$$

where

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{\#\ Scans}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(20)}^{t(52)} MW}{\#\ Scans}$$

Limits on Calculation of Initial Primary Frequency Response Performance:

If the generating unit/generating facility is operating within 2% of HSL from its operating limits at the time an FME occurs (pre-perturbation), then that unit/facility's Primary Frequency Response performance is not evaluated for that FME.

For negative frequency deviations, if

$MW_{Pre-perturbation} \geq (HSL\ x\ 0.98)$

then Primary Frequency Response is not evaluated for this FME.

For positive frequency deviations, if

$MW_{Pre-perturbation} \leq [LSL + (HSL\ x\ 0.02)]$

then Primary Frequency Response is not evaluated for this FME.

Expected PFR greater than Operating Margin: When a generating unit/generating facility has greater than 2% pre-perturbation operating margin, but the Expected Primary Frequency Response is greater than the available operating margin and the generating unit/generating facility's actual $PFR_{Initial}$ response is in the correct direction, the P.U. $PFR_{Resource}$ will be set to 0.75 or the calculated P.U. $PFR_{Resource}$, whichever is greater.

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance.

Sustained Primary Frequency Response Performance Calculation Methodology

Event Recovery Time (ERT): For low frequency events, the time at which frequency returns to pre-perturbation frequency or 59.984 Hz, whichever occurs first. For high frequency events, the time at which frequency returns to pre-perturbation frequency or 60.016 Hz, whichever occurs first.

Event Recovery Period (ERP): The period from T=0 to ERT expressed in seconds.

Each GO may submit to the BA any information used by the BA in this requirement to calculate sustained PFR performance for each generating unit/generating facility.

<u>Sustained Primary Frequency Response performance requirement:</u>

$$Avg_{Period}\,[P.U.PFR_{Resource}] \geq 0.75$$

<u>RampMW Calculation (MW/scan)</u>

$$RampMW_{pre-event} = \frac{MW_{(t-2)} - MW_{(t-60)} - EPFR_{delayed\,(t-2)} + EPFR_{delayed\,(t-60)}}{29}$$

Note: There are 29 two-second scans between t-2 and t-60. The terminology "$MW_{(t-2)}$" refers to MW output at 2 seconds before the Frequency Measurable Event (FME) occurs at t(0).

$$RampMW_{post-event} = \left[\frac{MW_{(ERT)} - MW_{(t-4)} + EPFR_{delayed(t-4)} - EPFR_{delayed(ERT)}}{\frac{ERP}{Seconds\ per\ Scan}}\right]$$

EPFR Calculations use droop and deadband values as stated in R6 with the exception of combined-cycle facilities while evaluated as a single resource (MW production of the steam turbine generator is included in the evaluation) where the evaluation droop will be 5.78%.

$EPFR_{ideal}$ Calculation

When the frequency is within the Governor deadband:

$EPFR_{ideal} = 0$

When the frequency is outside the Governor deadband and above 60 Hz:

$$EPFR_{ideal}[i] = \left[\frac{(HZ_{actual}[i] - 60 - Deadband)}{(Droop \times 60 - Deadband)} \times (Capacity) \times (-1)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$EPFR_{ideal}[i] = \left[\frac{(HZ_{actual}[i] - 60 + Deadband)}{(Droop \times 60 - Deadband)} \times (Capacity) \times (-1)\right]$$

$EPFR_{delayed}$ Calculation

For every scan *i* from 70 seconds prior to the FME (t-70) to ERT:

$$EPFR_{delayed}[i] = (Time\ Constant \times EPFR_{ideal}[i]) + \left((1 - Time\ Constant) \times EPFR_{delayed}[i-1]\right)$$

Where *Time Constant* is a value in the range 0.05 to 1.0. This value is provided by the GO for each generating unit/generating facility. The GO should determine (and provide to the BA) the Time Constant for each unit or facility that generally results in the best match between sustained EPFR and sustained APFR (and the highest sustained P.U. $PFR_{Resource}$). The Time Constant will not change unless the unit or facility is significantly reconfigured. However, implementation of control modifications that significantly improve PFR performance may justify changing (increasing) the Time Constant.

TargetMW Calculation

TargetMW[i] at t = -2:

$$TargetMW_{(t-2)} = MW_{Actual(t-2)}$$

Pre-Event TargetMW[i] for every scan *i* from t-4 to t-60 (between 4 and 60 seconds before the FME):

$$TargetMW[i] = TargetMW[i+2] - RampMW_{pre-event} - (EPFR_{delayed}[i+2] - EPFR_{delayed}[i])$$

Recovery TargetMW[i] for every scan from t(0) to Event Recovery Time:

$$TargetMW[i] = TargetMW[i-2] + RampMW_{post-event} + (EPFR_{delayed}[i] - EPFR_{delayed}[i-2])$$

Note: If TargetMW[i] exceeds HSL or is less than LSL it is limited to the corresponding HSL or LSL.

TargetMW$_{avg}$

$$TargetMW_{avg} = \frac{\sum_{t(+2)}^{t(ERT)}(TargetMW[i])}{\#Scans}$$

ActualMW$_{avg}$

$$ActualMW_{avg} = \frac{\sum_{t(+2)}^{t(ERT)}(ActualMW[i])}{\#Scans}$$

P.U. PFR Calculations

Consideration of resource ramp direction during the ERP impacts the method of determining P.U. PFR. If the ramp during the ERP is opposite in direction to the EPFR$_{final}$, special tests must be performed to determine the impact of the ramp on performance.

For Low Frequency events:

When the TargetMW$_{avg}$ minus the ActualMW$_{(t-4)}$ is less than 0, the unit will be considered in a hard down ramp. To allow for this situation an assessment is done to determine if the ActualMW$_{avg}$ performed by the unit is greater than the TargetMW$_{avg}$ the unit was expected to achieve. If it was, then the unit will be contributing to the performance of the system and given a score of 1.0. If not, an additional assessment will be made to determine if the ActualMW$_{avg}$ was greater than the RampMW$_{avg}$. If it was, then the unit will be credited with a 0.75 indicating it was not a detriment to the system and appeared to make an effort to contribute. If it was not, then the unit will be credited with 0.0 for not providing Primary Frequency Response.

When the TargetMW$_{avg}$ minus the ActualMW$_{(t-4)}$ is greater than or equal to 0, the unit will not be considered to be in a hard down ramp. For this situation an assessment is done to determine if the ActualMW$_{avg}$ – ActualMW$_{(t-4)}$ is greater than 0. If not, then a further assessment will be performed to determine if the ActualMW$_{avg}$ was greater than the RampMW$_{avg}$. If it was, then the unit will be credited with a 0.75 indicating it was not a detriment to the system and appeared to make an effort to contribute. If it was not, then the unit will be credited with 0.0 for not responding. If the ActualMW$_{avg}$ – ActualMW$_{(t-4)}$ is greater than 0, then the unit P.U.PFR performance will be calculated as shown below.

Sustained P.U.PFR Calculation – Low Frequency Event

For generating unit/generating facility whose MW output value at ERT is higher than MW output at t-4.

$$P.U.PFR_{Resource} = \frac{ActualMW_{avg} - ActualMW_{(t-4)}}{TargetMW_{avg} - ActualMW_{(t-4)}}$$

For generating unit/generating facility whose MW output value at ERT is lower than or equal to MW output at t-4.

$$P.U.PFR_{Resource} = \frac{ActualMW_{avg} - ActualMW_{(ERT)}}{TargetMW_{avg} - ActualMW_{(ERT)}}$$

The maximum achievable score will be constrained at 2.0.

<u>For High Frequency events:</u>

When the $TargetMW_{avg}$ minus the $ActualMW_{(t-4)}$ is greater than 0, the unit will be considered in a hard up ramp. To allow for this situation an assessment is done to determine if the $ActualMW_{avg}$ performed by the unit is less than the $TargetMW_{avg}$ the unit was expected to achieve. If it was, then the unit will be contributing to the performance of the system and given a score of 1.0. If not, an additional assessment will be made to determine if the $ActualMW_{avg}$ was less than the $RampMW_{avg}$. If it was, then the unit will be credited with a score of 0.75, indicating it was not a detriment to the system and appeared to make an effort to contribute. If it was not, then the unit will be given a score of 0.0 for not responding.

When the $TargetMW_{avg}$ minus the $ActualMW_{(t-4)}$ is less than or equal to 0, the unit will not be considered to be in a hard up ramp. For this situation, an assessment is done to determine if the $ActualMW_{avg} - ActualMW_{(t-4)}$ is less than 0. If not, then a further assessment will be performed to determine if the $ActualMW_{avg}$ was less than the $RampMW_{avg}$. If it was, then the unit will be credited with a score of 0.75 indicating it was not a detriment to the system and appeared to make an effort to contribute. If it was not, then it will be credited with 0.0 for not responding. If the $ActualMW_{avg} - ActualMW_{(t-4)}$ is less than 0, then the unit P.U.PFR performance will be calculated as shown below.

Sustained P.U.PFR Calculation – High Frequency Event

For generating unit/generating facility whose MW output value at ERT is higher than MW output at t-4.

$$P.U.PFR_{Resource} = \frac{ActualMW_{avg} - ActualMW_{(ERT)}}{TargetMW_{avg} - ActualMW_{(ERT)}}$$

For generating unit/generating facility whose MW output value at ERT is lower than MW output at t-4.

$$P.U.PFR_{Resource} = \frac{ActualMW_{avg} - ActualMW_{(t-4)}}{TargetMW_{avg} - ActualMW_{(t-4)}}$$

Revision History

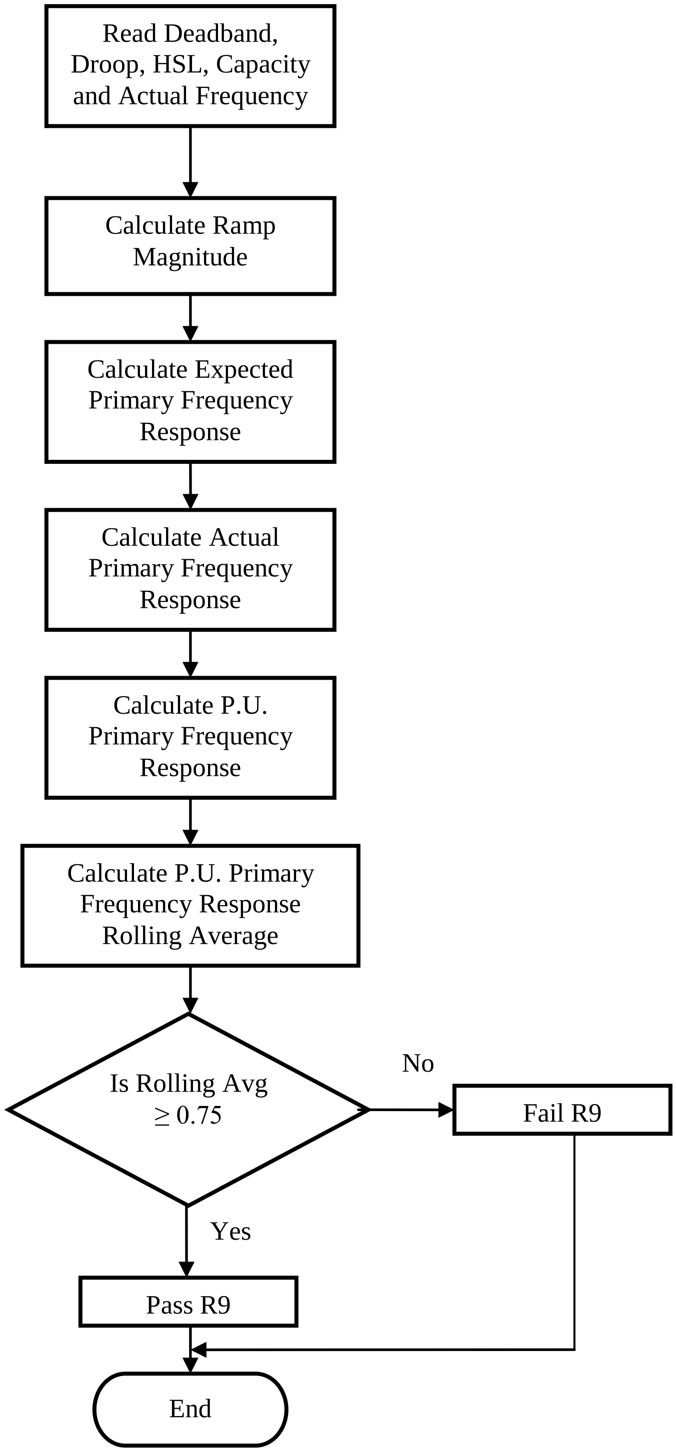
Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	

Attachment 8-004c

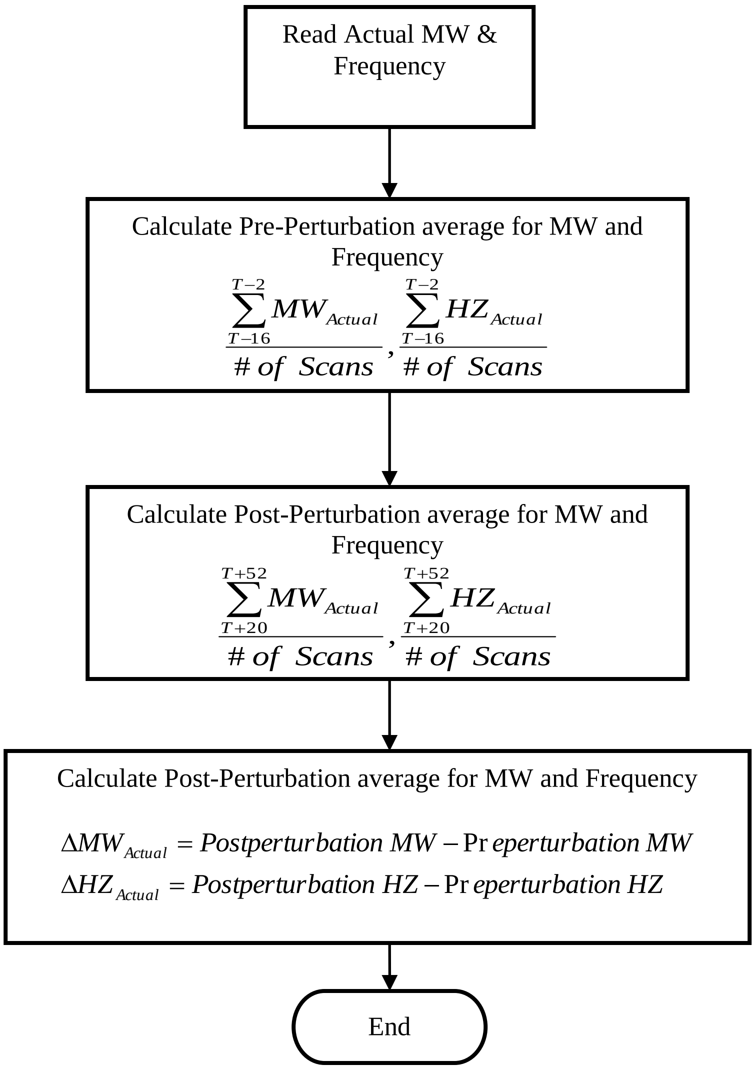
Attachment A to
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for
BAL-001-TRE-1

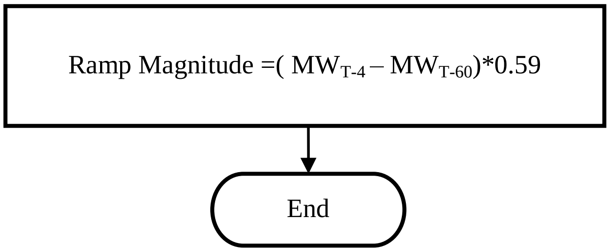
Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response



Perturbation Average MW and Average Frequency Calculations



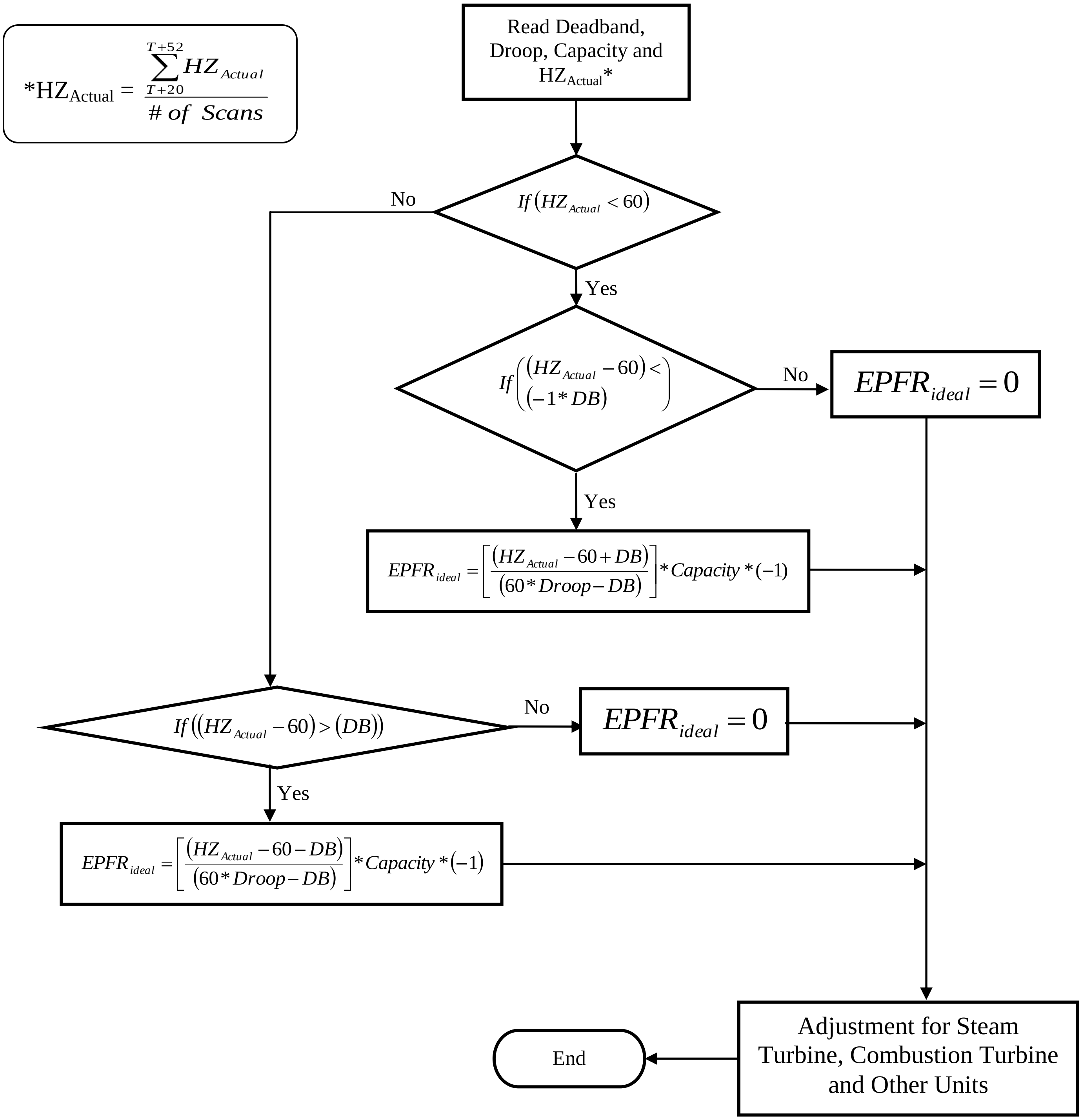
Ramp Magnitude Calculation



($MW_{T-4} - MW_{T-60}$) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response Calculation

Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



Adjustment for Steam Turbine

Read K(Limiting Factor), Rated Throttle Pressures, HSL and pre and post-perturbation MW_{Actual}

↓

$$\%\ Steam\ Flow = \frac{Post - perturbation\ Average\ MW_{Actual}}{HSL}$$

↓

$$Steam\ Flow\ Pressure\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{Adjustment} = EPFR_{ideal} * \frac{K}{Rated\ Throttle\ Pressure} * HSL * Steam\ Flow\ Pressure\ Change\ Factor$$

↓

Throttle Pressure = Interpolation of Pressure curve at pre-perturbation MW_{Actual}

↓

$$EPFR_{Adj} = \left(EPFR_{ideal} + MW_{Adjustment}\right) * \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

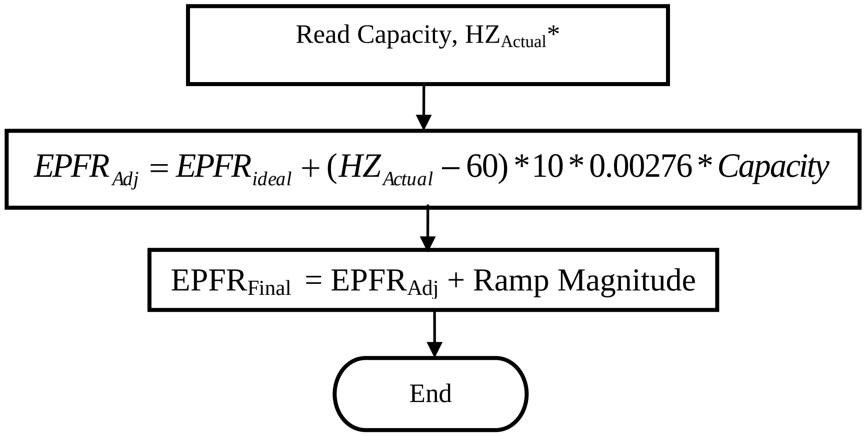
↓

$EPFR_{Final} = EPFR_{Adj}$ + Ramp Magnitude

↓

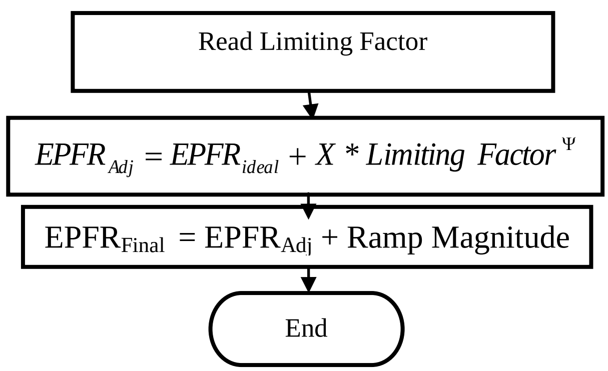
End

Adjustment for Combustion Turbine



0.00276 is MW/0.1 Hz change / MW Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

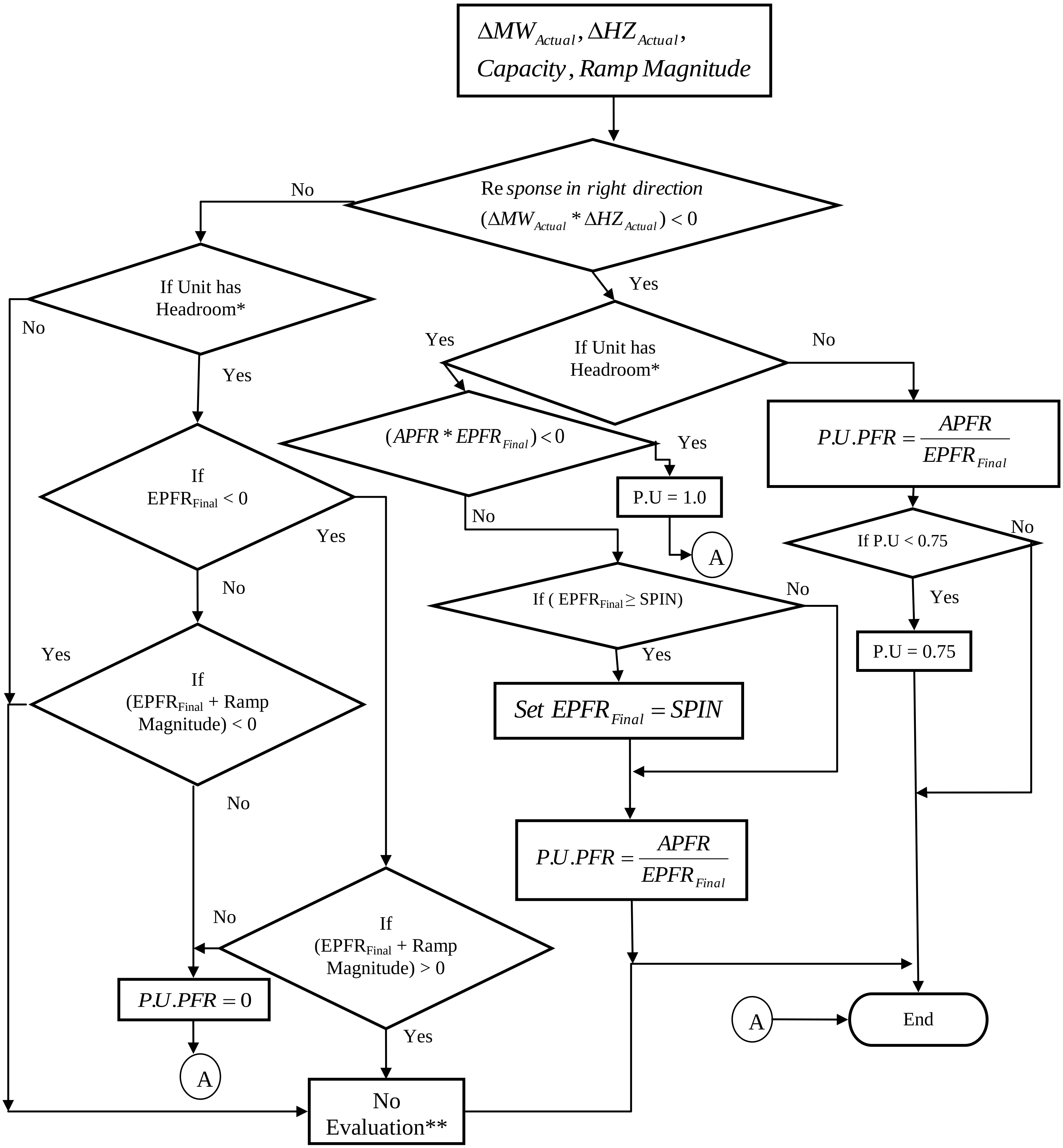
Adjustment for Other Units



$$*HZ_{Actual} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

$X\_and\_Limiting\ Factor^{\Psi}$ = This adjustment and Limiting Factor will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X and Limiting Factor may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Initial Primary Frequency Response Calculation



*check for 2% headroom. If a unit has only 2% of HSL or less as available headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency. If a unit has only 2% of HSL as down headroom it is considered operating at low capacity and will not be evaluated for high frequency.

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

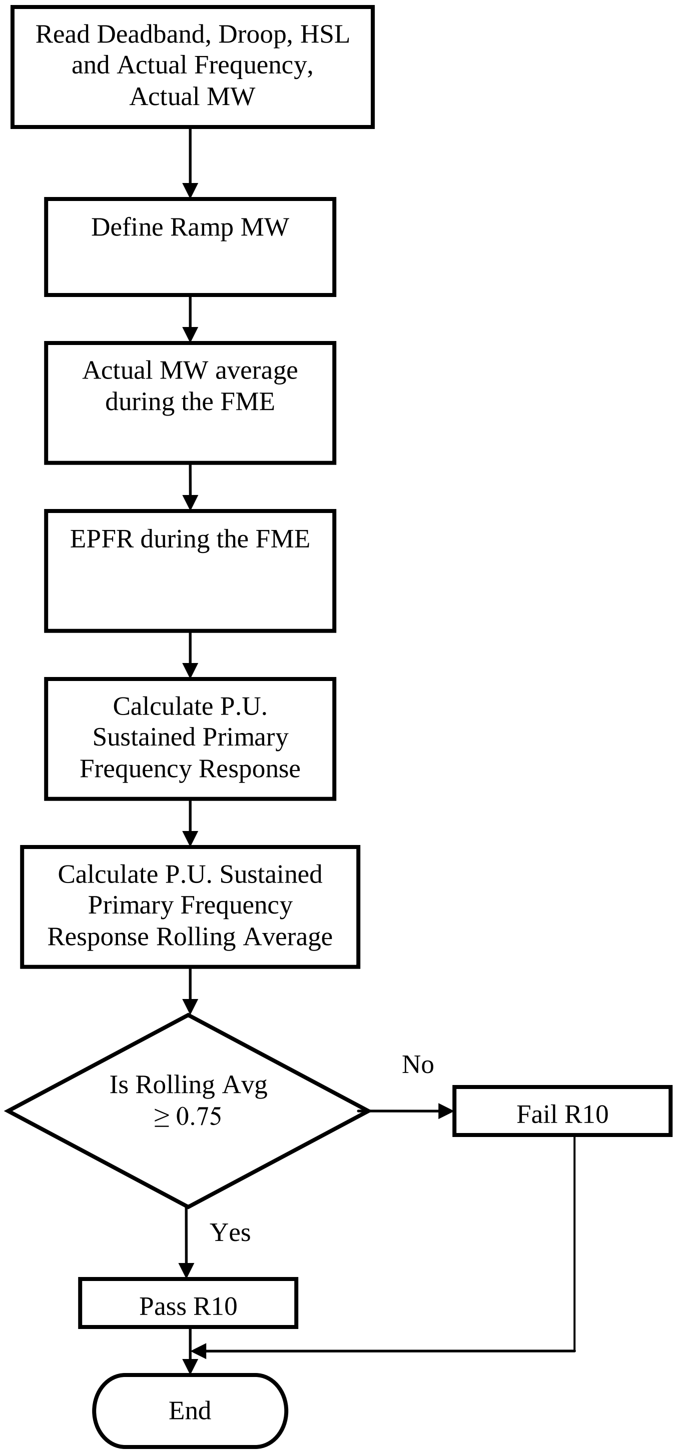
T = Time in Seconds

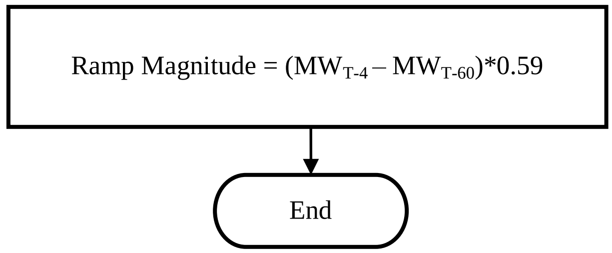
Attachment 8-004d

Attachment B to
Primary Frequency Response Reference Document

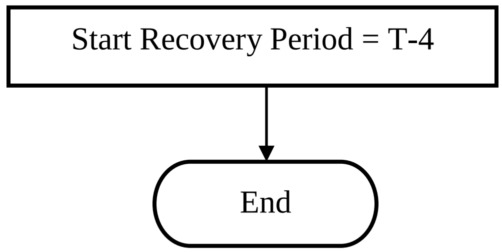
Sustained Primary Frequency Response Methodology for BAL-001-TRE-1

Primary Frequency Response Measurement and Rolling Average Calculation – Sustained Response

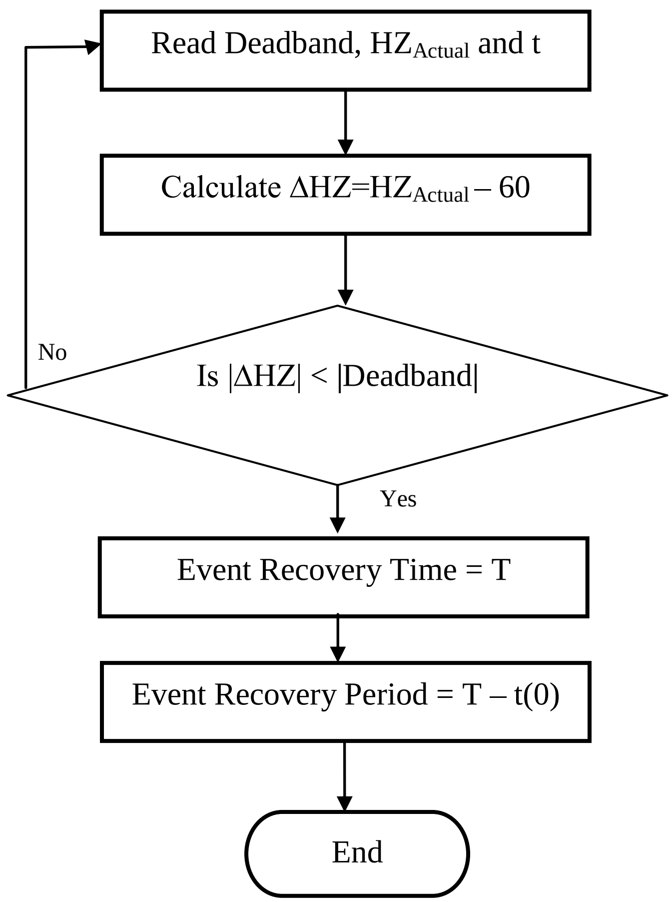



Ramp Magnitude = $(MW_{T-4} – MW_{T-60})*0.59$
End

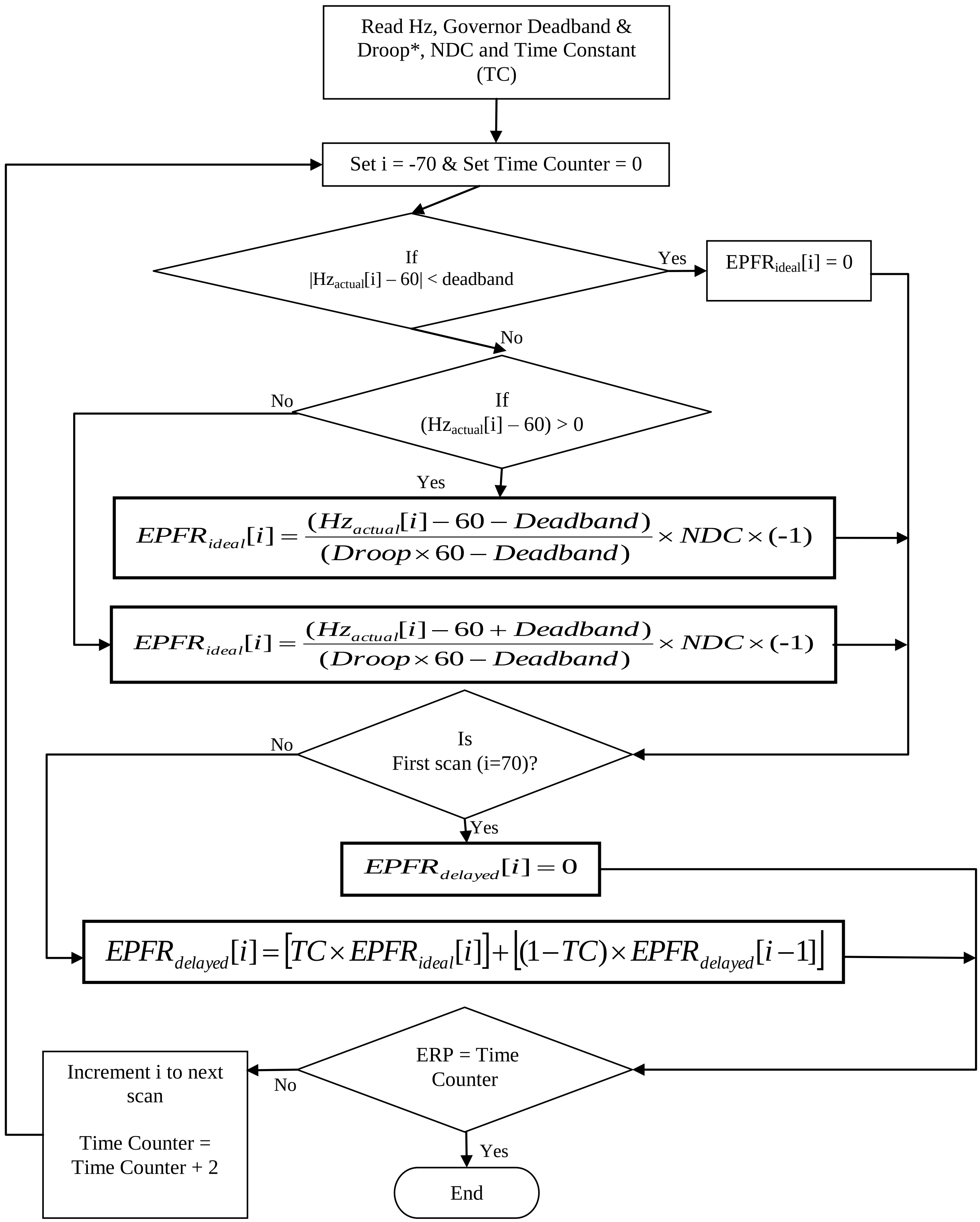
Start Recovery Period



Event Recovery Period (ERP)



$\mathbf{EPFR_{Delayed}}$ Calculation (Use the droop and deadband as required by R6). For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5% droop* in all calculations.

