Texas Reliability Entity, Inc.
Board of Directors
Meeting Agenda

September 16, 2026, at 12:00 p.m. Central Time**
Virtual Meeting

WebEx Link:
https://texasre.webex.com/texasre/j.php?MTID=m1b2e3f3fffba6ee822ec6d3ee551aa6d
Call-In: +1-855-797-9485

Item	Board of Directors Meeting
1.	**Call to Order** *Crystal Ashby, Board Chair*
2.	**Antitrust Admonition*** *Thad Crow, Communications and Training Coordinator*
3.	**Consent Agenda* (Vote)** *Crystal Ashby, Board Chair* a. Approval of May 13, 2026, Meeting Minutes
4.	**Remarks and Reports** *Crystal Ashby, Board Chair* a. Chief Executive Officer's Report *Jim Albright, President and Chief Executive Officer*
5.	**SAR-013 Revisions to Regional Standard BAL-001-TRE-2* (Vote)** *Rachel Coyne, Executive Chief of Staff*
6.	**Nominating Committee Report and Recommendation to Board Concerning Independent Director** *Jeffrey Corbett, Independent Director*
7.	**Human Resources Report*** *Kara Murray, Director, Human Resources*
8.	**Regional Risk Assessment Overview*** *David Penney, Director, Reliability Services*
9.	**Texas RE Chief Engineers Report*** *Mark Henry, Chief Engineer and Director, Reliability Outreach*
10.	**NERC Program Area Reports:** *(Staff may not present on these reports, but will be available to answer questions)* a. NERC Program Area Overview *Joseph Younger, Senior Vice President, and Chief Operating Officer* b. Compliance Monitoring and Risk Assessment Report* *Kenath Carver, Director, Compliance Assessments*

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	c. Enforcement Report and Registration Report* *Katie Van Zee, Director, Enforcement and Registration* d. Reliability Services Report* *David Penney, Director, Reliability Services*
11.	**Other Business & Future Agenda Items** *Crystal Ashby, Board Chair*
	Executive Session Agenda Items
12.	**Approval of May 13, 2026, Executive Session Meeting Minutes* (Vote)** *Crystal Ashby, Board Chair*
13.	**Discussion of other confidential matters: *** including compliance and enforcement matters, personnel matters, litigation, contracts, and leases, or commercially sensitive or critical infrastructure information *Crystal Ashby, Board Chair*
	Adjourn Meeting

* Background material may be distributed electronically prior to or at meeting.
** Start and end times may be adjusted should meetings conclude early or extend past their scheduled end time.

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Antitrust Compliance Reminder

Because this event brings together market participants who may be viewed as actual or potential competitors, we must be mindful to conduct it in a manner that is consistent with the antitrust and competition laws. Participants should not disclose non-public, proprietary, or competitively sensitive information.

Attendees should exercise independent judgment and avoid even the appearance of discussions of agreements or concerted actions that may be viewed as restraining competition. For example, avoid discussions regarding current or potential vendors or suppliers that involve sensitive information like pricing or terms, or discussions involving employee wages or hiring decisions. Any company decisions that are informed by your discussions today must be made independently.

This guidance is not intended as legal advice, and each attendee is responsible for seeking their own legal advice with respect to compliance with applicable antitrust and competition laws. However, any questions on Texas RE’s Antitrust Compliance Corporate Policy may be directed to Texas RE’s General Counsel.

DRAFT MINUTES OF THE BOARD OF DIRECTORS OF TEXAS RELIABILITY ENTITY, INC.

May 13, 2026

Board Members

Crystal Ashby	Board Chair, Independent Director
Jeff Corbett	Board Vice Chair, Independent Director
Milton Lee	Independent Director
Suzanne Spaulding	Independent Director (Remote)
Jim Albright	President and CEO
Curt Brockmann	Member Representatives Committee Chair (Remote)
Daniela Hammons	Member Representatives Committee Vice Chair

Texas RE Attendees

Joseph Younger, Senior Vice President and Chief Operating Officer
Derrick Davis, Senior Vice President and Chief Administrative Officer
Davida Dwyer, Vice President, General Counsel and Corporate Secretary
Donna Bjornson, Vice President and Chief Financial Officer
Kara Murray, Director, Human Resources
Mark Henry, Chief Engineer and Director, Reliability Outreach
Paul Curtis, Deputy General Counsel and Assistant Corporate Secretary
Matt Barbour, Manager, Communications and Training

Other Attendees

Rob Manning, NERC Board of Trustees
Additional Texas RE staff and other individuals attended in person or via public teleconference.

Call to Order

Pursuant to notice duly given, the meeting of the Texas Reliability Entity, Inc. (Texas RE) Board of Directors (Board) convened on May 13, 2026. Chair Ashby determined that a quorum was present and called the meeting to order at 2:00 p.m. Central Time.

Antitrust Admonition

At Chair Ashby's request, Thad Crow reviewed the antitrust admonition and reminded attendees to abide by Texas RE's antitrust guidelines.

Consent Agenda: Approval of February 25, 2026, Board of Directors Meeting Minutes and Approval of Resolution Ratifying Texas RE Vice President

Suzanne Spaulding made a motion to approve the consent agenda: the February 25, 2026, Board of Directors meeting minutes and the Ratification of Davida Dwyer as Texas RE Vice President, General Counsel and Corporate Secretary. Jeff Corbett seconded the motion. The motion passed unanimously.

Remarks and Reports

Rob Manning of the NERC Board of Trustees gave Keynote Remarks. He discussed the unprecedented pace of change in the electric utilities industry, including the onset of large loads, AI, and changes in the workforce.

Jim Albright welcomed Davida Dwyer, Texas RE's new Vice President, General Counsel and Corporate Secretary, and Mr. Albright provided the Chief Executive Officer's report. He discussed the ERO CMEP workshop, a recent Board to Board meeting, and the upcoming Assessment of Reliability Performance report.

Audit, Governance, Risk, and Finance Committee Meeting Report

Suzanne Spaulding, AGR&F Chair, reported that the AGR&F Committee met earlier today and recommends Board acceptance of 2025 Financial Statement audit, and approval of 2027 business plan and budget.

Acceptance of 2025 Financial Statement Audit

Donna Bjornson, Vice President and Chief Financial Officer, presented the 2025 Financial Statement Audit. Jeff Corbett made a motion to accept 2025 financial statement audit. Crystal Ashby seconded the motion. The motion passed by unanimous voice vote.

Approval of 2027 Business Plan and Budget

Donna Bjornson, Vice President and Chief Financial Officer, presented the 2027 Business Plan and Budget. Crystal Ashby made a motion to approve 2027 Business Plan and Budget. Jeff Corbett seconded the motion. The motion passed by unanimous voice vote.

2025 Assessment of Reliability Performance

David Penney, Director, Reliability Services, gave the report on the Assessment of Reliability Performance.

Texas RE Chief Engineer's Report

Mark Henry, Chief Engineer and Director, Reliability Outreach, presented the Chief Engineer's report.

Program Area Reports

Joseph Younger, Vice President and Chief Operating Officer, gave a NERC Program Area Overview. He said Texas RE staff was off to a great start for the year, and there is a tremendous amount of activity going on.

Texas RE staff members provided written program area quarterly reports and were available to answer questions.

Other Business & Future Agenda Items

Jim Albright and Derrick Davis recognized and thanked two Texas RE employees for their years of service to the company: Irma Bernard, Senior Accountant, who will soon be retiring; and Matt Barbour, Manager, Communications and Training, whose last day at Texas RE is May 13.

Adjournment

At 3:13 p.m., Chair Ashby adjourned the open portion of the meeting and convened in executive session.

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Davida Dwyer,
Corporate Secretary

MEMORANDUM

To:	Texas RE Board of Directors
From:	Rachel Coyne, Executive Chief of Staff
Date:	September 16, 2026
Re:	Item 05 – Status Update for Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

In accordance with Texas RE's Regional Standards Development Process (RSDP), I am submitting the Work Product for the Texas Board's consideration for approval of Regional Standard BAL-001-TRE-3 and the implementation plan.

The SDP provides that the Board may take one of the following actions regarding the proposed RSDP:

1. Adopt the proposed new Regional Standard, modification to an existing Regional Standard, or retirement of the existing Regional Standard;
2. Remand the proposed new Regional Standard, modification to an existing Regional Standard, or retirement of the existing Regional Standard to the MRC with comments and instructions; or
3. Reject the new Regional Standard, modification to an existing Regional Standard, or retirement of the existing Regional Standard without recourse.

In accordance with the RSDP, Texas RE conducted an additional 45-day comment period, with an additional ballot in the last 15 days for proposed Regional Standard BAL-001-TRE-3 and the implementation plan from May 14 – June 29, 2026. The additional ballot did pass. I subsequently conducted a 15-day final ballot from July 20 – August 4, 2026, which passed. During its meeting, the MRC will discuss whether to forward the RSDP to the Board for a final vote on approval. Assuming the MRC takes that action, the following documents are included for the Board's consideration of the approval of the RSDP:

- Proposed Regional Standard BAL-001-TRE-3_Clean
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Posted
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Approved
- Proposed Implementation Plan_Clean
- Proposed Implementation Plan_Redline to Last Posted
- Description of Revisions
- Updated Work Plan
- Additional Ballot Results
- SDT's Response to Comments
- Final Ballot Results

Upon adoption of Regional Standard BAL-001-TRE-3 and the implementation plan, the development record will be submitted to NERC for a 45-day public posting period, adoption by the NERC Board, and filing with FERC.

SAR-013: Revisions to Regional Standard BAL-001-TRE-2 Project Update

Board of Directors Meeting
September 16, 2026

Project Recap

- 6/28/2024 – SAR Receipt
- 11/6/2025 – Initial Comment Period and Ballot
- 6/29/2026 – Additional Comment Period and Ballot
- 8/4/2026 – Final Ballot

SAR-013 Project Activity (May 2026 – August 2026)

May 13, 2026 – MRC approved for additional comment and ballot period

May 14, – June 29, 2026 – Additional Comment Period (Ballot last 15 days)

July 20, 2026 – SDT Meeting

July 20 – August 4, 2026 – Final Ballot

Texas RE MRC and Board Consideration

Board Packet

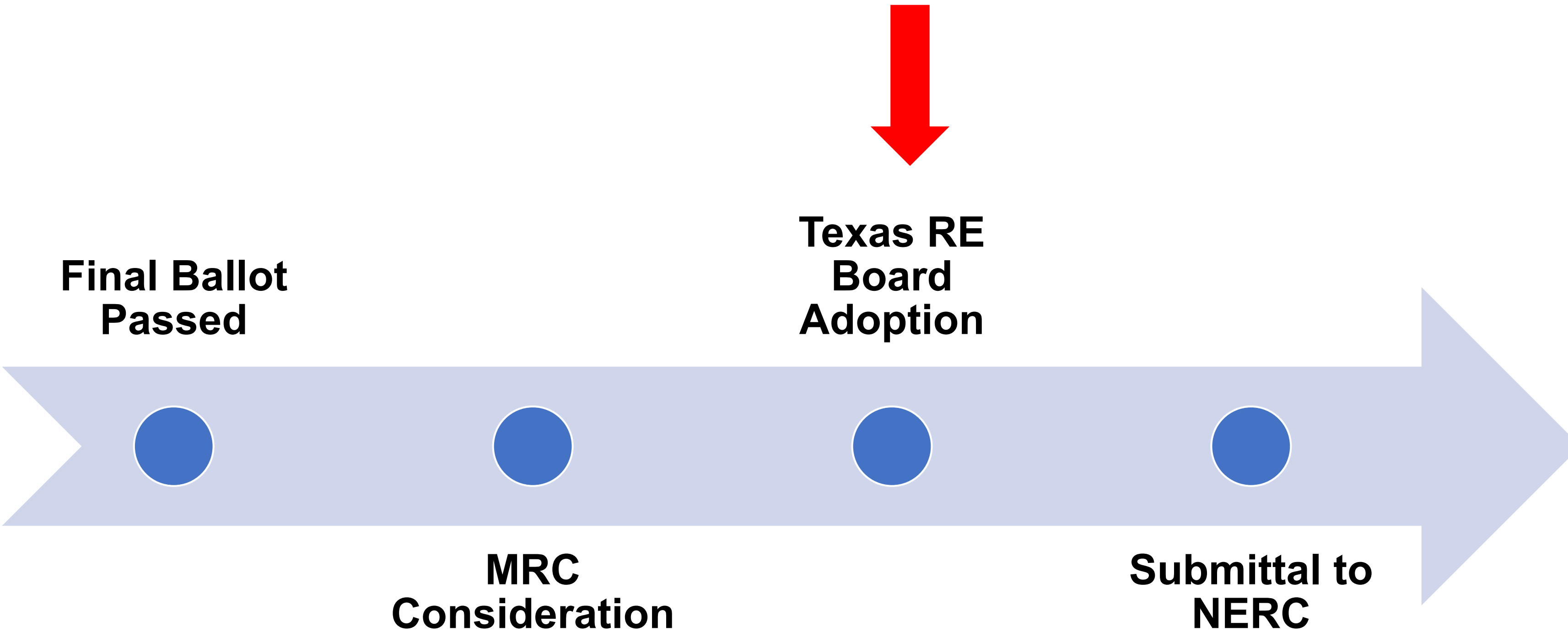
- Proposed Regional Standard BAL-001-TRE-3_Clean
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Posted
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Approved
- Proposed Implementation Plan_Clean
- Proposed Implementation Plan_Redline to Last Posted
- SDT's Response to Comments
- Description of Revisions
- Updated Work Plan
- Ballot Results
- SDT's Responses to Comments

Board Action

Requesting the Board adopt Regional Standard BAL-001-TRE-3

Public

Next Steps



A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-3
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owners

   4.1.3 Generator Operators

   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-3.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3.

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

5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-3.
6. **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 8.5. 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 (FME) (that starts at t(0)).