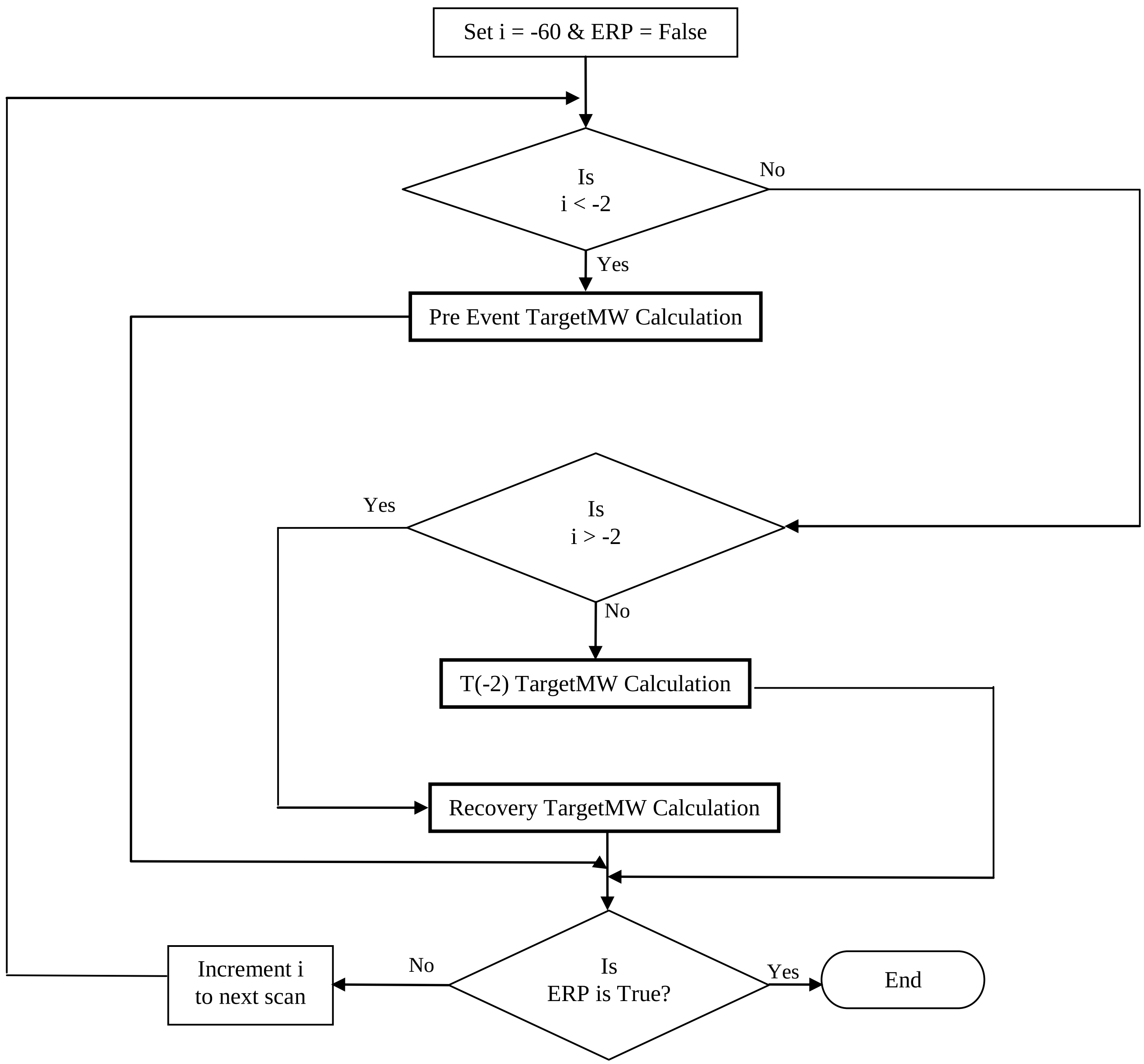

Read Hz, Governor Deadband & Droop*, NDC and Time Constant (TC)
Set i = -70 & Set Time Counter = 0
If $|Hz_{actual}[i] - 60| < deadband$
Yes
$EPFR_{ideal}[i] = 0$
No
If $(Hz_{actual}[i] - 60) > 0$
No
Yes
$EPFR_{ideal}[i] = \frac{(Hz_{actual}[i] - 60 - Deadband)}{(Droop \times 60 - Deadband)} \times NDC \times (-1)$
$EPFR_{ideal}[i] = \frac{(Hz_{actual}[i] - 60 + Deadband)}{(Droop \times 60 - Deadband)} \times NDC \times (-1)$
Is First scan (i=70)?
No
Yes
$EPFR_{delayed}[i] = 0$
$EPFR_{delayed}[i] = [TC \times EPFR_{ideal}[i]] + [(1-TC) \times EPFR_{delayed}[i-1]]$
ERP = Time Counter
No
Yes
Increment i to next scan
Time Counter = Time Counter + 2
End

Ramp MW Calculation

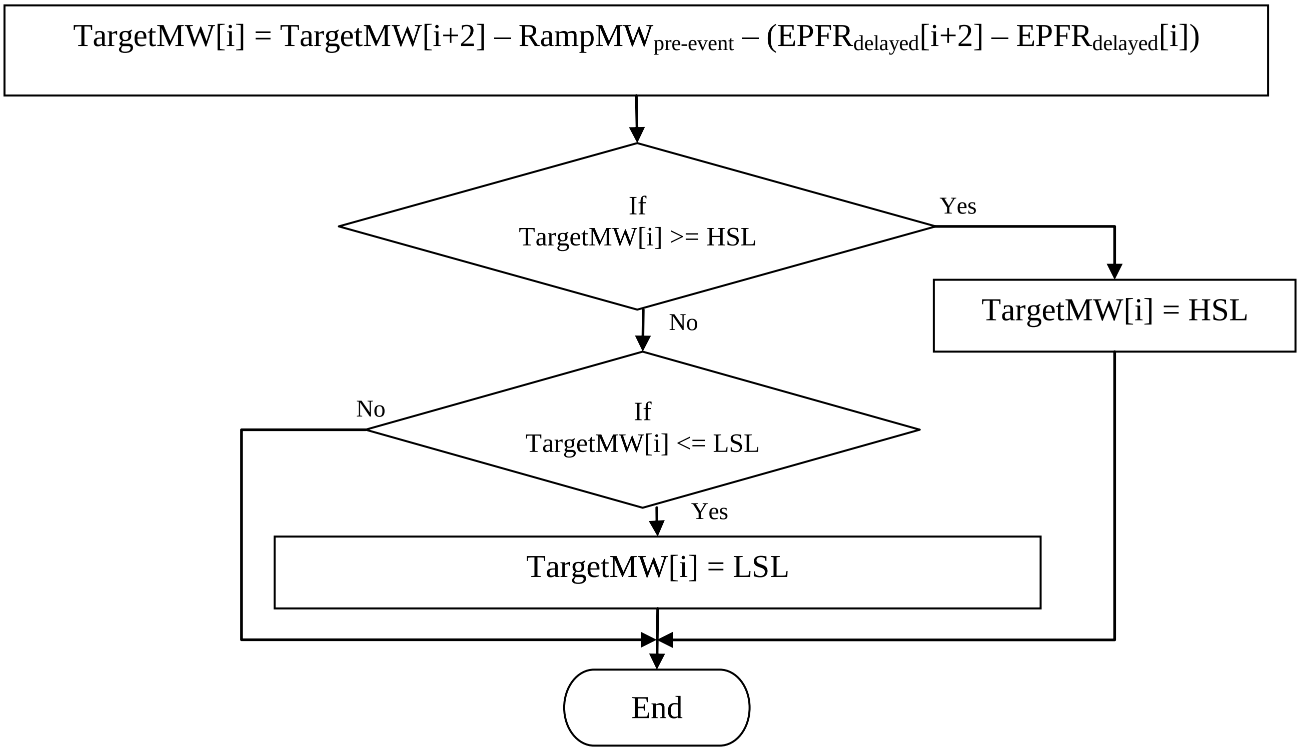
$$RampMW_{pre-event} = \frac{\lfloor MW_{(t-2)} - MW_{(t-60)} - EPFR_{delayed(t-2)} + EPFR_{delayed(t-60)} \rfloor}{29}$$

$$RampMW_{post-event} = \left[\frac{MW_{(ERT)} - MW_{(t-4)} + EPFR_{delayed(t-4)} - EPFR_{delayed(ERT)}}{\frac{ERP}{Seconds\ per\ Scan}} \right]$$

TargetMW Calculation



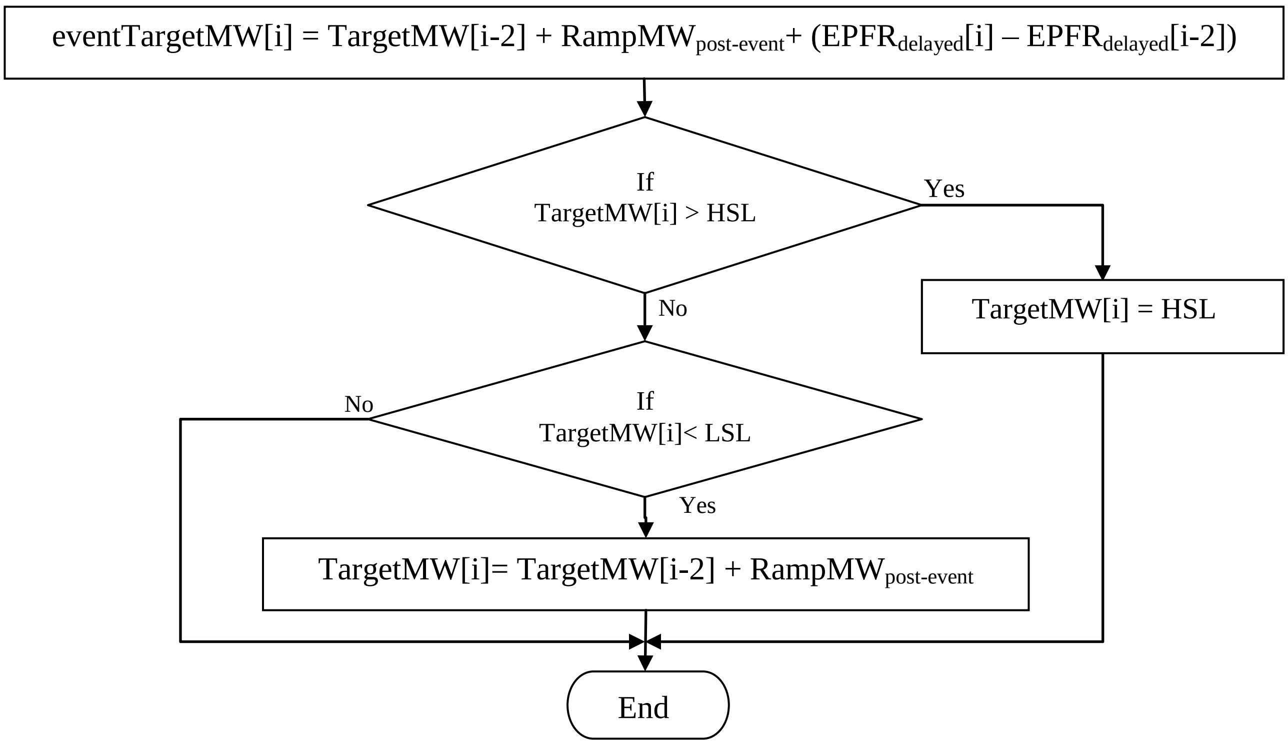
PreEvent TargetMW Calculation



T(-2) TargetMW Calculation

$$\boxed{TargetMW_{(t-2)} = MW_{Actual(t-2)}}$$

Recovery TargetMW Calculation for t(0) through ERT.



TargetMW$_{avg}$

$$TargetMW_{avg} = \frac{\sum_{t(+2)}^{t(ERT)}(TargetMW[i])}{\#Scans}$$

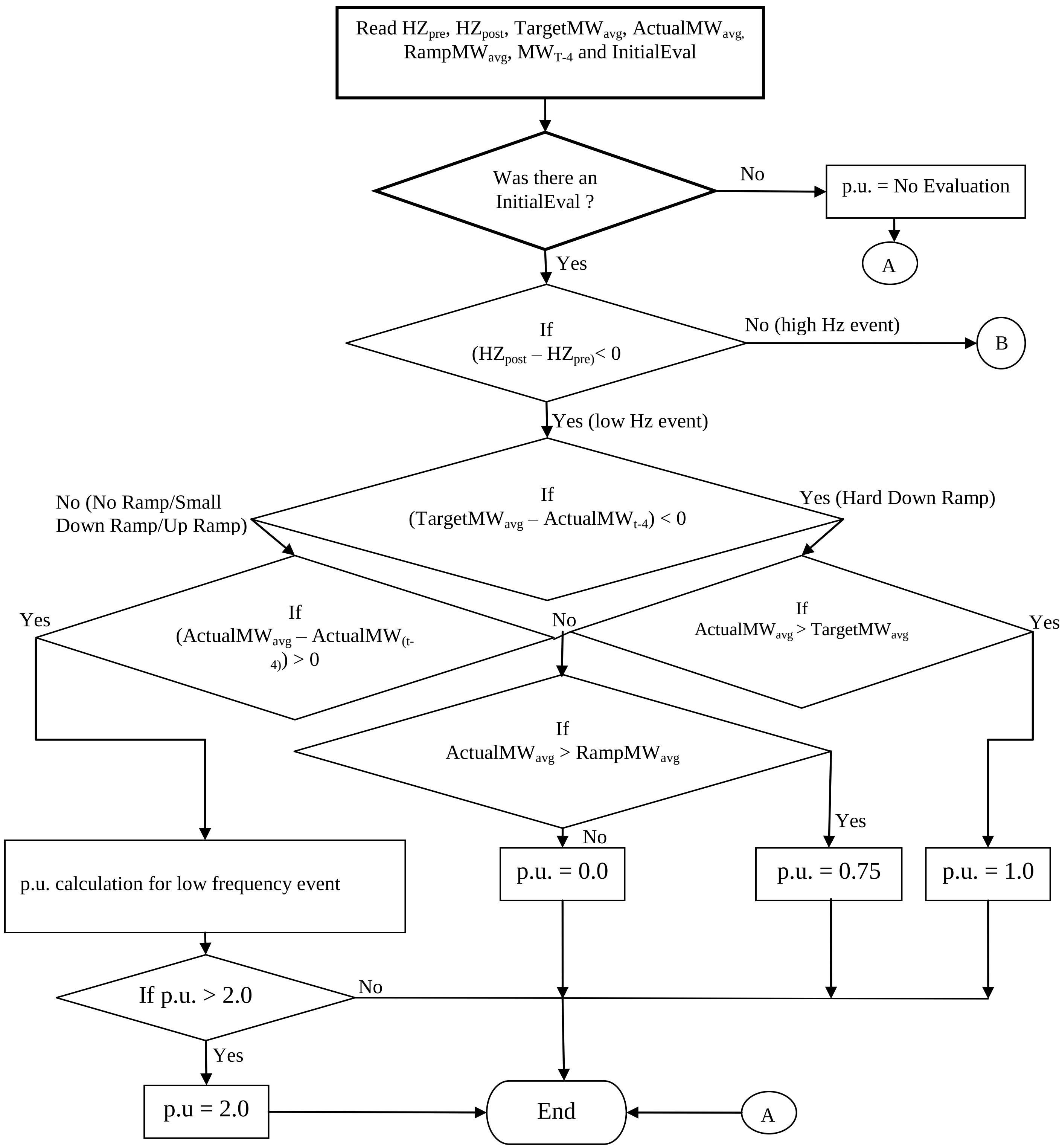
ActualMW$_{avg}$

$$ActualMW_{avg} = \frac{\sum_{t(+2)}^{t(ERT)}(ActualMW[i])}{\#Scans}$$

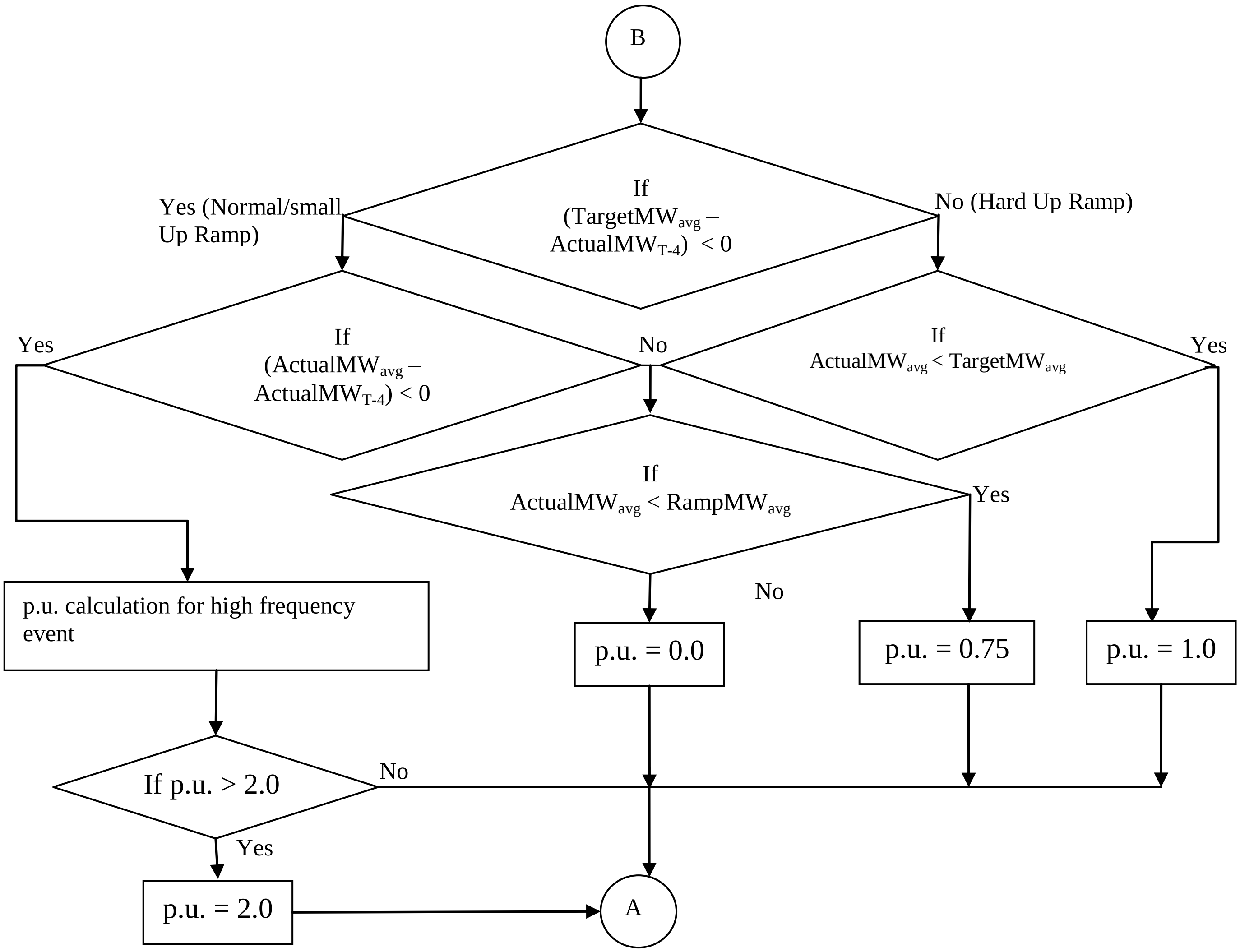
RampMW$_{avg}$

$$RampMW_{avg} = \frac{ActualMW_{(t-4)} + \sum_{t(+2)}^{t(ERT)}\left(RampMW_{post-event}\right)}{\#Scans}$$

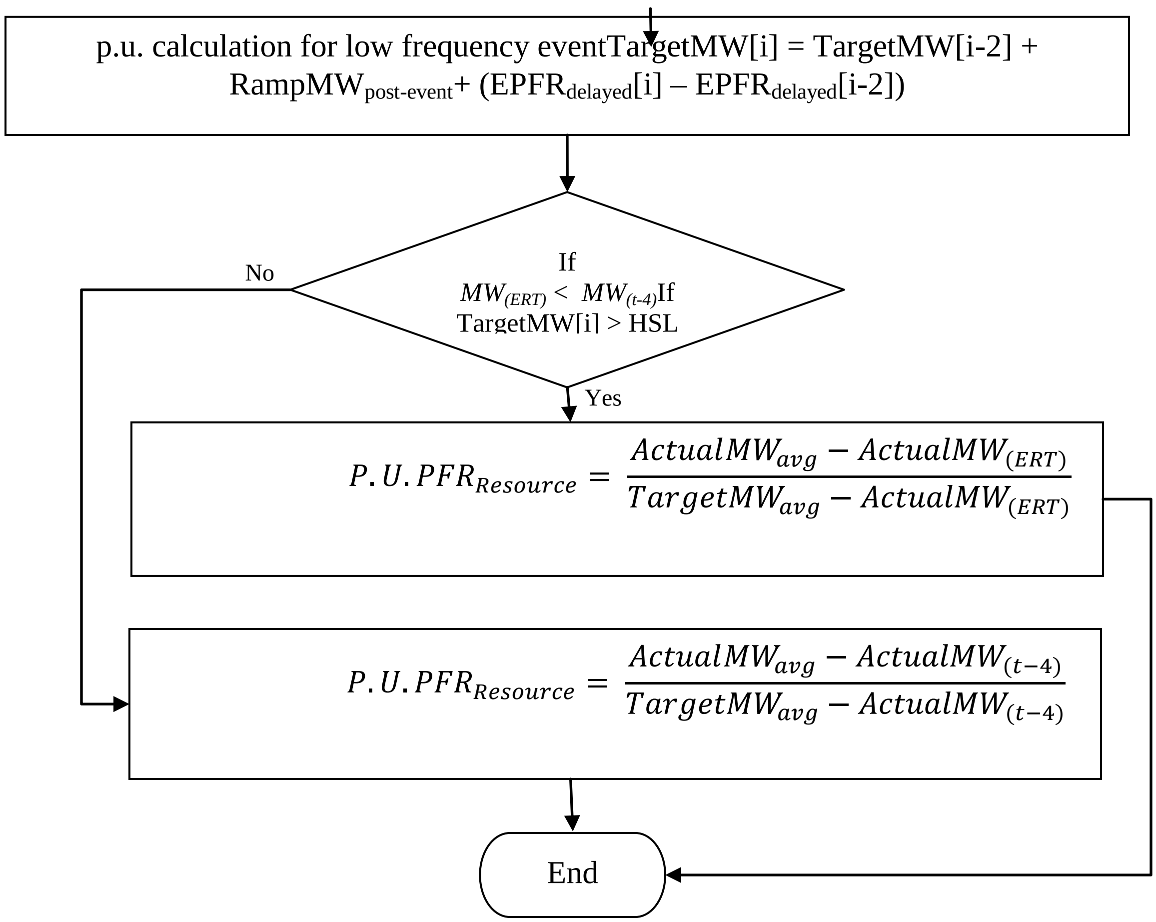
Sustained Primary Frequency Response P.U. calculation for Low Frequency Event



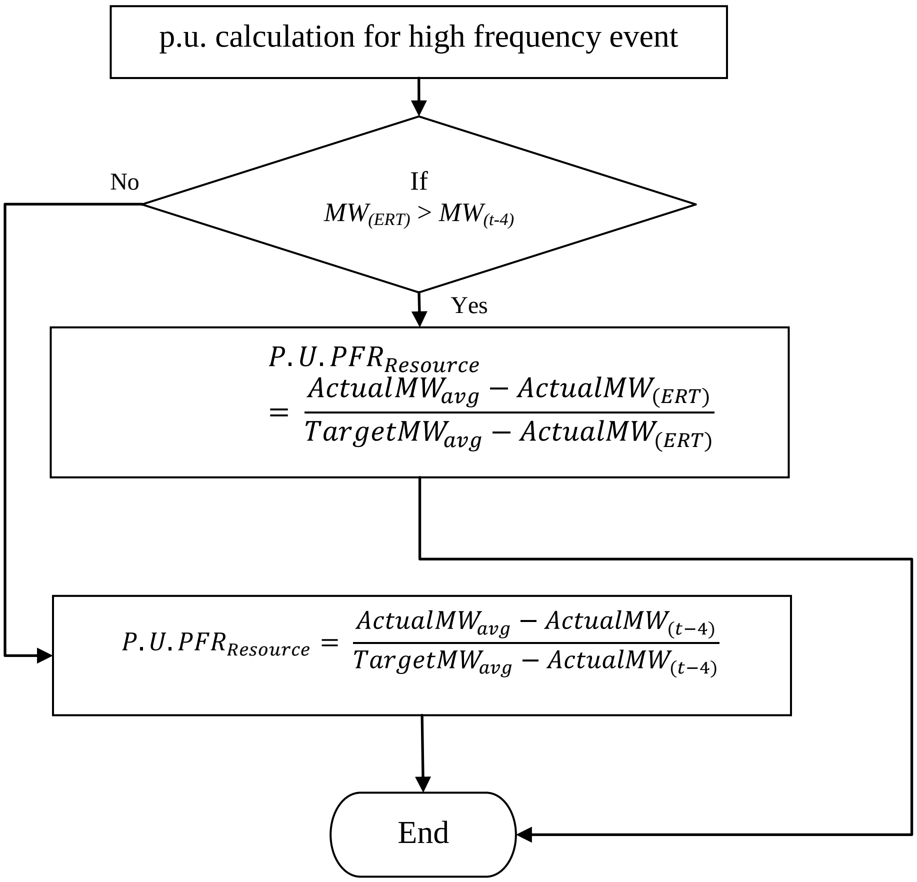
Sustained Primary Frequency Response P.U. calculation for High Frequency Event



P.U. Calculation for Low Frequency Event



P.U. Calculation for High Frequency Event



Attachment 8-004e

BAL-001-TRE-1

Attachment 1

Implementation Plan for Regional Standard BAL-001-TRE-1, Primary Frequency Response in the ERCOT Region

Prerequisite Approvals:
None

Revisions to Approved Standards and Definitions:
None

New Definitions:
- Frequency Measurable Event (FME)
- Governor
- Primary Frequency Response (PFR)

Compliance with the Standard

The following entities are responsible for being compliant with requirements of BAL-001-TRE-1:
- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)

- Exemptions:
    - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.
    - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.
    - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
The Effective Date of this standard shall be the first day of the first calendar quarter after final regulatory approval. Registered Entities must be compliant with the Requirements in accordance with the 30-month Implementation Plan set forth below.

- <u>12 months after Effective Date</u>
    - The BA must be compliant with Requirement R1
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R6 (if >1 unit/facility)
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R7 (if >1 unit/facility)
    - The GOP must be compliant with Requirement R8

- <u>18 months after Effective Date</u>
    - The BA must be compliant with Requirements R2, R3, R4, and R5
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R6
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R7

- <u>24 months after Effective Date</u>
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R9 (if >1 unit/facility)
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R10 (if >1 unit/facility)

- <u>30 months after Effective Date</u>
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R9
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R10

Attachment 8-005

Consideration of Comments from the First Ballot Period – September 2011
BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region

Commenter	Voted	Comment	Response
Andrew Gallo, Austin Energy	No	Our concern is with requirements 9 and 10. Measuring and evaluating primary frequency response is inexact and difficult. ERCOT's PDC Working Group is currently struggling with this issue. It is good/appropriate that a unit can be excluded due to a "legitimate operating condition", however, this possible exclusion introduces subjectivity into the evaluation making consistency of application a potential issue. Until the metrics are well defined, repeatable and less subjective, Texas RE should not impose fines or, at least, lessen both the VRF and VSL for these requirements.	The present PFR measurement method that is used by the PDCWG expects 70% of 5% droop performance by each generator on each event. This measurement technique, which has been used for over 15 years, encourages the "Step" response implementation at the dead-band in order to meet this performance level. The PDCWG and this drafting team have proven that the step response implementation is less reliable for the grid and is harder on the generator than the implementation that is required in this standard. This standard measures performance based on the dead-band requirement and droop implementation from the dead-band, adjusts expected performance based on known limitations of the generator type, averages performance for a minimum of twelve months, provides monthly feedback to the generator on its performance and has a minimum performance level of 75% of the adjusted expected performance. This standard is clearly superior to any method ever used and is completely fair to the generator in setting expected performance well within the abilities of the generator. Industry comments from previous postings clearly indicated the need for "legitimate operating conditions" exclusions. TRE has expressed no concern for these exclusions as they have had previous experience with similar exclusions when they enforced the SCPS 1 & 2 performance metric during Zonal operations in ERCOT.
Brenda Hampton, Luminant Generation Company	No	Requirement R7 of the Standard states that each unit will be operated with the Governor in service when the generating unit/generating facility is online and released for dispatch. We have no concerns with the Requirement; however, the Measure that goes with it (M7) is problematic. M7 requires evidence be produced to prove that the Governors are in service any time the unit is on line. Not only is the measure onerous, but there is a concern with exactly what would constitute reasonable "proof". We recommend this measure be re-worded to match that of similar standards (such as VAR-002).	The SDT agrees and has revised Measure M7 to address this concern.
Brenda Powell, Constellation Energy Commodity Group	No	Some of the requirements proposed are extremely onerous and present many compliance issues. Constellation believes that if TRE truly wants the more onerous requirements implemented, than the BA should be made the owner and authority of those requirements (mainly R8 and R9). The BA could then choose	The market is free to develop any product it wants to meet defined reliability requirements. Since the Protocols and Operating Guides already require generators to have PFR, this standard does not add any new functions of the generator. It only clearly states correct implementation and sets minimum performance measures.

		generators that they believe should comply with these requirements, as not all generators would need to comply. The chosen generators could then be paid ancillary services for complying with these requirements.	
Dana Showalter, Champion Wind Farm, EC&R Panther Creek Wind Farm I & II, EC&R Panther Creek Wind Farm III, EC&R Papalote Creek I, EC&R Papalote Creek II, Forest Creek Wind Farm, Indale Wind Farm, Pyron Wind Farm, Roscoe Wind Farm, Sand Bluff Wind Farm	No	The deadband is being cut in half from 0.036 Hz to 0.016 Hz. There are many exemptions included in the standard to account for physical machine limitation for thermal units. No such limitations are explicitly stated in the standard for Wind Units, which is an obvious inequity.	The dead-band has been reduced but at the same time the implementation of a proportional response from the dead-band, instead of the traditional "step" response implemented by many manufacturers, will greatly reduce the movement of the generator to small frequency deviations. Leaving the dead-band at the larger value of 0.036 Hz would have greatly reduced interconnection frequency response. The governor settings required in this standard will provide the greatest stability to the grid and to the generator. This has been proven with the improvement in ERCOT frequency performance over the past three years due to the participation of over 15,000 MW of capacity with these settings. The drafting team has solicited participation from all wind generators in developing proper implementation of PFR from wind generators. We have had three workshops and have requested participation through ERCOT working groups and committees. The draft standard allows for a fair and equitable adjustment to account for any physical machine limitation to be developed as shown in the "Adjustment for Other Units" calculations.
Grit Schmieder-Copeland, Pattern Gulf Wind	No	From a standpoint of Wind Turbine Generators the timeline required to implement is not realistic. Furthermore, the method of using the fixed load reference for PFR control will cause large system swings once the frequency returns to the dead band due to the fast response of WTGs. Additionally, vendors have had difficulty testing the scheme. In summary, we do not believe that the proposed standard is needed in ERCOT and most of all will result in the expected/promised "improvements".	It is incumbent upon the vendors and resource entities to develop Primary Frequency Response implementation for all types of generation resources that will meet performance measures of this standard to minimize grid instability. This standard has a three year implementation plan that is intended to provide adequate time to meet the requirements. This TRE regional standard only applies to wind generators that are required to provide PFR under the ERCOT rules. The ERCOT Protocol requirement that requires certain wind generators to provide PFR became effective on December 1, 2011 (8.5.1.3). When Wind Turbine Generators' market share became significant, they were appropriately required to provide the services that other generators had been providing. This includes primary frequency response.

Michelle D'Antuono, Ingleside Cogeneration	No	Although Ingleside Cogeneration LP understands the intent and the need for BAL-001-TRE-1, we are not confident that it can be properly implemented. The sheer variety and complexity of generator and governor technologies does not guarantee the actual frequency response will sufficiently match the expected response even if settings are perfectly in accordance with R6.1 through R6.3. A possible solution would be a TRE managed trial to work out the kinks, just like NERC is doing for BA-level frequency response. Assuming all GO/GOPs in the TRE region were engaged, the time-frames established in the implementation plan would be sufficient to derive a performance baseline. Without a trial, we see multiple weaknesses in BAL-001-TRE-1 which need to be addressed: 1) If for any reason, a GO cannot set a generator governor as required by R6.1 through R6.3, a technical exception must be made. As the Standard is written, only the BA can make this exception, with no allowance for an appeal even if the GO has a solid technical basis for such a request. 2) The purpose of R7 seems to be that the GOP must be notified if the Generator Owner has taken the governor offline for maintenance or a similar purpose. However, this requirement reads that the GO must ensure that the governor is online prior to every start-up which is an operations function. The requirement should be rewritten to accurately capture the intent. 3) Status changes in the governor should only be reported to the BA if (a) the governor will not be available at start-up due to maintenance or an unexpected deficiency, (b) the governor unexpectedly goes offline during normal operation, or (c) the governor comes back online after planned maintenance or an unplanned event. It is not necessary to notify the BA during normal start-up or shut-down where the governor engages/disengages coincident with the generator itself. This would seem to be an obvious reading of R8, but NERC has assessed violations related to AVR status for exactly this reason.	Several generators have implemented the settings required in R6 and have found that frequency response performance occurs as expected in accordance with R9 and R10. Note that the performance measures are based on rolling averages and substantially less than perfect performance is required. Also, a field trial was conducted that confirmed that generators with properly configured and maintained governor systems could easily meet this standard, which does not require perfect performance. The sustained PFR measure was revised as a result of experience from the field trial. 1) Presently over 15,000 MW of capacity already has the governor settings required in R6.1 through R6.3 implemented. This includes large steam coal, lignite, large steam gas, medium steam gas and combustion turbines. None of these generators have had a problem with the settings in their testing of these requirements. Some of these have had the settings since November of 2008 when work on this standard began. 2) The purpose of R7 is to require the unit's Governor to be in service whenever the unit is online and released for dispatch, and it requires notification of the GOP when the Governor is not in service. R7 does not require the Governor to be in service during start-up and shut-down sequences. 3) We agree that it is not necessary to notify the BA that the Governor is in service when the unit is started. The GOP and BA need to be notified only if the Governor is not in service when the unit is released for dispatch, and when the Governor status changes while the unit is online and released for dispatch. R7 and M7 have been revised to clarify expectations.

		4) R9 and R10 do not specify the point where the frequency response parameters are to be measured. This may not make a difference where the generator interconnection to the BES is short, but may be a problem at greater distances, a very common situation in the case of wind farms. 5) Since the BA will likely prioritize the capture of Frequency Measurable Events (FMEs) along critical paths, it is not clear to Ingleside Cogeneration LP that eight samples will be available outside major metropolitan areas. This turned out to be the case in the generator governor study that NERC performed last December, all the ERCOT events assessed simply had no measurable effect on our frequency response performance. 6) The Regional Standard does not address situations where poor frequency compensation within the local transmission system is driving costs to the Generator Operator. TOs will be provided essentially free frequency performance at those locations and will have little incentive to provide static or dynamic reactive compensators to mitigate it. A market model similar for those for ancillary services could be one solution or perhaps end-of-the month reconciliation of costs like those performed between interconnected Bas for inadvertent interchange. Without the assurance of a controlled trial, or definitive modifications to address our five concerns, Ingleside Cogeneration L.P. has to vote "no" on BAL-001-TRE-1.	4) It does not matter where the frequency response parameters are measured. Some differences in frequency measurement may exist during the first two to three seconds of a frequency event, but after that time period frequency is essentially the same across the interconnection. R9 starts measuring performance at 20 seconds after the beginning of the event. 5) It does not matter where FME data is captured (unlike voltage). Frequency within the time period of this standard is virtually the same throughout the interconnection. 6) Comments 4,5, and 6 appear to confuse voltage support services with Primary Frequency Response and are not applicable to this standard. Whereas voltage can vary significantly at different locations on the transmission system, frequency is effectively the same at all locations. Primary Frequency Response that is provided at any location is beneficial to stabilize system frequency after an event.

Mike Grimes, Mesquite Wind LLC, Post Oak Wind LLC	No	Post Oak Wind LLC & Mesquite Wind LLC appreciate the opportunity to comment on the proposed BAL-001-TRE-1,Primary Frequency Response in ERCOT. We support the concept embodied in the draft standard: that Primary Frequency Response should be better defined. Specifically defining the response expected from different technologies by including know limiting factors in the expected response enhances reliability by aligning the Balancing Authority's expectations with the design capabilities of ERCOT generation resources. However, this specificity only benefits reliability to the extent that the performance characteristics of any given technology are well understood. That information about wind resources is not available. Many wind resources operating in ERCOT cannot now provide PFR as defined in the ERCOT Protocols. There is no consensus on how to either retrofit the operating wind resources or to design new ones to provide PFR. This was demonstrated in the 24 August 2011 workshop on BAL-001-TRE-1, when different wind turbine vendors reported pursuing different approaches to Primary Frequency Response. Issues that remain to be resolved include: identifying the best proxy for reference frequency, the practicality of maintaining a consistent droop rate, and managing wind resource output when frequency returns within the dead band. Post Oak therefore votes against the adoption of BAL-001-TRE-1. Specific performance requirements should be delayed until sufficient experience with wind resource operations has been gained, so that those requirements produce the desired result. Implementing the requirements as drafted for wind resources would only penalize wind resources without benefiting system reliability. A delay could also permit the exploration of other means to support system frequency. These could include combining other technologies with variable generation resources. Another option is a paid frequency response service.	A standard cannot dictate required approaches to providing Primary Frequency Response for all generation technologies. It can only set required performance standards that must be achieved. The SDT agrees that expected performance for wind facilities is not well defined at this time, and included a variable that may be used to adjust expected Primary Frequency Response from non-conventional generators. Recent experience shows that many wind generators are able to provide adequate PFR when they have capacity available to do so. PFR has been required from many ERCOT wind generators since December 2011, and this standard only measures PFR from generators who are not exempted from providing PFR per the ERCOT Protocols.

Robert Bell, Kiowa Power Partners LLC	No	1. There are concerns surrounding the Frequency Bias and its application to the Automatic Generation Control (AGC) affecting unit performance against the standard. The Generator follows the AGC setpoint as sent by the QSE. The Frequency Bias is applied to the setpoint by the QSE. If the Frequency Bias is applied incorrectly, or not at all, the load control signal could have units respond counter to an event negating a sustained response. 2. The expected 5.78% combined cycle droop response assumes all combined cycle units will perform in similar fashion. This is not the case and response will vary by configuration and type of equipment. This expected response would need to be more specific by asset.	1. The Frequency Bias must be applied locally by the GO using the local frequency at the point of interconnection or measured at the generator terminals or from the speed of the generator rotor. The QSE should also apply a Frequency Bias in its control function in order to allow the Primary Frequency Response to be sustained and to prevent control action from reducing the response. Having local Frequency Bias applied allows for proper performance during periods of lost communication with the QSE, grid islanding events and during black start operations. 2. The standard as written allows for adjustments to the performance measures which include adjustments to the Expected Primary Frequency Response calculation. The evaluation tools, that have been available for two years, can be used by GOs and GOPs to self evaluate generator performance in order to determine if adjustments are needed.

Shari Heino, Brazos Electric Power Cooperative	No	Brazos supports this effort; however we still have some concerns with the standard as drafted. Therefore, Brazos votes NO to the standard and the corresponding VRF/VSL poll. Brazos' concerns are listed below: 1) Requirement 6.2 of the standard uses a 5.78% droop setting for a CC plant. We are told that this 5.78% droop setting is based on an "average" value but due to the lack of better analysis information, we could support either a 6% or 7% droop value. This droop value can be re-evaluated and the standard revised after better information is available for analysis. 2) It is unclear in the Req 6.2 regarding the evaluation of combined cycle units. Our concern is whether it is by plant configuration or by individual generator or both? If evaluation by plant is selected, would the evaluation performance then be based on a specific configuration? If the evaluation is both, then if the plant scores above the requirement, but the individual combustion turbine are below the requirement, do the requirements apply to both plant and individual combustion turbine causing the plant to possibly fail twice? 3) There is concern of a very high risk of receiving a Moderate to Severe VSL for peaking or seasonal units with one or two bad performances. These type units are on only during peak season and when other units are on maintenance. When a frequency event does occur, they may not be evaluated since they are usually near their capacity.	1) The proposed 5.78% droop figure is not a Governor setting, but rather an amount used in the PFR evaluation calculation to account for the steam turbine of the combined cycle train that is not responding to frequency. Use of the 5.78% effective droop to determine expected performance, combined with the 0.75 threshold and the rolling average calculation, will allow a properly configured CC unit to easily pass this standard. 2) Requirement R6.2 requires specific Governor settings for each component of the combined cycle train. Individual components may individually violate R6 but as a train shall not R9 and R10. The design of the performance measures is to measure performance of the combined cycle train as a single generator, not each individual component (combustion turbine or steam turbine). The performance measures will be calculated based on the specific operating configuration at the time of the FME. 3) This concern is addressed by the minimum eight FME rolling average calculation. All generating units, including peaking and seasonal units, are expected to operate with Governors in service and to provide proper Primary Frequency Response if they have sufficient capacity available to respond. If the generator is within 2% (or 2 MW) of its HSL when a low-frequency FME occurs, it will not be evaluated for that event.
H. Steven Myers, ERCOT	Yes	ERCOT believes that enhancements and improvements to this standard will likely continue in the future, but this standard is a positive step in the right direction.	Thank you for your comment.

Randy Jones, Calpine Cooperation	No	To date there has been no data or evidence presented that would speak to the long term cost impact to control systems and mechanisms that are involved in a tighter governor dead band setting (0.167 Hz versus 0.036 Hz). The ERCOT BA currently enjoys a 12-month rolling CPS1 average in excess of 145. It appears that the region's primary frequency response is more than adequate and that any additional maintenance cost imposed by this regional standard would be unnecessary and excessive. Primary frequency response in ERCOT is currently an unpaid, mutual assistance service and its individual requirements and metrics were simply imported from the legacy control area era. Before tighter control performance metrics for primary frequency response are imposed we believe that effort should be put into creating a market mechanism if a solution is truly needed by PFR.	Over 15,000 MW of generators have implemented the Governor settings as required in this standard, which has improved frequency control of the ERCOT grid. This has reduced maintenance costs due to a minimization in Governor movement. At the same time, the improved CPS1 score has been a direct result of these Governor setting changes. Furthermore, Primary Frequency Response in the ERCOT region has been adequate due to generators implementing PFR on their generators. In the ERCOT region, PFR is presently required from all generators. Any consideration of creating a market mechanism solution for PFR is beyond the scope of this project.

Attachment 9-001

Field Trial and Demonstration Report

<u>BAL-001-TRE-1</u>

PRIMARY FREQUENCY RESPONSE PERFORMANCE

OF SELECTED GENERATORS IN THE ERCOT REGION

AS MEASURED AGAINST PROPOSED NERC STANDARD

BAL-001-TRE-1

PREPARED FOR

Texas RE Reliability Standards Committee

By
Standard Drafting Team
BAL-001-TRE-1

Submitted: December, 2012

Table of Contents

Executive Summary

Introduction

This report provides performance results and conclusions on the Field Trial and Demonstration (FTD or Field Trial) of the proposed BAL-001-TRE-1 NERC regional standard. The objective behind conducting a field trial was to take a small sample of generators with different characteristics reflecting the generation-type mix within ERCOT and to measure the performance of these generators using the performance measures contained in the proposed regional standard. The Standard Drafting Team initiated this Field Trial in November of 2011, to see how well the regional NERC standard measures the various types of Generator performance during Frequency Measureable Events (FMEs) from June 2011 through June 2012.

Purpose

This report is to inform the Texas RE Reliability Standards Committee and others within the ERCOT Interconnection, of the performance of electric generation power plants and their ability to initially respond, and provide sustained response, to a significant frequency perturbation in the ERCOT Interconnection, as measured against criteria from proposed NERC Regional Standard BAL-001-TRE-1.

Scope

This Field Trial report will focus on activities from the draft standard which relate to Requirements:

- R2 (Balancing Authority calculation and reporting of Primary Frequency Response for each generating unit),
- R9 (Initial Primary Frequency Response performance) and
- R10 (Sustained Primary Frequency Response performance).

The Field Trial accepted 28 generating units into the trial: 7 coal, 4 gas, 2 simple cycle combustion turbine, 5 wind, and 10 combined cycle units.

Results

From the Field Trial performance analysis, the Standard Drafting Team learned that the proposed formula for calculating sustained primary frequency response occasionally favored poor performing units, and that the quality of the sustained results was inconsistent. These problems were largely due to changes in operating circumstances (such as receipt of revised base points) during the period in which the sustained response was measured. In addition, the formula for calculating the sustained response was very complex for the information needed. Based on an evaluation of the Field Trial results, the Standard Drafting Team modified Requirement R10 (Sustained Primary Frequency Response performance) to simplify the calculation and to avoid the problems that were encountered in the Field Trial. All Frequency Measurable Events and affected units were re-assessed using the revised methodology for assessing sustained Primary Frequency Response. The Field Trial performance report showed that the modified R10 more accurately measures the sustained performance of the different types of generators. This modified requirement consistently captures observed Generator performance. The revised R10 incorporates a method similar to what the ERCOT Performance Disturbance Analysis Working Group (PDCWG) has been using for several years.

Conclusion

With the revised method applied in R10, both initial and sustained Primary Frequency Response metrics accurately reflect unit performance. Four types of units were able to successfully maintain passing scores. Wind generators did not participate in enough events to qualify for an assessment; however, evaluation of the limited number of events showed the wind units passed either the initial or sustained performance criteria or both. Overall, although most units were able to successfully meet expectations, some specific units did not pass. These units should be able to identify the source of the problems and adjust their control systems to prepare for future success.

Background

In response to FERC order 693 §315, the Texas RE submitted a SAR on April 15, 2008 to produce a regional standard (BAL-001-TRE-1) on frequency response. Per the order, the new standard was to incorporate expectations found in ERCOT Zonal Protocols 5.9 *Frequency Response Requirements and Monitoring*. The intent of the order was to establish a regional standard on frequency in lieu of the Control Performance Standard (CPS2) for which this same FERC order provided an ongoing waiver.

The BAL-001-TRE-1 Standard Drafting Team (SDT) posted their first proposal in March of 2009. Since then there have been two (2) other postings for comments, several workshops, and a posting for Comment and Ballot in September of 2011.

As a result of stakeholder comments from the September 2011 comment/ballot period, the SDT decided to conduct a Field Trial and Demonstration (FTD) to apply the performance measures proposed in the standard to actual unit Primary Frequency Response performance in the ERCOT region.

Goal of Field Trial and Demonstration

The SDT established this Field Trial to assuage the concerns of affected parties regarding the new performance requirements appearing in the standard. It would also demonstrate the benefits of implementing the proposed Primary Frequency Response (PFR) metric calculations as drafted.

Based on industry comments and feedback during workshops it was apparent that some entities were concerned that the proposed Standard would be overly burdensome. The Standard Drafting Team hoped the Field Trial would demonstrate that those entities which were currently operating to existing ERCOT Protocol requirements would have no problem passing the proposed Standard. Those who encountered insurmountable physical obstacles preventing the expected response during a Frequency Measureable Event would realize there would be no assessment of their performance for that event; thus not impacting their rolling 12-month score per the new Standard. Those unable to provide expected response would discover opportunities to adjust the performance of their system to achieve requirements currently existing in the ERCOT Protocols, and thus position themselves to have no concerns from implementation of the FERC Order and the regional standard.

The Standard Drafting Team's objective was to achieve instructions from the FERC Order in a manner that incorporated Section 5.9 from the ERCOT Zonal Protocols. The perception was that Section 5.9 sought to ensure the Balancing Authority actively monitored and adjusted reserves and/or system performance elements to assure an effective frequency response. Section 5.9 also sought to establish consistent Primary Frequency Response performance from each generating unit. This would enhance system reliability because each unit would carry their share of frequency response requirements, and consequences of non-compliance would create an incentive not to squelch, de-tune, or remove from service the governors of a generator. The goal of the Standard was to be of minimum impact to any generator appropriately configured to support system frequency response, while requiring improved participation any who had previously been willing to let others carry the load. An effective Field Trial would demonstrate the benefit to each participating unit by assuring fair expectations and an equally effective response from every other unit across the Interconnect.

Field Trial Overview

This Field Trial initially measured performance based on the requirements in the draft standard that were posted for the first ballot period,[1] which are:

R2. R2.The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.2 This calculation shall be a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. The calculation results shall be submitted to the Compliance Enforcement Authority by the end of the month in which they were completed. If the generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, performance shall be based on a rolling eight FME average response.

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined-cycle facility will be determined using an expected performance droop of 5.78%.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME. The initial Primary Frequency Response performance for each FME shall be between 0.0 and 2.0.

[1] Note that the requirements have changed in important ways since the Field Trial was conducted.

[2] The Primary Frequency Response Reference Document contains the calculations that the BA will use to determine Primary Frequency Response performance of generating units/generating facilities. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Compliance Enforcement Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance.

R10. Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the event recovery period following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance

In November, 2011, the Standard Drafting Team solicited and selected various generators to participate in a Field Trial to test these proposed requirements. The Standard Drafting Team engaged 28 generating units into the trial from a number of different Generator Operators (GOPs)/Qualified Scheduling Entities (QSEs). This diverse group of generators included 7 coal, 4 gas, 5 wind, 2 simple cycle combustion turbine and 10 combined cycle units. Wind generators selected came from two (2) categories of volunteers: from those that indicate they currently provide PFR, and from those that are required to provide PFR after December 1, 2011.

The Standard Drafting Team worked with ERCOT and the Performance, Disturbance, Compliance Working Group (PDCWG) to evaluate the Primary Frequency Response performance of the selected generators. ERCOT evaluated performance of fossil-fueled generators during historical Frequency Measurable Events (FME) that occurred from June through December of 2011, as well as additional FMEs that occurred before June 15, 2012. ERCOT evaluated Wind generation resources (WGR) during Frequency Measureable Events occurring after December 1, 2011, when some Wind Generation Resources were required to provide Primary Frequency Response pursuant to the ERCOT protocols. The assessment team based their evaluations on the actual deadband and droop settings employed by the various units.[3]

During the field trial, the Standard Drafting Team identified the challenges in calculating the expected governor response due to the effect of power augmentation capacity in the telemetered High Sustainable Limit of the Generation Resources. To resolve this issue the assessment team determined, through consensus, to remove the power augmentation capacity from the telemetered HSL for expected governor response calculation. This improved the accuracy of measured performance for the affected generators.

At the conclusion of the Field Trial, Standard Drafting Team representatives from the assessment team provided detailed results and explanations to each of the Generator Owners (GOs) for their generators participating in the field trial. The Standard Drafting Team representatives conducted this review via a series of web-enabled conference calls.

During the review the Standard Drafting Team representatives requested comments from participants in the Field Trial. The comments received are included in this report.

This report presents Field Trial outcomes in a way that protects proprietary information.

Detailed Sequence of Events

2011

Date	**Occurrence**
July	Standard Drafting Team finalized Standard
August	Regional Standards Committee approved the Standard for Ballot
September 9-23	Current draft of BAL-001-TRE-1 submitted for Comment/Ballot
October	SDT considered that the Standard failed to pass by one (1) vote, and the several comments that received through the process. SDT determined to conduct a Field Trial
November	Solicited volunteers to participate in a Field Trial. SDT began working with ERCOT and the Performance, Disturbance, Compliance Working Group (PDCWG) to evaluate the PFR performance of the selected generators.

[3] In the full implementation of the proposed standard, units will be evaluated based on the deadband and droop requirements set forth in the standard.

2012

May	Evaluation team completed evaluation of many generators. They identified the challenges in calculating the expected governor response due to (a) operational changes occurring during the sustained response evaluation period, and (b) reflection of power augmentation capacity in the telemetered High Sustainable Limit of the Generation Resources The SDT decided to recalculate the metrics using a revised sustained response approach, and removing the power augmentation capacity from the telemetered HSL for expected governor response calculation.
June	Field Trial Ended
July	Detailed results and explanations reviewed with the GOs for their generators involved. Requested feedback from those participating.
August	SDT Considered Field Trial results and concluded the revised sustained performance metric was not producing fair and consistent results. Technical experts on SDT proposed simpler calculation method, similar to what PDCWG had been using for years; SDT agreed. Technical experts began re-analysis using new methodology.
September	SDT reviewed results of new R10 sustained metric methodology and approved revision to Standard to incorporate such.
October	Field Trial report developed

Detailed Performance Analysis Results

The list of Frequency Measurable Events evaluated during the Field Trial is available on the TRE website. The team also selected some smaller frequency events to further evaluate unit performance, as necessary. The Excel spreadsheets used to calculate results are on the SAR-003 Project page.

The charts below show the average initial and sustained frequency response performance for the generators in the Field Trial. These results were largely based on historical data, so the generators did not have the opportunity to take steps to improve their scores before or during the Field Trial. These results were calculated using the revised methodology that is incorporated into the current drafts of the Standard and the Reference Document.

Table 1 Coal Plant Performances during the field-trial

Generator Code	R9 - Performance	R10 - Performance	Comments
Generator 1	**0.5841**	**0.6460**	Failed R9 & R10
Generator 2	0.4643	0.3706	Participation in less than 8 events
Generator 3	1.1892	1.2609	
Generator 4	0.8872	0.9909	
Generator 5	0.2530	0.4113	Participation in less than 8 events
Generator 6	**0.6092**	0.8444	Failed R9
Generator 7	1.1987	1.3827	

Table 2 Gas Plant Performances during the field-trial

Generator Code	R9 - Performance	R10 - Performance	Comments
Generator 1	0.7712	1.1068	
Generator 2	**0.4716**	**0.7218**	Failed R9 & R10 due to huge data latency
Generator 3	1.3608	1.3778	Participation in less than 8 events
Generator 4	1.3415	1.7862	Participation in less than 8 events

Table 3 Simple cycle combustion turbine performances during the field-trial

Generator Code	R9 - Performance	R10 - Performance	Comments
Generator 1	**0.1001**	**0.0178**	Participation in less than 8 events
Generator 2	**0.7409**	0.8621	Failed R9 by .0091

Table 4 Wind Generation Resources performances during the field-trial

Generator Code	R9 - Performance	R10 - Performance	Comments
Generator 1	1.3824	1.3737	Participation in less than 8 events
Generator 2	No Evaluation	No Evaluation	No Participation
Generator 3	No Evaluation	No Evaluation	No Participation
Generator 4	0.6259	1.0435	Participation in less than 8 events
Generator 5	0.8189	0.7211	Participation in less than 8 events

Note: Wind resources are generally only able to respond to high-frequency events, which are rare. These results show that these generators were able to provide significant frequency response when conditions allowed them to respond.

Table 5 Combined Cycle Generation Resources performances during the field-trial

Generator Code	R9 - Performance	R10 - Performance	Comments
Generator 1	**0.2712**	**0.2360**	Failed R9 & R10
Generator 2	1.5976	1.7676	Participation in less than 8 events
Generator 3	0.7664	0.7863	
Generator 4	**0.5668**	**0.6246**	Failed R9 & R10
Generator 5	0.9181	1.2397	
Generator 6	1.1232	1.4586	
Generator 7	**0.6946**	0.9575	Failed R9
Generator 8	**0.5710**	0.8235	Failed R9
Generator 9	**0.3705**	**0.7409**	Failed R9 & R10
Generator 10	0.7794	1.1074	

Findings, Conclusions, and Recommendations

Findings

Most of the participants in the Field Trial were able to successfully maintain passing scores.

Through analysis of the Field Trial results, the Standard Drafting Team learned that the originally proposed formula for R10, calculating sustained primary frequency response, provided inconsistent results and occasionally favored poor performing units. While performance was generally reflective of expectations, the quality of the results was inconsistent. In addition, R10 originally used a very complex formula for the information needed, and it looked out several minutes after the event occurred. This issue was addressed by simplifying the R10 formula to measure the sustained response at a point approximately 46 seconds after the event, rather than averaging the response over a longer period. The Field Trial data was recalculated using the revised approach, and the results were more consistent and properly indicative of the unit performance. The charts above reflect the modified approach.

The Field Trial assessment team also discovered inconsistent results while calculating the expected governor response due to influence of power augmentation capacity in the telemetered High Sustainable Limit of some Generation Resources. This was addressed by defining the available capacity of a unit as the telemetered HSL minus any power augmentation capacity included in the HSL. In this way, only the portion of the capacity that is expected to be responsive to frequency is used to calculate the expected response.

Conclusions

Units with governors in service and set properly, and where the governor response is not overridden by other controls, are able to successfully meet the requirements of BAL-001-TRE-1 without incurring additional cost.

With the revised method applied to calculate the sustained response, the requirement assessments provided results which accurately reflected unit performance for both initial and sustained Primary Frequency Response, consistent with expectations established in BAL-001-TRE-1.

Those units that did not pass during the Field Trial were capable of achieving a passing score. Most would benefit by adjusting their governors and/or other control parameters to meet existing Protocol expectations as well as this proposed regional standard.

Recommendations

Move forward with the process of preparing, submitting, and balloting BAL-001-TRE-1.

Encourage all segments of the ballot pool to support this Standard to improve system reliability, and to require fair and equitable frequency response performance from all generation resources.

Attachment 10-001

BAL-001-TRE-1
Primary Frequency Response

Update for Texas RE RSC

October 3, 2012

SAR-003 Standard Drafting Team

Name	Company
Sydney Niemeyer (Chair)	NRG Energy
Ananth Palani (Vice-Chair)	Optim Energy
Pamela Zdenek	Infigen Energy
Vann Weldon	ERCOT
Brenda Hampton	Luminant
Sandip Sharma	ERCOT (Non-voting SME)

Requirements Overview

- **Applies to BA, GO and GOP function**
- **Provides requirements for:**
  - Identifying Frequency Measureable Events (FME)
  - Calculating the Primary Frequency Response (PFR) of each resource in the Region
  - Calculating the Interconnection minimum Frequency Response
  - Monitoring the actual Frequency Response of the Interconnection
  - Setting Governor deadband and droop parameters
  - Providing Primary Frequency Response performance requirements.
- **Importantly, the standard narrows the governor deadband and requires the droop curve to begin at the edge of the deadband with no step function.**

PFR Performance Measures

- **Under this standard, two Primary Frequency Response performance measures are calculated: "initial" and "sustained."**
- **The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts.**
- **The sustained PFR performance (R10) measures the best actual response from t(46) to t(60), compared to the expected response at t(46).**

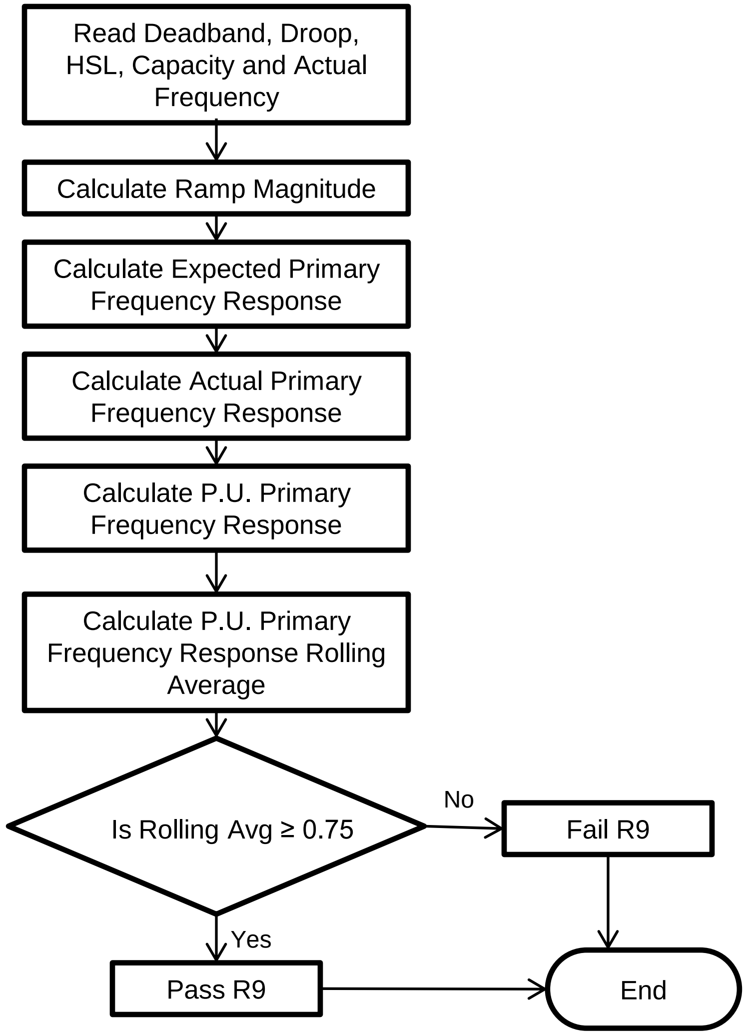
Primary Frequency Response Reference Document

- This Primary Frequency Response Reference Document is not considered to be a part of the regional standard.
- This document will be maintained by Texas RE and will be subject to modification as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.
  - This arrangement provides Regional flexibility in adjusting the technical details of the performance metric calculations.
  - The PFR Reference Document includes flowcharts that detail the calculations

PFR Reference Document Revision Process

- **A Revision Request may be submitted to the Texas RE Reliability Standards Manager**
- **The Reliability Standards Committee (RSC) will consider the request**
  - The revision request will be posted in accordance with RSC procedures
  - The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request
  - The RSC will make a recommendation to the Texas RE Board of Directors
- **The Board may adopt the revision request, reject it, or adopt it with modifications**
  - Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes

Technical Document – Initial Flowchart Overview



Field Trial Results

- **28 generating units were evaluated in the trial, which included 7 coal, 4 gas, 2 simple cycle combustion turbine, 5 wind, and 10 combined cycle units.**
- **Based on events from June 2011 to June 2012.**
- **No high-frequency events were evaluated.**
- **8-event average was not possible with some units.**
- **These results use NEW R10 calculation.**

Field Trial Results – Coal Units

Coal Plant

	R9	R10	Comments
Generator 1	0.5841	0.6460	
Generator 2	0.4643	0.3706	Participation in less than 8 events
Generator 3	1.1892	1.2609	
Generator 4	0.8872	0.9909	
Generator 5	0.2530	0.4113	Participation in less than 8 events
Generator 6	0.6092	0.8444	
Generator 7	1.1987	1.3827	

Field Trial – Gas Units

Gas Plant

	R9	R10	Comments
Generator 1	0.7712	1.1068	
Generator 2	0.4716	0.7218	huge data latency
Generator 3	1.3608	1.3778	Participation in less than 8 events
Generator 4	1.3415	1.7862	Participation in less than 8 events

Simple cycle combustion turbine

	R9	R10	Comments
Generator 1	0.1001	0.0178	Participation in less than 8 events
Generator 2	0.7409	0.8621	

Field Trial – Wind Units

Wind Generation

	R9	R10	Comments
Generator 1	1.3824	1.3737	Participation in less than 8 events
Generator 2	No Evaluation	No Evaluation	No Participation
Generator 3	No Evaluation	No Evaluation	No Participation
Generator 4	0.6259	1.0435	Participation in less than 8 events
Generator 5	0.8189	0.7211	Participation in less than 8 events

Field Trial – Combined Cycle Units

Combined Cycle

	R9	R10	Comments
Generator 1	0.2712	0.2360	
Generator 2	1.5976	1.7676	Participation in less than 8 events
Generator 3	0.7664	0.7863	
Generator 4	0.5668	0.6246	
Generator 5	0.9181	1.2397	
Generator 6	1.1232	1.4586	
Generator 7	0.6946	0.9575	
Generator 8	0.5710	0.8235	
Generator 9	0.3705	0.7409	
Generator 10	0.7794	1.1074	

Changes Made after Field Trial and Comments

- **Changed Sustained Measure (R10) from average over several minutes to instantaneous at t(46).**
  - Too much happens during former averaging window.
- **Added 2 MW limit to the 2% exception criteria.**
  - Applies to generators < 100 MW.
- **Moved examples of “legitimate operating conditions that may support exclusion” from Measures to Requirements (R9 and R10).**
- **M7 re-written to focus on notice from GO to GOP of change in Governor status.**
  - Avoids concern about 24/7 proof issue.
- **Changed deadband setting from 0.01666 to 0.017 Hz.**
- **Reformatted R2 to break into sub-requirements.**
- **Intend to deal with augmented capacity issue.**
  - Duct burners, etc.

Implementation Plan

- **12 months after Effective Date**
  - The BA must be compliant with Requirement R1
  - At least 50% of the GO’s generating units/generating facilities must be compliant with Requirement R6 (if >1 unit/facility)
  - At least 50% of the GO’s generating units/generating facilities must be compliant with Requirement R7 (if >1 unit/facility)
  - The GOP must be compliant with Requirement R8

- **18 months after Effective Date**
  - The BA must be compliant with Requirements R2, R3, R4, and R5
  - 100% of the GO’s generating units/generating facilities must be compliant with Requirement R6
  - 100% of the GO’s generating units/generating facilities must be compliant with Requirement R7

Implementation Plan

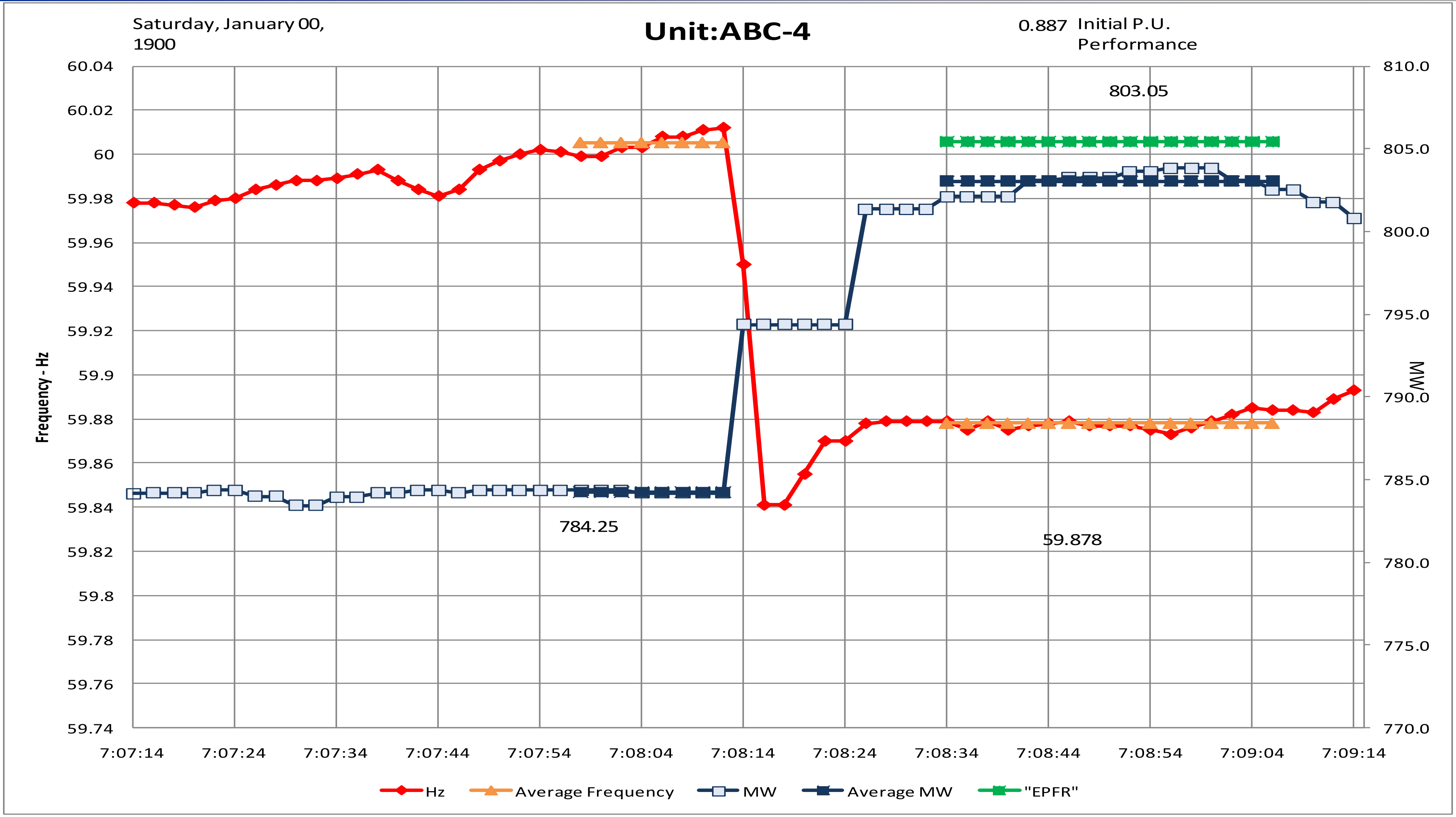
- **<u>24 months after Effective Date</u>**
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R9 (if >1 unit/facility)
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R10 (if >1 unit/facility)

- **<u>30 months after Effective Date</u>**
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R9
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R10

Path Forward

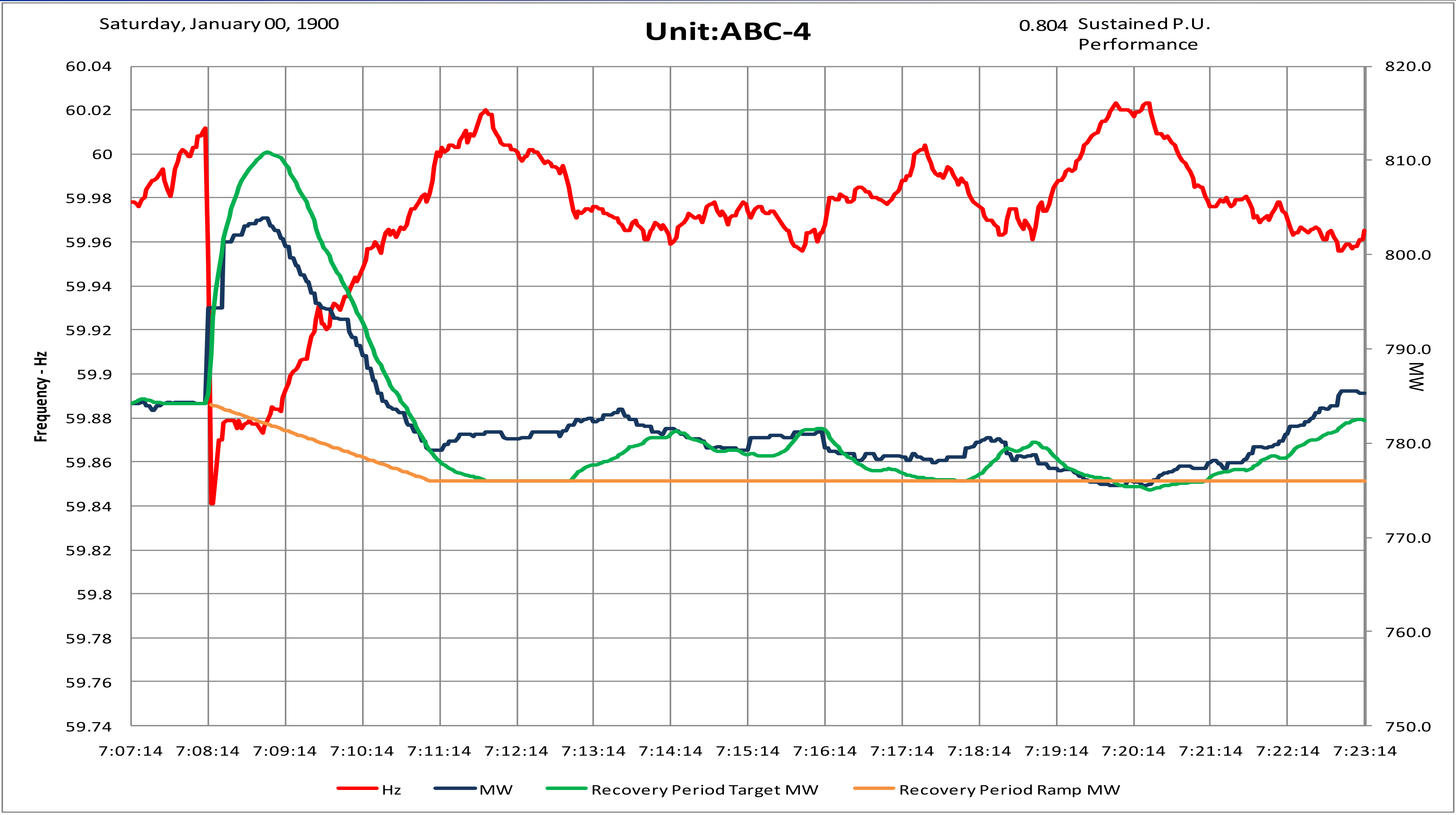
- **Drafting Team is finishing standard and related documents.**
  - Expect completion in November. (11/7 SDT Mtg.)
- **Submit for RSC approval in November.**
  - Can do by e-mail or call a special meeting.
- **Post for Review and Ballot in December – January.**
  - Avoid ballot during Holidays.
- **RSC Approves ballot results.**
- **TRE Board approval.**
- **NERC/FERC process.**