   This Regional Standard provides requirements related to identifying Frequency Measurable 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 (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).

In this Regional Standard the terms "resource" and "generating unit/generating facility" refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

B. Requirements and Measures

R1. The Balancing Authority shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME, the Balancing Authority 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 Balancing Authority shall have evidence that 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 Balancing Authority 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. *[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]*

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

[1] Attachment 1: Primary Frequency Response Reference Document contains the calculations that the Balancing Authority 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.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the Generator Owner 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 eight (8) FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

M2. The Balancing Authority 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 Balancing Authority 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 Balancing Authority shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The Balancing Authority 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 occur, the Balancing Authority 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. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M4. The Balancing Authority 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 Balancing Authority 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 Balancing Authority 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 Generator Owner shall set its Governor parameters, as set forth in Requirement R6, Parts 6.1, 6.2, and 6.3. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the Balancing Authority.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
Generating units/generating facilities that are not qualified [2] to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings	+/- 0.036 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 Balancing Authority.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Combustion Turbine (Combined Cycle)	**4%**
All other generating units/generating facilities	**5%**

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.

[2] Refers to ancillary service qualification criteria as required by the Balancing Authority.

Where

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

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

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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Generator Owner 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
- Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz

R7. Each Generator Owner 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 Generator Owner has a valid reason for operating with the Governor not in service and the Generator Operator has been notified that the Governor is not in service. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

M7. Each Generator Owner shall have evidence that it notified the Generator Operator 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 Generator Operator shall notify the Balancing Authority 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 Generator Operator shall have evidence that it notified the Balancing Authority within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9. Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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 by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each Generator Owner 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 Generator Owner shall have documented evidence of any FMEs where the generating unit performance was excluded from the rolling average calculation.

R10. Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

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 by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

M10. Each Generator Owner 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 Generator Owner shall have documented evidence of any Frequency Measurable Events where generating unit performance was excluded from the rolling average calculation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit's/generating facility's rolling average for R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). After CEA consultation with the BA, and if the CEA approves the request to reset the rolling average(s), the CEA shall notify the BA that the GO may begin a new rolling average(s). In the CEA's notice to the BA, the CEA shall provide the BA with an effective date of the reset time for the rolling average(s). Upon receipt of the notice from the CEA, the BA shall, as soon as practicable, implement the change to the GO's rolling average(s). The first performance during an FME following the CEA's effective date to the BA shall count as the first event in the rolling average(s), and the entity will have an average frequency performance score after 12 successive months or eight events under Requirements R9 and R10 of the Regional Standard.

1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

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

- The Balancing Authority shall retain a list of identified FMEs and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The Balancing Authority shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The Balancing Authority 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 Balancing Authority shall retain all data and calculations relating to the Interconnection's combined Frequency Response performance, and all evidence of actions taken to increase the Interconnection's combined Frequency Response performance, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each Generator Operator shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each Generator Owner 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 CEA shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority 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 Balancing Authority 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 Generator Owner operated with its Governor out of service and did not notify the Generator Operator upon discovery of its Governor out of service.
R8	The Generator Operator notified the Balancing Authority of a change in Governor status between 31 minutes and one hour after the General Operator was	The General Operator notified the Balancing Authority of a change in Governor status more than 1 hour but within 4 hours after the Generator Operator was	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hours but within 24 hours after the Generator	The Generator Operator failed to notify the Balancing Authority of a change in Governor status within 24 hours after the Generator Operator was notified of the discovery of the change.

	notified of the discovery of the change.	notified of the discovery of the change.	Operator was notified of the discovery of the change.	
R9	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	8/15/2013	Adopted by NERC Board of Trustees	
1	1/16/2014	FERC Order issued approving BAL-001-TRE-1. (Order becomes effective April 1, 2014.)	
2	12/11/2019	Approved by Texas RE Board of Directors	Removed the requirement Governor droop and deadband settings for Steam Turbine(s) of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process and legitimate operating conditions for submitting an FME exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1.
3			Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA). Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regard to resetting the 12-month rolling average Primary Frequency Response (PFR) performance score.

			Define PFR performance requirements for Battery Energy Storage Systems (BESS).

Standard Attachments

1. Attachment 1 – 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 Member Representatives Committee (MRC) for consideration. The revision request will be posted in accordance with MRC procedures. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC 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.

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-3
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 is maintained by Texas RE and subject to modifications 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 Member Representatives Committee (MRC) for consideration. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC 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.

[1] These spreadsheets are available on Texas RE's public website.

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 capability of a generating unit/generating facility. This value could be negative for BESS to represent the charging capability.

Maximum Megawatt Governor Control System (MW_{GCS}) for the purposes of this standard, maximum megawatt control range of the Governor control system MW_{GCS} is calculated from HSL to LSL for BESS and HSL to 0 for all other all generator types.

Design Settings versus real-time Evaluation: Settings and verifications (Requirement R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.

In this Regional Standard the terms "resource" and "generating unit/generating facility" refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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 by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial PFR 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 PFR ($APFR_{Adj}$), 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 PFR [$P.U.PFR_{Resource}$] for any FME.

<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 PFR of a resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Primary\ Frequency\ Response_{Final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The adjusted actual PFR ($APFR_{Adj}$) and the final expected PFR ($EPFR_{final}$) 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.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

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 PFR 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 = (MWT-4 – MWT-60)*0.59

(MWT-4 – MWT-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

[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.

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 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 - deadband_{\max}\ \right)}{\left(60\ x\ droop_{max} - \ deadband_{\max}\ \right)}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 - deadband_{\max}\ \right)}{\left(60\ x\ droop_{max} - \ deadband_{\max}\ \right)}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{\left(HZ_{pre-perturbation} - 60.0 + deadband_{\max}\ \right)}{\left(60\ x\ droop_{max} - \ deadband_{\max}\ \right)}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + deadband_{\max}\ \right)}{\left(60\ x\ droop_{max} - \ deadband_{\max}\ \right)}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The deadbandmax and droopmax 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 net dependable capacity (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.

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

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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:

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

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 an 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 BESS with capacity that is not expected to provide PFR

$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

$EPFR_{final}$ 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. Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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 by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner 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.

This process calculates the per unit sustained PFR 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 PFR (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 PFR [$P.U.SPFR_{Resource}$] for any FME.

<u>Sustained Primary Frequency Response performance requirement:</u>

The standard requires an average performance over a period of 12 months (including at least

[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.

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 PFR 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 PFR performances when the unit provided frequency response during an FME.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained PFR of a resource during identified FMEs. 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 PFR 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 T=t(0). 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 T=t(0).*

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 T=t(0). 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 (MWT-4 – MWT-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 PFR ($ESPFR_{final}$) 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, HSL/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 PFR ($ESPFR_{ideal}$) 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 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - \ deadband_{max})}{(droop_{max}\ x\ 60 - \ deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + \ deadband_{max})}{(droop_{max}\ x\ 60 - \ deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

Capacity and 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 $deadband_{max}$ 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 MW_{GCS}. Other generator types may also have power as 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

$$ESPFR_{final} = ESPFR_{ideal} + \ (HZ_{T+46} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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:

$$MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Throttle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\% \, Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

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 and ranges between 0.0 and 0.6 psig per MW change when responding during an 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 BESS with capacity that is not expected to provide PFR

$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

$ESPFR_{final}$ 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 a generating unit/generating facility is operating within 2% of its (MW_{GCS} – PA capacity and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} less capacity not expected to provide PFR 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:

$$MW_{pre-perturbation} \geq \min[([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}\ ]\ x\ .98), ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}\ ] - Y\ MW)]$$

then PFR is not evaluated for this FME, where Y is 5 MW for generating units/generating facility and 3 MW for BESS

For frequency deviations above 60 Hz (HzPost-perturbation > 60, if:

$$MW_{pre-perturbation} \leq \max\left[\left(LSL + ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}]\ x\ 0.02)\right), (LSL + Y\ MW)\right]$$

then PFR is not evaluated for this FME where Y is 5 MW for generating units/generating facility and 3 MW for BESS

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 (MW_{GCS} less PA capacity) or 5 MW for generating units/generating facilities or 3 MW for BESS, 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 BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity and

additional capacity not expected to provide PFR) and greater than 3 MW; and

c. The Expected Primary Frequency Response$_{final}$ is greater than the generating unit/generating facility's available frequency responsive capacity[4]; and
d. 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 (MW$_{GCS}$ less PA capacity and additional capacity not expected to provide PFR) 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 PFR measures.

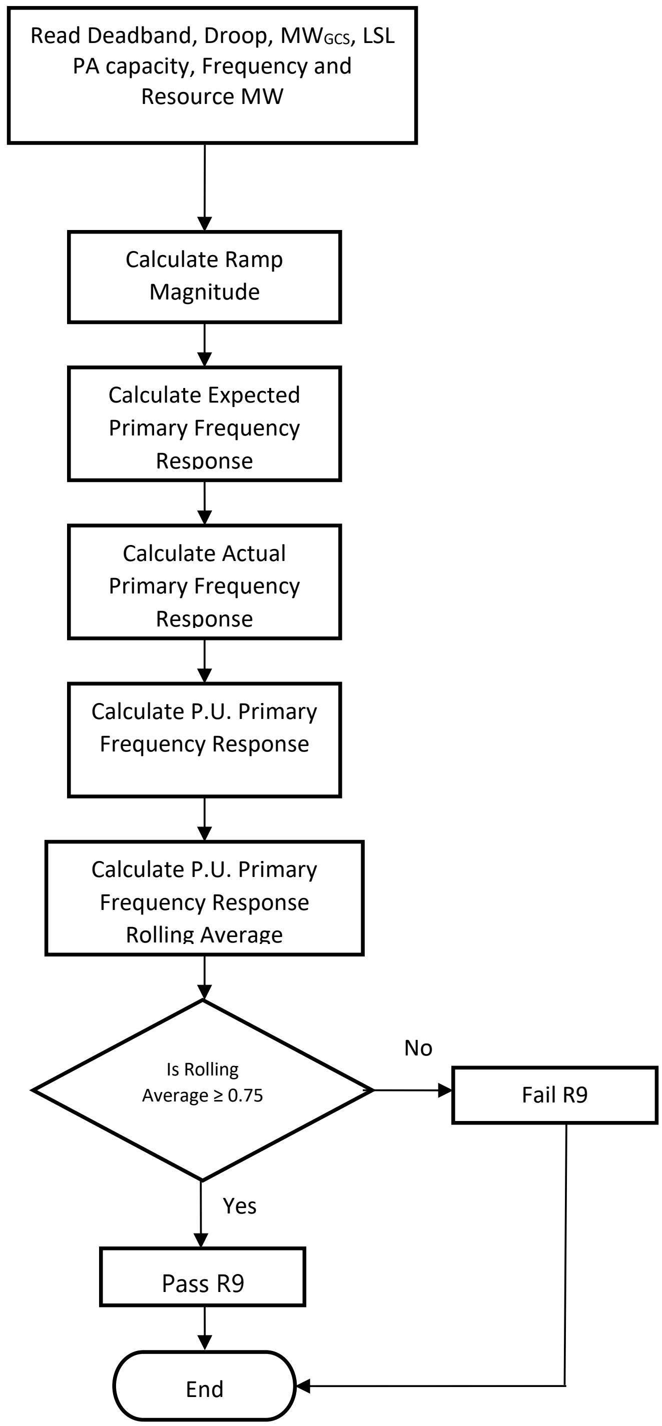
[4] In this circumstance, when frequency is below 60 Hz, the EPFR$_{final}$ is set to operating margin based on MW$_{GCS}$ (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR$_{final}$ is set to operating margin based on LSL for the purpose of calculating PUPFR$_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

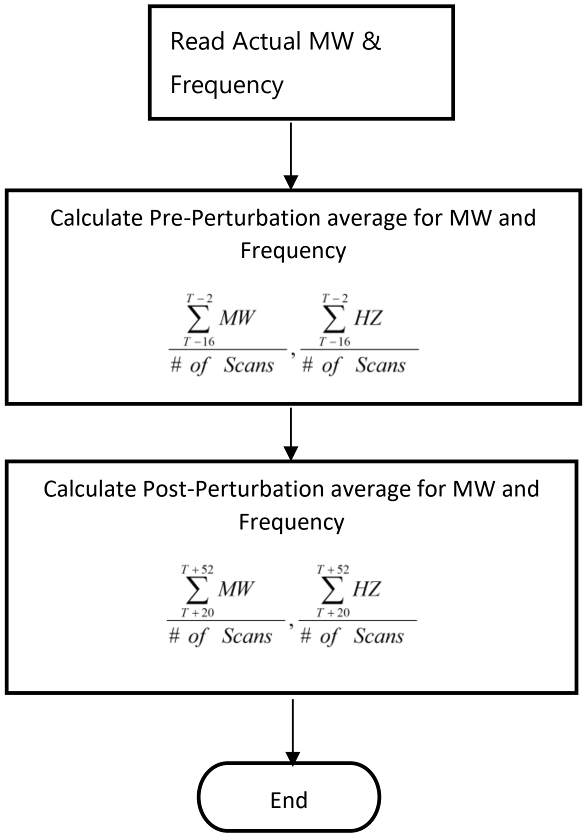
Initial Primary Frequency Response Methodology for
BAL-001-TRE-3

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

PA = Power Augmentation
HSL = High Sustained Limit
LSL = Low Sustained Limit
MW_{GCS} = maximum megawatt control range of the Governor control system


Read Deadband, Droop, MWGCS, LSL PA capacity, Frequency and Resource MW
Calculate Ramp Magnitude
Calculate Expected Primary Frequency Response
Calculate Actual Primary Frequency Response
Calculate P.U. Primary Frequency Response
Calculate P.U. Primary Frequency Response Rolling Average
Is Rolling Average ≥ 0.75
No
Fail R9
Yes
Pass R9
End

Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

Ramp Magnitude = $(MW_{T-4} – MW_{T-60})*0.59$

End

(MWT-4 – MWT-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.