R9: Initial Response Performance - Steam Turbine

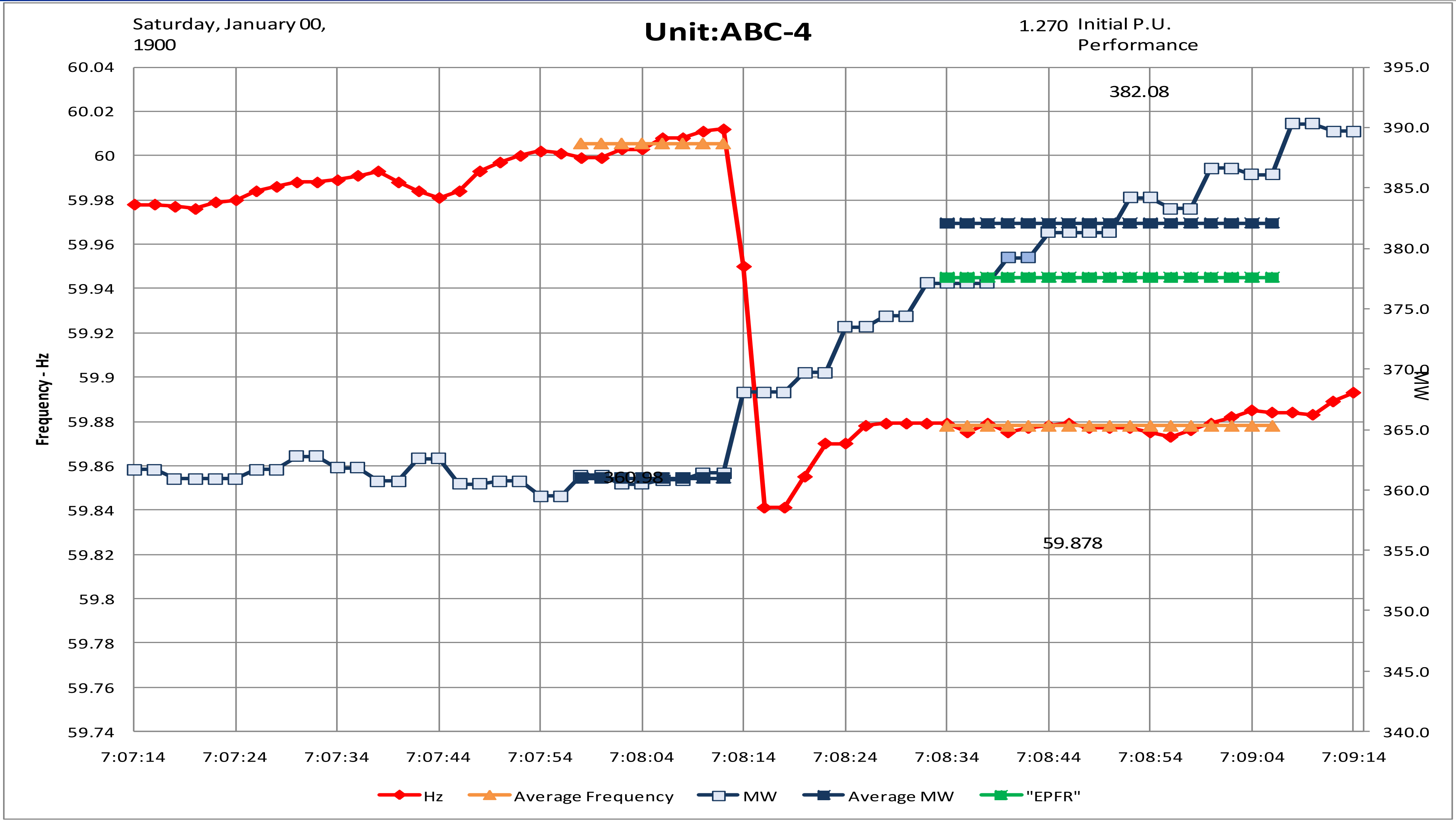


TEXAS RELIABILITY ENTITY

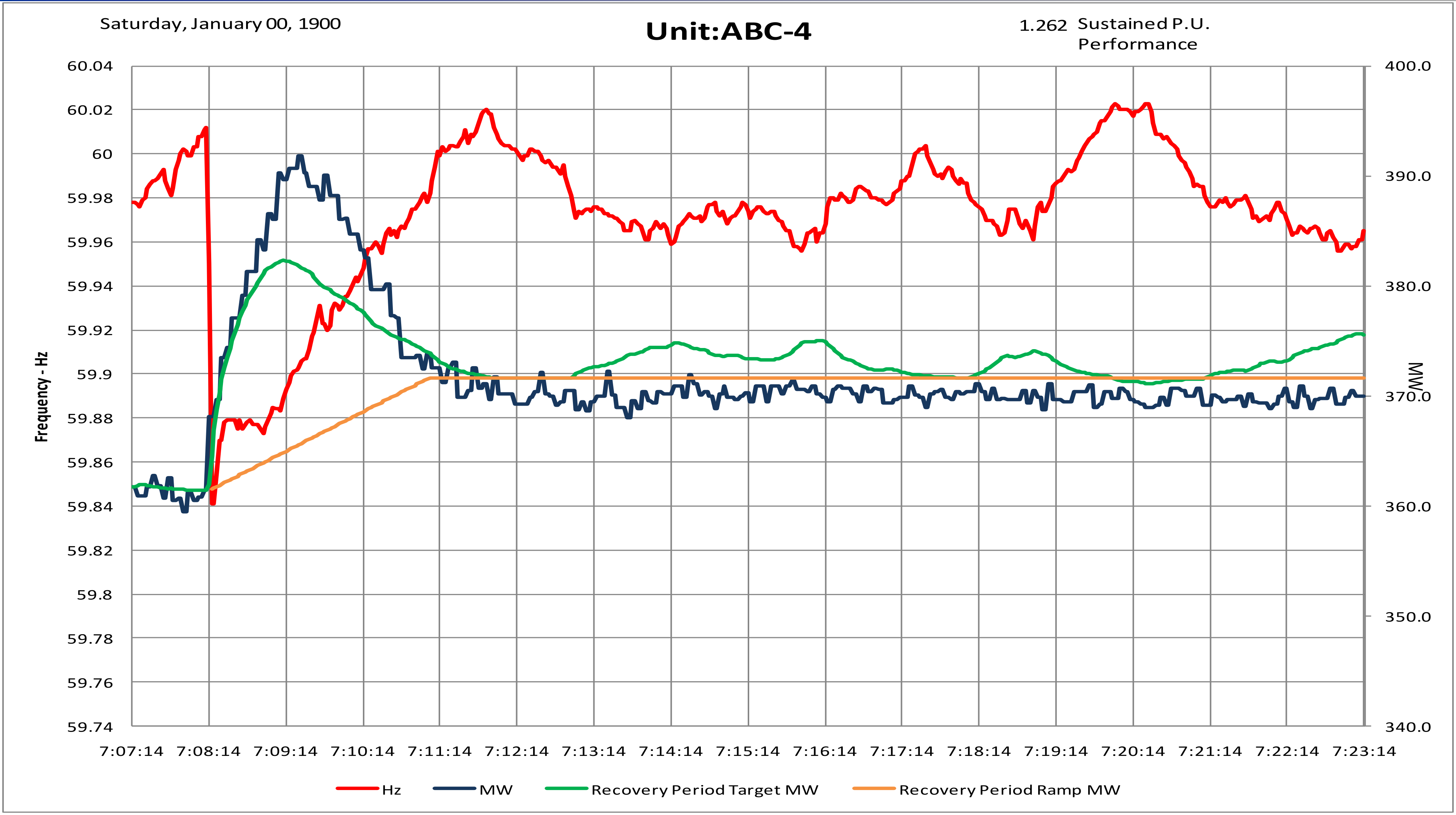
R10: Sustained Response Performance - Steam Turbine



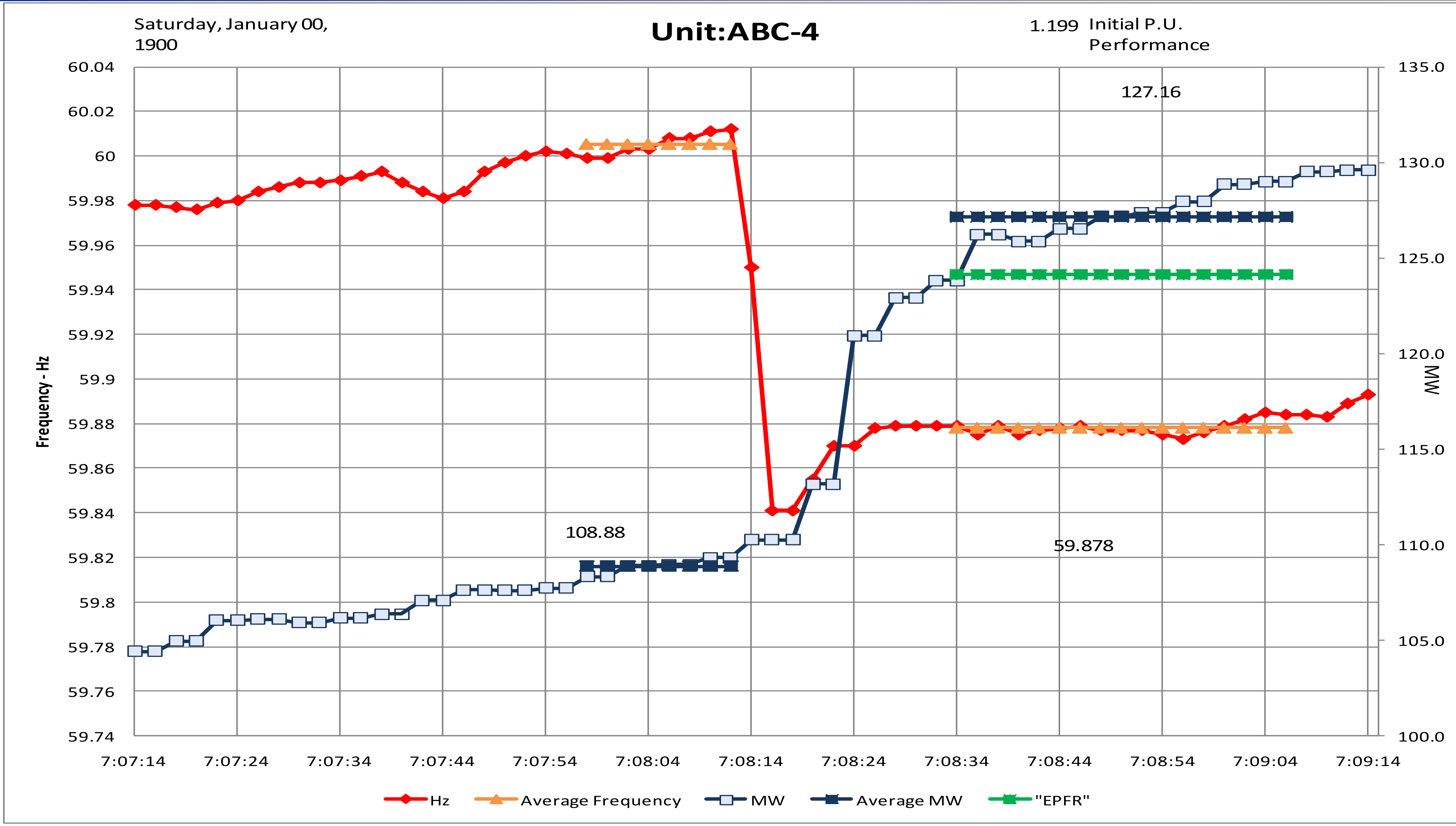
R9: Initial Response Performance - Steam Turbine



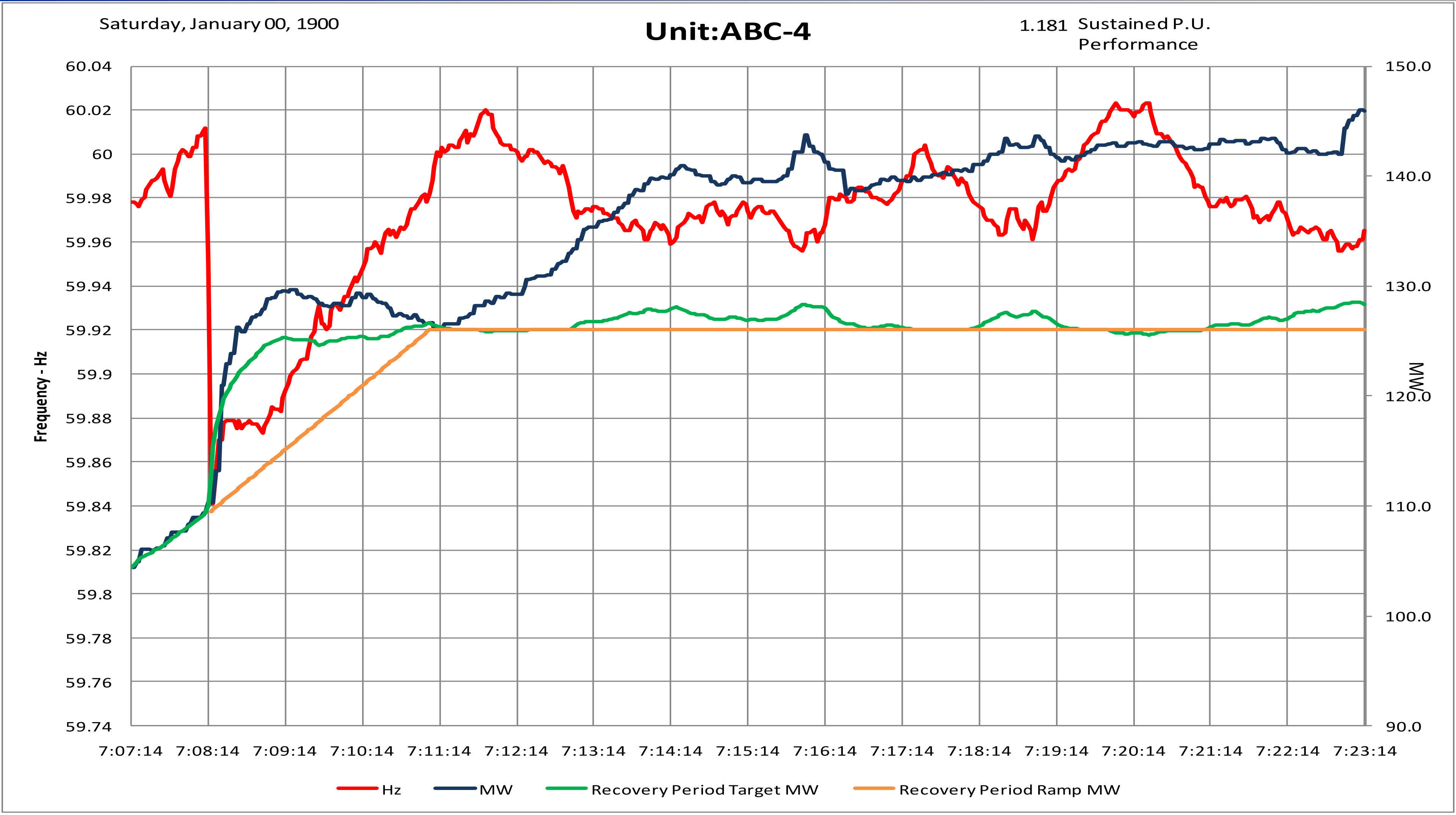
R10: Sustained Response Performance - Steam Turbine



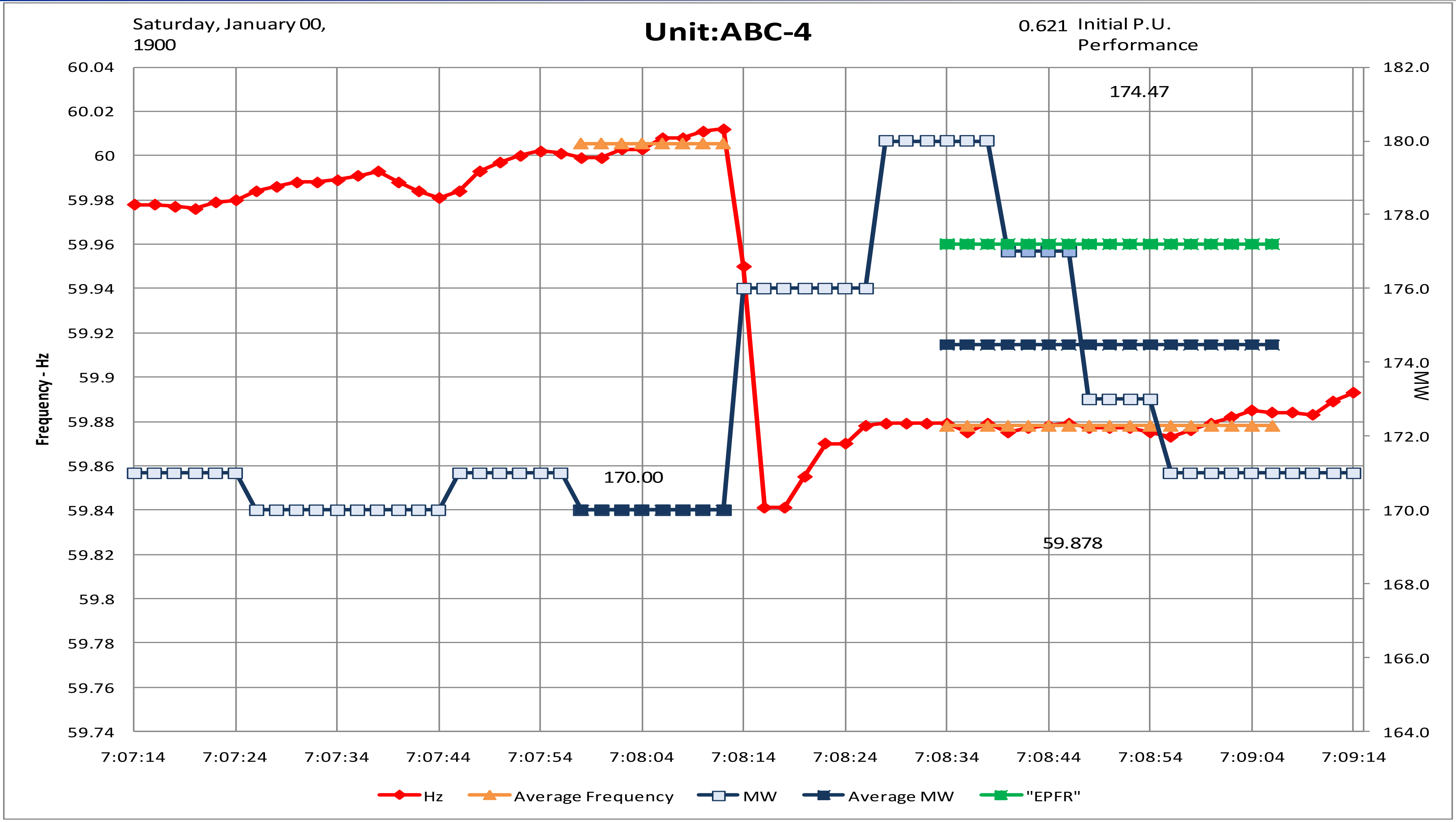
R9: Initial Response Performance - Steam Turbine



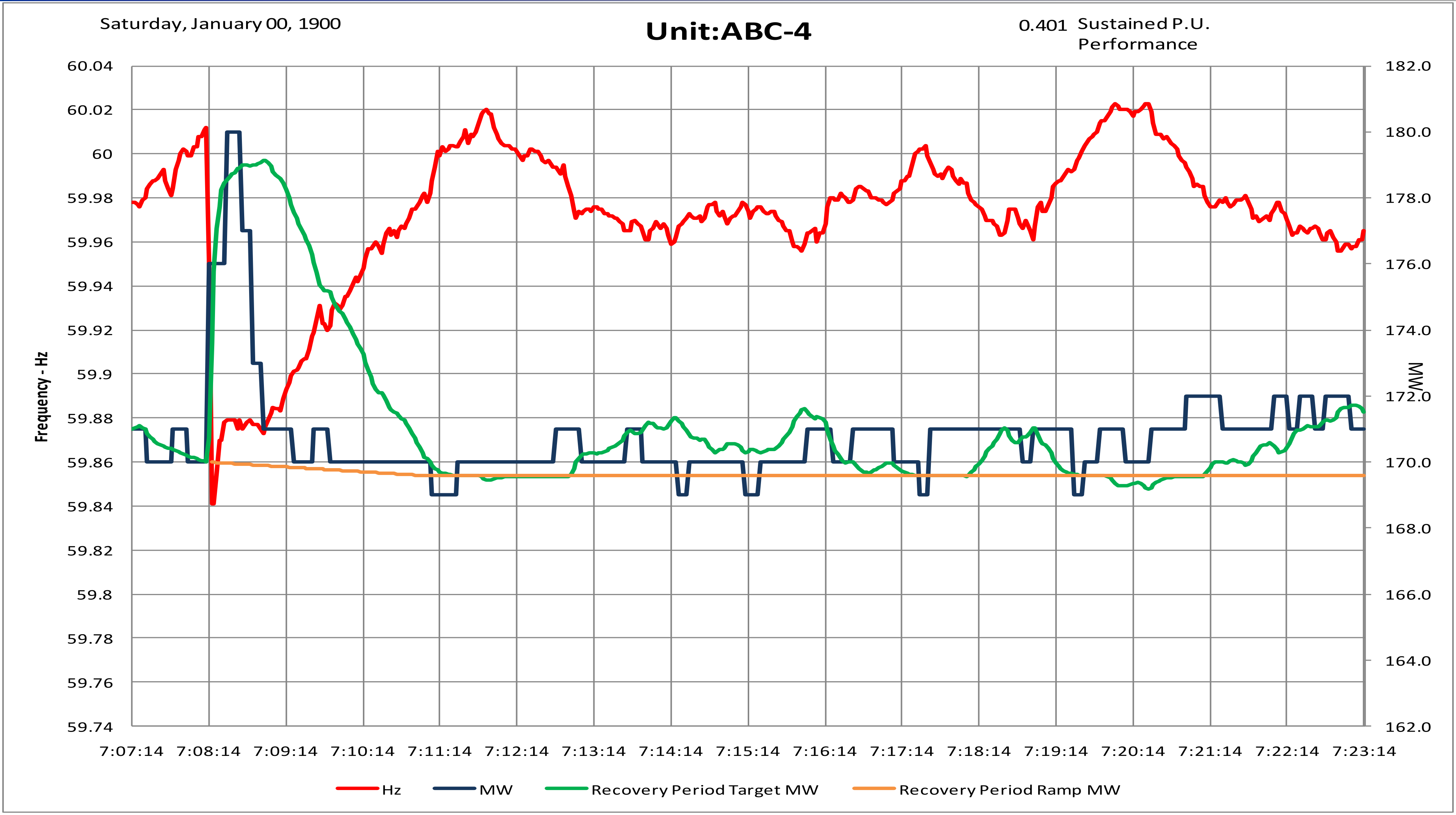
R10: Sustained Response Performance - Steam Turbine while Ramping up before and during event



R9: Initial Response Performance - Combustion Turbine with below standard performance



R10: Sustained Response Performance – Combustion Turbine with below standard performance



Attachment 10-002

TEXAS RELIABILITY ENTITY

Reliability Standards Committee Minutes

January 9, 2013
Texas RE Office
805 Las Cimas Parkway
Austin, TX 78746

Administrative

1. *Introduction and Attendance*

2012 RSC Brenda Hampton welcomed the participants to the meeting. The attendees were as follows (Voting RSC members shown in bold font):

Name	Company	Sector	Present	Called-in
Brenda Hampton (Acting Chair)	Luminant Energy Company, LLC	Generation	X	
Paul Gabba	The Dow Chemical Company	Generation	X	
Karin Schweitzer (Alternate)	Lower Colorado River Authority	Generation	X	
Daniela Hammons (Proxy)	CenterPoint Energy Houston Electric	Transmission	X	
Paul Johnson	American Electric Power Service Corp.	Transmission	X	
Christina Conway (Alternate)	Oncor Electric Delivery Company	Transmission	X	
Barry Kremling	Guadalupe Valley Electric Cooperative	Cooperative	X	
Tony Kroskey	Brazos Electric Cooperative, Inc.	Cooperative	X	
Andrew Gallo	Austin Energy	Municipal	X	
Jose Escamilla (Proxy)	CPS Energy	Municipal	X	
John Fontenot (Alternate)	Bryan Texas Utilities	Municipal	X	
JC Culberson	ERCOT	System Coordination and Planning	X	
Matt Stout (Alternate)	ERCOT	System Coordination and Planning	X	
John Varnell	Tenaska Power Services	Load Serving and Marketing	X	
Tim Soles	Occidental Power Services, Inc.	Load Serving and Marketing	X	
Rick Keetch (Alternate)	NRG Power Marketing LLC	Load Serving and Marketing	X	
Lisa Martin	Austin Energy		X	
Sydeny Niemeyer	NRG Power Marketing LLC		X	
Jen Fiegel	Oncor Electric Delivery Company.		X	
Christine Hasha	ERCOT		X	
Nick Henry	FERC		X	
Genese Galvan	Lonestar		X	
Phillip Mincemoyer	Direct Energy		X	
Sarah Lewis	Texas Reliability Entity		X	
Rochelle Brown	Texas Reliability Entity		X	
Don Jones	Texas Reliability Entity		X	

Susan Vincent	Texas Reliability Entity		X	
Alton A. Aars	TNMP			X
Jeannie Doty	Austin Energy			X
Renee Davidson (Alternate)	South Texas Electric Cooperative, Inc.			X
Dana Showalter	e.on Climate & Renewables			X
Shari Heino	Brazos Electric Cooperative, Inc.			X
Pam Zdenek	Infigen			X
Cameron Moore	Texas Reliability Entity			X
Jim Clawson	Texas Reliability Entity			X

At least one representative from four of the six sectors is required to constitute a quorum. At this meeting, a quorum was achieved with at least one representative from all six sectors being present.

2. *Antitrust Admonition & Meeting Minutes*

The Texas Reliability Entity (Texas RE) Antitrust Admonition was displayed and reviewed for the members. Don Jones reminded participants that it is Texas RE policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

Approval of October 3, 2012 Meeting Minutes

The October 3, 2012 meeting minutes were presented for committee members. A motion was made by Paul Johnson to approve the minutes. The motion was seconded and the October 2012 minutes were approved.

3. Announcements (D. Jones/Brenda Hampton)

Don and Brenda asked the committee to select a new Chair and Vice Chair for 2013. Brenda Hampton was selected as Chair and Andrew Gallo was selected as Vice Chair, both by consensus.

Don made a number of announcements regarding upcoming NERC and Texas RE activities. He reminded participants that the NERC Standards Review Subcommittee (NSRS) would be meeting in the afternoon following the RSC meeting.

Discussion and Activities

4. Regional Standard BAL-001-TRE-1 (Sydney Neimeyer)

Sydney Niemeyer gave a presentation requesting approval from the RSC to post for ballot the proposed Primary Frequency Response Regional Standard BAL-001-TRE-1. The presentation covered the following items: members of the drafting team, a requirements overview, generator PFR performance measures, interconnection frequency performance, maintenance and operating costs, field trail results, and the implementation plan.

A motion was made by Jose Escamilla to approve posting the Standard for ballot and JC Culberson seconded. After some discussion regarding application of the requirements to combined-cycle generators, power augmentation adjustment, and communication procedure issues, the motion passed with Tim Soles abstaining.

Don Jones then outlined the Texas RE regional standard voting process and the remaining process steps for approval of this standard.

5. Reliability Assurance Initiative (Lane Lanford)

Texas RE President and CEO Lane Lanford provided information to the group regarding the status of NERC's Reliability Assurance Initiative (RAI). He also expressed concern that the ERCOT Region is not adequately involved in NERC decision-making, particularly at the Board of Trustees level. Lane encouraged ERCOT Region entities to increase their participation in NERC activities, including perhaps identifying someone from the Region to sit on the NERC Board.

6. NSRS Quarterly Report (A. Gallo)

Andrew Gallo provided an updated of upcoming schedule meetings for the NSRS Committee. He mentioned hot topics that NSRS has addressed during the past few months, including CIP Version 5 and Paragraph 81. An overview was provided of recent Standards posted for comment and ballot. Andrew mentioned the upcoming NERC MRC Pre-Meeting conference call and Informational Webinar that will take place on January 16, 2013, and he reminded participants that Texas RE will hold "Talk with Texas RE" meetings on January 22, 2013, February 21, 2013 and March 21, 2013.

7. Other

Two agenda items, "Evolving NERC Standards Process and Practices" and "Severe Weather Preparation" were deferred to the NSRS meeting.

Future RSC meetings are scheduled for April 3, 2013, June 26, 2013 and October 2, 2013. Don asked participants to submit agenda items for future meetings.

The meeting adjourned at 11:45 a.m. The next meeting is scheduled for Wednesday, April 3, 2013 at 9:30 am at the Texas RE Office.

Attachment 10-003

Summary of February 2013 Ballot

BAL-001-TRE-1 Regional Standard Ballot Feb. 1-15, 2013

Ballot Voting Summary

Sector	Ballot Pool Members	Yes	No	Abstain	Percent Affirmative
Cooperative	3	2	1	0	66.7%
Generation	28	8	2	12	80.0%
Load Serving and Marketing	3	2	1	0	66.7%
Municipal Utility	3	2	1	0	66.7%
System Coordination and Planning	1	1	0	0	100.0%
Transmission and Distribution	2	2	0	0	100.0%
					80.0%

VRF/VSL Poll Summary

Sector	Ballot Pool Members	Yes	No	Abstain	Percent Affirmative
Cooperative	3	2	1	0	66.7%
Generation	28	7	3	12	70.0%
Load Serving and Marketing	3	1	0	2	100.0%
Municipal Utility	3	1	1	1	50.0%
System Coordination and Planning	1	1	0	0	100.0%
Transmission and Distribution	2	1	0	1	100.0%
					81.1%

Attachment 10-004

BAL-001-TRE-1 Regional Standard Ballot Feb. 1-15, 2013

Company	Sector	Name	Standard Vote	VRFs/VSLs vote
South Texas Electric Coop, Inc.	Cooperative	Renee Davidson	no	no
Brazos Electric Power Co Op, Inc.	Cooperative	Shari Heino	yes	yes
Guadalupe Valley Electric Co Op Inc	Cooperative	Barry Kremling	yes	yes
Sand Bluff Wind Farm LLC	Generation	Dana Showalter	abstain	abstain
Scurry County Wind LP	Generation	Mark Soutter		
Silver Star I Power Partners, LLC	Generation	Carla Bayer	abstain	abstain
South Trent Wind, LLC	Generation	Scott Gowder	yes	yes
Buffalo Gap Wind Farm, LLC	Generation	Tracy Jarvis		
Calpine Corporation	Generation	Randy Jones	yes	no
Champion Wind Farm	Generation	Dana Showalter	abstain	abstain
EC&R Panther Crk WF I & II, LLC	Generation	Dana Showalter	abstain	abstain
EC&R Panther Crk WF III, LLC	Generation	Dana Showalter	abstain	abstain
EC&R Papalote Creek I, LLC	Generation	Dana Showalter	abstain	abstain
EC&R Papalote Creek II	Generation	Dana Showalter	abstain	abstain
Elbow Creek Wind Project	Generation	Kevin Matt	yes	yes
Forest Creek Wind Farm, LLC	Generation	Dana Showalter		
Inadale Wind Farm, LLC	Generation	Dana Showalter	abstain	abstain
Ingleside Cogeneration, LP	Generation	Michelle D'Antuono	abstain	abstain
Kiowa Power Partners, LLC	Generation	Robert Bell		
Langford Wind Power, LLC	Generation	Rick Keetch	yes	yes
Lower Colorado River Authority	Generation	Karin Schweitzer	yes	yes
Luminant Generation Company, LLC	Generation	Brenda Hampton	yes	yes
Mesquite Wind LLC	Generation	Mike Grimes		
Notrees Windpower, LP	Generation	Kevin Carter	no	no
NRG Cedar Bayou Dev Co, LLC	Generation	John Palen	yes	yes
NRG Texas Power, LLC	Generation	Robert Bailey	yes	yes
Pattern Gulf Wind LLC	Generation	Grit Schmieder-Copeland	no	no
Post Oak Wind, LLC	Generation	Mike Grimes		
Pyron Wind Farm, LLC	Generation	Dana Showalter	abstain	abstain
Roscoe Wind Farm, LLC	Generation	Dana Showalter	abstain	abstain
Sherbino I Wind Farm, LLC	Generation	Carla Bayer	abstain	abstain
Tenaska Power Services Co.	Load Serving and Marketing	Brad Cox	yes	abstain
Constellation Enrgy Commod Grp Inc.	Load Serving and Marketing	Donald Schopp	no	abstain
NRG Power Marketing, LLC	Load Serving and Marketing	Rick Keetch	yes	yes
Texas Municipal Power Agency	Municipal Utility	Brent Hebert	no	no
City of Austin dba Austin Energy	Municipal Utility	Andrew Gallo	yes	abstain
CPS Energy	Municipal Utility	Jose Escamilla	yes	yes
Elec Reliab. Council of Texas, Inc.	System Coordination and Planning	H. Steven Myers	yes	yes
CenterPoint Enrgy Houston Elec, LLC	Transmission and Distrubition	John Brockhan	yes	abstain
Oncor Electric Delivery Company LLC	Transmission and Distrubition	Jen Fiegel	yes	yes

	BALLOT RESULTS	VRFs/VSLs RESULTS
	YES- 2 (.667) NO-1 (.333)	YES- 2 (.667) NO-1 (.333)
	YES-8 (.8) NO-2 (.2) ABSTAIN - 12	YES-7 (.7) NO-3 (.3) ABSTAIN- 12
	YES-2 (.667) NO-1 (.333)	YES-1 (1.000) ABSTAIN-2
	YES- 2 (.667) NO-1 (.333)	YES-1 (.5) NO-1 (.5) ABSTAIN-1
	YES-1 (1)	YES-1 (1)
	YES- 2 (1.000)	YES- 1 (1.000) ABSTAIN-1
TOTAL	YES - 4.801 NO- 1.199	YES- 4.867 NO- 1.133
	80.0%	**81.1%**

Attachment 10-005

BAL-001-TRE-1
Comments and Responses from Second Ballot Period
February 2013

Comment	Response
H. Steven Myers, ERCOT	
1. The VRF for R4 should be a "lower" VRF; it seems that application of the VRF Guidelines would identify it as administrative.	The drafting team does not consider this to be an "administrative" requirement. Determining the ICFR is an important operational function that is necessary for the BA to monitor the status of the interconnection.
2. Seemingly, the applicable entity for R7 should be an operating entity such as the GOP rather than the GO. We recognize that what is required is that the resources must have governors and the status and changes to status should be controlled and reported. We don't propose to specify "how" this should be done. This appears to be a complexity of trying to cover what must be done within the context of the construct of the ERCOT organizational and market structure.	Under the NERC functional model, the GO is responsible for providing and maintaining a generating unit that is able to meet reliability standards, including with Governor in service and responsive to frequency. This requirement is appropriately assigned to the GO.
3. Seemingly the stated Data Retention period is too long. The "past year" (or two at max) should suffice. The last audit is typically about 3 years in the past for a BA and may be up to 6 years for a GO/GOP. Operations that far in the past should not be given much attention as that does not have a significant impact upon reliability.	Data retention since the last audit is standard practice at this time. We do not expect this to be unduly burdensome in connection with these requirements.
Grit Schmieder-Copeland, Pattern Gulf Wind LLC	
The standard continues to fail to address older wind generators that are technically incapable of providing this capability and have been granted an exemption under the ERCOT PRR 833 protocol. Enforcement of this new standard would subject existing generation resources to the burden of purchasing expensive equipment which wasn't required, contemplated, or available at the time of initial construction and interconnection. Pattern would be supportive of the standard as	See Exemption 4.2.3: "Any generators that are not required by the BA to provide primary frequency response are exempt from this standard." This is intended to exempt wind generators that are not required to provide frequency response under PRR 833.

Comment	Response
proposed as long as the requirements acknowledge exemptions for existing technology that was not required to provide the PFR when initially interconnected and is technically not capable of doing so.	
Michelle D'Antuono, Ingleside Cogeneration, LP	
1. The proposed regional standard goes beyond the FERC directive and the results of the field trial are insufficient for generators to ascertain if they can meet the performance requirements. The reason for development of this regional standard is the FERC directive to the ERO in Order 693, which was based on incorporating ERCOT Zonal Protocol Section 5 into a 'regional difference.' Further, FERC states in Section 314 of the Order that Section 5 of the Protocols is more stringent than the then applicable NERC BAL standard. This proposed regional standard is a significant extension of this directive. The proposed performance requirements seem to be technically sound and certainly well thought out. They provide for corrections to expected performance for combined cycle units for power augmentation, decay of response for gas and steam turbines, and pre-event ramp rate. However, without testing, GOs won't know whether they can meet the performance requirements without significant changes to equipment. The fact that 50% of the combined cycle units in the field test did not pass the performance test in R9 (based on whatever droop and deadband settings were employed at the time by those units) provides little incite for GOs on how their units will perform under the proposed standard.	Thank you for your comments. The drafting team believes that individual generating unit frequency response performance must be provided and monitored in order to ensure the interconnection-wide performance called for under the FERC directive, and to ensure that all generators are appropriately supporting interconnection frequency response. The requirements were designed to be achievable by all types of generating units, including combined-cycle units, based on extensive testing in the Field Trial and outside of the Field Trial. Note that some of the Field Trial generators did not attempt to improve their performance for the trial, resulting in low scores. Finally, the implementation plan does not require full compliance until 30 months after the effective date, which is intended to allow adequate time for any upgrades and tuning that may be necessary.
2. R6.1 allows directed changes in generator governor deadband setting by ERCOT. The wording of R6.1 implies that ERCOT could require an increase or decrease in the deadband setting for a generator by directive. Based on a reading of R6.2, the intent of the SDT may have been that ERCOT could increase the deadband, but not decrease it over the values listed in Table 6.1. If this is correct, the wording needs to be changed accordingly.	First, the BA may direct changes in deadband and droop settings in order to comply with R5, which would normally be to lower required deadband and droop settings to improve interconnection frequency response. Second, the BA may direct different settings on a unit that cannot meet the stated settings in R6. The performance measures in R9 and R10 are based on the deadband and droop settings set forth in the standard or any different settings directed by the BA.

Comment	Response
3. The communication path depicted in R7 and R8 is not compatible with all ERCOT Market Participants. Apparently the SDT considered the GOP as the QSE in the standard and this is not the case for all GOs that will need to comply with the proposed standard. Some change will need to be incorporated in the regional standard for this to work for all entities. One possibility is to remove GOP from the Applicability section and combine R7 and R8 to say: “Each GO shall operate . . . unless the GO has a valid reason for operating with the Governor not in service. Using ERCOT communication protocols, the GO is responsible for conveying a Governor status change to the BA within 30 minutes of the discovery of a Governor status change.” The Measure would also have to be changed accordingly.	Under the NERC functional model, the GOP is responsible for obtaining generating unit status and operating information and providing it to the BA. In the ERCOT region, some GOs do not have means to communicate directly with the BA. Requirements R7 and R8 were written to include the applicable functional entities, regardless of whether the GOP is a QSE.
4. R8 needs to be on the same basis as R7. If R7 and R8 are not combined as proposed above, the following needs to be added at the end of the existing R8: “for generating units/generating facilities that are online and released for dispatch.”	The drafting team’s intention is that a Governor’s status is only material when the generating unit is operating.
5. The Reference Document needs clarification of mechanisms for transfer of information. The Reference Document states that the GO needs to submit information on various corrections to the measured frequency response to ERCOT. However, it doesn’t say how this is to be accomplished. In particular, the mechanism for providing information (evidence) concerning power augmentation to ERCOT needs to be clarified. Since this standard will make these transfers subject to compliance evaluation, this may need to be detailed in the document or in the ERCOT Protocols.	The drafting team expects that administrative implementation details will be worked out during the implementation period, through the development of ERCOT procedures. We don’t think the details of how the requirements are implemented need to be in the standard or in the Reference Document.

Comment	Response
Don Schopp, Constellation/Exelon	
It is unclear whether the 12-month rolling average calculation takes into account or is adjusted for generators that have low capacity factors and may only run for a fraction of the 12-month period.	The measures of R9 and R10 are adjusted for generators that do not participate in many Frequency Measurable Events (FME) by requiring at least 8 FMEs in the rolling average. Generators may participate in few events because either (a) they don't run very much, or (b) they usually run at or near HSL. See Requirement R2.3.
There does not appear to be an effective feedback mechanism from the BA to the GOP regarding unit performance. That is, the Compliance Enforcement Authority is notified of unit performance before the GOP is notified.	The BA is to submit the calculated unit performance to both the Compliance Enforcement Authority and to the applicable GO each month. See Requirement R2.2.
Renee Davidson, South Texas Electric Cooperative	
STEC believes the Regional Standard is much improved from previous versions, but believes additional tweaks need to be made to governor deadband requirements associated with table 6.1 in light of findings with its own resources. STEC is concerned about limiting the .034 deadband to only steam and hydro turbines with mechanical governors. STEC believes possible modifications to the language should be implemented to state that any unit with a mechanical governor is allowed a .034 Hz deadband. There are other technologies in ERCOT that employ mechanical governors and requiring alternate technologies to upgrade their governors to either digital or electronic governors may be cost prohibitive and drive those units into retirement. In light of resource adequacy concerns both at the PUCT and by NERC, it would seem that any Regional Standard that could result in actions contrary to resource adequacy need to be reconsidered. STEC would like to propose .034 Hz deadband for reciprocating engines. STEC conducted testing with its reciprocating units in a zero deadband mode where the results	Thank you for your comments. The drafting team would like STEC to test their reciprocating engines at the 0.017 Hz dead-band for stable operation while operating to the ERCOT grid frequency that we are experiencing today. The drafting team has observed a significant improvement in grid frequency stability beginning October 2012. This improved frequency control has reduced the primary frequency response burden on individual generators significantly. If testing your generators at this lower dead-band continues to indicate very unstable operation, the standard allows the BA to direct different settings on a unit that cannot meet the stated settings in R6. The performance measures in R9 and R10 are based on the dead-band and droop settings set forth in the standard or any different settings directed by the BA.

Comment	Response
showed the units were very unstable and oscillated around the nominal load set point. The increased movement causes oscillating rich to lean fuel inputs within in turn has led to increased spark plug fouling thereby resulting in decreased unit reliability and availability.	
INFORMAL COMMENT – Pamela Hunter, Southern Power Company	
The Standard should grandfather existing generation that might not be able to meet these new requirements - it is inappropriate to retroactively apply controller specifications.	Reliability standards generally apply uniformly to all entities. The intent is to bring all generators into compliance in order to ensure BES reliability. Also, the generator requirements in this regional standard are similar to those contained in the ERCOT Protocols, which all non-exempt ERCOT generators are required to comply with.

Attachment 10-006

TEXAS RELIABILITY ENTITY

Reliability Standards Committee Minutes

March 6, 2013
Special Telephone Meeting

Administrative

1. *Introduction and Attendance*

Vice Chair Andy Gallo welcomed the participants to the meeting. The attendees were as follows (RSC Members and Alternates shown in bold font):

Name	Company	Sector
Paul Gabba	The Dow Chemical Company	Generation
Christina Conway	Oncor Electric Delivery Company	Transmission
Barry Kremling	Guadalupe Valley Electric Cooperative	Cooperative
Tony Kroskey	Brazos Electric Cooperative, Inc.	Cooperative
Andrew Gallo	Austin Energy	Municipal
John Fontenot	Bryan Texas Utilities	Municipal
Matt Stout	ERCOT	System Coordination and Planning
Tim Soles	Occidental Power Services, Inc.	Load Serving and Marketing
Jose Escamilla	CPS Energy	
Chuck Moore	Twin Eagle	
Valerie Penemonte	American Electric Power Service Corp.	
Sydney Niemeyer	NRG Power Marketing LLC	
Nick Henery	FERC	
Alton A. Aars	TNMP	
Pam Zdenek	Infigen	
Don Jones	Texas Reliability Entity	

2. *Antitrust Admonition*

The Texas Reliability Entity (Texas RE) Antitrust Admonition was reviewed for the members. Don Jones reminded participants that it is Texas RE policy to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition.

3. *Approve BAL-001-TRE-1 for submission to Texas RE Board of Directors*

Don Jones presented the Regional Standard Ballot results, and he discussed several of the comments that were received and the Standard Drafting Team's responses. There was further discussion on several issues.

Andrew Gallo made the following motion, which was seconded by Tony Kroskey:

> "The Texas RE Reliability Standards Committee hereby certifies the ballot results approving Regional Standard BAL-001-TRE-1, and submits the Regional Standard to the

Texas RE Board of Directors for further action pursuant to the Texas RE Standards Development Process."

Don then explained that the RSC procedures allow an email vote but not a phone vote. The email vote will be conducted over the next few days, closing on Friday March 8 if sufficient votes are received to meet quorum requirements.

The meeting adjourned at 3:10 p.m. The next RSC meeting is scheduled for Wednesday, April 3, 2013 at 9:30 am at the Texas RE Office.

Attachment 10-007

2013 Reliability Standards Committee Members

System Coord & Planning	~~JC Culberson~~	Electric Reliability Council of Texas, Inc. Cheryl Mosely
System Coord & Planning Alternate	Matthew Stout - YES	Electric Reliability Council of Texas, Inc. – Present
Transmission	John Brockhan- yes	CenterPoint Energy Houston Electric, LLC
Transmission	Paul Johnson – YES	American Electric Power Service Corp. Valerie Penemonte
Transmission Alternate	Christina Conway – ~~YES~~	Oncor Electric Delivery Company – Present
Cooperative	Barry Kremling - yes	Guadalupe Valley Electric Cooperative – Present
Cooperative	Tony Kroskey	Brazos Electric Power Cooperative, Inc. – Present
Cooperative Alternate	Renee Davidson	South Texas Electric Cooperative, Inc.
Municipal	~~David Detelich~~ Jose - Present - YES	CPS Energy
Municipal	Vice – Andrew Gallo – YES	Austin Energy – Present
Municipal Alternate	John Fontenot ~~(YES)~~	Bryan Texas Utilities – Present
Generation	Chair – Brenda Hampton - YES	Luminant Energy Company, LLC
Generation	Paul Gabba - YES	The Dow Chemical Company – Present
Generation Alternate	Karin Schweitzer ~~(YES)~~	Lower Colorado River Authority
Load Serving & Marketing	John Varnell	Tenaska Power Services
Load Serving & Marketing	Tim Soles Abstain	Occidental Power Services, Inc. – Present
Load Serving & Marketing Alternate	Rick Keetch - yes	NRG Power Marketing LLC

TEXAS RELIABILITY ENTITY

Sydney / Pam // -
Chuck Moore - Twin Eagle
Alton Aars -

Nick Henery

Attachment 11-001a

TEXAS RELIABILITY ENTITY

RESOLUTION OF THE BOARD OF DIRECTORS OF TEXAS RELIABILITY ENTITY, INC.

April 23, 2013

WHEREAS, the Board of Directors (Board) of Texas Reliability Entity, Inc. (Texas RE), a Texas non-profit corporation, deems it desirable and in the best interest of reliability in the Electric Reliability Council of Texas, Inc. (ERCOT) region to approve the regional reliability standard (regional standard) BAL-001-TRE-1 Primary Frequency Response in the ERCOT Region for submission to North American Electric Reliability Corporation; and

WHEREAS, the Registered Ballot Body voted to approve this regional standard with an 80% affirmative vote, and Texas RE staff recommends approval of the regional standard; and

WHEREAS, Texas RE staff recommends approval of the associated Violation Severity Levels and Violation Risk Factors, which were also approved by the Registered Ballot Body;

THEREFORE be it RESOLVED, that the Board hereby approves:

- Regional standard BAL-001-TRE-1, which is attached hereto as Attachment A and incorporated herein for all purposes; and
- The Violation Severity Levels and Violation Risk Factors included in Attachment A.

CORPORATE SECRETARY'S CERTIFICATE

I, Susan Vincent, Corporate Secretary of Texas Reliability Entity, Inc., do hereby certify that, at the April 23, 2013, Texas Reliability Entity, Inc. Board Meeting, the Board of Directors approved the above referenced Resolution. The Motion passed by unanimous voice vote.

IN WITNESS WHEREOF, I have hereunto set my hand this 23rd day of April, 2013.

Susan V

Susan Vincent, Corporate Secretary

Attachment A

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.
SAR posted for comment on April 24, 2008.
SAR approved May 27, 2008.
Drafting Team nominated and selected in June 2008.
First posting of standard on March 16, 2009.
Drafting Team held technical workshop on March 31, 2009.
Second posting of standard on February 12, 2010.
Drafting Team held technical workshop on March 3, 2010.
Drafting Team held a performance evaluation workshop on August 6, 2010.
Third posting requested at RSC Meeting September 1, 2010.
Third posting ended on November 11, 2010.
Drafting Team reviewed and revised the Standard on May 5-6, 2011.
Texas RE staff received comments from NERC Staff review and revised standard draft to address comments (5/24/11).
Drafting Team finalized Standard and approved final version on July 25, 2011.
RSC approved the Standard for ballot on August 5, 2011.
First ballot conducted Sept. 9-23, 2011 and failed to obtain 2/3 affirmative vote.
Field Trial conducted ending June, 2012. Specific members of the drafting team evaluated 28 various types of resource's performance during 35 FMEs occurring over approximately one year.
Drafting Team provided feedback to each field trial participant in August and September, 2012.
Drafting Team revised the Standard based on results of the field trial in September and October, 2012.

Description of Current Draft

The drafting team has revised the draft based on comments received with the first ballot and Field Trial results. In particular the sustained performance measure was changed to examine a point in time about one minute following the FME, rather than a period covering several minutes after the FME. This draft will be finalized and posted for ballot in late 2012.

Future Development Plan:

Anticipated Actions	Anticipated Date
Respond to comments and field trial/revise draft	July to December 2012
Present revised draft to RSC	January 2013
Second Ballot	January-Feb. 2013
TRE Board Adopt (Tentative)	April 2013

NERC Submit (Tentative)	May 2013
FERC Approval (Tentative)	??

Definitions of Terms Used in Standard

Frequency Measurable Event (FME): An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

or

ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region

2. **Number:** BAL-001-TRE-1

3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.

4. **Applicability:**

   4.1. Functional Entities:

   1. Balancing Authority (BA)
   2. Generator Owners (GO)
   3. Generator Operators (GOP)

   4.2. Exemptions:

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.

   4.2.3 Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

5. **Background:**

The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (that starts at t(0)).

> Note that in Project 2010-14.1, NERC proposes to eliminate the CPS2 measure, and there are no ERCOT-specific provisions in the new proposed standards.

This regional standard provides requirements related to identifying Frequency Measureable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

Under this standard, two Primary Frequency Response performance measures are calculated: “initial” and “sustained.” The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual

response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this regional standard the term "resource" is synonymous with "generating unit/generating facility".

6. (**Proposed) Effective Date:**

After final regulatory approval and in accordance with the 30-month Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements. See attached Implementation Plan (Attachment 1).

B. Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M1. The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months.

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the GO by the end of the month in which they were completed.

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M2. The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in Requirement R2.

[1] The Primary Frequency Response Reference Document contains the calculations that the BA will use to determine Primary Frequency Response performance of generating units/generating facilities. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

R3. The BA shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

M3. The BA shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The BA shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. After each calendar month in which one or more FMEs occurs, the BA shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month.

R4 Example: If there is one (or more) FME in April, the BA must determine and publish the rolling average by the end of May. The rolling average will include the last six FMEs before the end of April.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M4. The BA shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M5. The BA shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each GO shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.017 Hz

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

$$\text{For 5\% Droop:} \quad \text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

$$\text{For 4\% Droop:} \quad \text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M6. Each GO shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

R7. Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service.

[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]

M7. Each GO shall have evidence that it notified the GOP as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor.

[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]

M8. Each GOP shall have evidence that it notified the BA within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9 measures *initial* unit PFR performance (A-value to B-value). This requirement specifies a certain level of average measured performance over a 12-month period.

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation.

R10 measures *sustained* unit PFR performance during the period t(46) to t(60). This requirement specifies a certain level of average measured performance over a 12-month period.

R10. Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M10. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each GO shall have documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation.

C. Compliance

1. Compliance Enforcement Authority

Texas Reliability Entity

2. Compliance Monitoring Period and Reset Time Frame

2.1. If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

3. Data Retention

3.1. The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain a list of identified Frequency Measurable Events and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The BA shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The BA shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The BA shall retain all data and calculations relating to the Interconnection's Frequency Response, and all evidence of actions taken to increase the Interconnection's Frequency Response, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each GOP shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each GO shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

D. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The BA reported an FME more than 14 days but less than 31 days after identification of the event.	The BA reported an FME more than 30 days but less than 51 days after identification of the event.	The BA reported an FME more than 50 days but less than 71 days after identification of the event.	The BA reported an FME more than 70 days after identification of the event.
R2	The BA submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The BA submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The BA submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The BA failed to submit a monthly report within 90 days after the end of the reporting month.
R3	The BA did not make the calculation and criteria for determination of the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR for the following year in December.	The BA did not calculate the IMFR for a calendar year.
R4	N/A	N/A	The BA did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The BA did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.

R5	N/A	N/A	N/A	The BA did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7	N/A	N/A	N/A	The GO operated with its Governor out of service and did not notify the GOP upon discovery of its Governor out of service.
R8	The GOP notified the BA of a change in Governor status between 31 minutes and one hour after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 1 hour but within 4 hours after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 4 hours but within 24 hours after the GOP was notified of the discovery of the change.	The GOP failed to notify the BA of a change in Governor status within 24 hours after the GOP was notified of the discovery of the change.
R9	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

E. Associated Documents

1. Attachment 1 – Implementation Plan.
2. Attachment 2 – Primary Frequency Response Reference Document, including Flow Charts A and B.
    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9 and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.
    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/2012	Approved by SDT for submission to Texas RE RSC for approval to post for second regional ballot	Changed sustained measure from average over event recovery period to point at 46 seconds after SME, and other changes to respond to field trial results, comments and corrections.

Attachment 11-001b

RESOLUTION OF THE BOARD OF DIRECTORS OF TEXAS RELIABILITY ENTITY, INC.

April 23, 2013

WHEREAS, the Board of Directors (Board) of Texas Reliability Entity, Inc. (Texas RE), a Texas non-profit corporation, deems it desirable and in the best interest of reliability in the Electric Reliability Council of Texas, Inc. (ERCOT) region to approve the regional reliability standard (regional standard) BAL-001-TRE-1 Primary Frequency Response in the ERCOT Region for submission to North American Electric Reliability Corporation; and

WHEREAS, the Registered Ballot Body voted to approve this regional standard with an 80% affirmative vote, and Texas RE staff recommends approval of the regional standard; and

WHEREAS, Texas RE staff recommends approval of the associated Violation Severity Levels and Violation Risk Factors, which were also approved by the Registered Ballot Body;

THEREFORE be it RESOLVED, that the Board hereby approves:

- Regional standard BAL-001-TRE-1, which is attached hereto as Attachment A and incorporated herein for all purposes; and
- The Violation Severity Levels and Violation Risk Factors included in Attachment A.

CORPORATE SECRETARY'S CERTIFICATE

I, Susan Vincent, Corporate Secretary of Texas Reliability Entity, Inc., do hereby certify that, at the April 23, 2013, Texas Reliability Entity, Inc. Board Meeting, the Board of Directors approved the above referenced Resolution. The Motion passed by unanimous voice vote.

IN WITNESS WHEREOF, I have hereunto set my hand this 23rd day of April, 2013.

Susan V

Susan Vincent, Corporate Secretary

Attachment 11-002

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.
SAR posted for comment on April 24, 2008.
SAR approved May 27, 2008.
Drafting Team nominated and selected in June 2008.
First posting of standard on March 16, 2009.
Drafting Team held technical workshop on March 31, 2009.
Second posting of standard on February 12, 2010.
Drafting Team held technical workshop on March 3, 2010.
Drafting Team held a performance evaluation workshop on August 6, 2010.
Third posting requested at RSC Meeting September 1, 2010.
Third posting ended on November 11, 2010.
Drafting Team reviewed and revised the Standard on May 5-6, 2011.
Texas RE staff received comments from NERC Staff review and revised standard draft to address comments (5/24/11).
Drafting Team finalized Standard and approved final version on July 25, 2011.
RSC approved the Standard for ballot on August 5, 2011.
First ballot conducted Sept. 9-23, 2011 and failed to obtain 2/3 affirmative vote.
Field Trial conducted ending June, 2012. Specific members of the drafting team evaluated 28 various types of resource's performance during 35 FMEs occurring over approximately one year.
Drafting Team provided feedback to each field trial participant in August and September, 2012.
Drafting Team revised the Standard based on results of the field trial in September and October, 2012.

Description of Current Draft

The drafting team has revised the draft based on comments received with the first ballot and Field Trial results. In particular the sustained performance measure was changed to examine a point in time about one minute following the FME, rather than a period covering several minutes after the FME. This draft will be finalized and posted for ballot in late 2012.

Future Development Plan:

Anticipated Actions	Anticipated Date
Respond to comments and field trial/revise draft	July to December 2012
Present revised draft to RSC	January 2013
Second Ballot	January-Feb. 2013
TRE Board Adopt (Tentative)	April 2013

NERC Submit (Tentative)	May 2013
FERC Approval (Tentative)	??

Definitions of Terms Used in Standard

Frequency Measurable Event (FME): An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

or

ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-1
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

   4.1. Functional Entities:

   1. Balancing Authority (BA)
   2. Generator Owners (GO)
   3. Generator Operators (GOP)

   4.2. Exemptions:

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.

   4.2.3 Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

5. **Background:**

The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (that starts at t(0)).

> Note that in Project 2010-14.1, NERC proposes to eliminate the CPS2 measure, and there are no ERCOT-specific provisions in the new proposed standards.

This regional standard provides requirements related to identifying Frequency Measureable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

Under this standard, two Primary Frequency Response performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual

response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this regional standard the term "resource" is synonymous with "generating unit/generating facility".

6. (**Proposed) Effective Date:**

After final regulatory approval and in accordance with the 30-month Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements. See attached Implementation Plan (Attachment 1).

B. Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M1. The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months.

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the GO by the end of the month in which they were completed.

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M2. The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in Requirement R2.

[1] The Primary Frequency Response Reference Document contains the calculations that the BA will use to determine Primary Frequency Response performance of generating units/generating facilities. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

R3. The BA shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

M3. The BA shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The BA shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. After each calendar month in which one or more FMEs occurs, the BA shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month.

R4 Example: If there is one (or more) FME in April, the BA must determine and publish the rolling average by the end of May. The rolling average will include the last six FMEs before the end of April.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M4. The BA shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M5. The BA shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each GO shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.017 Hz

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M6. Each GO shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

R7. Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service.

[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]

M7. Each GO shall have evidence that it notified the GOP as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor.

[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]

M8. Each GOP shall have evidence that it notified the BA within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

> R9 measures *initial* unit PFR performance (A-value to B-value). This requirement specifies a certain level of average measured performance over a 12-month period.

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation.

R10 measures *sustained* unit PFR performance during the period t(46) to t(60). This requirement specifies a certain level of average measured performance over a 12-month period.

R10. Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M10. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each GO shall have documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation.

C. Compliance

1. Compliance Enforcement Authority

Texas Reliability Entity

2. Compliance Monitoring Period and Reset Time Frame

2.1. If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

3. Data Retention

3.1. The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain a list of identified Frequency Measurable Events and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The BA shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The BA shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The BA shall retain all data and calculations relating to the Interconnection’s Frequency Response, and all evidence of actions taken to increase the Interconnection’s Frequency Response, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each GOP shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each GO shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

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Compliance Violation Investigations

Self-Reporting

Complaints

D. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The BA reported an FME more than 14 days but less than 31 days after identification of the event.	The BA reported an FME more than 30 days but less than 51 days after identification of the event.	The BA reported an FME more than 50 days but less than 71 days after identification of the event.	The BA reported an FME more than 70 days after identification of the event.
R2	The BA submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The BA submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The BA submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The BA failed to submit a monthly report within 90 days after the end of the reporting month.
R3	The BA did not make the calculation and criteria for determination of the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR for the following year in December.	The BA did not calculate the IMFR for a calendar year.
R4	N/A	N/A	The BA did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The BA did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.

R5	N/A	N/A	N/A	The BA did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7	N/A	N/A	N/A	The GO operated with its Governor out of service and did not notify the GOP upon discovery of its Governor out of service.
R8	The GOP notified the BA of a change in Governor status between 31 minutes and one hour after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 1 hour but within 4 hours after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 4 hours but within 24 hours after the GOP was notified of the discovery of the change.	The GOP failed to notify the BA of a change in Governor status within 24 hours after the GOP was notified of the discovery of the change.
R9	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

E. Associated Documents

1. Attachment 1 – Implementation Plan.
2. Attachment 2 – Primary Frequency Response Reference Document, including Flow Charts A and B.
    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9 and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.
    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/2012	Approved by SDT for submission to Texas RE RSC for approval to post for second regional ballot	Changed sustained measure from average over event recovery period to point at 46 seconds after SME, and other changes to respond to field trial results, comments and corrections.

Attachment 11-003

BAL-001-TRE-1

Attachment 1

Implementation Plan for Regional Standard BAL-001-TRE-1, Primary Frequency Response in the ERCOT Region

Prerequisite Approvals:
None

Revisions to Approved Standards and Definitions:
None

New Definitions:
- Frequency Measurable Event (FME)
- Governor
- Primary Frequency Response (PFR)

Compliance with the Standard

The following entities are responsible for being compliant with requirements of BAL-001-TRE-1:
- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)

- Exemptions:
  - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.
  - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.
  - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
The Effective Date of this standard shall be the first day of the first calendar quarter after final regulatory approval. Registered Entities must be compliant with the Requirements in accordance with the 30-month Implementation Plan set forth below.

- <u>12 months after Effective Date</u>
  - The BA must be compliant with Requirement R1
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R6 (if >1 unit/facility)
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R7 (if >1 unit/facility)
  - The GOP must be compliant with Requirement R8

- <u>18 months after Effective Date</u>
  - The BA must be compliant with Requirements R2, R3, R4, and R5
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R6
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R7

- <u>24 months after Effective Date</u>
    - At least 50% of the GO’s generating units/generating facilities must be compliant with Requirement R9 (if >1 unit/facility)
    - At least 50% of the GO’s generating units/generating facilities must be compliant with Requirement R10 (if >1 unit/facility)

- <u>30 months after Effective Date</u>
    - 100% of the GO’s generating units/generating facilities must be compliant with Requirement R9
    - 100% of the GO’s generating units/generating facilities must be compliant with Requirement R10

Attachment 11-004

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-1
Requirements R2, R9 and R10
Performance Metric Calculations

I. Introduction

This Primary Frequency Response Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities following Frequency Measurable Events (FMEs) in accordance with Requirements R2, R9 and R10. Flowcharts in Attachment A (Initial PFR) and Attachment B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Primary Frequency Response Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available[1] for reference and use in understanding and performing these calculations.

This Primary Frequency Response Reference Document is not considered to be a part of the regional standard. This document will be maintained by Texas RE and will be subject to modification as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.

Revision Process: The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

> **High Sustained Limit (HSL)** for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility.
>
> **Low Sustained Limit (LSL)** for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy production capability of a generating unit/generating facility.

In this regional standard, the term “resource” is synonymous with “generating unit/generating facility”.

[1] These spreadsheets are available at www.TexasRE.org.

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12 month period (or 8 event minimum) to establish whether a resource is compliant with Requirement R9.

This process calculates the initial Per Unit Primary Frequency Response of a resource [P.U. $PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$), adjusted for the pre-event ramping of the unit, and the Final Expected Primary Frequency Response ($EPFR_{Final}$) as calculated using the Pre-perturbation and Post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of resource, the initial Per Unit Primary Frequency Response [P.U.$PFR_{Resource}$] for any Frequency Measurable Event (FME).

> Each GO may submit to the BA unit-specific information used by the BA in this requirement to calculate initial PFR performance for each generating unit/generating facility.

<u>Initial Primary Frequency Response performance requirement:</u>

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

where P.U. $PFR_{Resource}$ is the per unit measure of the initial Primary Frequency Response of a resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{Final}}$$

where P.U. $PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The Adjusted Actual Primary Frequency Response ($APFR_{Adj}$) and the Final Expected Primary Frequency Response ($EPFR_{Final}$) are calculated as described below.

EPFR Calculations use droop and deadband values as stated in Requirement R6 with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation droop will be 5.78%.[2]

Actual Primary Frequency Response ($APFR_{adj}$)

The adjusted Actual Primary Frequency Response ($APFR_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} \quad = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

where:

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{\#\ Scans}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(20)}^{t(52)} MW}{\#\ Scans}$$

Ramp Adjustment: The Actual Primary Frequency Response number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = (MW_{T-4} – MW_{T-60})*0.59

[2] The effective droop of a typical combined-cycle facility with governor settings per Requirement R6 is 5.78%, assuming a 2-to-1 ratio between combustion turbine capacity and steam turbine capacity. Use 5.78% effective droop in all combined-cycle performance calculations.

($MW_{T-4} - MW_{T-60}$) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all generator types, the *ideal* Expected Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60 Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 - deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 - deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 + deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from t(-16) to t(-2)

$$Hz_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} Hz}{\#\ Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from t(20) to t(52)

$$Hz_{post-perturbation} = \frac{\sum_{t(20)}^{t(52)} Hz}{\#\ Scans}$$

Capacity and NDC (Net Dependable Capacity) are used interchangeably and the term Capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. The Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

Power Augmentation: For Combined Cycle facilities, Capacity is adjusted by subtracting power augmentation (PA) capacity, if any, from the HSL. Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO should provide the BA with documentation and conditions when power augmentation is to be considered in PFR calculations.

$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor\ \times -1$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ F\overset{x}{a}ctor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of
Pressure curve at $MW_{pre\text{-}perturbation}$

The Rated Throttle Pressure and the Pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of Pressure and MW breakpoints where the Rated Throttle Pressure and MW output, where Rated Throttle Pressure is achieved, is the first pair and the Minimum Throttle Pressure and MW output, where the Minimum Throttle Pressure is achieved, as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during a FME. The GO can measure the drop in throttle pressure when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the Steam Flow Change Factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{final} = EPFR_{ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

10.1 The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2 If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3 A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);

- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

Each GO may submit to the BA any information used by the BA in this requirement to calculate sustained PFR performance for each generating unit/generating facility.

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12 month period (or 8 event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the sustained Per Unit Primary Frequency Response of a resource [P.U. $SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [P.U.$SPFR_{Resource}$] for any Frequency Measurable Event (FME).

<u>Sustained Primary Frequency Response performance requirement:</u>

The standard requires an average performance over a period of 12 months (including at least 8 measured events) that is ≥ 0.75.

$$Avg_{Period}\,[P.U.SPFR_{Resource}] \geq 0.75$$

$Avg_{Period}\,[P.U.SPFR_{Resource}]$ is either:

- the average of each resource's sustained Primary Frequency Response performances [*P.U.* $SPFR_{Resource}$] during all of the assessable Frequency Measurable Events (FMEs), for the most recent rolling 12 month period; or
- if the unit has not experienced at least 8 assessable FMEs in the most recent 12 month period, the average of the unit's last 8 sustained Primary Frequency Response performances when the unit provided frequency response during a Frequency Measurable Event.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Response_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

[3] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

P.U. SPFR$_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. For any given event *P.U.SPFR*$_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

Actual Sustained Primary Frequency Response (*ASPFR*) Calculations

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{\# \, Scans}$$

and:

MW$_{MaximumResponse}$ = *maximum MW value telemetered by a unit from T+46 through T+60 during low frequency events and the minimum MW value telemetered by a unit from T+46 through T+60 during a high frequency event.*

Actual Sustained Primary Frequency Response, Adjusted (*ASPFR*$_{Adj}$)

$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – The Standard requires a unit/facility to sustain its response to a Frequency Measureable Event. An adjustment available in determining a unit's sustained Primary Frequency Response performance (*P.U. SPFR*$_{Resource}$) is to account for the direction in which a resource was moving (increasing or decreasing output) when the event occurred (T0). This is the *RampMW* Sustained adjustment:

> *RampMW Sustained* = ($MW_{(T-4)}$ – $MW_{(T-60)}$) x 0.821
>
> *Note: The terminology "*$MW_{(T-4)}$*" refers to MW output at 4 seconds before the Frequency Measurable Event (FME) occurs at (T0).*

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T0.

The formula is then modified by a factor to indicate where the generator would have been at T+46, had the event not occurred: the "*RampMW Sustained*." It does this by multiplying the MW change over 56 seconds before the event ($\mathrm{MW}_{(T-4)}$ – $\mathrm{MW}_{(T-60)}$) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46 \text{ seconds}}{56 \text{ seconds}}$ or 0.821.

Expected Sustained Primary Frequency Response (*ESPFR*) Calculations

The Expected Sustained Primary Frequency Response ($ESPFR_{Final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

This $ESPFR_{Final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, High Sustainable Limit (HSL), Low Sustainable Limit (LSL) and actual frequency. It then allows for adjusting the value to compensate for the various types of Limiting Factors each generating units / generating facilities may have and any Power Augmentation Capacity (PA Capacity) that may be included in the HSL/LSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For all generator types, the ideal Expected Sustained Primary Frequency Response ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ is the same $EPFR_{pre\text{-}perturbation}$ value used in the Initial measure of R9.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60 Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + Deadband_{Max})}{(Droop_{Max} \times 60 - Deadband_{Max})} \times (HSL - PA\ Capacity) \times (-1)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - Deadband_{Max})}{(Droop_{Max} \times 60 - Deadband_{Max})} \times (HSL - PA\ Capacity) \times (-1)\right]$$

Capacity and Net Dependable Capability (NDC) are used interchangeably and the term Capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. The capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original HSL. Other generator types may also have Power Augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO is required to provide the BA with documentation and identify conditions when this augmentation is in service.

$ESPFR_{Final}$ for Combustion Turbines and Combined Cycle Facilities

$$ESPFR_{Final} = ESPFR_{ideal} + (HZ_{T+46} - 60.0) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZ_{T+46}. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

$ESPFR_{Final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PACapacity) \times Steam\ Flow\ Change\ Factor$$

where:

$$Steam\ Flow\ \ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{HSL}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The Rated Throttle Pressure and the Pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of Pressure and MW breakpoints where the Rated Throttle Pressure and MW output where Rated Throttle Pressure is achieved is the first pair and the Minimum Throttle Pressure and MW output where the Minimum Throttle Pressure is achieved as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource and ranges between 0.0 and 0.6 psig per MW change when responding during a FME. The GO can measure the drop in throttle pressure, when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the Steam Flow Change Factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between ESPFR and ASPFR (resulting in the highest $P.U.SPFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$ESPFR_{Final}$ for Other Generating Units/Generating Facilities

$$ESPFR_{Final} = ESPFR_{ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) from its applicable operating limit (high or low) at the time an FME occurs (pre-perturbation), then that resource's Primary Frequency Response performance is not evaluated for that FME.

For frequency deviations below 60 Hz ($Hz_{Post\text{-}perturbation}$ < 60 if:

$$MW_{pre-perturbation} \geq min[([HSL - PA\ Capacity]\ x\ 0.98),\ ([HSL - PA\ Capacity] - 5\ MW)]$$

then Primary Frequency Response is not evaluated for this FME.

For frequency deviations above 60 Hz ($Hz_{Post\text{-}perturbation}$ > 60, if:

$$MW_{pre-perturbation} \leq max[\big(LSL + ([HSL - PA\ Capacity]\ x\ 0.02)\big), (LSL + 5\ MW)]$$

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:

Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), but with Expected Primary Frequency $Response_{final}$ greater than the actual margin available.

1. The $P.U.PFR_{Resource}$ will be set to the greater of 0.75 or the calculated $P.U.PFR_{Resource}$ if all of the following conditions are met:
    a. The generating unit/generating facility's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (HSL less PA Capacity) and greater than 5 MW; and

b. The Expected Primary Frequency Response$_{Final}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and

c. The generating unit/generating facility's APFR$_{adj}$ response is in the correct direction.

2. When calculation of the P.U.PFR$_{Resource}$ uses the resource's (HSL less PA Capacity) as the maximum expected output, the calculated P.U. PFR$_{Resource}$ will not be greater than 1.0.

3. When calculation of the P.U.PFR$_{Resource}$ uses the resource's LSL as the minimum expected output, the calculated P.U.PFR$_{Resource}$ will not be greater than 1.0.

4. If the APFR$_{Adj}$ is in the wrong direction, then P.U.PFR$_{Resource}$ is 0.0.

5. These caps and limits apply to both the Initial and Sustained Primary Frequency Response measures.

Revision History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	Dec. 2012	Revised after field trial to reflect new sustained PFR approach	

[4] In this circumstance, the EPFR$_{final}$ is set to the operating margin based on HSL (adjusted for any augmentation capacity) for the purpose of calculating P.U.PFR$_{Resource}$.