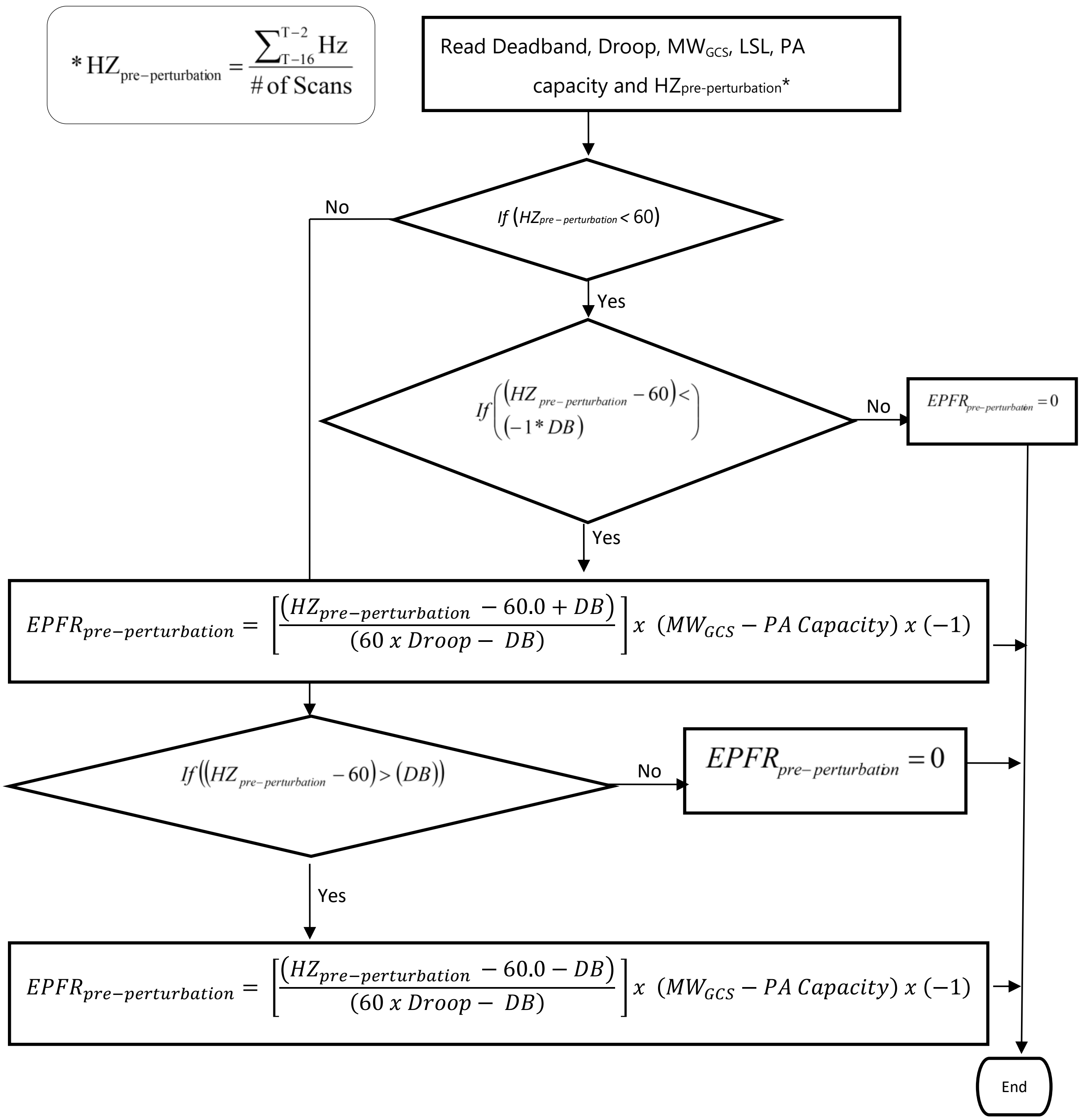
Actual Primary Frequency Response (APFRAdj)

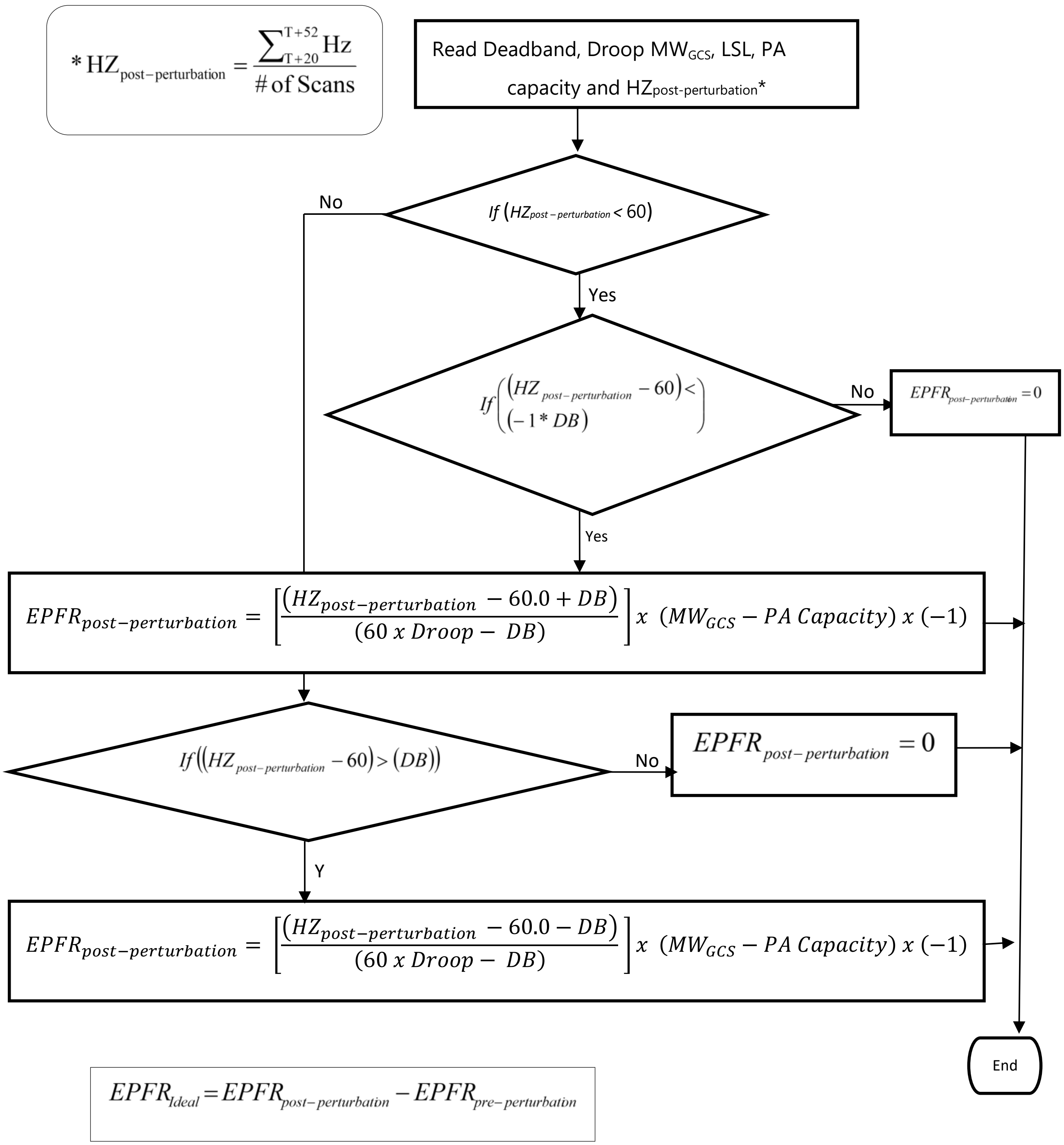
$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

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.




$* HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# \text{ of Scans}}$
Read Deadband, Droop MW_{GCS}, LSL, PA capacity and $HZ_{post\text{-}perturbation}$*
$If\ (HZ_{post-perturbation} < 60)$
No
Yes
$If\left(\begin{matrix}(HZ_{post-perturbation} - 60) < \\ (-1 * DB)\end{matrix}\right)$
No
$EPFR_{post-perturbation} = 0$
Yes
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + DB)}{(60\ x\ Droop - DB)}\right] x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)$
$If((HZ_{post-perturbation} - 60) > (DB))$
No
$EPFR_{post-perturbation} = 0$
Y
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - DB)}{(60\ x\ Droop - DB)}\right] x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)$
End
$EPFR_{Ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS} $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

↓

$$\%\,Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x(MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

↓

$$EPFR_{final} = \left(EPFR_{Ideal} + MW_{Adjustment}\right)* \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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 BESS with capacity that is not expected to provide PFR

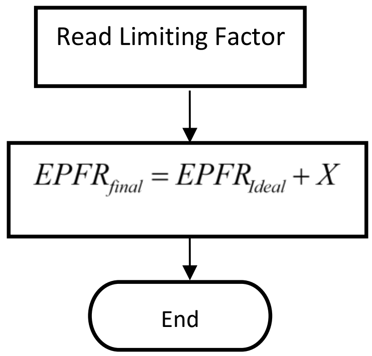
Read MW_{GCS}, capacity not expected to provide PFR

$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

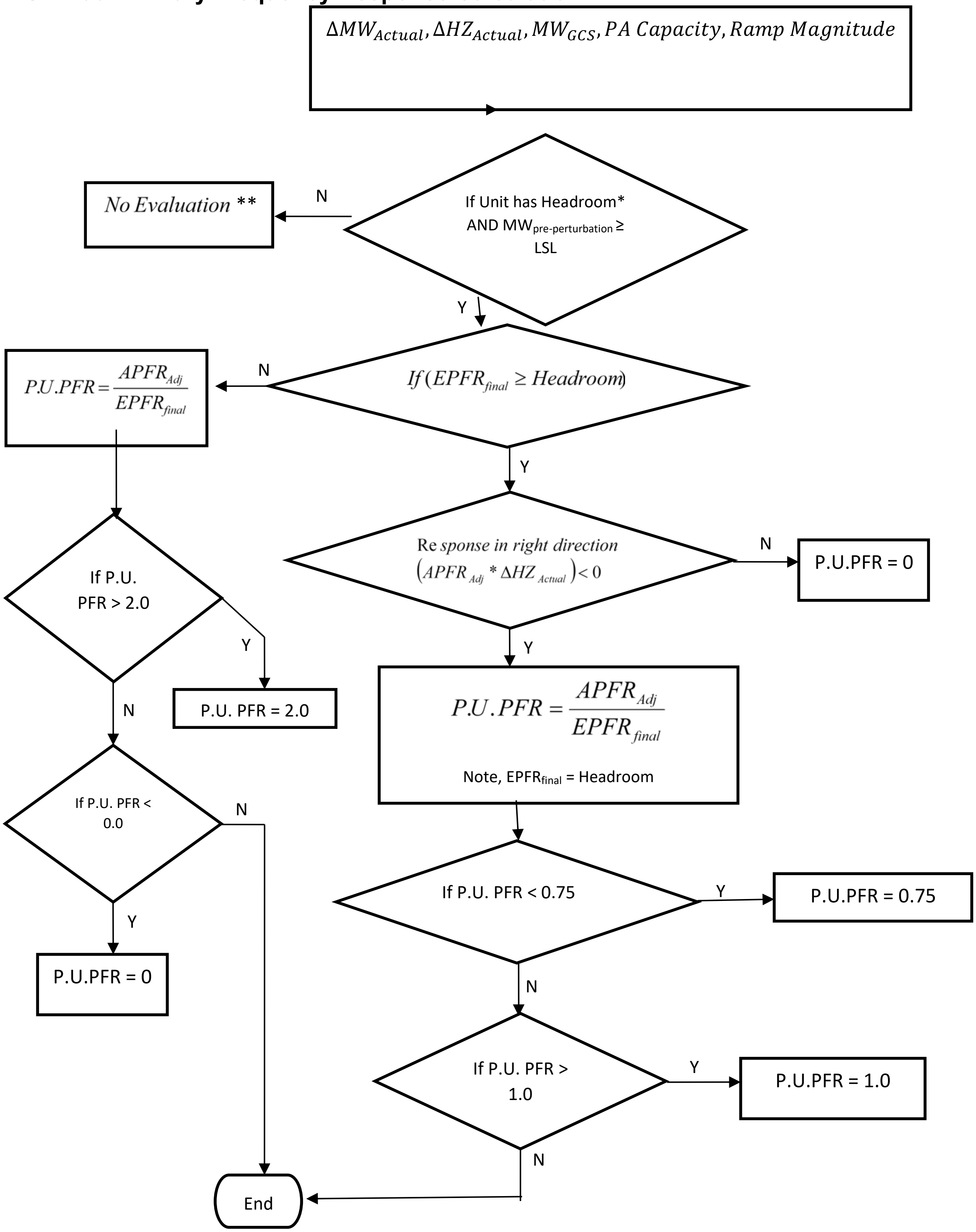
Adjustment for Other Units



$$* \, HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\# \text{ of Scans}}$$

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



*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

For low frequency events:

$$\boxed{Headroom = HSL - PA\ Capacity - capacity\ not\ expected\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**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.