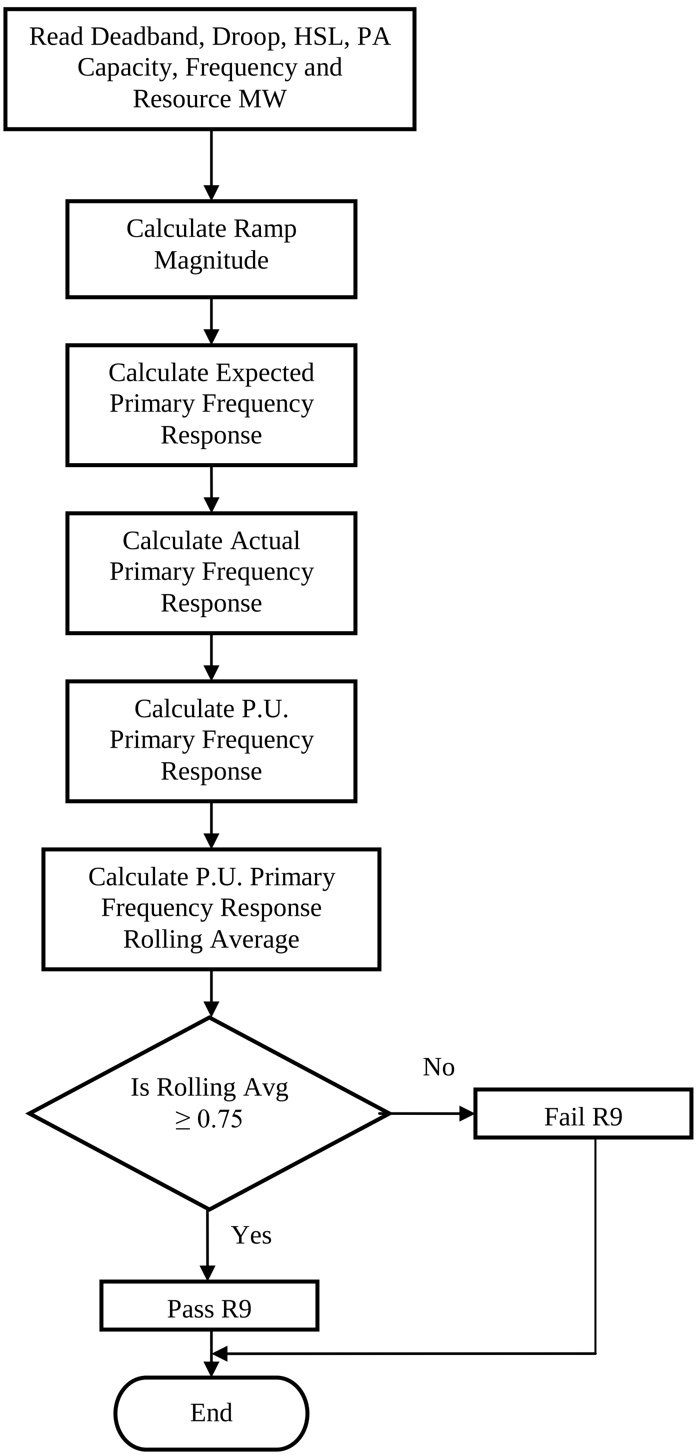
Attachment 11-005

Attachment A to
Primary Frequency Response Reference Document

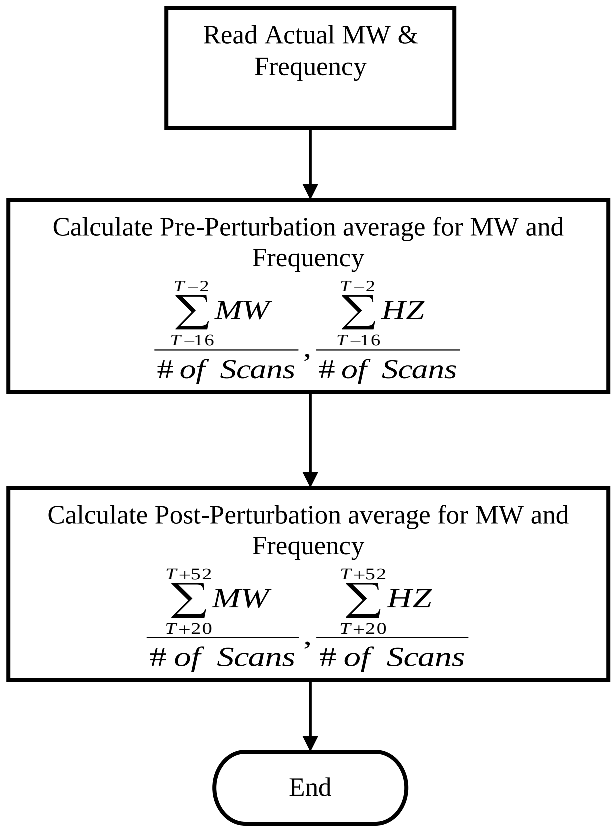
Initial Primary Frequency Response Methodology for
BAL-001-TRE-1

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

$$\text{Ramp Magnitude} = (MW_{T-4} - MW_{T-60})*0.59$$

End

$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

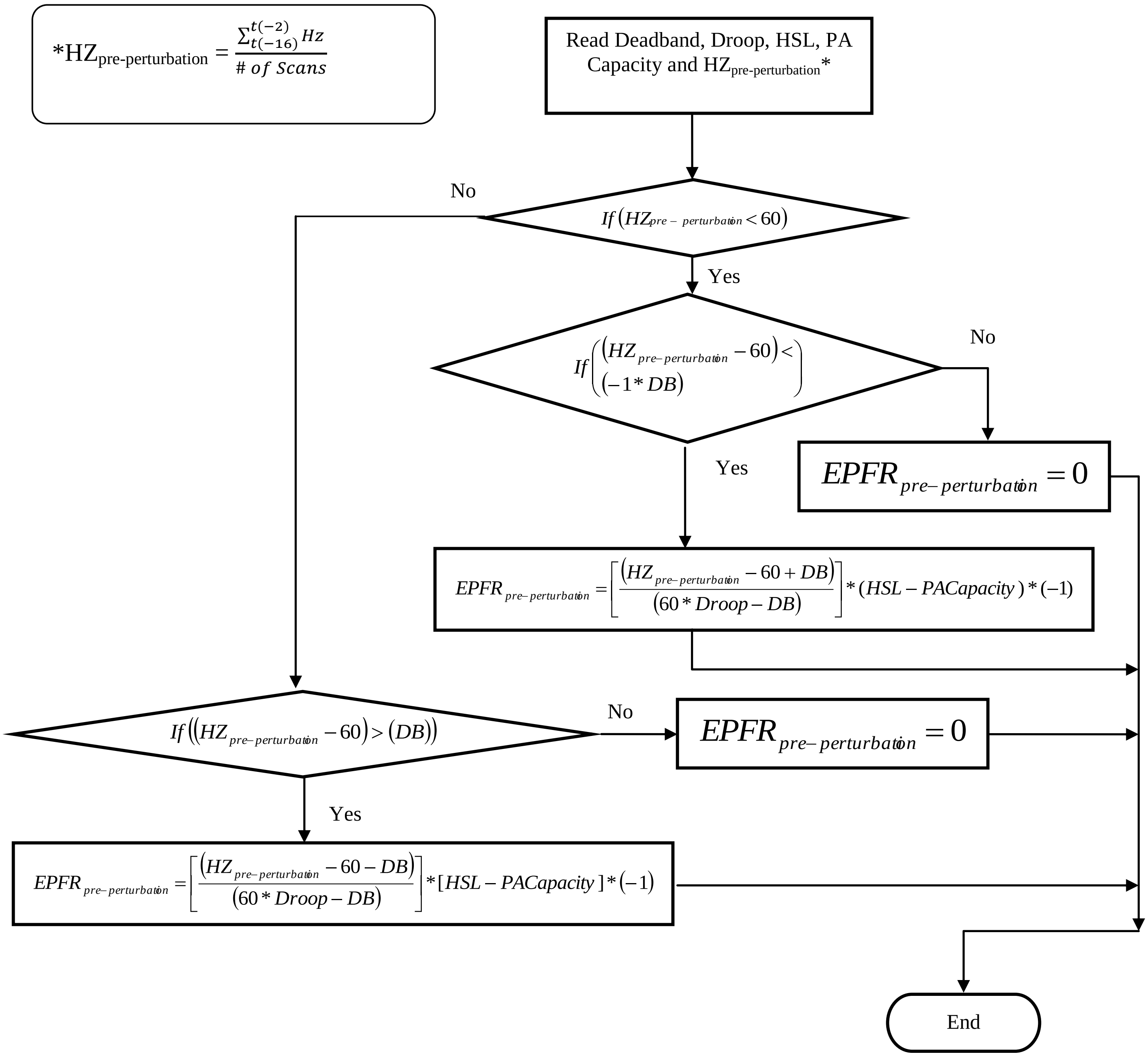
Actual Primary Frequency Response ($APFR_{adj}$)

$$APFR_{ADJ} = MW_{post\text{-}perturbation} - MW_{pre\text{-}perturbation} - \text{Ramp Magnitude}$$

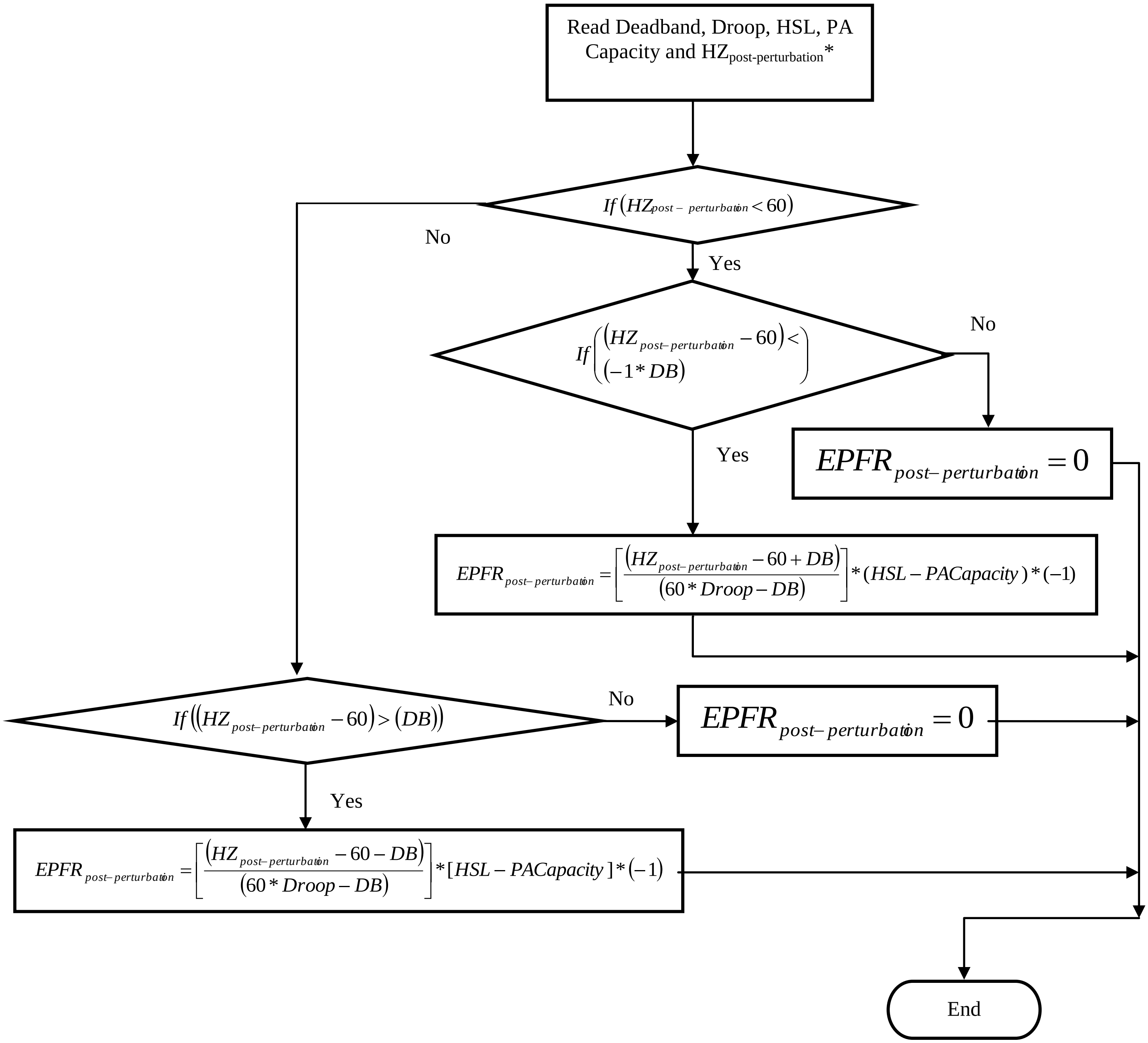
End

Expected Primary Frequency Response Calculation

Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



$$*\mathrm{HZ}_{\text{post-perturbation}} = \frac{\sum_{t(+20)}^{t(+52)} Hz}{\#\ of\ Scans}$$



$$\boldsymbol{EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}}$$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

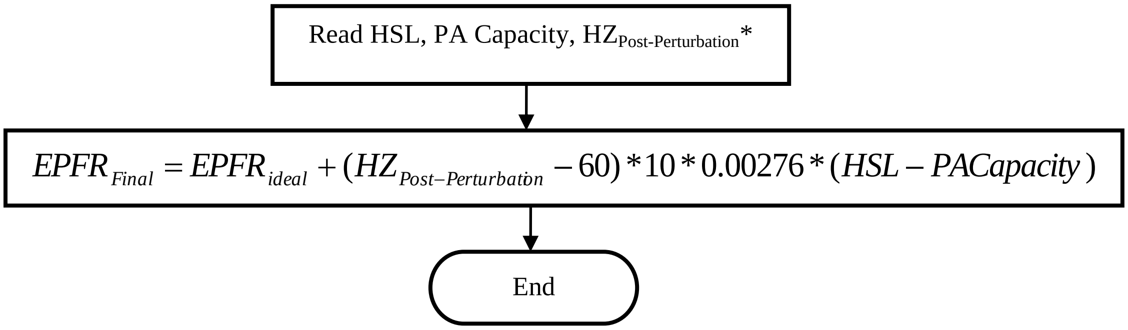
$$MW_{Adj} = EPFR_{ideal} * \frac{K}{Rated\ Throttle\ Pressure} * HSL * Steam\ Flow\ Change\ Factor * -1$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

$$EPFR_{Final} = (EPFR_{Ideal} + MW_{Adj}) \text{ x } \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

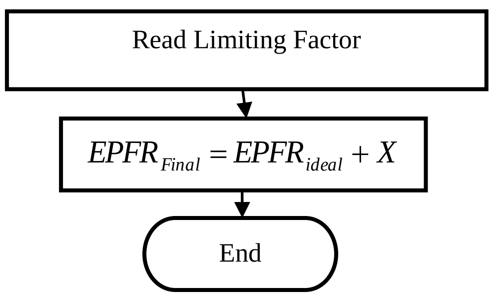
End

Adjustment for Combustion Turbines and Combined Cycle Facilities



0.00276 is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

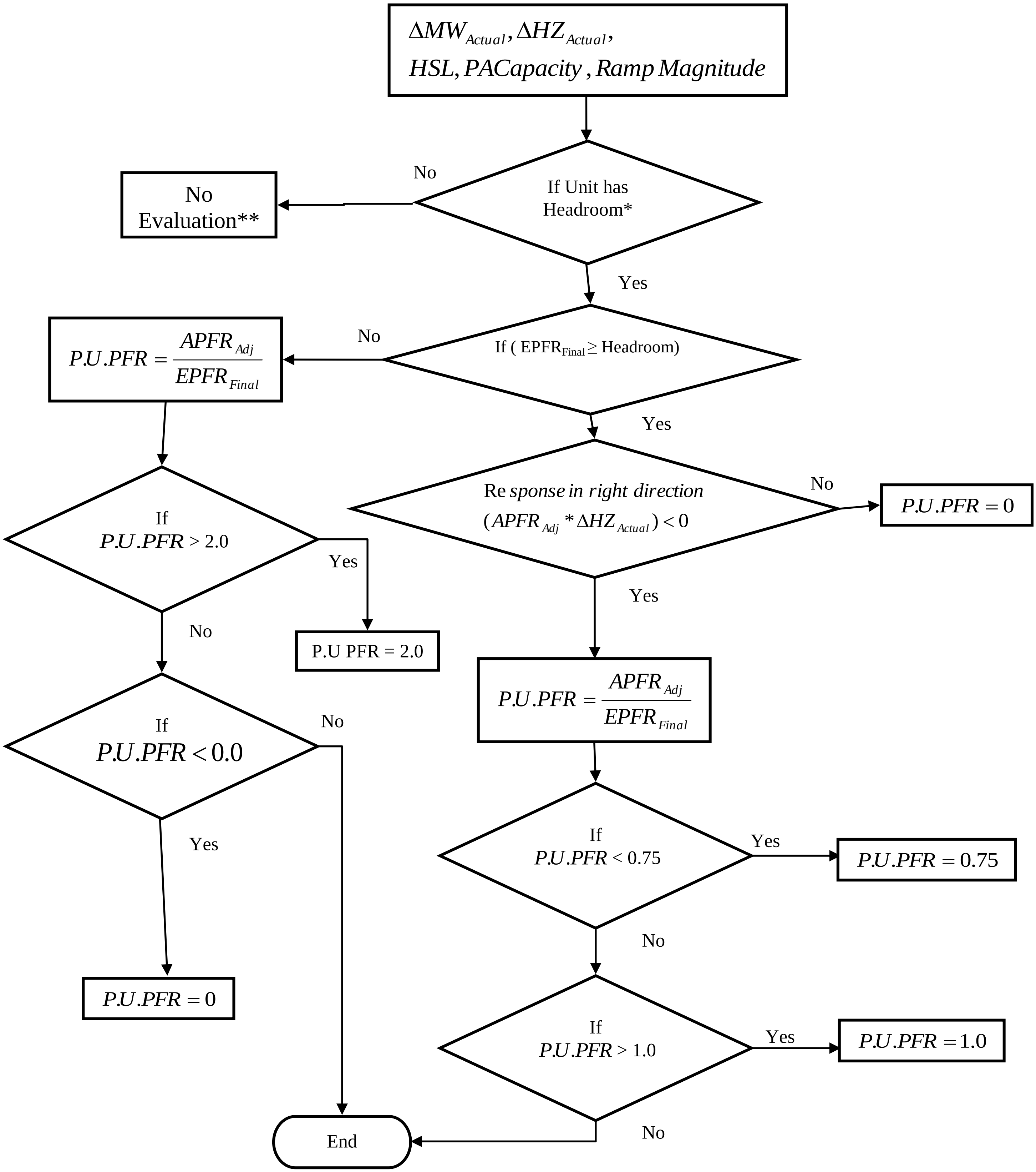
Adjustment for Other Units



$$*HZ_{Post\text{-}Perturbation} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Initial Primary Frequency Response Calculation



$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom*
No
No Evaluation**
Yes
If ($EPFR_{Final} \geq$ Headroom)
No
$P.U.PFR = \frac{APFR_{Adj}}{EPFR_{Final}}$
Yes
$Response\ in\ right\ direction$
$(APFR_{Adj} * \Delta HZ_{Actual}) < 0$
No
$P.U.PFR = 0$
Yes
$P.U.PFR = \frac{APFR_{Adj}}{EPFR_{Final}}$
If $P.U.PFR > 2.0$
Yes
P.U PFR = 2.0
No
If $P.U.PFR < 0.0$
No
Yes
$P.U.PFR = 0$
If $P.U.PFR < 0.75$
Yes
$P.U.PFR = 0.75$
No
If $P.U.PFR > 1.0$
Yes
$P.U.PFR = 1.0$
No
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

$$\boxed{\text{Headroom} = \text{HSL} - \text{PA Capacity} - \text{MW}_{T-2}}$$

For high frequency events:

$$\boxed{\text{Headroom} = \text{MW}_{T-2} - \text{LSL}}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

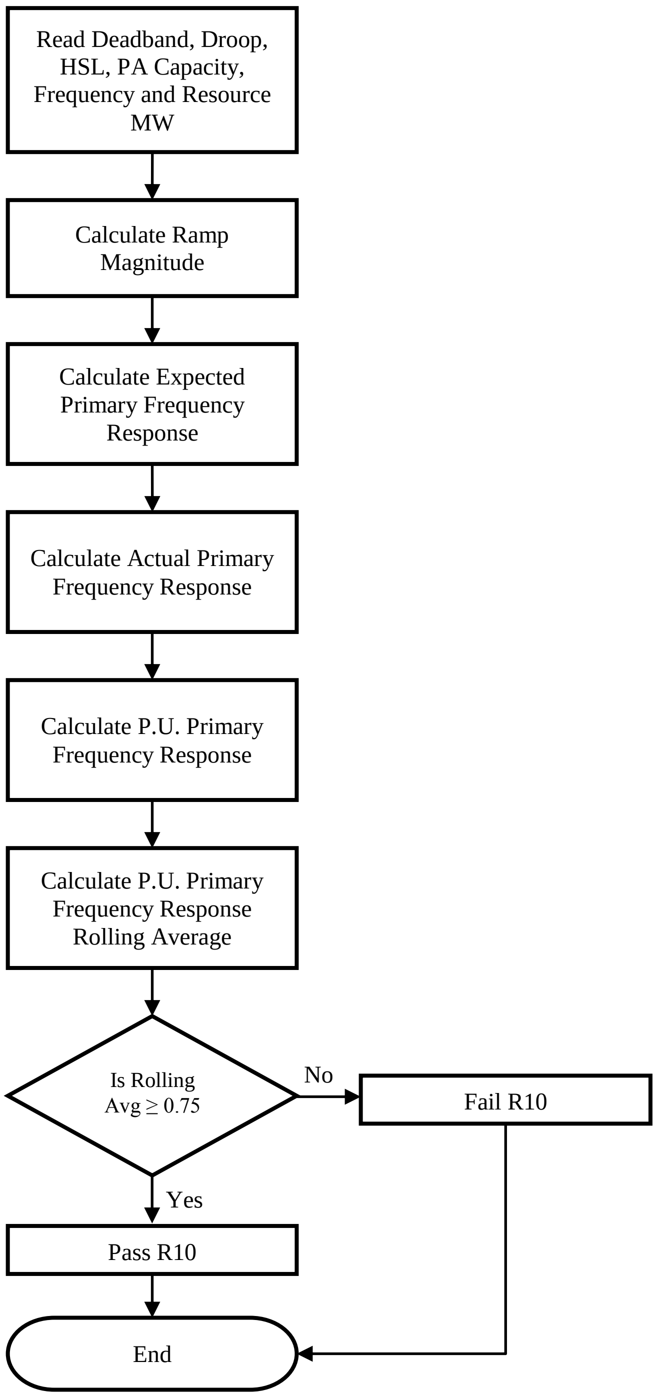
T = Time in Seconds

Attachment 11-006

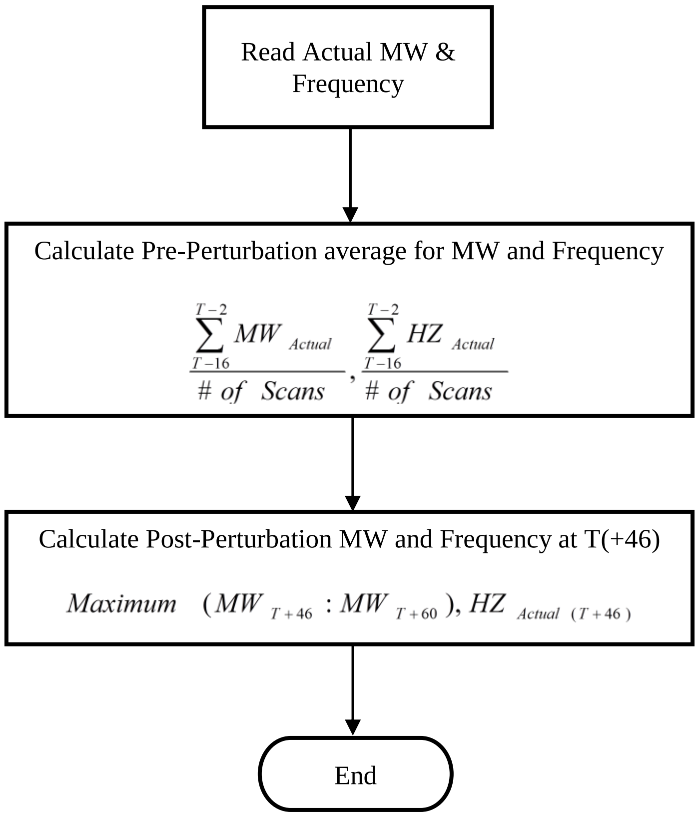
Attachment B to
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for BAL-001-TRE-1

Primary Frequency Response Measurement and Rolling Average Calculation – Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation – Sustained

$$\text{Ramp Magnitude}_{\text{Sustained}} = (MW_{T-4} - MW_{T-60}) * 0.821$$

$\downarrow$

End

$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 adjusts this full minute ramp to represent the ramp the generator would have changed the system had it been allowed to continue on its ramp to T+46 unencumbered.

Actual Sustained Primary Frequency Response ($ASPFR_{adj}$)

For low frequency events:

$$ASPFR_{ADJ} = \text{Maximum}(MW_{T+46} : MW_{T+60}) - \text{Ramp Magnitude}_{\text{Sustained}}$$

$\downarrow$

End

For high frequency events:

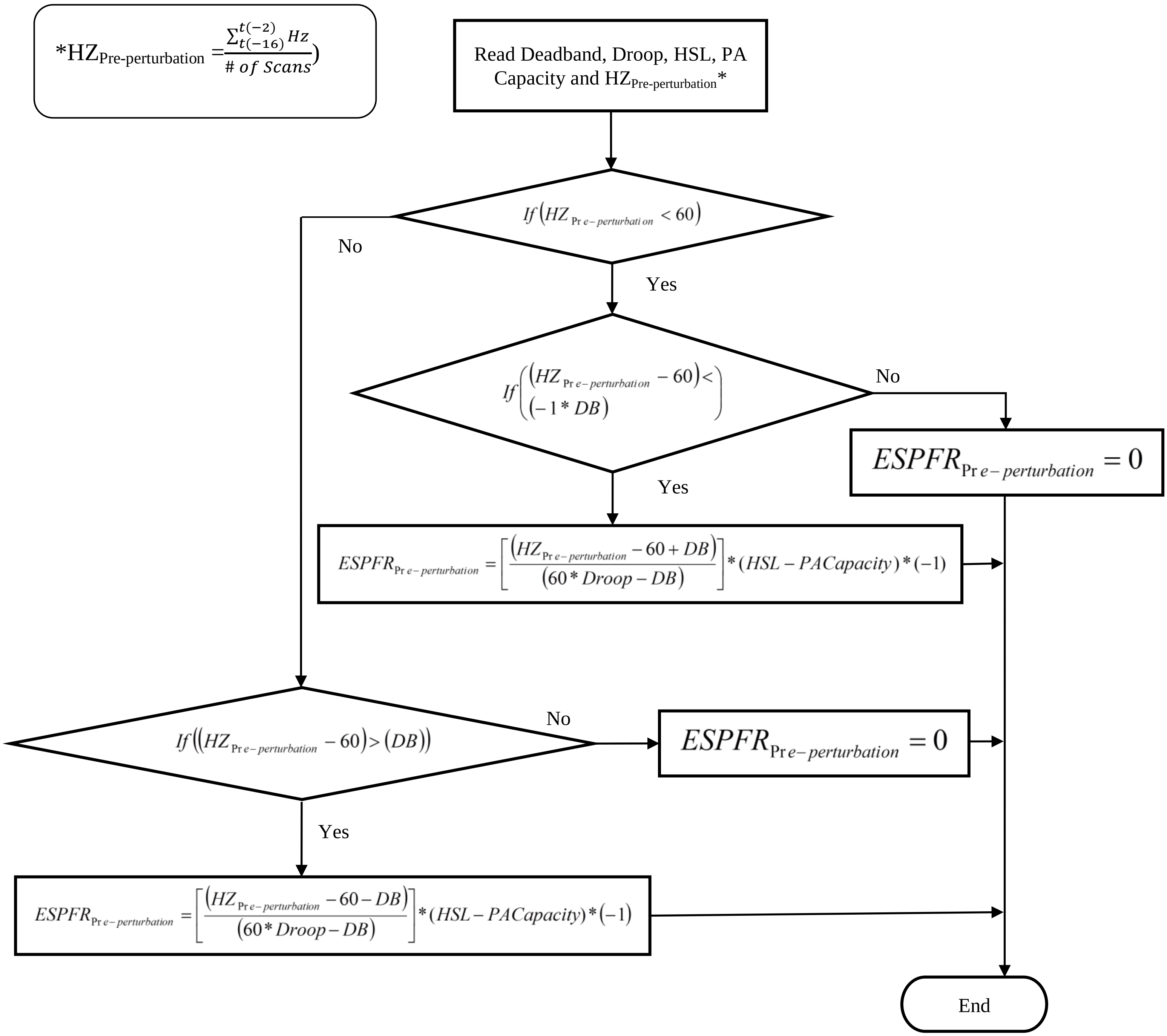
$$ASPFR_{ADJ} = \text{Minimum}(MW_{T+46} : MW_{T+60}) - \text{Ramp Magnitude}_{\text{Sustained}}$$

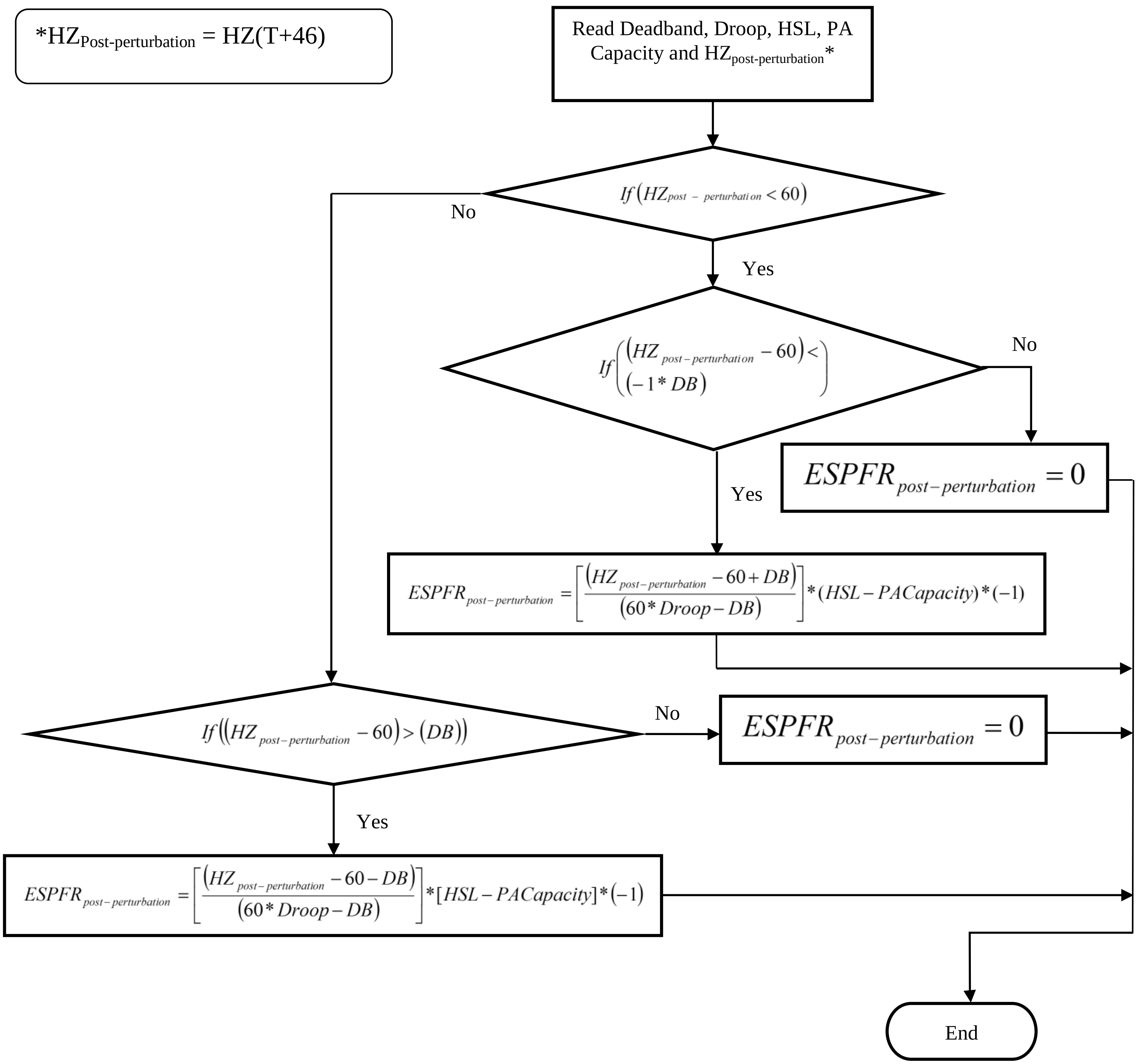
$\downarrow$

End

Expected Sustained Primary Frequency Response Calculation

Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.





$$\boxed{ESPFR_{ideal} = ESPFR_{\ post-perturbation} - ESPFR_{pre-perturbation}}$$

Adjustment for Steam Turbine

$MW_{Post\text{-}perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{Post\text{-}perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$MW_{Adj} = ESPFR_{ideal} * \frac{K}{Rated\ Throttle\ Pressure} * HSL * Steam\ Flow\ Change\ Factor * -1$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

$$ESPFR_{Final} = (ESPFR_{Ideal} + MW_{Adj}) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

End

Adjustment for Combustion Turbine and Combined Cycle Facilities

Read HSL, PA Capacity, $HZ_{Post\text{-}Perturbation}$*

↓

$$ESPFR_{Final} = ESPFR_{ideal} + (HZ_{Post-Perturbation} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

↓

End

0.00276 is MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Adjustment for Other Units

Read Limiting Factor

↓

$$ESPFR_{Final} = ESPFR_{ideal} + X$$

↓

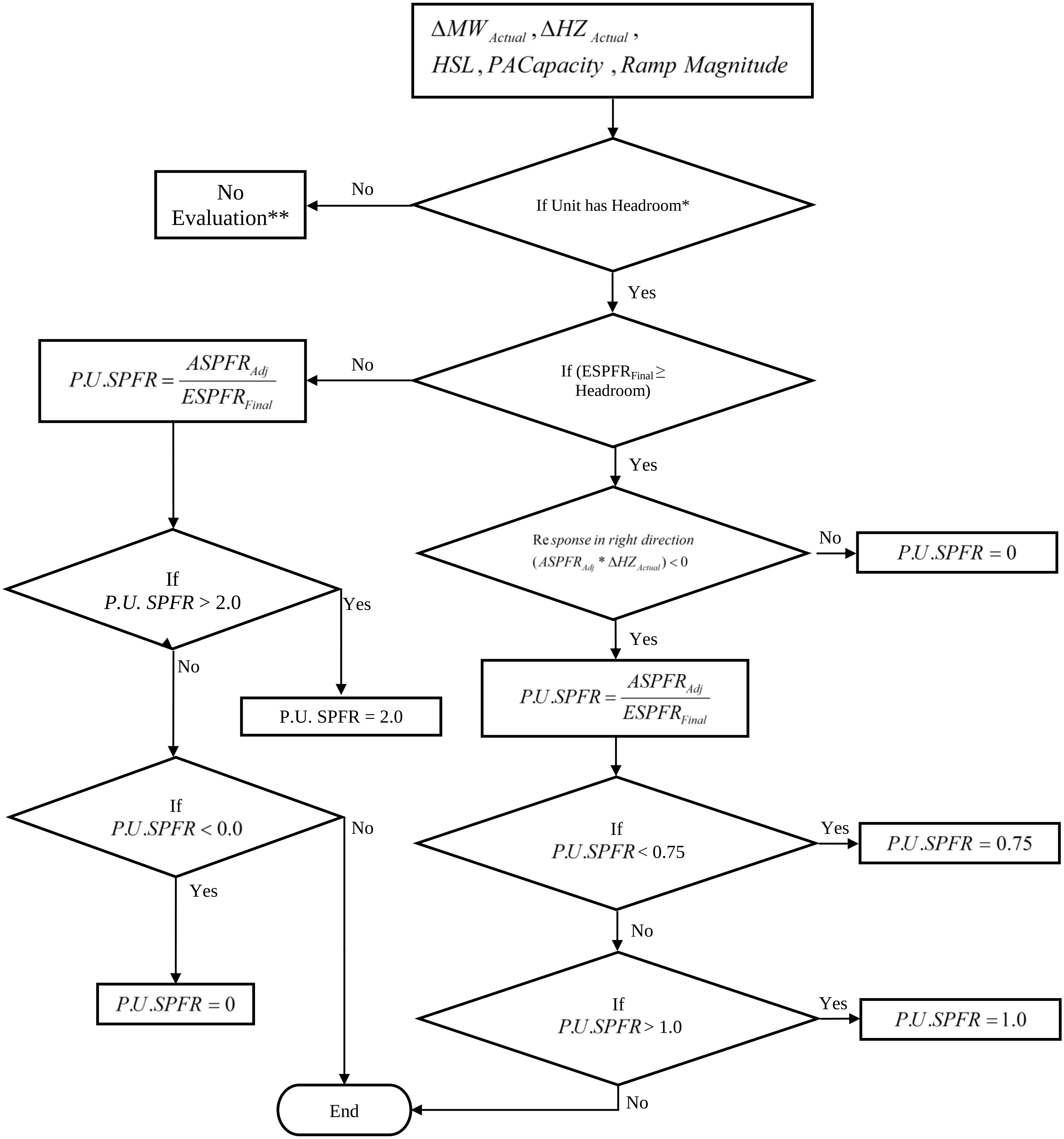
End

*HZ_{Actual} = HZ(T+46)

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Sustained Primary Frequency Response Calculation

*HZ_{Actual} = HZ(T+46)


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom*
No
No Evaluation**
Yes
If ($ESPFR_{Final} \geq$ Headroom)
No
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
Yes
$Response\ in\ right\ direction$
$(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
No
$P.U.SPFR = 0$
If
$P.U.\ SPFR > 2.0$
Yes
No
P.U. SPFR = 2.0
Yes
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
If
$P.U.SPFR < 0.0$
No
Yes
$P.U.SPFR = 0$
If
$P.U.SPFR < 0.75$
Yes
$P.U.SPFR = 0.75$
No
If
$P.U.SPFR > 1.0$
Yes
$P.U.SPFR = 1.0$
No
End

* Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

$$\boxed{\text{Headroom} = \text{HSL} - \text{PA Capacity} - \text{MW}_{T\text{-}2}}$$

For high frequency events:

$$\boxed{\text{Headroom} = \text{MW}_{T\text{-}2} - \text{LSL}}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

Attachment 13-001

Consideration of Comments

Regional Reliability Standard BAL-001-TRE-01

NERC thanks all commenters who submitted comments on regional reliability standard BAL-001-TRE-01 Primary Frequency Response in the ERCOT Region. The standard was posted for a 45-day comment period from May 31, 2013 through July 15, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 3 sets of responses, including comments from 4 different people from 3 companies representing 4 of the 10 of the Industry Segments as shown in the table on the page 3 of this report.

All comments submitted may be reviewed in their original format on the regional standards development page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Colby Bellville	Duke Energy Generation Services					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Carter		ERCOT	5

				1	2	3	4	5	6	7	8	9	10
2.	Individual	Marcus Pelt	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	X		X		X	X				
3.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

Summary Consideration: N/A

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	AEP is confident that TRE did indeed follow their internal procedures in developing this regional standard. Though we were not able to participate in this project's commenting periods (AEP was apparently not a part of the original ballot pool for this project), AEP looks forward to working with TRE to ensure that we don't miss out on future opportunities to contribute.
Response: Thank you for your comment.		
Duke Energy Generation Services	Yes	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Summary Consideration: N/A

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP is not aware of any adverse impacts posed to reliability or commerce, in a neighboring region or interconnection, as a result of this proposed standard.
Response: Thank you for your comment.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration: N/A

Organization	Yes or No	Question 3 Comment
American Electric Power	No	AEP is not aware of any serious and substantial threats posed to public health, safety, welfare, or national security as a result of this proposed standard.
Response: Thank you for your comment.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	No	

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration: See Responses below.

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is not aware of any serious and substantial burden posed on competitive markets within the interconnection that is not necessary for reliability as a result of this proposed standard.
Response: Thank you for your comment.		
Duke Energy Generation Services	Yes	Duke Energy believes that the implementation of this standard will require substantial upgrades and costs to wind farm control systems of older plants in order to enable the frequency response feature. Some older wind turbines are incapable of meeting this proposed requirement without major SCADA and turbine hardware upgrades due to the pitch control, generator type, and converters used in these systems. If these major upgrades are not realized during the design and build phase of a project, some owners may be unable to absorb the costs necessary for compliance to this standard. Since primary over frequency response is not a paid service in the ERCOT market at this time, there is the potential for lost revenue associated with lost MW's produced by a generating plant when responding to an over frequency event. For the above stated reasons, Duke Energy believes that the proposed standard poses a serious and substantial burden on competitive markets.
Response: Thank you for your comment. These issues were considered extensively during the development of this standard and		

Organization	Yes or No	Question 4 Comment
addressed in several ways. First, note that the applicability section states "Any generators that are not required by the BA to provide primary frequency response are exempt from this standard." This was added to address concerns of wind generators for which compliance is not technically feasible, so that the standard is only applicable to the generators that have similar obligations under the ERCOT market rules. Second, standard drafting team members worked with wind industry representatives and wind generation vendors to ensure that most wind projects will be able to meet the requirements. Finally, a generous implementation period is provided to give entities plenty of time to make changes necessary to comply with this standard.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	Possibly. If an entities speed control equipment is not currently capable of being programmed as specified in the proposed standard, it should be allowed to be exempt from the requirements rather than required to make investments to alter the functional capabilities of the existing equipment.
Response: Thank you for your comment. A generous implementation period is provided to give entities plenty of time to make changes necessary to comply with this standard, as it was recognized that some generators will need to adjust, reprogram, or replace related equipment. Most generation facilities should be able to comply with the requirements without overly burdensome changes to their equipment, particularly considering that ERCOT market rules already require most generators to provide primary frequency response. Finally, note that in Requirements 6.1 and 6.2 the BA is authorized to allow a GO to apply alternate deadband and droop settings in appropriate circumstances.		

5. **Does the proposed regional reliability standard meet at least one of the following criteria? - The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard - The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard - The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration: N/A

Organization	Yes or No	Question 5 Comment
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard - there is no existing continent wide standard specifying the Governor setting or performance criterion specification.
Response: Thank you for your comment.		
American Electric Power	Yes	

END OF REPORT

Attachment 13-002

Primary Frequency Response in the ERCOT Region—BAL-001-TRE-1

Action

Approve the following standard document and direct staff to file with applicable regulatory authorities:

- **Reliability Standard BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region**

  [BAL-001-TRE-1-clean]

- **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for BAL-001-TRE-1 [VRFs and VSLs are available in the Standard above]**

- **Implementation Plan for BAL-001-TRE-1**

  [BAL-001-TRE-1 Implementation Plan]

  - The implementation schedule for BAL-001-TRE-1 requires that entities comply with the requirements in phases over a 30-month period. The 30-month phasing allows the Balancing Authority (BA) and each generating unit/generating facility time to meet the requirements.

- **Definitions**
  The following terms are proposed as regional definitions for the ERCOT region:

  Frequency Measurable Event (FME): An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:

  i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

  or

  ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

  Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

  Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

- **Retirements**
  None

Background

The ERCOT Interconnection was initially given a waiver of BAL-001 Requirement R2. The BAL-001 Reliability Standard's purpose is to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. The purpose of BAL-001, Requirement R2 is to require BAs to operate in such a manner that its Area Control Error is within a specific limit. In FERC Order No. 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9, requiring governors to be in-service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to an FME.

Pertinent FERC Order No. 693 directives

Para 315

As proposed in the NOPR, the Commission directs the ERO to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols. As with other new regional differences, the Commission expects that the ERCOT regional difference will include Requirements, Measures and Levels of Non-Compliance sections.

Summary

BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region was developed to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

As described above, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. This Regional Standard provides requirements that apply primarily to BAs and Generator Owners (GO). The standard drafting team (SDT) determined that obtaining adequate individual generating unit performance is the key to ensuring sufficient overall Frequency Response in the Interconnection.

- In BAL-001-TRE-1, the BA, ERCOT, is required to identify FME, calculate the Primary Frequency Response of each resource in the Region, calculate the Interconnection minimum Frequency Response, monitor the actual Frequency Response of the Interconnection, and take action to improve Interconnection Frequency Response, if necessary. In addition, GOs are required to use prescribed Governor deadband and droop parameters, operate with governors in-service, and satisfy Primary Frequency Response performance requirements for individual units and facilities.

This Regional Standard does not apply to nuclear-powered generating units, generating units operating in synchronous condenser mode, and generators that are not required by the BA to provide primary frequency response such as some wind-power facilities.

Under this Regional Standard, two unit-specific Primary Frequency Response (PFR) performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0). The details of the calculations involved in determining Primary Frequency Response performance are set forth in the TRE Primary Frequency Response Reference Document.[1]

Requirements R9 and R10 are satisfied if a generating unit or facility provides at least 75 percent of expected Frequency Response performance over a 12-month rolling average. At least eight valid data points are required for a compliance evaluation. Units operating within two percent or 5 MW of their operating limits when an FME occurs are not evaluated.

Standard Development Process

This standard development project was initiated in April 2008 when a Standard Authorization Request was submitted to Reliability Entity (Texas RE) in accordance with Texas RE's FERC-approved Standards Development Process. A SDT was promptly formed and development work commenced. Drafts of the standard were posted for comment in March 2009, February 2010, and October 2010, and the standard was revised based on input received during each comment period. Workshops were also conducted in March 2009 and March 2010 to obtain additional stakeholder input.

After an initial ballot failed to obtain the required 2/3 affirmative vote in September 2011, a Field Trial and Demonstration project was conducted in 2012 that evaluated 28 diverse generating units in accordance with Requirements R9 and R10. The Field Trial evaluated unit-specific Frequency Response performance during FMEs that occurred from June 2011 to June 2012. A number of significant revisions were made in the requirements as a result of lessons learned from the Field Trial.

In the second ballot conducted in February 2013, this Regional Standard was approved by a sector-weighted vote of 80 percent affirmative (over the necessary 2/3 affirmative vote). Every Sector voted to approve the Regional Standard. Thirty-five members of the Texas RE Registered Ballot Body participated in this ballot, representing all sectors, with 12 abstentions (mostly wind-generation entities). The ballot results were accepted and approved by the Texas RE Reliability Standards Committee. The Texas RE Board of Directors approved this Regional Standard at its April 23, 2013 meeting.

Unresolved Minority Issues

None

[1] *See* TRE Primary Frequency Response Reference Document, *available at* http://www.texasre.org/CPDL/03-Primary%20Freq%20Resp%20Reference%20Doc%2012.7.12.pdf.

Additional Information
Links to the project history and related files are included here for reference:

Before July 2010:

[**TRE Reliability Standards Tracking**]

After July 2010:

[**TRE Reliability Standards Tracking**]

Texas RE Project Web Page:

[**TRE - BAL-001-TRE-1: Primary Frequency Response in the ERCOT Region**]

Regional Reliability Standards Under Development

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Texas Reliability Entity (TRE)				
BAL-001-TRE-01	Primary Frequency Response in the ERCOT Region	NERC Board Adopted August 15, 2013	5/31/2013 - 7/15/2013	Info **(1)** Submit Comments Unofficial Comment Form (Word Version) **(2)** BAL-001-TRE-1 **(3)** Implementation Plan **(4)** Reference Document **(5)** Initial Primary Frequency Response Methodology (Att A) **(6)** Sustained Primary Frequency Response Methodology (Att B) **(7)** Comments Received **(8)** Consideration of Comments **(9)**

Regional Reliability Standards Announcement

BAL-001-TRE-01

Comment Period: May 31, 2013 – July 15, 2013

Now available

Proposed Standard for the Texas Reliability Entity (TRE)

TRE has requested NERC to post regional reliability standard BAL-001-TRE-01 – Primary Frequency Response in the ERCOT Region for a 45-day industry review as permitted by the NERC Rules of Procedure.

Instructions

Please use the electronic form to submit comments. The comment form must be completed by 8:00 p.m. ET **July 15, 2013.** If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the regional standards development page.

Background

The TRE BAL Standard: BAL-001-TRE-1 ("TRE Primary Frequency Response in the ERCOT Region Standard") was developed to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

The ERCOT Interconnection was initially given a waiver of BAL-001 R2. In FERC Order 693 the NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event.

This regional standard provides requirements related to identifying Frequency Measureable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

Under this standard, two Primary Frequency Response performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0). In this regional standard the term "resource" is synonymous with "generating unit/generating facility".

Regional Reliability Standards Development Process
Section 300 of the *Rules of Procedure for the Electric Reliability Organization* governs the regional reliability standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Regional Reliability Standard BAL-001-TRE-01

Please **DO NOT** use this form. Please use the electronic form to submit comments on the Regional Reliability Standard BAL-001-TRE-1. Comments must be submitted by **July 15, 2013.** If you have questions please contact Howard Gugel at howard.gugel@nerc.net or Stephen Eldridge at stephen.eldridge@nerc.net.

http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx

Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

BAL-001-TRE-01 was developed to maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

Each **Texas Reliability Entity (TRE)** Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk electric system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform under normal and abnormal conditions as defined in the NERC Standards.
- The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

- The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

The proposed **TRE** Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, the **TRE** Regional Reliability Standard obligates the **TRE** to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

BAL-001-TRE-01 Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.1 This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months.

R3. The BA shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available.

R4. After each calendar month in which one or more FMEs occurs, the BA shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

R6. Each GO shall set its Governor parameters as follows:

6.1 Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	**Max. Deadband**
Steam Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.017 Hz

6.2 Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	**Max. Droop % Setting**
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of a combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

For 5% Droop: Slope = ____________________

For 4% Droop: Slope = ____________________

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

R7 Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service.

R8. Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor.

R9 Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

R10 Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No
   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No
   Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No
   Comments:

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

☐ Yes
☐ No
Comments:

5. Does the proposed regional reliability standard meet at least one of the following criteria?
- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

☐ Yes
☐ No
Comments:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR submitted April 15, 2008.
SAR posted for comment on April 24, 2008.
SAR approved May 27, 2008.
Drafting Team nominated and selected in June 2008.
First posting of standard on March 16, 2009.
Drafting Team held technical workshop on March 31, 2009.
Second posting of standard on February 12, 2010.
Drafting Team held technical workshop on March 3, 2010.
Drafting Team held a performance evaluation workshop on August 6, 2010.
Third posting requested at RSC Meeting September 1, 2010.
Third posting ended on November 11, 2010.
Drafting Team reviewed and revised the Standard on May 5-6, 2011.
Texas RE staff received comments from NERC Staff review and revised standard draft to address comments (5/24/11).
Drafting Team finalized Standard and approved final version on July 25, 2011.
RSC approved the Standard for ballot on August 5, 2011.
First ballot conducted Sept. 9-23, 2011 and failed to obtain 2/3 affirmative vote.
Field Trial conducted ending June, 2012. Specific members of the drafting team evaluated 28 various types of resource's performance during 35 FMEs occurring over approximately one year.
Drafting Team provided feedback to each field trial participant in August and September, 2012.
Drafting Team revised the Standard based on results of the field trial in September and October, 2012.

Description of Current Draft

The drafting team has revised the draft based on comments received with the first ballot and Field Trial results. In particular the sustained performance measure was changed to examine a point in time about one minute following the FME, rather than a period covering several minutes after the FME. This draft will be finalized and posted for ballot in late 2012.

Future Development Plan:

Anticipated Actions	Anticipated Date
Respond to comments and field trial/revise draft	July to December 2012
Present revised draft to RSC	January 2013
Second Ballot	January-Feb. 2013
TRE Board Adopt (Tentative)	April 2013

NERC Submit (Tentative)	May 2013
FERC Approval (Tentative)	??

Definitions of Terms Used in Standard

Frequency Measurable Event (FME): An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:

i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).

or

ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).

Governor: The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

Primary Frequency Response (PFR): The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region

2. **Number:** BAL-001-TRE-1

3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.

4. **Applicability:**

   4.1. Functional Entities:

   1. Balancing Authority (BA)
   2. Generator Owners (GO)
   3. Generator Operators (GOP)

   4.2. Exemptions:

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.

   4.2.3 Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

5. **Background:**

The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 5.9. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (that starts at t(0)).

> Note that in Project 2010-14.1, NERC proposes to eliminate the CPS2 measure, and there are no ERCOT-specific provisions in the new proposed standards.

This regional standard provides requirements related to identifying Frequency Measureable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

Under this standard, two Primary Frequency Response performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual

response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this regional standard the term "resource" is synonymous with "generating unit/generating facility".

6. (**Proposed) Effective Date:**

After final regulatory approval and in accordance with the 30-month Implementation Plan to allow the BA and each generating unit/generating facility time to meet the requirements. See attached Implementation Plan (Attachment 1).

B. Requirements

R1. The BA shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the BA shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M1. The BA shall have evidence it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The BA shall calculate the Primary Frequency Response of each generating unit/generating facility in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months.

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the GO by the end of the month in which they were completed.

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]

M2. The BA shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility monthly as required in Requirement R2.

[1] The Primary Frequency Response Reference Document contains the calculations that the BA will use to determine Primary Frequency Response performance of generating units/generating facilities. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

R3. The BA shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available.

[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

M3. The BA shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The BA shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. After each calendar month in which one or more FMEs occurs, the BA shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month.

R4 Example: If there is one (or more) FME in April, the BA must determine and publish the rolling average by the end of May. The rolling average will include the last six FMEs before the end of April.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M4. The BA shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the BA shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M5. The BA shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each GO shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the BA.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities	+/- 0.017 Hz

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the BA.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Nuclear	5%
Coal and Lignite	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine (Simple Cycle)	5%
Steam Turbine (Combined Cycle)*	5%
Diesel	5%
Wind Powered Generator	5%
DC Tie Providing Ancillary Services	5%
Renewable (Non-Hydro)	5%

*Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

where MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

M6. Each GO shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

R7. Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service.

[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]

M7. Each GO shall have evidence that it notified the GOP as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. Each GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor.

[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]

M8. Each GOP shall have evidence that it notified the BA within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9 measures *initial* unit PFR performance (A-value to B-value). This requirement specifies a certain level of average measured performance over a 12-month period.

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each GO shall have documented evidence of any FMEs where the generating unit performance should be excluded from the rolling average calculation.

R10 measures *sustained* unit PFR performance during the period t(46) to t(60). This requirement specifies a certain level of average measured performance over a 12-month period.

R10. Each GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3. A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M10. Each GO shall have evidence that each of its generating units/generating facilities achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each GO shall have documented evidence of any Frequency Measurable Events where generating unit performance should be excluded from the rolling average calculation.

C. Compliance

1. Compliance Enforcement Authority

Texas Reliability Entity

2. Compliance Monitoring Period and Reset Time Frame

2.1. If a generating unit/generating facility completes a mitigation plan and implements corrective action to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

3. Data Retention

3.1. The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The BA shall retain a list of identified Frequency Measurable Events and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The BA shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The BA shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The BA shall retain all data and calculations relating to the Interconnection’s Frequency Response, and all evidence of actions taken to increase the Interconnection’s Frequency Response, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each GOP shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each GO shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

4. Compliance Monitoring and Assessment Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

D. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The BA reported an FME more than 14 days but less than 31 days after identification of the event.	The BA reported an FME more than 30 days but less than 51 days after identification of the event.	The BA reported an FME more than 50 days but less than 71 days after identification of the event.	The BA reported an FME more than 70 days after identification of the event.
R2	The BA submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The BA submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The BA submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The BA failed to submit a monthly report within 90 days after the end of the reporting month.
R3	The BA did not make the calculation and criteria for determination of the IMFR publicly available.	The BA did not make the IMFR publicly available.	The BA did not calculate the IMFR for the following year in December.	The BA did not calculate the IMFR for a calendar year.
R4	N/A	N/A	The BA did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The BA did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.

R5	N/A	N/A	N/A	The BA did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7	N/A	N/A	N/A	The GO operated with its Governor out of service and did not notify the GOP upon discovery of its Governor out of service.
R8	The GOP notified the BA of a change in Governor status between 31 minutes and one hour after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 1 hour but within 4 hours after the GOP was notified of the discovery of the change.	The GOP notified the BA of a change in Governor status more than 4 hours but within 24 hours after the GOP was notified of the discovery of the change.	The GOP failed to notify the BA of a change in Governor status within 24 hours after the GOP was notified of the discovery of the change.
R9	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A GO's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A GO's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

E. Associated Documents

1. Attachment 1 – Implementation Plan.
2. Attachment 2 – Primary Frequency Response Reference Document, including Flow Charts A and B.
    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9 and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.
    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/2012	Approved by SDT for submission to Texas RE RSC for approval to post for second regional ballot	Changed sustained measure from average over event recovery period to point at 46 seconds after SME, and other changes to respond to field trial results, comments and corrections.

BAL-001-TRE-1

Attachment 1

Implementation Plan for Regional Standard BAL-001-TRE-1, Primary Frequency Response in the ERCOT Region

Prerequisite Approvals:
None

Revisions to Approved Standards and Definitions:
None

New Definitions:
- Frequency Measurable Event (FME)
- Governor
- Primary Frequency Response (PFR)

Compliance with the Standard

The following entities are responsible for being compliant with requirements of BAL-001-TRE-1:
- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)

- Exemptions:
  - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-01.
  - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-01.
  - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
The Effective Date of this standard shall be the first day of the first calendar quarter after final regulatory approval. Registered Entities must be compliant with the Requirements in accordance with the 30-month Implementation Plan set forth below.

- <u>12 months after Effective Date</u>
  - The BA must be compliant with Requirement R1
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R6 (if >1 unit/facility)
  - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R7 (if >1 unit/facility)
  - The GOP must be compliant with Requirement R8

- <u>18 months after Effective Date</u>
  - The BA must be compliant with Requirements R2, R3, R4, and R5
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R6
  - 100% of the GO's generating units/generating facilities must be compliant with Requirement R7

- <u>24 months after Effective Date</u>
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R9 (if >1 unit/facility)
    - At least 50% of the GO's generating units/generating facilities must be compliant with Requirement R10 (if >1 unit/facility)

- <u>30 months after Effective Date</u>
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R9
    - 100% of the GO's generating units/generating facilities must be compliant with Requirement R10

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-1
Requirements R2, R9 and R10
Performance Metric Calculations

I. Introduction

This Primary Frequency Response Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities following Frequency Measurable Events (FMEs) in accordance with Requirements R2, R9 and R10. Flowcharts in Attachment A (Initial PFR) and Attachment B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Primary Frequency Response Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available[1] for reference and use in understanding and performing these calculations.

This Primary Frequency Response Reference Document is not considered to be a part of the regional standard. This document will be maintained by Texas RE and will be subject to modification as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.

Revision Process: The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Reliability Standards Committee (RSC) for consideration. The revision request will be posted in accordance with RSC procedures. The RSC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The RSC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

> **High Sustained Limit (HSL)** for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility.
>
> **Low Sustained Limit (LSL)** for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy production capability of a generating unit/generating facility.

In this regional standard, the term “resource” is synonymous with “generating unit/generating facility”.

[1] These spreadsheets are available at www.TexasRE.org.

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12 month period (or 8 event minimum) to establish whether a resource is compliant with Requirement R9.

This process calculates the initial Per Unit Primary Frequency Response of a resource [P.U. $PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$), adjusted for the pre-event ramping of the unit, and the Final Expected Primary Frequency Response ($EPFR_{Final}$) as calculated using the Pre-perturbation and Post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of resource, the initial Per Unit Primary Frequency Response [P.U.$PFR_{Resource}$] for any Frequency Measurable Event (FME).

Each GO may submit to the BA unit-specific information used by the BA in this requirement to calculate initial PFR performance for each generating unit/generating facility.

<u>Initial Primary Frequency Response performance requirement:</u>

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

where P.U. $PFR_{Resource}$ is the per unit measure of the initial Primary Frequency Response of a resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{Final}}$$

where P.U. $PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The Adjusted Actual Primary Frequency Response ($APFR_{Adj}$) and the Final Expected Primary Frequency Response ($EPFR_{Final}$) are calculated as described below.

EPFR Calculations use droop and deadband values as stated in Requirement R6 with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation droop will be 5.78%.[2]

Actual Primary Frequency Response ($APFR_{adj}$)

The adjusted Actual Primary Frequency Response ($APFR_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} \quad = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

where:

Pre-perturbation Average MW: Actual MW averaged from t(-16) to t(-2)

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{\#\ Scans}$$

Post-perturbation Average MW: Actual MW averaged from t(20) to t(52)

$$MW_{post-perturbation} = \frac{\sum_{t(20)}^{t(52)} MW}{\#\ Scans}$$

Ramp Adjustment: The Actual Primary Frequency Response number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = $(MW_{T-4} - MW_{T-60})$*0.59

[2] The effective droop of a typical combined-cycle facility with governor settings per Requirement R6 is 5.78%, assuming a 2-to-1 ratio between combustion turbine capacity and steam turbine capacity. Use 5.78% effective droop in all combined-cycle performance calculations.

($MW_{T-4} - MW_{T-60}$) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all generator types, the *ideal* Expected Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60 Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 - deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 - deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 + deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + deadband_{max}\right)}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from t(-16) to t(-2)

$$Hz_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} Hz}{\#\ Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from t(20) to t(52)

$$Hz_{post-perturbation} = \frac{\sum_{t(20)}^{t(52)} Hz}{\# \ Scans}$$

Capacity and NDC (Net Dependable Capacity) are used interchangeably and the term Capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. The Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

<u>Power Augmentation:</u> For Combined Cycle facilities, Capacity is adjusted by subtracting power augmentation (PA) capacity, if any, from the HSL. Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO should provide the BA with documentation and conditions when power augmentation is to be considered in PFR calculations.

$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor\ \times -1$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of
Pressure curve at $MW_{pre\text{-}perturbation}$

The Rated Throttle Pressure and the Pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of Pressure and MW breakpoints where the Rated Throttle Pressure and MW output, where Rated Throttle Pressure is achieved, is the first pair and the Minimum Throttle Pressure and MW output, where the Minimum Throttle Pressure is achieved, as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during a FME. The GO can measure the drop in throttle pressure when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the Steam Flow Change Factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{final} = EPFR_{ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. The GO shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.

10.1 The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2 If a generating unit/generating facility has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3 A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);

- Data telemetry failure. The Compliance Enforcement Authority may request raw data from the GO as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12 month period (or 8 event minimum) to establish whether a resource is compliant with Requirement R10.

Each GO may submit to the BA any information used by the BA in this requirement to calculate sustained PFR performance for each generating unit/generating facility.

This process calculates the sustained Per Unit Primary Frequency Response of a resource [$P.U.\ SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [$P.U.SPFR_{Resource}$] for any Frequency Measurable Event (FME).

<u>Sustained Primary Frequency Response performance requirement:</u>

The standard requires an average performance over a period of 12 months (including at least 8 measured events) that is ≥ 0.75.

$$Avg_{Period}\,[P.U.SPFR_{Resource}] \geq 0.75$$

$Avg_{Period}\,[P.U.SPFR_{Resource}]$ is either:

- the average of each resource's sustained Primary Frequency Response performances [$P.U.\ SPFR_{Resource}$] during all of the assessable Frequency Measurable Events (FMEs), for the most recent rolling 12 month period; or
- if the unit has not experienced at least 8 assessable FMEs in the most recent 12 month period, the average of the unit's last 8 sustained Primary Frequency Response performances when the unit provided frequency response during a Frequency Measurable Event.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Response_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

[3] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

$P.U.\ SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. For any given event $P.U.SPFR_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

Actual Sustained Primary Frequency Response (*ASPFR*) Calculations

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre-perturbation} = \frac{\sum_{t(-16)}^{t(-2)} MW}{\#\ Scans}$$

and:

$MW_{MaximumResponse}$ = maximum MW value telemetered by a unit from T+46 through T+60 during low frequency events and the minimum MW value telemetered by a unit from T+46 through T+60 during a high frequency event.

Actual Sustained Primary Frequency Response, Adjusted (*$ASPFR_{Adj}$*)

$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – The Standard requires a unit/facility to sustain its response to a Frequency Measureable Event. An adjustment available in determining a unit's sustained Primary Frequency Response performance ($P.U.\ SPFR_{Resource}$) is to account for the direction in which a resource was moving (increasing or decreasing output) when the event occurred (T0). This is the *RampMW* Sustained adjustment:

RampMW Sustained = ($MW_{(T-4)}$ – $MW_{(T-60)}$) x 0.821

Note: The terminology "$MW_{(T-4)}$" refers to MW output at 4 seconds before the Frequency Measurable Event (FME) occurs at (T0).

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T0.

The formula is then modified by a factor to indicate where the generator would have been at T+46, had the event not occurred: the "*RampMW Sustained*." It does this by multiplying the MW change over 56 seconds before the event ($MW_{(T-4)}$ – $MW_{(T-60)}$) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\text{ seconds}}{56\text{ seconds}}$ or 0.821.

<u>Expected Sustained Primary Frequency Response (*ESPFR*) Calculations</u>

The Expected Sustained Primary Frequency Response ($ESPFR_{Final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

This $ESPFR_{Final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, High Sustainable Limit (HSL), Low Sustainable Limit (LSL) and actual frequency. It then allows for adjusting the value to compensate for the various types of Limiting Factors each generating units / generating facilities may have and any Power Augmentation Capacity (PA Capacity) that may be included in the HSL/LSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For all generator types, the ideal Expected Sustained Primary Frequency Response ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ is the same $EPFR_{pre\text{-}perturbation}$ value used in the Initial measure of R9.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60 Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + Deadband_{Max})}{(Droop_{Max} \times 60 - Deadband_{Max})} \times (HSL - PA\ Capacity) \times (-1)\right]$$

When the frequency is outside the Governor deadband and below 60 Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - Deadband_{Max})}{(Droop_{Max} \times 60 - Deadband_{Max})} \times (HSL - PA\ Capacity) \times (-1)\right]$$

Capacity and Net Dependable Capability (NDC) are used interchangeably and the term Capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. The capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original HSL. Other generator types may also have Power Augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO is required to provide the BA with documentation and identify conditions when this augmentation is in service.

$ESPFR_{Final}$ for Combustion Turbines and Combined Cycle Facilities

$$ESPFR_{Final} = ESPFR_{ideal} + (HZ_{T+46} - 60.0) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZ_{T+46}. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

$ESPFR_{Final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PACapacity) \times Steam\ Flow\ Change\ Factor$$

where:

$$Steam\ Flow\ \ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{HSL}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The Rated Throttle Pressure and the Pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of Pressure and MW breakpoints where the Rated Throttle Pressure and MW output where Rated Throttle Pressure is achieved is the first pair and the Minimum Throttle Pressure and MW output where the Minimum Throttle Pressure is achieved as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource and ranges between 0.0 and 0.6 psig per MW change when responding during a FME. The GO can measure the drop in throttle pressure, when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the Steam Flow Change Factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between ESPFR and ASPFR (resulting in the highest $P.U.SPFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

ESPFR$_{Final}$ for Other Generating Units/Generating Facilities

$$ESPFR_{Final} = ESPFR_{ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) from its applicable operating limit (high or low) at the time an FME occurs (pre-perturbation), then that resource's Primary Frequency Response performance is not evaluated for that FME.

For frequency deviations below 60 Hz (Hz$_{Post\text{-}perturbation}$ < 60 if:

$$MW_{pre-perturbation} \geq min[([HSL - PA\ Capacity]\ x\ 0.98),\ ([HSL - PA\ Capacity] - 5\ MW)]$$

then Primary Frequency Response is not evaluated for this FME.

For frequency deviations above 60 Hz (Hz$_{Post\text{-}perturbation}$ > 60, if:

$$MW_{pre-perturbation} \leq max[\big(LSL + ([HSL - PA\ Capacity]\ x\ 0.02)\big), (LSL + 5\ MW)]$$

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response (EPFR$_{final}$) is greater than Operating Margin:

Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), but with Expected Primary Frequency Response$_{final}$ greater than the actual margin available.

1. The P.U.PFR$_{Resource}$ will be set to the greater of 0.75 or the calculated P.U.PFR$_{Resource}$ if all of the following conditions are met:
    a. The generating unit/generating facility's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (HSL less PA Capacity) and greater than 5 MW; and

b. The Expected Primary Frequency Response$_{Final}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and

c. The generating unit/generating facility's APFR$_{adj}$ response is in the correct direction.

2. When calculation of the P.U.PFR$_{Resource}$ uses the resource's (HSL less PA Capacity) as the maximum expected output, the calculated P.U. PFR$_{Resource}$ will not be greater than 1.0.

3. When calculation of the P.U.PFR$_{Resource}$ uses the resource's LSL as the minimum expected output, the calculated P.U.PFR$_{Resource}$ will not be greater than 1.0.

4. If the APFR$_{Adj}$ is in the wrong direction, then P.U.PFR$_{Resource}$ is 0.0.

5. These caps and limits apply to both the Initial and Sustained Primary Frequency Response measures.

Revision History

Version	Date	Action	Change Tracking
1	7-25-11	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	Dec. 2012	Revised after field trial to reflect new sustained PFR approach	

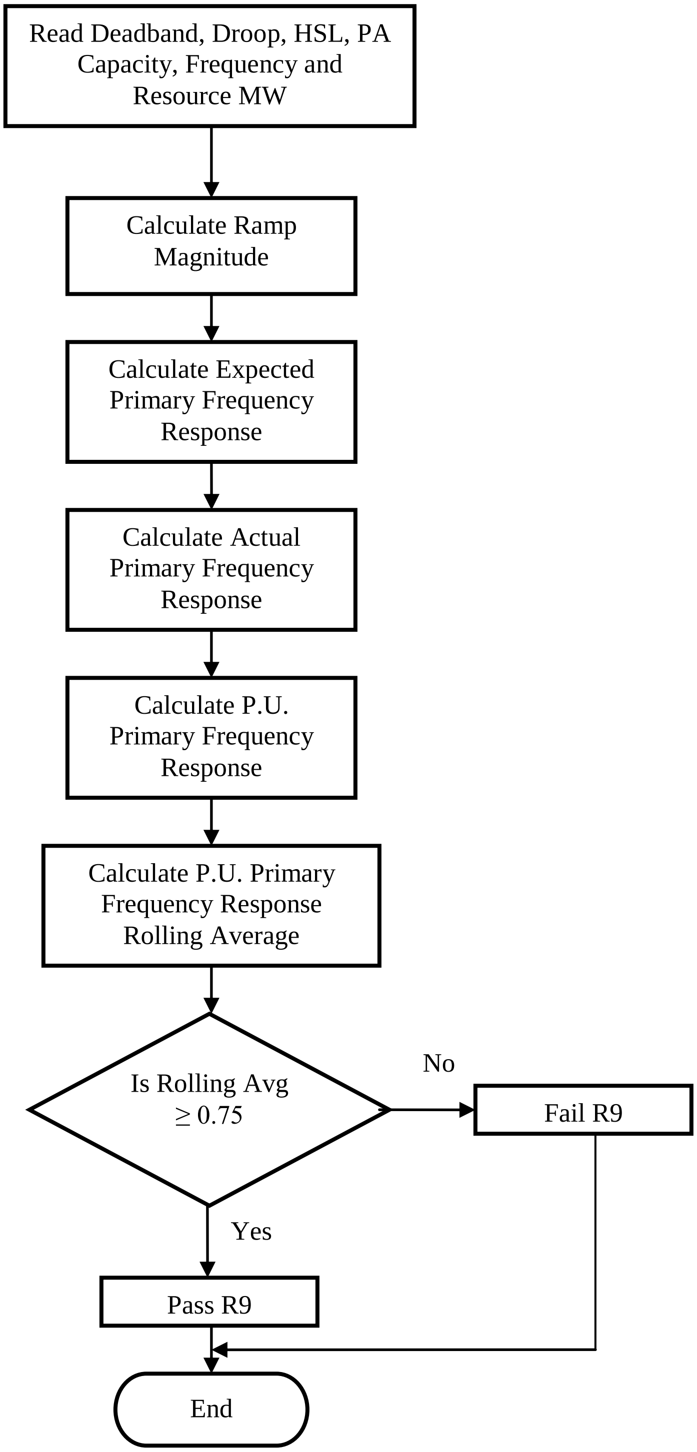
[4] In this circumstance, the EPFR$_{final}$ is set to the operating margin based on HSL (adjusted for any augmentation capacity) for the purpose of calculating P.U.PFR$_{Resource}$.