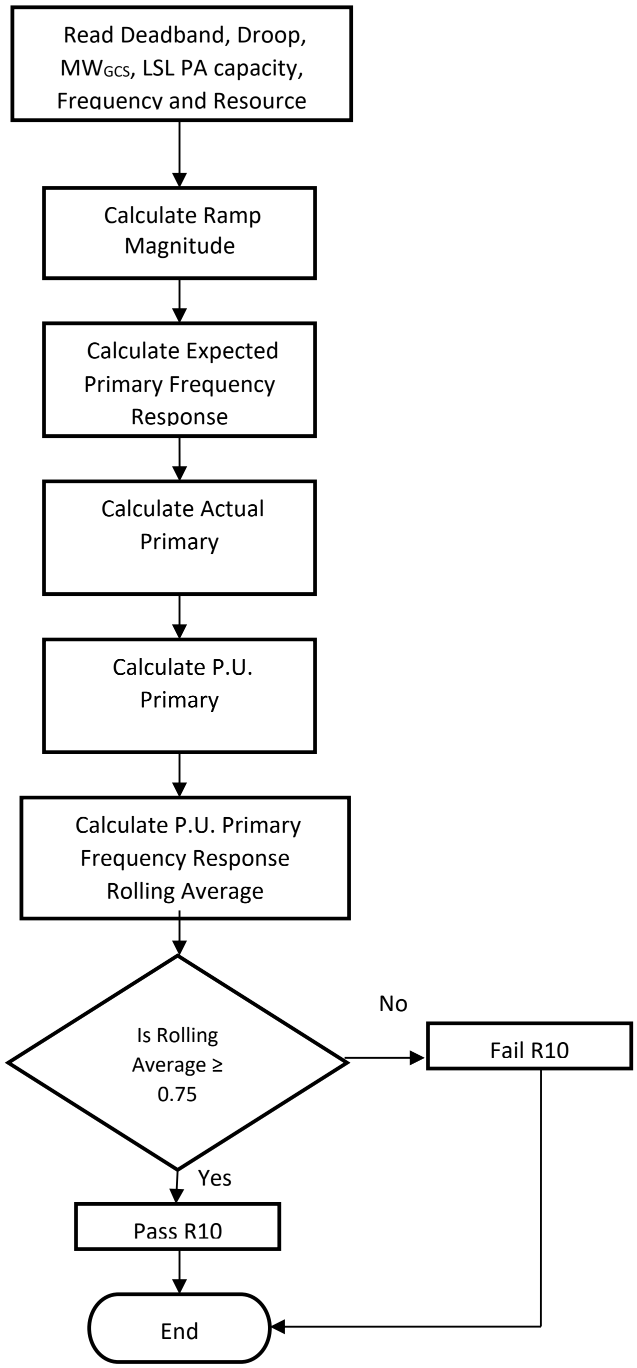
T = Time in Seconds

Attachment B to

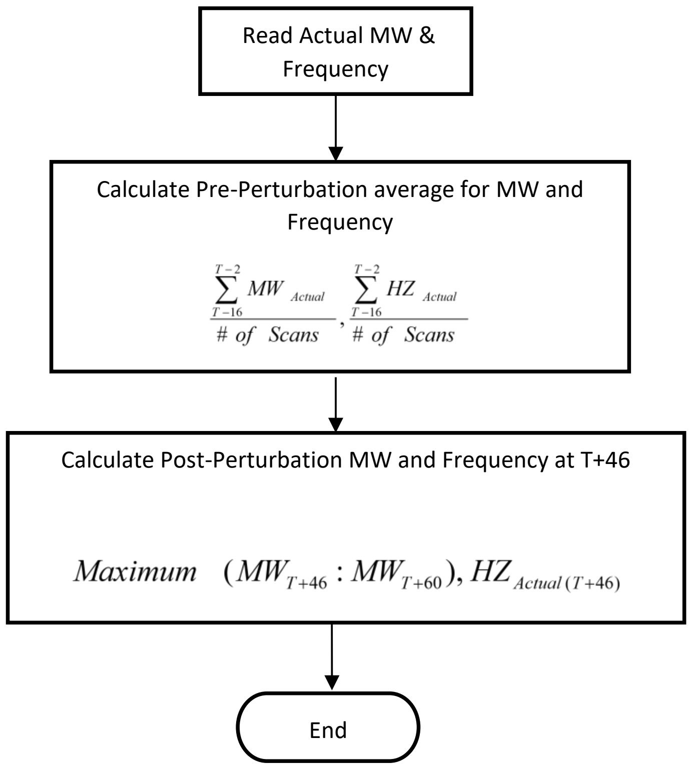
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for BAL-001-TRE-3

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

$$Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821$$

End

(MWT-4 – MWT-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 (ASPFRadj)

For low frequency events:

$$ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

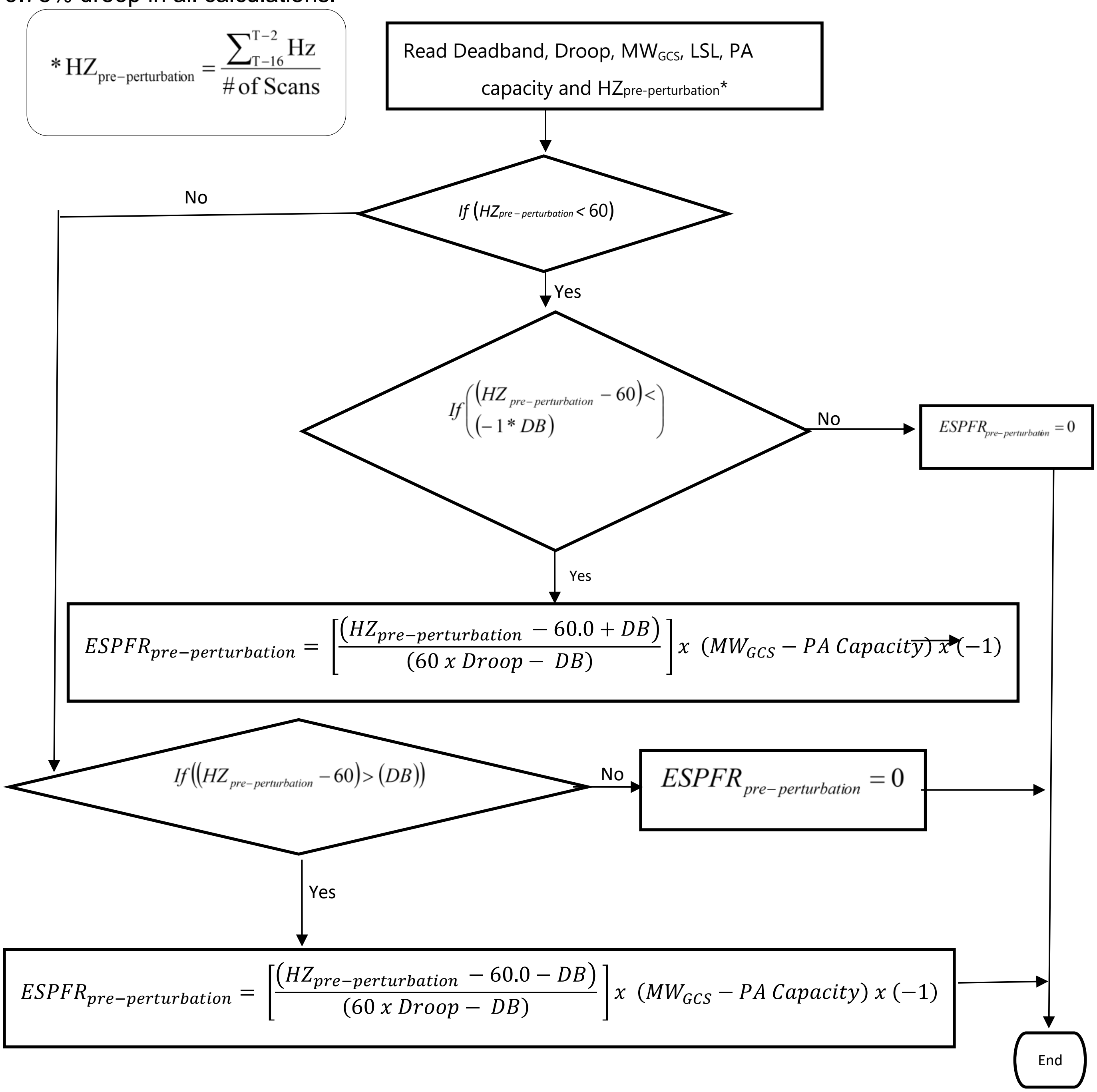
For high frequency events:

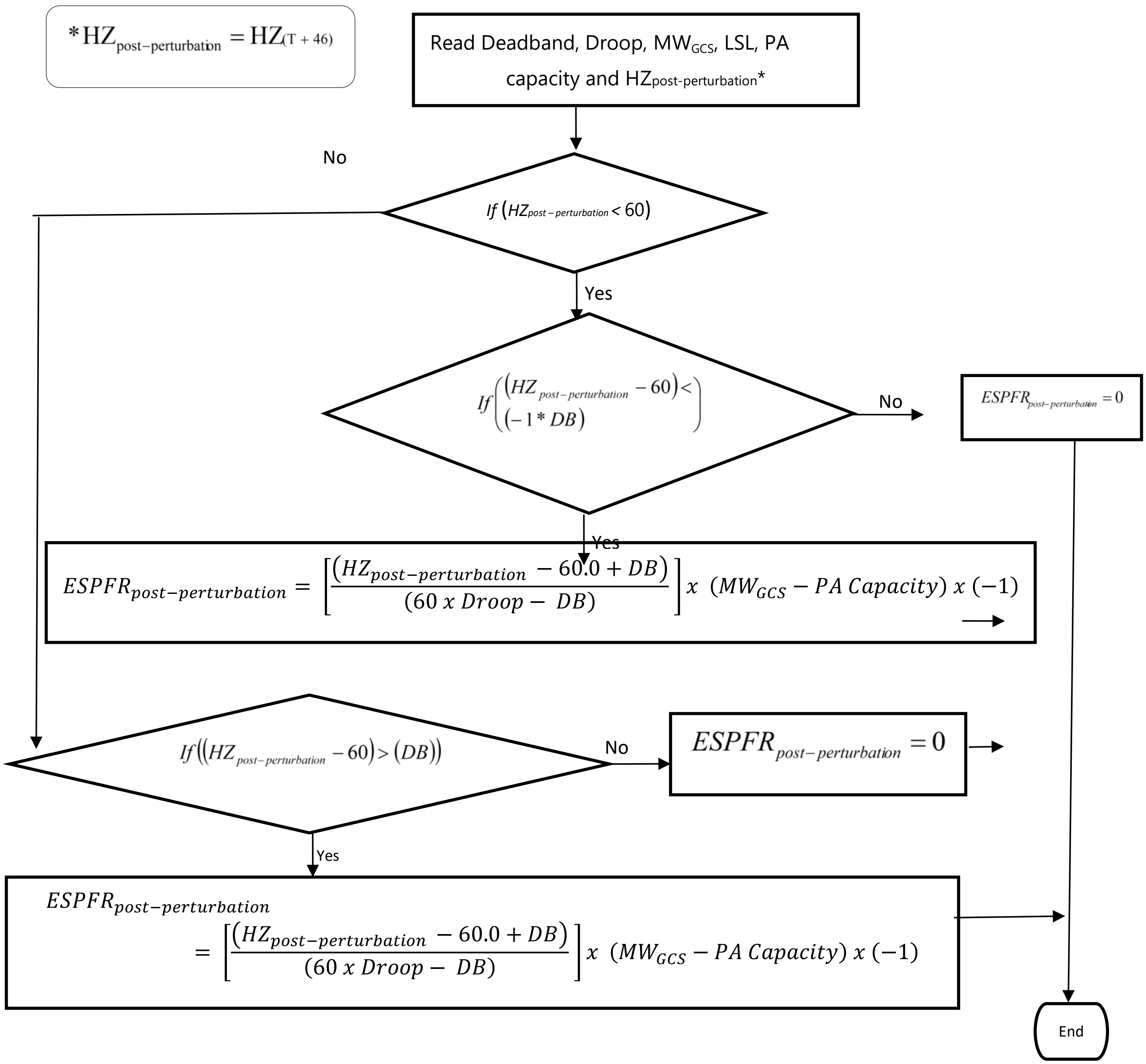
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

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

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

$$\%\,Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$MW_{adj} = ESPFR_{ideal}\,x\,\frac{K}{Rated\ Trottle\ Pressure}\,x(MW_{GCS} - PA\ Capacity)xSteam\ Flow\ Change\ Factorx(-1)$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

$$ESPFR_{final} = \left(ESPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

End

$MW_{post-perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Adjustment for Combustion Turbines and Combined Cycle Facilities

Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$ESPFR_{final} = ESPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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 BESS with capacity that is not expected to provide PFR

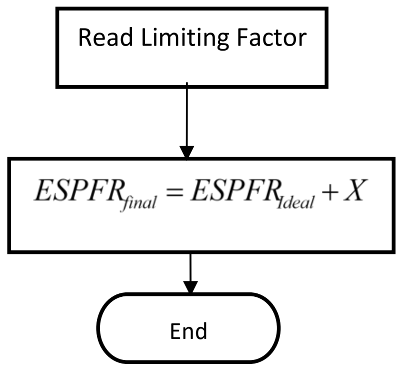
Read MW_{GCS}, capacity not expected to provide PFR

$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

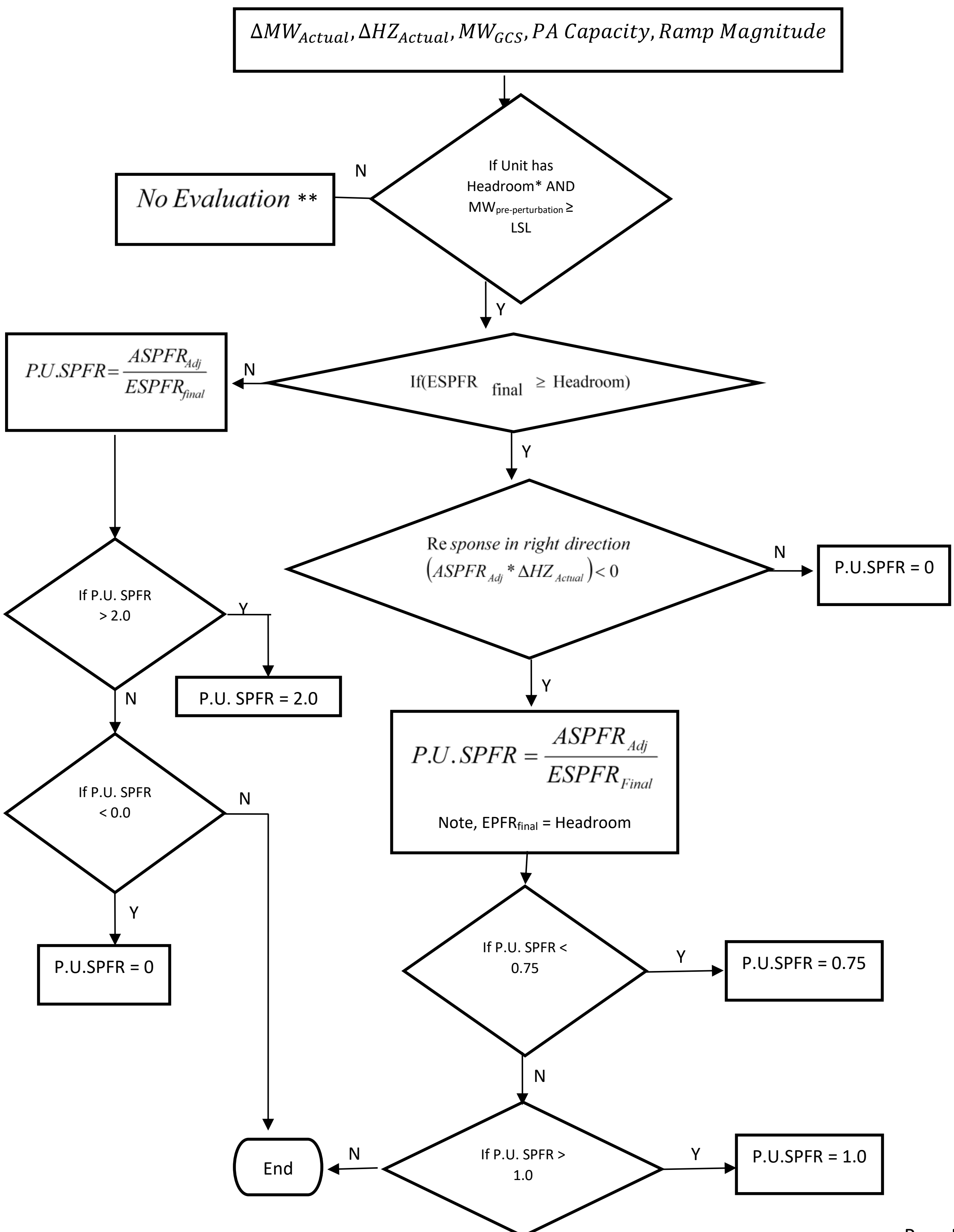


$*HZ_{Actual} = HZ_{(T + 46)}$

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

$*HZ_{Actual} = HZ_{(T + 46)}$


$\Delta MW_{Actual}, \Delta HZ_{Actual}, MW_{GCS}, PA\ Capacity, Ramp\ Magnitude$
If Unit has Headroom* AND $MW_{pre\text{-}perturbation} \geq$ LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
Response in right direction $(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
N
P.U.SPFR = 0
If P.U. SPFR > 2.0
Y
P.U. SPFR = 2.0
N
If P.U. SPFR < 0.0
N
Y
P.U.SPFR = 0
Y
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
Note, $EPFR_{final}$ = Headroom
If P.U. SPFR < 0.75
Y
P.U.SPFR = 0.75
N
If P.U. SPFR > 1.0
Y
P.U.SPFR = 1.0
N
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

For low frequency events:

$$\boxed{Headroom = HSL - PA\ Capacity - capacity\ not\ expected\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**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

Revision History

Version	Date	Action	Change Tracking
1	7/25/2011	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/7/2012	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 FME, and other changes to respond to field trial results, comments, and corrections.
1.1	3/6/2013	Texas RE RSC approves submittal to Texas RE Board	
1.1	4/23/2013	Texas RE Board approves submittal to NERC and FERC	
1.1	9/18/2013	NERC and Texas RE file Petition for approval to FERC	
1.1	1/16/2014	Approved by FERC	
1.2	5/21/2015	Texas RE Board approves revisions to Attachment 2 Primary Frequency Response Reference Document	For clarification and consistency of the equations used in the Attachment, changes performed to: - “T” in the equations refers to the start of the Frequency Measurable Event. - “T-2” nomenclature utilized for clarity rather than “t(-2)” (applicable to numerous equations) - Removed floating x in $EPFR_{final}$ for Steam Turbine equation - Corrected sign convention for Expected Sustained Primary Frequency Response to match the calculation for expected primary frequency response. Corrected Adjusted MW for $ESPFR_{final}$ for Steam Turbine by multiplying -1 to calculate proper value. - On Steam Flow Change Factor removed floating x and reinserted PA capacity. - Clarified Footnote 5 for scenario of high frequency event for setting LSL as operating margin (similar to HSL for low frequency events). - Clarified in flowcharts for both P.U. Initial Primary & Sustained

			Frequency Response Calculations: ○ Unit needs to have Headroom and be above LSL to be scored. ○ Cap $EPFR_{final}$ at value of Headroom on unit - Per RSC 5/11/2015, all references to “Final” were changed to “final”. - Per RSC 5/11/2015, P.U.PFR and P.U.S.PFR removed italics in flowcharts.
1.3	11/14/2016	RSC approves minor changes to Attachment 2 Primary Frequency Response Reference Document	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
1.3	12/07/2016	Texas RE Board approves minor changes to Attachment 2 Primary Frequency Response Reference Document.	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
2.0	12/11/2019	Texas RE Board approves changes to the Attachment.	Removed the requirement for Governor droop and deadband settings for Steam turbines of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process for submitting an exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1. Changed numbering on Attachment 2 to Attachment 1
3.0	TBD		Attachment 1 was updated to align the MW_{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and

			account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-3
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1 Balancing Authority

    4.1.2 Generator Owners

    4.1.3 Generator Operators

    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-3.

    4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3.

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

5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-3.
6. **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 8.5. 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 (FME) (that starts at t(0)).

    This Regional Standard provides requirements related to identifying Frequency Measurable 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 (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).

In this Regional Standard the terms “resource” and “generating unit/generating facility” refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services~~In this Regional Standard the term “resource” is synonymous with “generating unit/generating facility/battery energy storage system (BESS)”.~~

B. Requirements and Measures

R1. The Balancing Authority shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME, the Balancing Authority 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 Balancing Authority shall have evidence that 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 Balancing Authority shall calculate the Primary Frequency Response of each generating unit/generating facility~~/BESS~~ 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. *[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]*

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[1] Attachment 1: Primary Frequency Response Reference Document contains the calculations that the Balancing Authority will use to determine Primary Frequency Response performance of generating units/generating facilities~~/BESS~~. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

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 Generator Owner by the end of the month in which they were completed.

2.3. If a generating unit/generating facility~~/BESS~~ has not participated in a minimum of ~~(8)~~ eight (8) FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

M2. The Balancing Authority shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility~~/BESS~~ monthly as required in Requirement R2.

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R3. The Balancing Authority 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 Balancing Authority shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The Balancing Authority 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 occur, the Balancing Authority 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. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M4. The Balancing Authority 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 Balancing Authority 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.~~ T~~M5. T~~he Balancing Authority 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.

M5.

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~~R7.~~R6. ~~R6.~~ Each Generator Owner shall set its Governor parameters, ~~-~~as set forth in Requirement R6, Parts 6.1, 6.2, and 6.3~~follows:~~. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the Balancing Authority.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
Generating u~~U~~nits/generating facilities that are not qualified [2] to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings	+/- 0.036 Hz
All Other g~~G~~enerating u~~U~~nits/g~~G~~enerating f~~F~~acilities~~/BESS~~[3]	+/- 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 Balancing Authority.

Table 6.2 Governor Droop Settings

Generator Type	**Max. Droop % Setting**
Combustion Turbine (Combined Cycle)	4%
All other generating units/generating facilities	5%
~~**Generator Type**~~	~~**Max. Droop % Setting**~~
~~Hydro~~	~~5%~~
~~Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)~~	~~5%~~

[2] Refers to ancillary service qualification criteria as required by the Balancing Authority.

~~[3] Requirements~~ R6, Parts ~~R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.~~

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~~Combustion Turbine (Combined Cycle)~~	~~4%~~
~~Steam Turbine[4]~~	~~5%~~
~~Diesel~~	~~5%~~
~~BESS~~	~~5%~~
~~DC Tie Providing Ancillary Services~~	~~5%~~
~~Variable Renewable (Non-Hydro)~~	~~5%~~

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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.

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Where

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

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

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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. ~~M6.~~ Each Generator Owner shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

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- Governor test reports
- Governor setting sheets
- Performance monitoring reports
- Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz

~~**R8.**~~**R7.** ~~R7.~~ Each Generator Owner shall operate each generating unit/generating facility~~/BESS~~ that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility~~/BESS~~ is online and released for dispatch, unless the Generator Owner has a

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[4] ~~Requirements~~ R6, Parts ~~R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.~~

valid reason for operating with the Governor not in service and the Generator Operator has been notified that the Governor is not in service. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

M7. ~~M7.~~ Each Generator Owner shall have evidence that it notified the Generator Operator as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility~~/BESS~~ was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. ~~R8.~~ Each Generator Operator shall notify the Balancing Authority 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. ~~M8.~~ Each Generator Operator shall have evidence that it notified the Balancing Authority within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility~~/BESS~~, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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~~/BESS~~ 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~~/BESS~~ initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

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[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. ~~**M9.**~~ Each Generator Owner shall have evidence that each of its generating units/generating facilities~~/BESS~~ achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each Generator Owner shall have documented evidence of any FMEs where the generating unit performance was excluded from the rolling average calculation.

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R10. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility~~/BESS~~, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

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~~/BESS~~ 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~~/BESS~~ sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

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M10. ~~**M10.**~~ Each Generator Owner shall have evidence that each of its generating units/generating facilities~~/BESS~~ achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each Generator Owner shall have documented evidence of any Frequency Measurable Events where generating unit performance was excluded from the rolling average calculation.

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C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit's/generating facility's~~/BESS's~~ rolling average for R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). After CEA consultation with the BA, and i~~I~~f the CEA approves the request to reset the rolling average(s), the CEA shall notify the BA that the GO may begin a new rolling average(s). In the CEA's notice to the BA, the CEA shall provide the BA with an effective date of the reset time for the rolling average(s). Upon receipt of the notice from the CEA, the BA shall, as soon as practicable, implement the change to the GO's rolling average(s). The first performance during an FME following the CEA's effective date to the BA shall count as the first event in the rolling average(s), and the entity will have an average frequency performance score after 12 successive months or eight events under Requirements R9 and R10 of the Regional Standard.

1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the ~~Compliance Enforcement Authority~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

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~~CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Balancing Authority shall retain a list of identified FMEs and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The Balancing Authority shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.

- The Balancing Authority 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 Balancing Authority shall retain all data and calculations relating to the Interconnection's combined Frequency Response performance, and all evidence of actions taken to increase the Interconnection's combined Frequency Response performance, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each Generator Operator shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each Generator Owner 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~~CEA shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority 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 Balancing Authority 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 Generator Owner operated with its Governor out of service and did not notify the Generator Operator upon discovery of its Governor out of service.
R8	The Generator Operator notified the Balancing Authority of a change in Governor status between 31 minutes and one hour after the General Operator was	The General Operator notified the Balancing Authority of a change in Governor status more than 1 hour but within 4 hours after the Generator Operator was	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hours but within 24 hours after the Generator	The Generator Operator failed to notify the Balancing Authority of a change in Governor status within 24 hours after the Generator Operator was notified of the discovery of the change.

	notified of the discovery of the change.	notified of the discovery of the change.	Operator was notified of the discovery of the change.	
R9	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	8/15/2013	Adopted by NERC Board of Trustees	
1	1/16/2014	FERC Order issued approving BAL-001-TRE-1. (Order becomes effective April 1, 2014.)	
2	12/11/2019	Approved by Texas RE Board of Directors	Removed the requirement Governor droop and deadband settings for Steam Turbine(s) of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process and legitimate operating conditions for submitting an FME exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1.
3			Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA). Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regard to resetting the 12-month rolling average

			Primary Frequency Response (PFR) performance score. Define PFR performance requirements for Battery Energy Storage Systems (BESS).

Standard Attachments

1. Attachment 1 – 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 Member Representatives Committee (MRC) for consideration. The revision request will be posted in accordance with MRC procedures. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC 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.

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-~~3~~2
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 is maintained by Texas RE and subject to modifications 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 Member Representatives Committee (MRC) for consideration. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC 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~~/BESS~~: 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~~/BESS~~.

> **Low Sustained Limit (LSL)** for a generating unit/generating facility~~/BESS~~: The limit

[1] These spreadsheets are available on Texas RE's public website.

established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy capability of a generating unit/generating facility~~/BESS~~. This value could be negative for BESS to represent the charging capability.

Maximum Megawatt Governor Control System (MW_{GCS}) for the purposes of this standard, maximum megawatt control range of the Governor control system MW_{GCS} is calculated from HSL to LSL ~~less any capacity that is not expected to provide PFR~~ for BESS and HSL to 0 for all other all generator types.~~. For all generator types, except BESS, MW_{GCS}, is calculated from HSL to 0 while BESS is calculated from HSL to LSL.~~

Design Settings versus real-time Evaluation: Settings and verifications (Requirement R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.

In this Regional Standard the terms “resource” and “generating unit/generating facility” refers to any resource ~~injecting power to serve load~~capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services
- ~~Battery Energy Storage System (BESS)~~

~~DC Tie Providing Ancillary Services~~~~In this regional standard, the term “resource” is synonymous with “generating unit/generating facility/BESS”.~~

~~**Design Settings versus real-time Evaluation:** Settings and verifications (R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.~~

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility~~/BESS~~, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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.