Attachment A to
Primary Frequency Response Reference Document

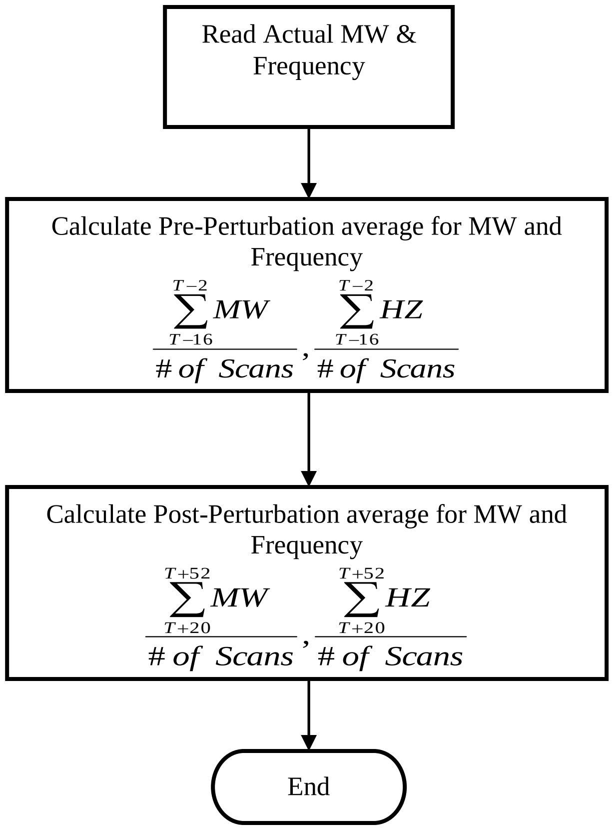
Initial Primary Frequency Response Methodology for
BAL-001-TRE-1

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

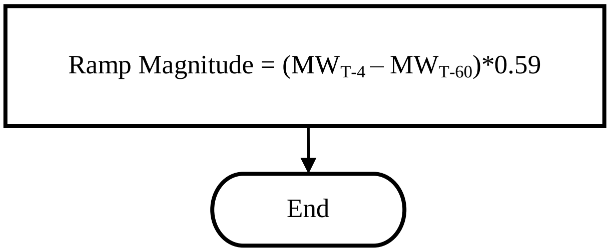
PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations

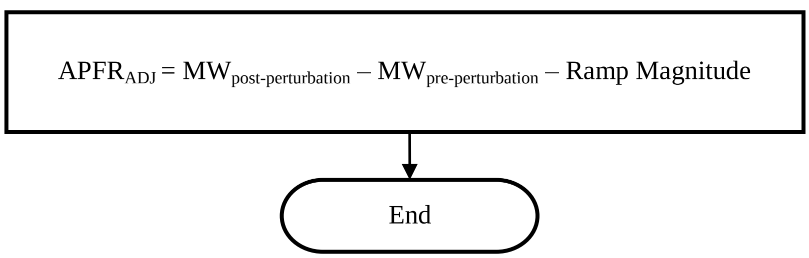


Ramp Magnitude Calculation



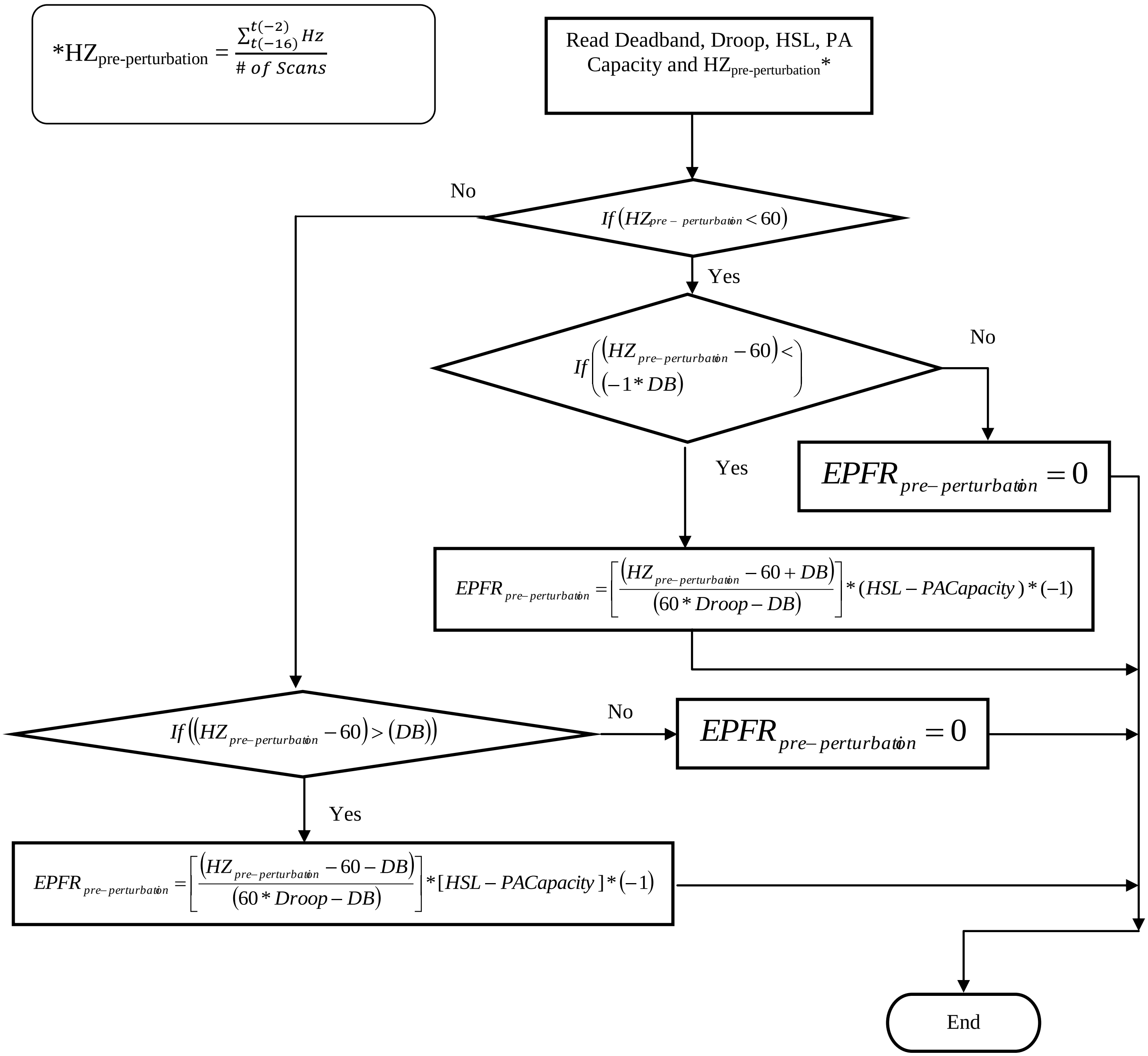
$(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Actual Primary Frequency Response ($APFR_{adj}$)

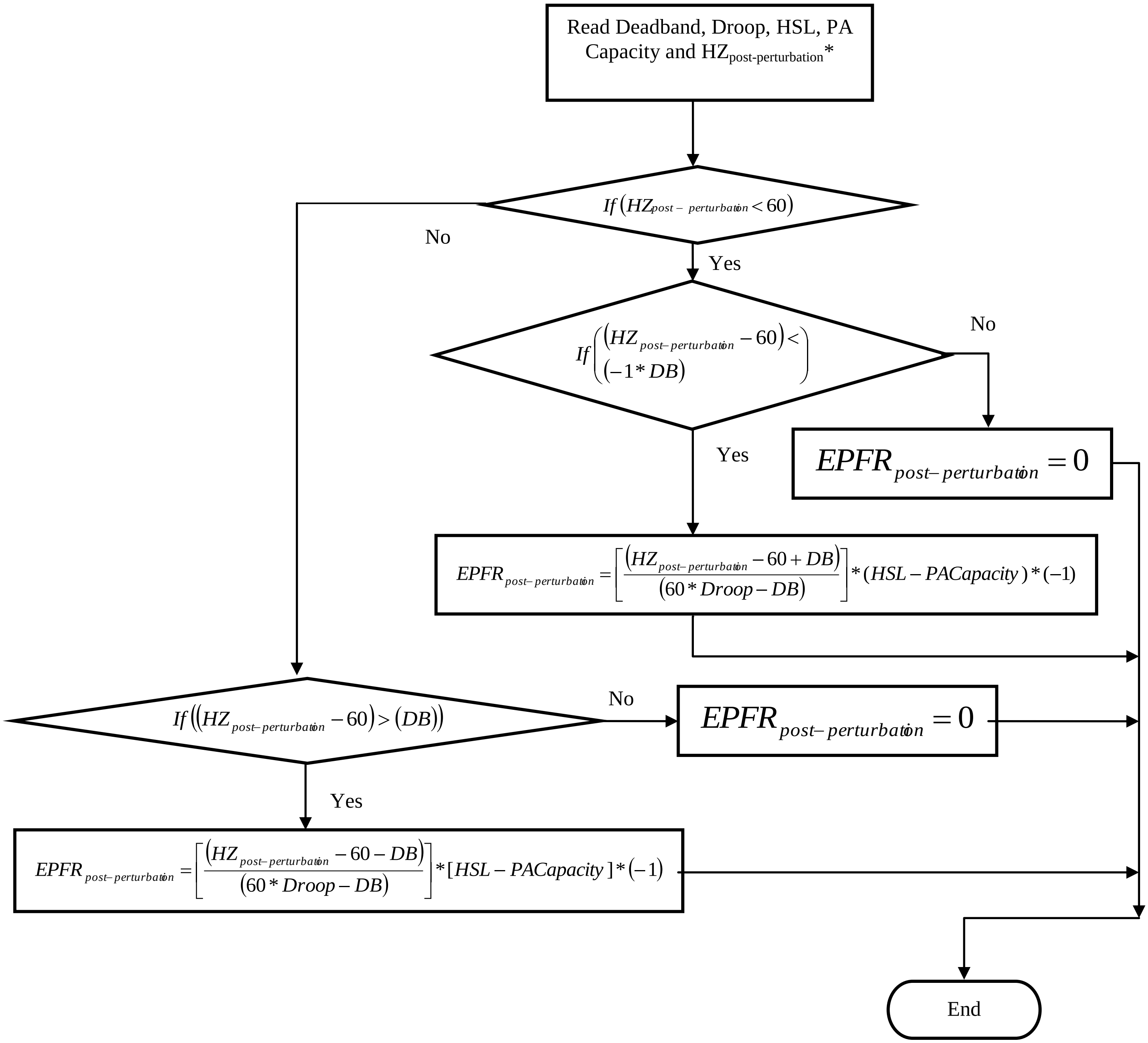


Expected Primary Frequency Response Calculation

Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



$$*HZ_{\text{post-perturbation}} = \frac{\sum_{t(+20)}^{t(+52)} Hz}{\#\ of\ Scans}$$



$$\boldsymbol{EPFR_{ideal} = EPFR_{\ post-perturbation} - EPFR_{pre-perturbation}}$$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

↓

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{Adj} = EPFR_{ideal} * \frac{K}{Rated\ Throttle\ Pressure} * HSL * Steam\ Flow\ Change\ Factor * -1$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

↓

$$EPFR_{Final} = (EPFR_{Ideal} + MW_{Adj}) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

Read HSL, PA Capacity, $HZ_{Post-Perturbation}$*

↓

$$EPFR_{Final} = EPFR_{ideal} + (HZ_{Post-Perturbation} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

↓

End

0.00276 is the MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Adjustment for Other Units

Read Limiting Factor

↓

$$EPFR_{Final} = EPFR_{ideal} + X$$

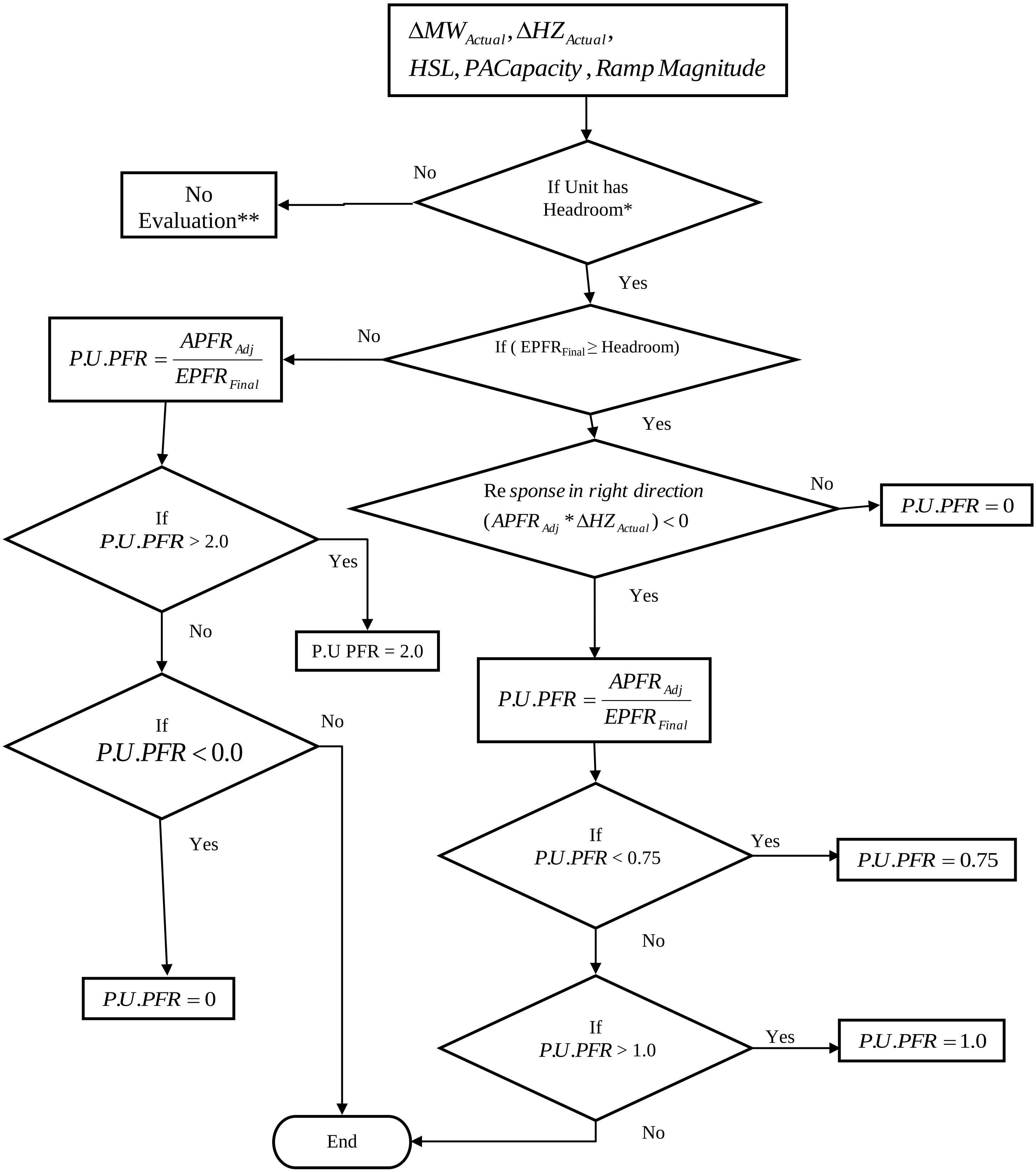
↓

End

$$*HZ_{Post-Perturbation} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Initial Primary Frequency Response Calculation


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom*
No
No Evaluation**
Yes
If ($EPFR_{Final} \geq$ Headroom)
No
$P.U.PFR = \frac{APFR_{Adj}}{EPFR_{Final}}$
Yes
$Response\ in\ right\ direction$
$(APFR_{Adj} * \Delta HZ_{Actual}) < 0$
No
$P.U.PFR = 0$
Yes
$P.U.PFR = \frac{APFR_{Adj}}{EPFR_{Final}}$
If $P.U.PFR > 2.0$
Yes
P.U PFR = 2.0
No
If $P.U.PFR < 0.0$
Yes
$P.U.PFR = 0$
No
If $P.U.PFR < 0.75$
Yes
$P.U.PFR = 0.75$
No
If $P.U.PFR > 1.0$
Yes
$P.U.PFR = 1.0$
No
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

$$\boxed{\text{Headroom} = \text{HSL} - \text{PA Capacity} - MW_{T-2}}$$

For high frequency events:

$$\boxed{\text{Headroom} = MW_{T-2} - \text{LSL}}$$

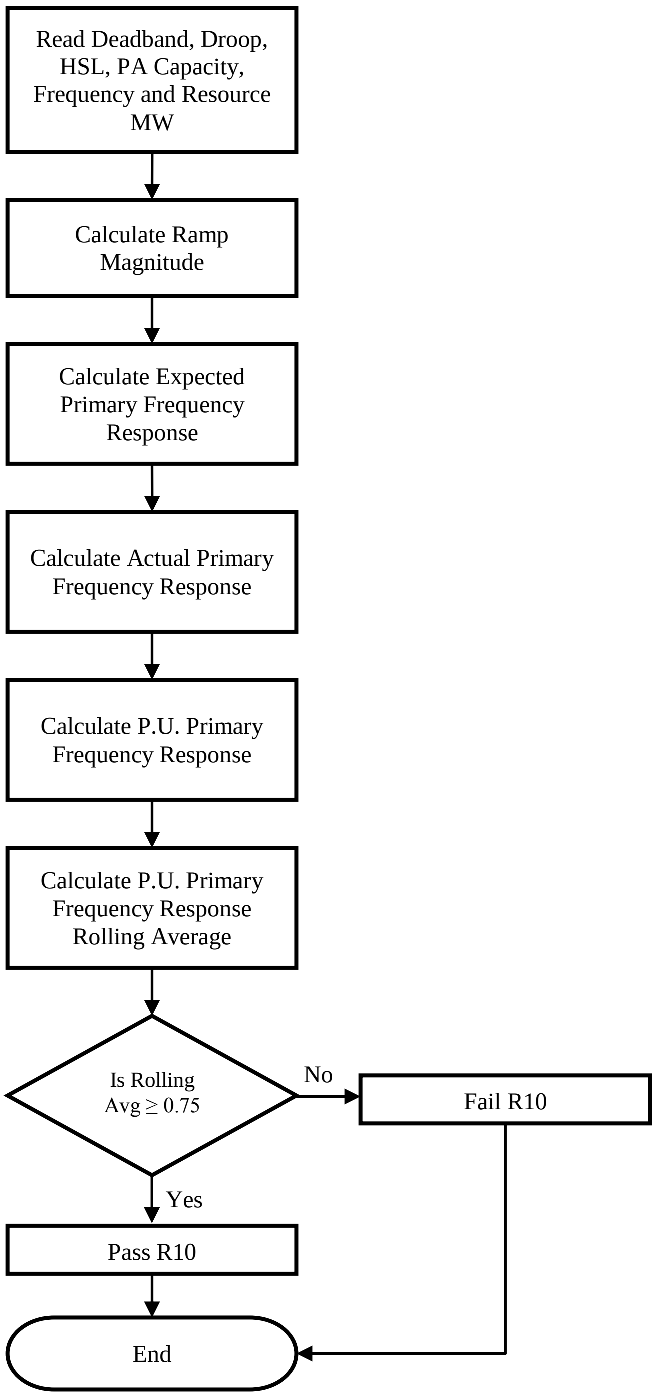
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

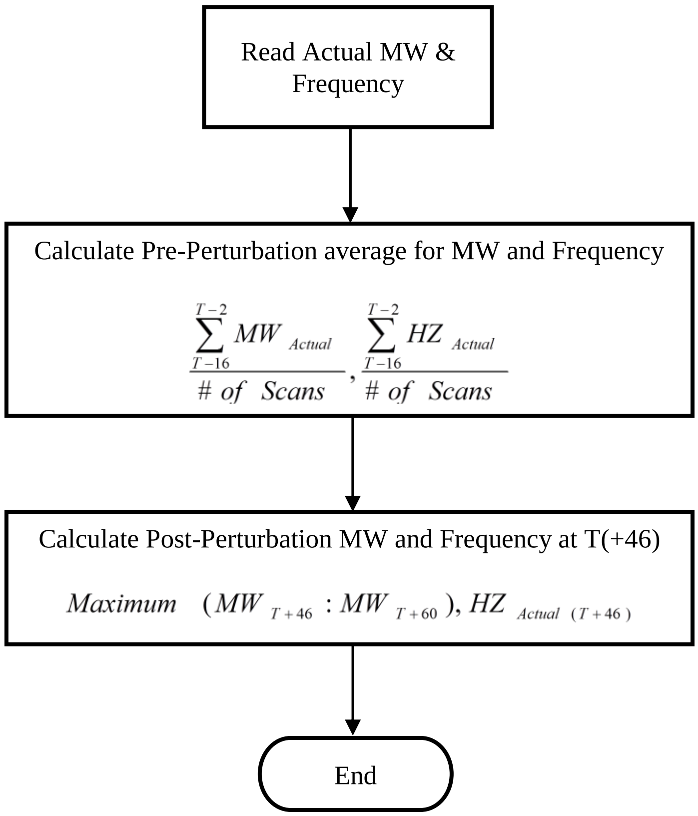
Attachment B to
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for BAL-001-TRE-1

Primary Frequency Response Measurement and Rolling Average Calculation – Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation – Sustained

$$\text{Ramp Magnitude}_{\text{Sustained}} = (\ MW_{T-4} - MW_{T-60})*0.821$$

End

$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 adjusts this full minute ramp to represent the ramp the generator would have changed the system had it been allowed to continue on its ramp to T+46 unencumbered.

Actual Sustained Primary Frequency Response ($ASPFR_{adj}$)

For low frequency events:

$$ASPFR_{ADJ} = \text{Maximum}\ (MW_{T+46} : MW_{T+60}\ ) - \text{Ramp Magnitude}_{\text{Sustained}}$$

End

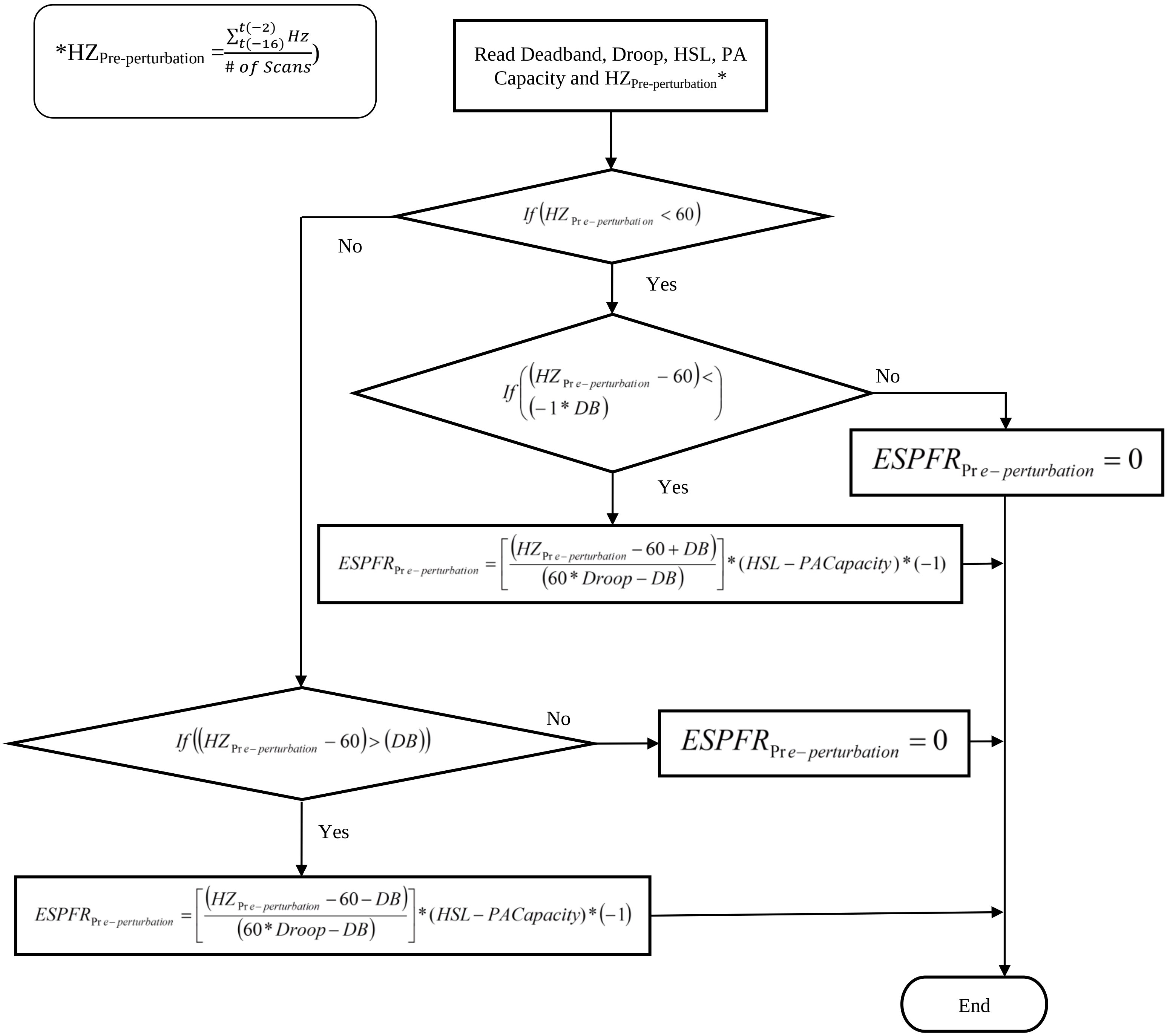
For high frequency events:

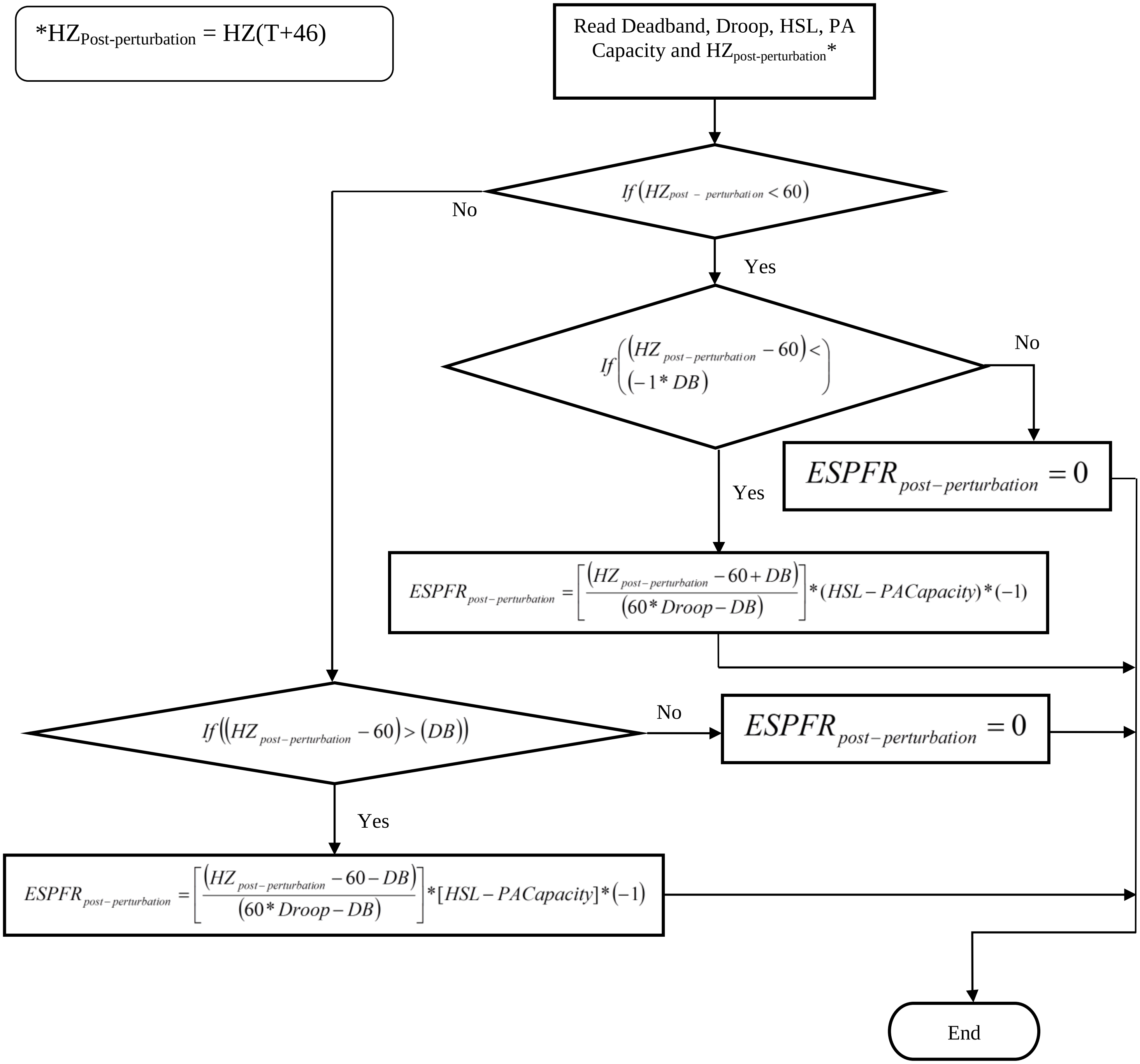
$$ASPFR_{ADJ} = \text{Minimum}\ (MW_{T+46} : MW_{T+60}\ ) - \text{Ramp Magnitude}_{\text{Sustained}}$$

End

Expected Sustained Primary Frequency Response Calculation

Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.





$$ESPFR_{ideal} = ESPFR_{\;post-perturbation} - ESPFR_{pre-perturbation}$$

Adjustment for Steam Turbine

$MW_{Post\text{-}perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{Post\text{-}perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$MW_{Adj} = ESPFR_{ideal} * \frac{K}{Rated\ Throttle\ Pressure} * HSL * Steam\ Flow\ Change\ Factor * -1$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

$$ESPFR_{Final} = (ESPFR_{Ideal} + MW_{Adj}) \text{ x } \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

End

Adjustment for Combustion Turbine and Combined Cycle Facilities

Read HSL, PA Capacity, $HZ_{Post\text{-}Perturbation}$*

↓

$$ESPFR_{Final} = ESPFR_{ideal} + (HZ_{Post-Perturbation} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

↓

End

0.00276 is MW/0.1 Hz change per MW of Capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Adjustment for Other Units

Read Limiting Factor

↓

$$ESPFR_{Final} = ESPFR_{ideal} + X$$

↓

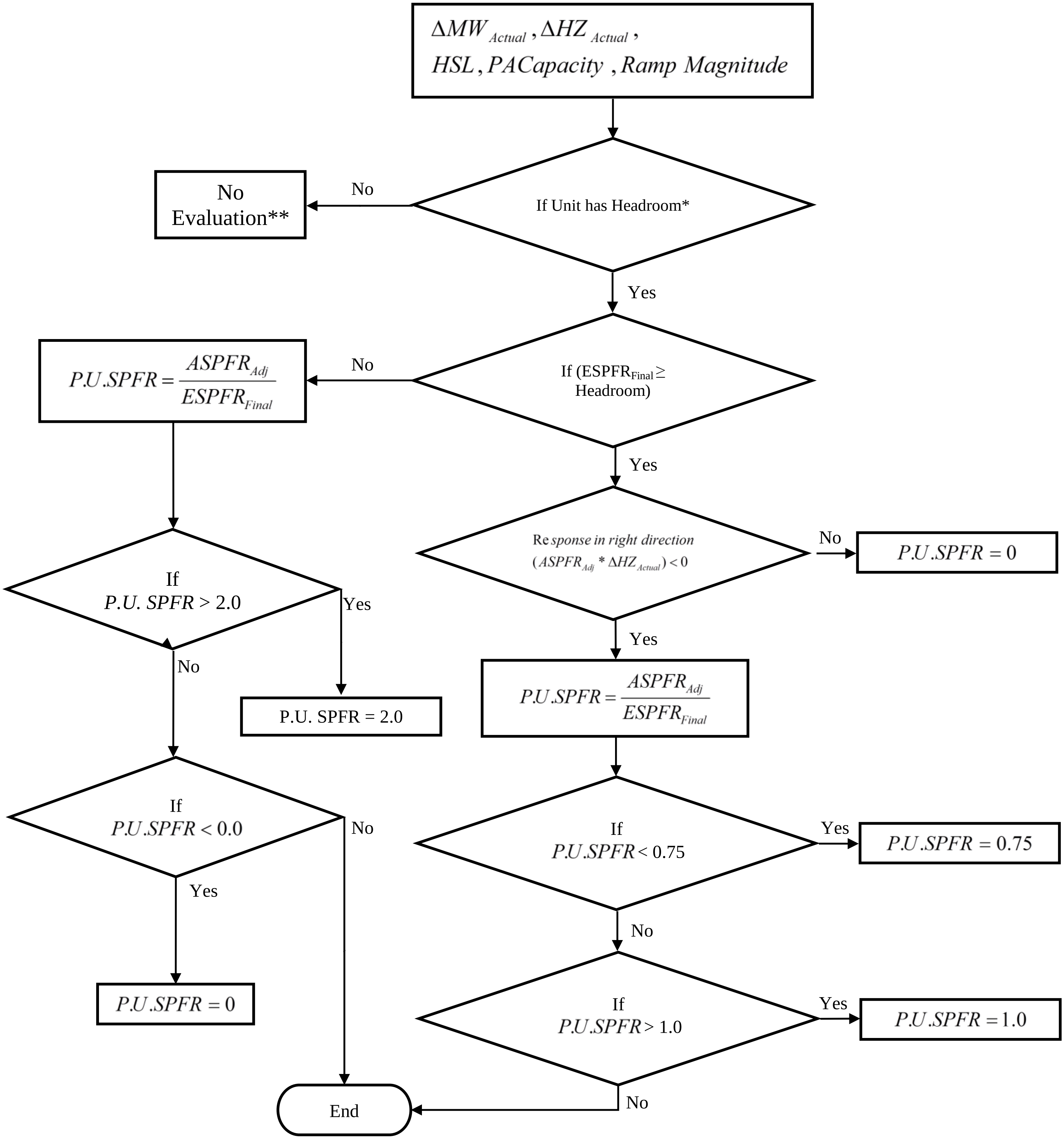
End

*HZ_{Actual} = HZ(T+46)

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Sustained Primary Frequency Response Calculation

*HZ_{Actual} = HZ(T+46)


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom*
No
No Evaluation**
Yes
If ($ESPFR_{Final} \geq$ Headroom)
No
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
Yes
Response in right direction
$(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
No
$P.U.SPFR = 0$
If
$P.U.\ SPFR > 2.0$
Yes
P.U. SPFR = 2.0
No
Yes
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
If
$P.U.SPFR < 0.0$
No
Yes
$P.U.SPFR = 0$
If
$P.U.SPFR < 0.75$
Yes
$P.U.SPFR = 0.75$
No
If
$P.U.SPFR > 1.0$
Yes
$P.U.SPFR = 1.0$
No
End

* Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

$$\boxed{\text{Headroom} = \text{HSL} - \text{PA Capacity} - \text{MW}_{T\text{-}2}}$$

For high frequency events:

$$\boxed{\text{Headroom} = \text{MW}_{T\text{-}2} - \text{LSL}}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

Individual or group. (3 Responses)
Name (1 Responses)
Organization (1 Responses)
Group Name (2 Responses)
Lead Contact (2 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (3 Responses)
Question 1 (3 Responses)
Question 1 Comments (3 Responses)
Question 2 (2 Responses)
Question 2 Comments (3 Responses)
Question 3 (2 Responses)
Question 3 Comments (3 Responses)
Question 4 (3 Responses)
Question 4 Comments (3 Responses)
Question 5 (2 Responses)
Question 5 Comments (3 Responses)

Group
Duke Energy Generation Services
Colby Bellville
Yes
Yes
Duke Energy believes that the implementation of this standard will require substantial upgrades and costs to wind farm control systems of older plants in order to enable the frequency response feature. Some older wind turbines are incapable of meeting this proposed requirement without major SCADA and turbine hardware upgrades due to the pitch control, generator type, and converters used in these systems. If these major upgrades are not realized during the design and build phase of a project, some owners may be unable to absorb the costs necessary for compliance to this standard. Since primary over frequency response is not a paid service in the ERCOT market at this time, there is the potential for lost revenue associated with lost MWh's produced by a generating plant when responding to an over frequency event. For the above stated reasons, Duke Energy believes that the proposed standard poses a serious and substantial burden on competitive markets.

Individual
Thomas Foltz
American Electric Power
Yes
AEP is confident that TRE did indeed follow their internal procedures in developing this regional standard. Though we were not able to participate in this project's commenting periods (AEP was apparently not a part of the original ballot pool for this project), AEP looks forward to working with TRE to ensure that we don't miss out on future opportunities to contribute.
No
AEP is not aware of any adverse impacts posed to reliability or commerce, in a neighboring region or interconnection, as a result of this proposed standard.
No
AEP is not aware of any serious and substantial threats posed to public health, safety, welfare, or national security as a result of this proposed standard.
No
AEP is not aware of any serious and substantial burden posed on competitive markets within the interconnection that is not necessary for reliability as a result of this proposed standard.
Yes
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing
Marcus Pelt
Yes
No
No
Yes
Possibly. If an entities speed control equipment is not currently capable of being programmed as specified in the proposed standard, it should be allowed to be exempt from the requirements rather than required to make investments to alter the functional capabilities of the existing equipment.
Yes
The proposed standard has requirements that are not included in the corresponding continent-

wide reliability standard - there is no existing continent wide standard specifying the Governor setting or performance criterion specification.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Regional Reliability Standard BAL-001-TRE-01

NERC thanks all commenters who submitted comments on regional reliability standard BAL-001-TRE-01 Primary Frequency Response in the ERCOT Region. The standard was posted for a 45-day comment period from May 31, 2013 through July 15, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 3 sets of responses, including comments from 4 different people from 3 companies representing 4 of the 10 of the Industry Segments as shown in the table on the page 3 of this report.

All comments submitted may be reviewed in their original format on the regional standards development page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Colby Bellville	Duke Energy Generation Services					X					
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Kevin Carter		ERCOT	5									
2.	Individual	Marcus Pelt	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	X		X		X	X				
3.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				

1. **Do you agree the proposed standard is being developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

Summary Consideration: N/A

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	AEP is confident that TRE did indeed follow their internal procedures in developing this regional standard. Though we were not able to participate in this project's commenting periods (AEP was apparently not a part of the original ballot pool for this project), AEP looks forward to working with TRE to ensure that we don't miss out on future opportunities to contribute.
Response: Thank you for your comment.		
Duke Energy Generation Services	Yes	
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Summary Consideration: N/A

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP is not aware of any adverse impacts posed to reliability or commerce, in a neighboring region or interconnection, as a result of this proposed standard.
Response: Thank you for your comment.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration: N/A

Organization	Yes or No	Question 3 Comment
American Electric Power	No	AEP is not aware of any serious and substantial threats posed to public health, safety, welfare, or national security as a result of this proposed standard.
Response: Thank you for your comment.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	No	

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration: See Responses below.

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is not aware of any serious and substantial burden posed on competitive markets within the interconnection that is not necessary for reliability as a result of this proposed standard.
Response: Thank you for your comment.		
Duke Energy Generation Services	Yes	Duke Energy believes that the implementation of this standard will require substantial upgrades and costs to wind farm control systems of older plants in order to enable the frequency response feature. Some older wind turbines are incapable of meeting this proposed requirement without major SCADA and turbine hardware upgrades due to the pitch control, generator type, and converters used in these systems. If these major upgrades are not realized during the design and build phase of a project, some owners may be unable to absorb the costs necessary for compliance to this standard. Since primary over frequency response is not a paid service in the ERCOT market at this time, there is the potential for lost revenue associated with lost MW's produced by a generating plant when responding to an over frequency event. For the above stated reasons, Duke Energy believes that the proposed standard poses a serious and substantial burden on competitive markets.
Response: Thank you for your comment. These issues were considered extensively during the development of this standard and		

Organization	Yes or No	Question 4 Comment
addressed in several ways. First, note that the applicability section states "Any generators that are not required by the BA to provide primary frequency response are exempt from this standard." This was added to address concerns of wind generators for which compliance is not technically feasible, so that the standard is only applicable to the generators that have similar obligations under the ERCOT market rules. Second, standard drafting team members worked with wind industry representatives and wind generation vendors to ensure that most wind projects will be able to meet the requirements. Finally, a generous implementation period is provided to give entities plenty of time to make changes necessary to comply with this standard.		
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	Possibly. If an entities speed control equipment is not currently capable of being programmed as specified in the proposed standard, it should be allowed to be exempt from the requirements rather than required to make investments to alter the functional capabilities of the existing equipment.
Response: Thank you for your comment. A generous implementation period is provided to give entities plenty of time to make changes necessary to comply with this standard, as it was recognized that some generators will need to adjust, reprogram, or replace related equipment. Most generation facilities should be able to comply with the requirements without overly burdensome changes to their equipment, particularly considering that ERCOT market rules already require most generators to provide primary frequency response. Finally, note that in Requirements 6.1 and 6.2 the BA is authorized to allow a GO to apply alternate deadband and droop settings in appropriate circumstances.		

5. Does the proposed regional reliability standard meet at least one of the following criteria? - The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard - The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard - The proposed regional difference is necessitated by a physical difference in the bulk power system.

Summary Consideration: N/A

Organization	Yes or No	Question 5 Comment
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	Yes	The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard - there is no existing continent wide standard specifying the Governor setting or performance criterion specification.
Response: Thank you for your comment.		
American Electric Power	Yes	

END OF REPORT