Commented [JH1]: Removing this call out to align with our discussion with SDT that this should be a static droop value. Calculations modified to show that response should be limited to PFR capacity available.

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9.2 If a generating unit/generating facility~~/BESS~~ 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~~/BESS~~ initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial PFR 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 PFR ($APFR_{Adj}$), 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 PFR [$P.U.PFR_{Resource}$] for any FME.

<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 PFR of a resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Primary\ Frequency\ Response_{Final}}$$

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The adjusted actual PFR ($APFR_{Adj}$) and the final expected PFR ($EPFR_{final}$) are calculated as described below.

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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 ($APFR_{adj}$)

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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.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

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 PFR number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility~~/BESS~~ during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = (MWT-4 – MWT-60)*0.59

(MWT-4 – MWT-60) represents the MW ramp of the generator resource/generator

[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.

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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 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The deadbandmax and droopmax quantities come from Requirement R6.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

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$$Hz_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\# Scans}$$

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 net dependable capacity (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.

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Power Augmentation: For c~~C~~ombined -c~~C~~ycle 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

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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.

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$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

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$$MW_{adj} = EPFR_{ideal}\, x\, \frac{K}{Rated\ Trottle\ Pressure}\, x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\% \; Steam \; Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA \; Capacity)}$$

$$Steam \; Flow \; Change \; Factor = \frac{\% \; Steam \; Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

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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 an 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 BESS with capacity that is not expected to provide PFR

$$EPFR_{final} = Minimum \; (EPFR_{ideal}, MW_{GCS} - capacity \; not \; expected \; to \; provide \; PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{final} = EPFR_{ideal} + X$$

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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. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility~~/BESS~~, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. ~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*~~

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~~/BESS~~ 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~~/BESS~~ sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner 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.

This process calculates the per unit sustained PFR 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 PFR (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 PFR [$P.U.SPFR_{Resource}$] for any 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 PFR 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 PFR performances when the unit provided frequency response during an FME.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

$$\cancel{P.U.PFR_{Resource}} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}$$

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained PFR of a resource during identified FMEs. For any given event $P.U.SPFR_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

<u>Actual Sustained Primary Frequency Response (*ASPFR*) Calculations</u>

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

Where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

[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.

$$MW_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\# Scans}$$

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.

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Actual Sustained Primary Frequency Response, Adjusted (*$ASPFR_{Adj}$*)

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$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

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 PFR 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 T=t(0). 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 T=t(0).*

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 T=t(0). ~~–~~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 (MWT-4 – MWT-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.

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<u>**Expected Sustained Primary Frequency Response (*ESPFR*) Calculations**</u>

The expected sustained PFR (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, HSL/LSL and actual frequency. It then allows for adjusting the value to compensate for the various types of l~~L~~imiting f~~F~~actors 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 PFR ($ESPFR_{ideal}$) 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.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

$$\cancel{ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{max})}{(droop_{max} \ x \ 60 - deadband_{max})} x \ (MW_{GCS} - PA\ Capacity) \ x \ (-1)\right]}$$

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{max})}{(droop_{max} \ x \ 60 - deadband_{max})} x \ (MW_{GCS} - PA\ Capacity) \ x \ (-1)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$\cancel{ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband_{max})}{(droop_{max} \ x \ 60 - deadband_{max})} x \ (MW_{GCS} - PA\ Capacity) \ x \ (-1)\right]}$$

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband_{max})}{(droop_{max} \ x \ 60 - deadband_{max})} x \ (MW_{GCS} - PA\ Capacity) \ x \ (-1)\right]$$

Capacity and 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 $deadband_{max}$ 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 MW_{GCS}. Other generator types may also have power as 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

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$$ESPFR_{final} = ESPFR_{ideal} + (HZ_{T+46} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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.)

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$ESPFR_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

$$MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Throttle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

$$\cancel{MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Throttle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x(-1)}$$

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Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

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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 an 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 BESS with capacity that is not expected to provide PFR

$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

ESPFR$_{final}$ for Other Generating Units/Generating Facilities~~/BESS~~

$$ESPFR_{final} = ESPFR_{Ideal} + X$$

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 a generating unit/generating facility is operating within 2% of its (MW$_{GCS}$ – PA capacity and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW$_{GCS}$ less capacity not expected to provide PFR 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:

$$\cancel{MW_{pre-perturbation} \geq \min[([MW_{GCS} - PA\ Capacity]\ x\ .98), ([MW_{GCS} - PA\ Capacity] - X\ MW)]}$$

$$MW_{pre-perturbation} \geq \min[([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}]\ x\ .98), ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}] - Y\ MW)]$$

then PFR is not evaluated for this FME, where Y~~X~~ is 5 MW for generating units/generating facility and 3 MW for BESS

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For frequency deviations above 60 Hz (HzPost-perturbation > 60, if:

$$\cancel{MW_{pre-perturbation} \le \max[(LSL + ([MW_{GCS} - PA\ Capacity]\ x\ 0.02)), (LSL + X\ MW)]}$$

$$MW_{pre-perturbation} \le \max[(LSL + ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}]\ x\ 0.02)), (LSL + Y\ MW)]$$

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then PFR is not evaluated for this FME where ~~X~~ Y is 5 MW for generating units/generating facility and 3 MW for BESS

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 (MW_{GCS} less PA capacity) or 5 MW for generating units/generating facilities or 3 MW for BESS, 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 BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) and greater than 3 MW; and
   c. The Expected Primary Frequency $Response_{final}$ is greater than the generating unit/generating facility's~~/BESS~~ available frequency responsive capacity[4]; and
   d. The generating unit/generating facility's~~/BESS~~ $APFR_{adj}$ response is in the correct direction.

2. When calculation of the $P.U.PFR_{Resource}$ uses the resource's (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) 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] In this circumstance, when frequency is below 60 Hz, the $EPFR_{final}$ is set to operating margin based on MW_{GCS} (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the $EPFR_{final}$ is set to operating margin based on LSL for the purpose of calculating $PUPFR_{resource}$.

Public

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 PFR measures.

Attachment A to
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for
BAL-001-TRE-~~2~~3

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Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

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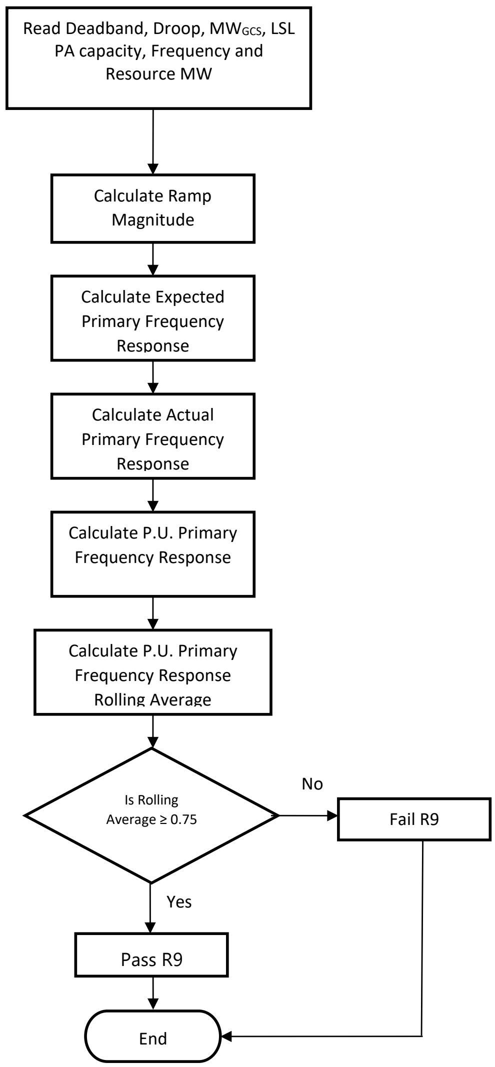
PA = Power Augmentation
HSL = High Sustained Limit
LSL = Low Sustained Limit
MW_{GCS} = maximum megawatt control range of the Governor control system



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Pre/Post-Perturbation Average MW and Average Frequency Calculations

Read Actual MW & Frequency

↓

Calculate Pre-Perturbation average for MW and Frequency

$$\frac{\sum_{T-16}^{T-2} MW}{\#\ of\ \ Scans}, \frac{\sum_{T-16}^{T-2} HZ}{\#\ of\ \ Scans}$$

↓

Calculate Post-Perturbation average for MW and Frequency

$$\frac{\sum_{T+20}^{T+52} MW}{\#\ of\ \ Scans}, \frac{\sum_{T+20}^{T+52} HZ}{\#\ of\ \ Scans}$$

↓

End

Ramp Magnitude Calculation

Ramp Magnitude = $(MW_{T-4} – MW_{T-60})*0.59$

End

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(MWT-4 – MWT-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.

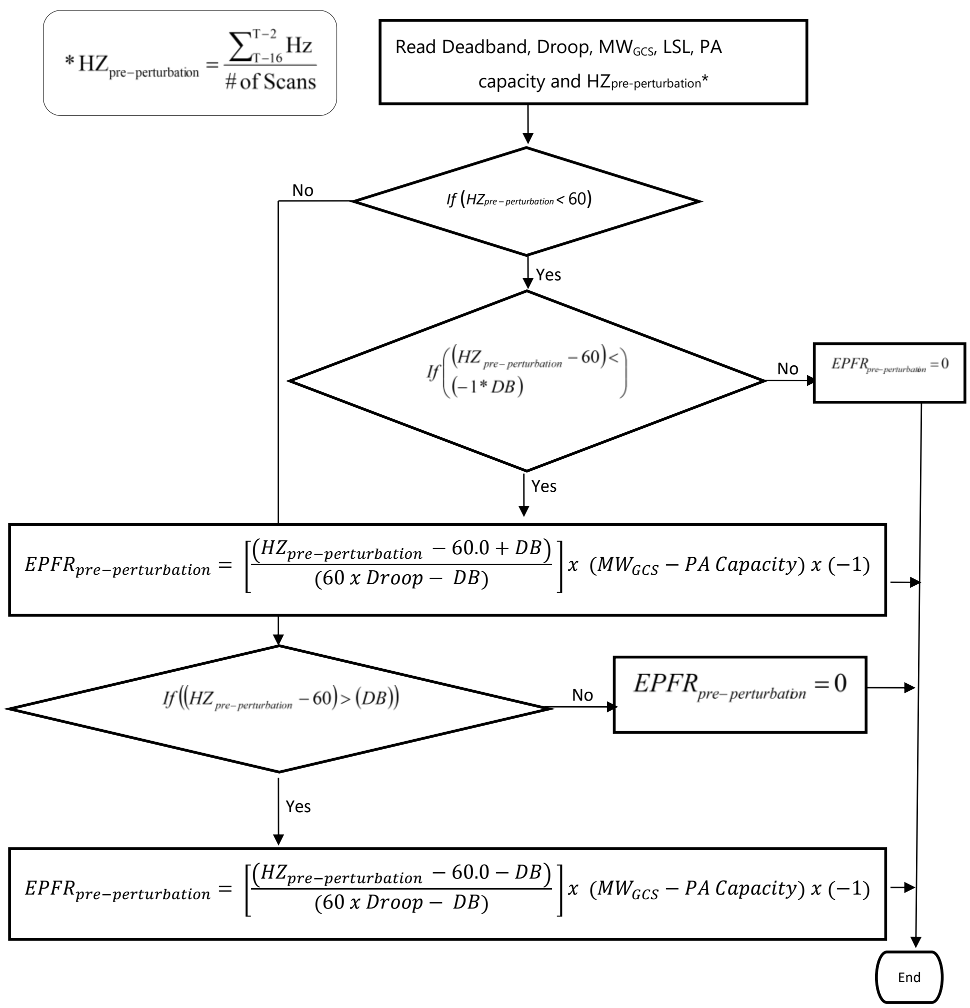
Actual Primary Frequency Response (APFRAdj)

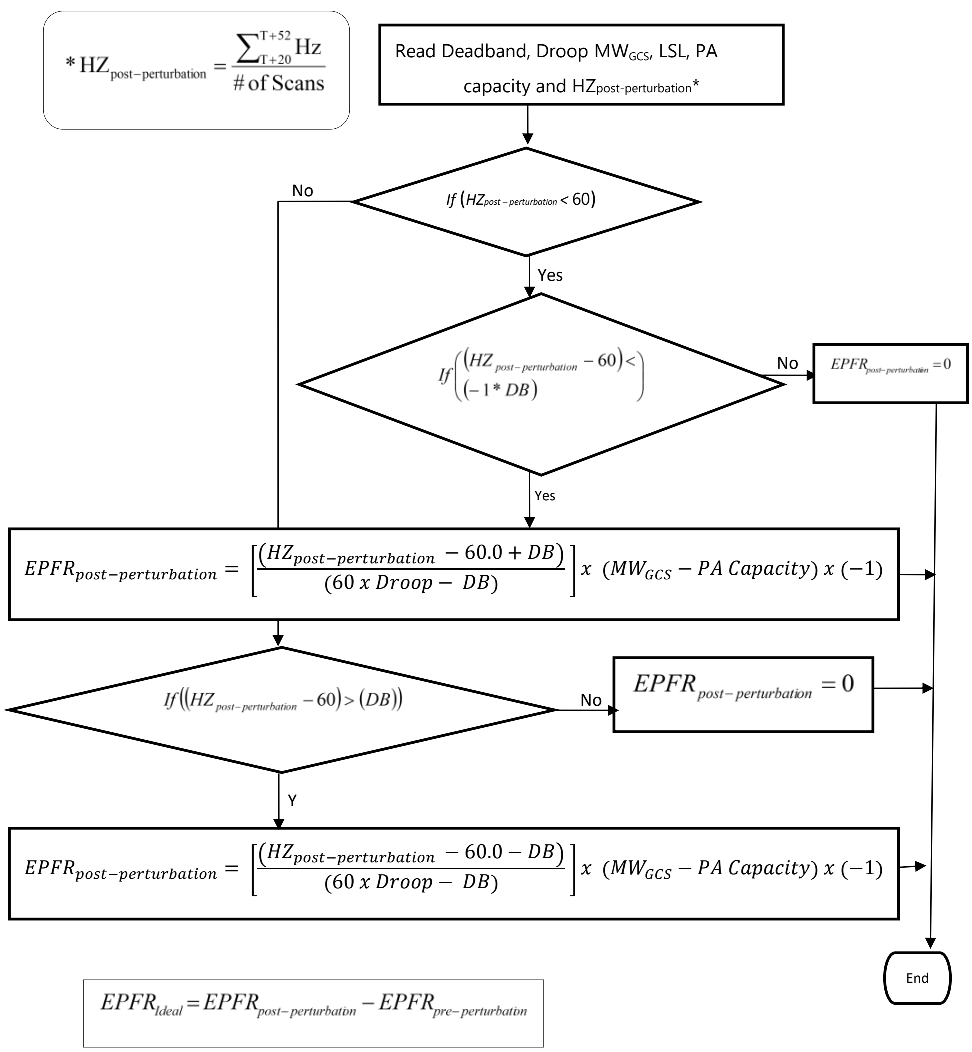
$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

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.




$* HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# \text{ of Scans}}$
Read Deadband, Droop MW_{GCS}, LSL, PA capacity and $HZ_{post-perturbation}$*
$If\left(HZ_{post-perturbation} < 60\right)$
No
Yes
$If\left(\left(HZ_{post-perturbation} - 60\right) < \left(-1 * DB\right)\right)$
No
$EPFR_{post-perturbation} = 0$
Yes
$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + DB\right)}{\left(60\ x\ Droop - DB\right)}\right] x\ \left(MW_{GCS} - PA\ Capacity\right) x\ (-1)$
$If\left(\left(HZ_{post-perturbation} - 60\right) > \left(DB\right)\right)$
No
$EPFR_{post-perturbation} = 0$
Y
$EPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 - DB\right)}{\left(60\ x\ Droop - DB\right)}\right] x\ \left(MW_{GCS} - PA\ Capacity\right) x\ (-1)$
End
$EPFR_{Ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS} $MW_{pre-perturbation}$ and $MW_{post-perturbation}$

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$$\%\,Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre-perturbation}$

↓

$$EPFR_{final} = \left(EPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

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Read MW_{GCS}, PA capacity, $HZ_{post-perturbation}$*

$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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.)

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Adjustment for BESS with capacity that is not expected to provide PFR

Read MW_{GCS}, capacity not expected to provide PFR

$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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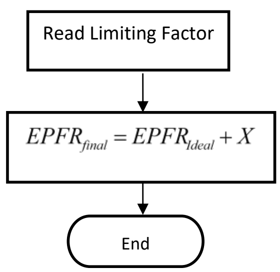

$$* \, HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\#\ of\ Scans}$$

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.

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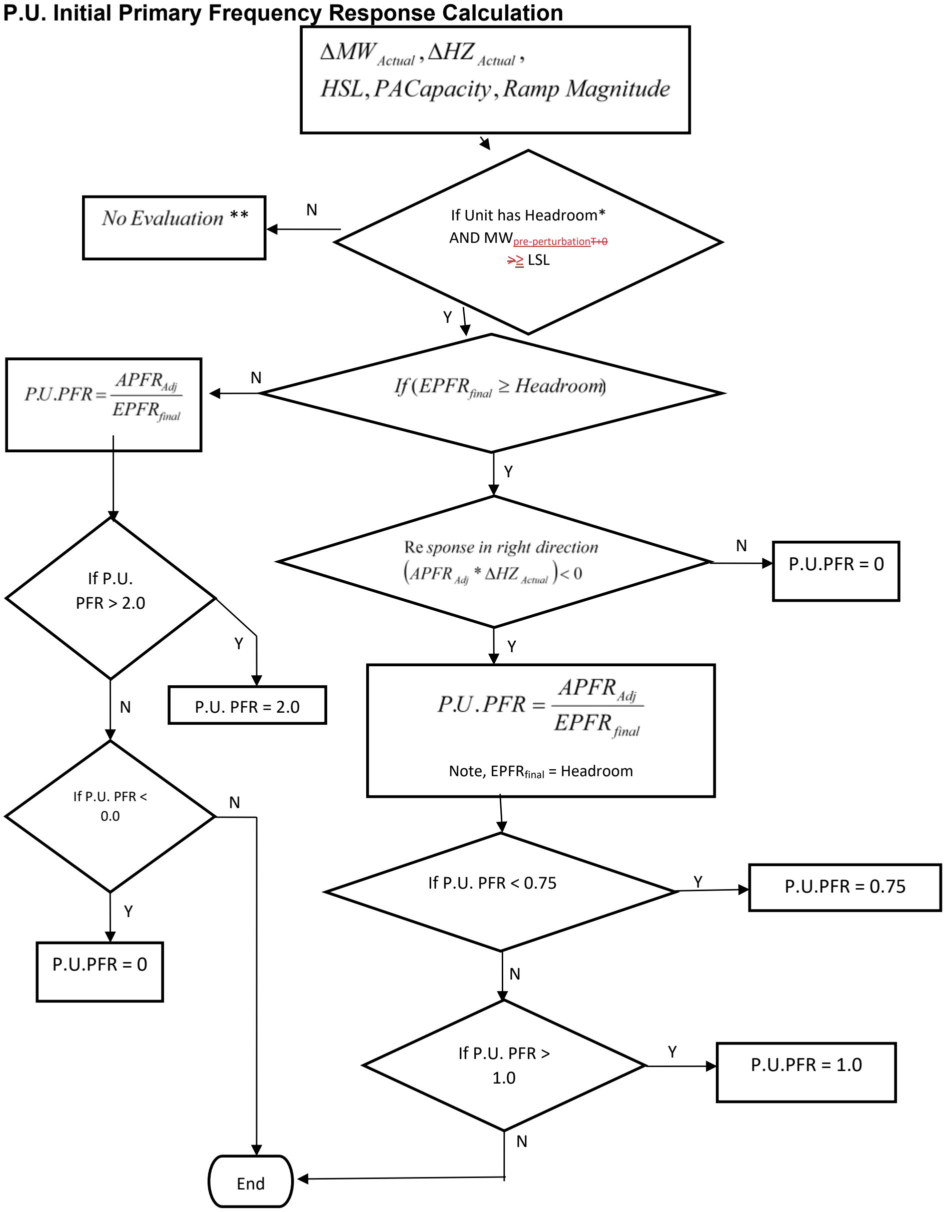
P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW$_{GCS}$ less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW$_{GCS}$ less PA capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

For low frequency events:

$$\boxed{Headroom = \cancel{MW_{GCS}} HSL - PA\ Capacity - capcity\ not\ expeced\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**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

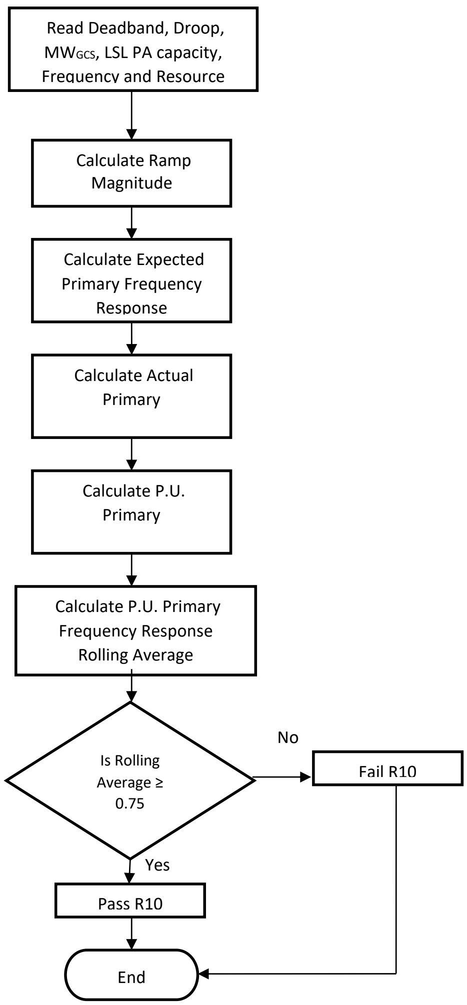
Attachment B to

Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for

BAL-001-TRE-~~2~~3

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations

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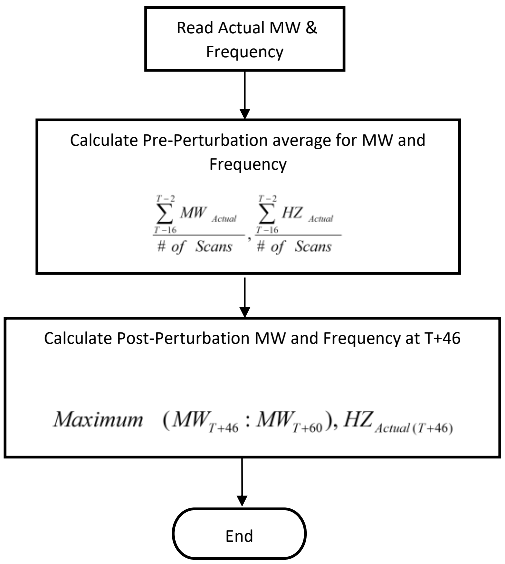

Ramp Magnitude Calculation - Sustained

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$$\boxed{Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821}$$

End

(MWT-4 – MWT-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.

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Actual Sustained Primary Frequency Response (ASPFRadj)

For low frequency events:

$$\boxed{ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}}$$

End

For high frequency events:

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$$\boxed{ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}}$$

End

Expected Sustained Primary Frequency Response Calculation

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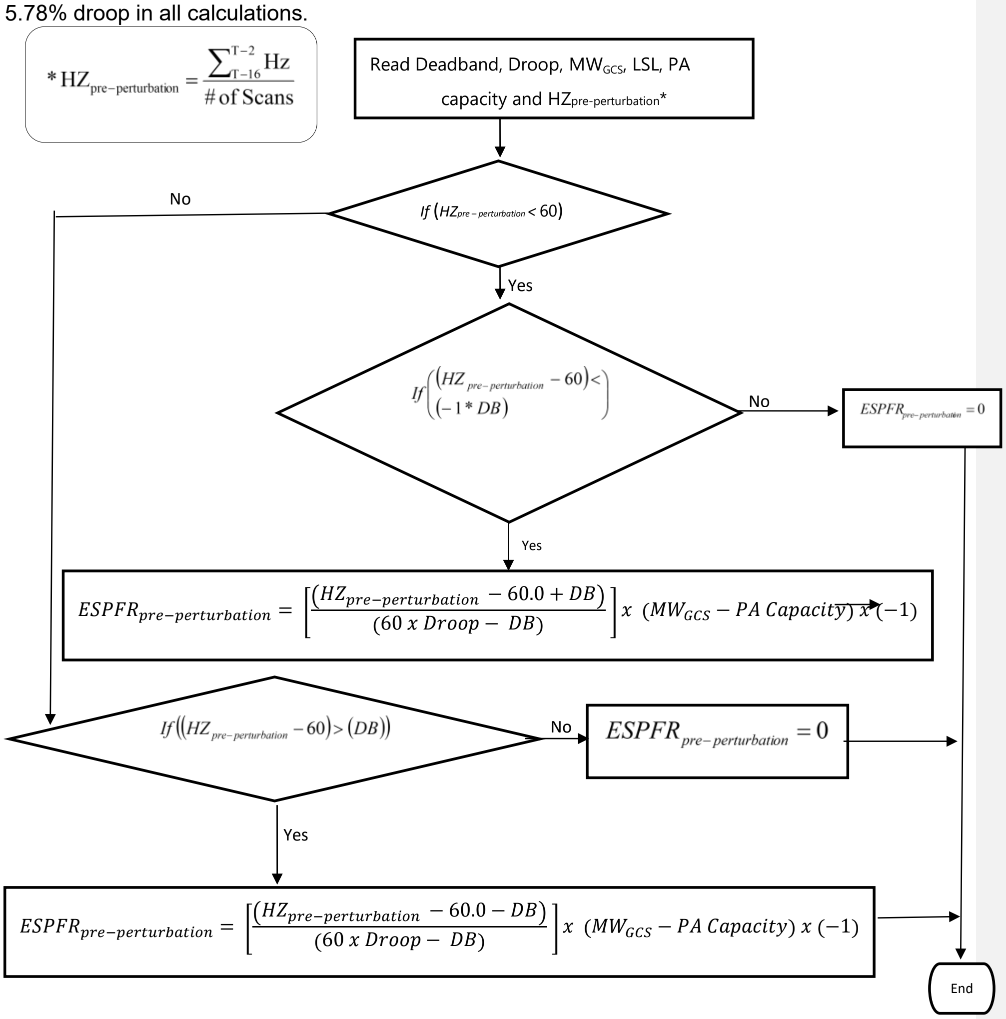
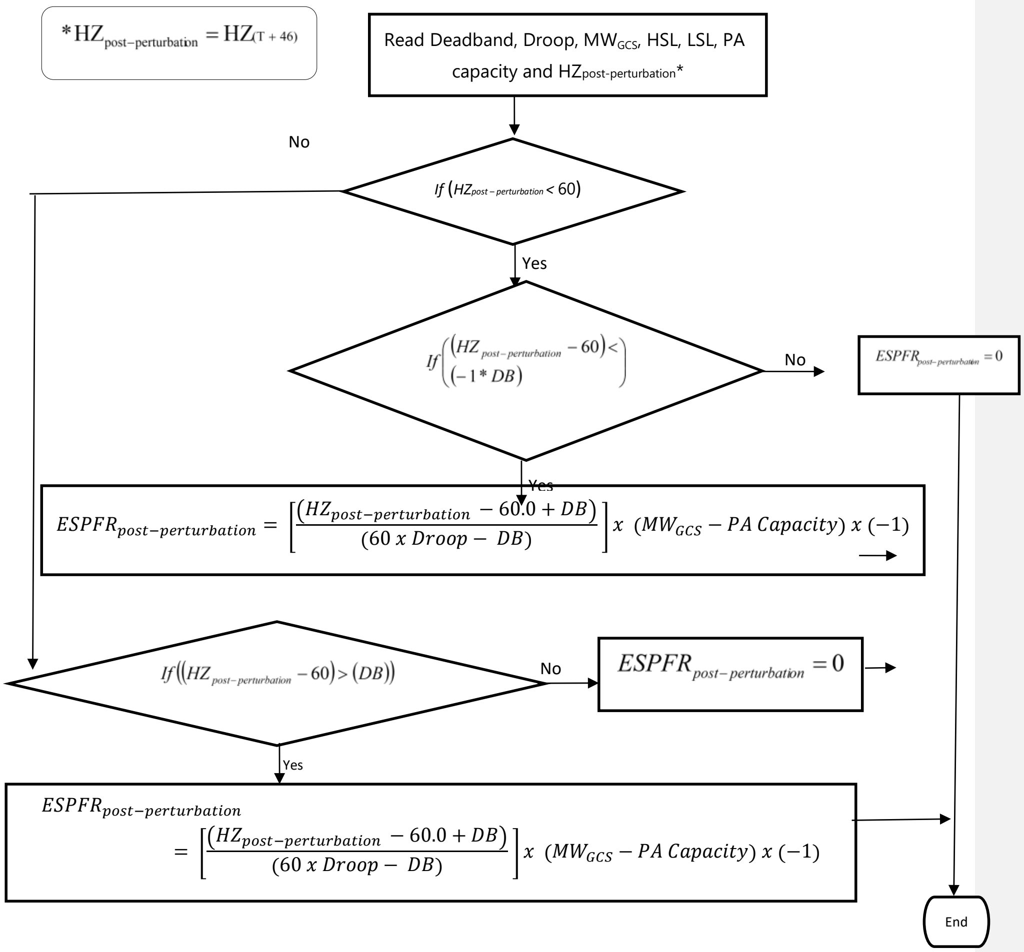
Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use

5.78% droop in all calculations.





$$ESPFR_{Ideal} = ESPFR_{post-perturbation} - ESPFR_{pre-perturbation}$$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

↓

$$\%\,Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{adj} = ESPFR_{ideal}\,x\,\frac{K}{Rated\ Trottle\ Pressure}\,x(MW_{GCS} - PA\ Capacity)xSteam\ Flow\ Change\ Factorx(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

↓

$$ESPFR_{final} = \left(ESPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

End

$MW_{post-perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Adjustment for Combustion Turbines and Combined Cycle Facilities

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Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$ESPFR_{final} = ESPFR_{ideal} + (HZ_{post-perturbation} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

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.)

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Adjustment for BESS with capacity that is not expected to provide PFR

Read MW_{GCS}, capacity not expected to provide PFR

$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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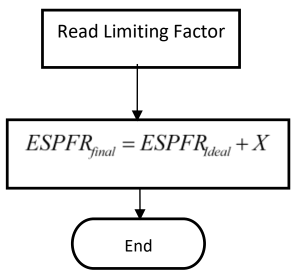

$$*HZ_{Actual} = HZ_{(T+46)}$$

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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.

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P.U. Sustained Primary Frequency Response Calculation

$$*HZ_{Actual} = HZ_{(T+46)}$$

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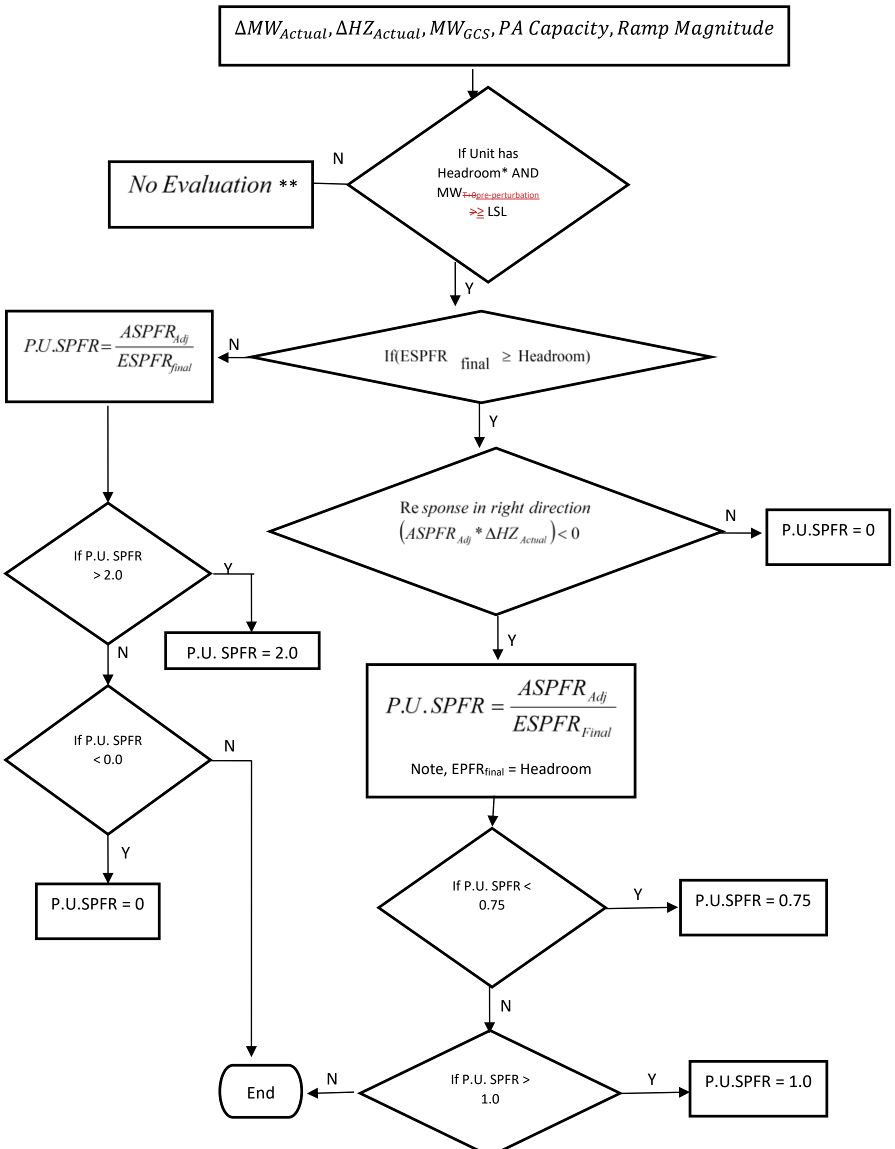
ΔMW_Actual, ΔHZ_Actual, MW_GCS, PA Capacity, Ramp Magnitude
If Unit has Headroom* AND MW~~T-0~~pre-perturbation ~~>~~≥ LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
P.U.SPFR = ASPFR_Adj / ESPFR_final
Y
Response in right direction (ASPFR_Adj * ΔHZ_Actual) < 0
N
P.U.SPFR = 0
Y
P.U.SPFR = ASPFR_Adj / ESPFR_Final
Note, EPFR_final = Headroom
If P.U. SPFR > 2.0
Y
P.U. SPFR = 2.0
N
If P.U. SPFR < 0.0
Y
P.U.SPFR = 0
N
If P.U. SPFR < 0.75
Y
P.U.SPFR = 0.75
N
If P.U. SPFR > 1.0
Y
P.U.SPFR = 1.0
N
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

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Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

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For low frequency events:

$$\boxed{Headroom = MW_{GCS} - PA\ Capacity - MW_{T-2}}$$

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For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**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.

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T = Time in Seconds

Revision History

Version	Date	Action	Change Tracking
1	7/25/2011	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/7/2012	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 FME, and other changes to respond to field trial results, comments, and corrections.
1.1	3/6/2013	Texas RE RSC approves submittal to Texas RE Board	
1.1	4/23/2013	Texas RE Board approves submittal to NERC and FERC	
1.1	9/18/2013	NERC and Texas RE file Petition for approval to FERC	
1.1	1/16/2014	Approved by FERC	
1.2	5/21/2015	Texas RE Board approves revisions to Attachment 2 Primary Frequency Response Reference Document	For clarification and consistency of the equations used in the Attachment, changes performed to: - “T” in the equations refers to the start of the Frequency Measurable Event. - “T-2” nomenclature utilized for clarity rather than “t(-2)” (applicable to numerous equations) - Removed floating x in EPFR$_{final}$ for Steam Turbine equation - Corrected sign convention for Expected Sustained Primary Frequency Response to match the calculation for expected primary frequency response. Corrected Adjusted MW for ESPFR$_{final}$ for Steam Turbine by multiplying -1 to calculate proper value. - On Steam Flow Change Factor removed floating x and reinserted PA capacity. - Clarified Footnote 5 for scenario of high frequency event for setting LSL as operating margin (similar to HSL for low frequency events). - Clarified in flowcharts for both P.U. Initial Primary & Sustained

			Frequency Response Calculations: ○ Unit needs to have Headroom and be above LSL to be scored. ○ Cap $EPFR_{final}$ at value of Headroom on unit - Per RSC 5/11/2015, all references to “Final” were changed to “final”. - Per RSC 5/11/2015, P.U.PFR and P.U.S.PFR removed italics in flowcharts.
1.3	11/14/2016	RSC approves minor changes to Attachment 2 Primary Frequency Response Reference Document	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
1.3	12/07/2016	Texas RE Board approves minor changes to Attachment 2 Primary Frequency Response Reference Document.	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
2.0	12/11/2019	Texas RE Board approves changes to the Attachment.	Removed the requirement for Governor droop and deadband settings for Steam turbines of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process for submitting an exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1. Changed numbering on Attachment 2 to Attachment 1
3.0	TBD		Attachment 1 was updated to align the MW_{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and

			account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.~~[Description of Changes to reference document]~~

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-~~2~~3
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

   4.1. Functional Entities:

   - **4.1.1** Balancing Authority
   - **4.1.2** Generator Owners
   - **4.1.3** Generator Operators

   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-~~2~~3.
   - **4.2.2** Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-~~2~~3.
   - **4.2.3** Any generators that are not required by the Balancing Authority to provide primary frequency response are exempt from this standard.

5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-~~2~~3.
6. **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 8.5. 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 (FME) (that starts at t(0)).

   This Regional Standard provides requirements related to identifying Frequency ~~Measureable~~Measurable 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 (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

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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~~terms "resource" ~~is synonymous with~~and "generating unit/generating facility~~".~~" refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

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B. Requirements and Measures

R1. The Balancing Authority shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME, the Balancing Authority 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 Balancing Authority shall have evidence that 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.

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R2. The Balancing Authority 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. *[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]*

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

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[1] ~~The~~ Attachment 1: Primary Frequency Response Reference Document contains the calculations that the Balancing Authority 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.

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2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the Generator Owner 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 (8) FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

M2. The Balancing Authority 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 Balancing Authority 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 Balancing Authority shall demonstrate that the IMFR was determined in December of each year per ~~per~~ Requirement R3. The Balancing Authority 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~~occur, the Balancing Authority 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. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M4. The Balancing Authority 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 Balancing Authority 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 Balancing Authority shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average

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combined Frequency Response performance was less than the IMFR, per Requirement R5.

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R6. Each Generator Owner shall set its Governor parameters, as ~~follows:~~ set forth in Requirement R6, Parts 6.1, 6.2, and 6.3. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

~~6.1.~~ 6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the Balancing Authority.

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*~~ Generating units/generating facilities that are not qualified [2] to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings	+/- 0.~~017~~036 Hz
All Other generating units/generating facilities	+/- 0.017 Hz

~~6.2.~~ 6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the Balancing Authority.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
~~Hydro~~	~~5%~~
~~Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)~~	~~5%~~
Combustion Turbine (Combined Cycle)	**4%**
~~Steam Turbine*~~ All other generating units/generating facilities	**5%**
~~Diesel~~	~~5%~~
~~DC Tie Providing Ancillary Services~~	~~5%~~

[2] Refers to ancillary service qualification criteria as required by the Balancing Authority.

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~~Variable Renewable (Non-Hydro)~~	~~5%~~

~~*Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.~~

~~6.3.~~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.

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

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

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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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M6. Each Generator Owner 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
- Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz

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R7. Each Generator Owner 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

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released for dispatch, unless the Generator Owner has a valid reason for operating with the Governor not in service and the Generator Operator has been notified that the Governor is not in service. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

M7. Each Generator Owner shall have evidence that it notified the Generator Operator 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.

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R8. Each Generator Operator shall notify the Balancing Authority 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]*

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M8. Each Generator Operator shall have evidence that it notified the Balancing Authority within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

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~~**R9.**~~ **R9.** Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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~~9.1.~~ 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.

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~~9.2.~~ 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.~~ 9.3 A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each Generator Owner 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 Generator Owner shall have documented evidence of any FMEs where the generating unit performance was excluded from the rolling average calculation.

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~~**R10.**~~ **R10.** Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

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~~10.1.~~ 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.

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~~10.2.~~ 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.~~ 10.3. A generating unit/generating facility's sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority 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~~,~~, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority ~~-~~may request raw data from the Generator Owner as a substitute.

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M10. Each Generator Owner 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 Generator Owner shall have documented evidence of any Frequency Measurable Events where generating unit performance was excluded from the rolling average calculation.

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C. Compliance

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1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating ~~unit/generating facility completes a mitigation plan and implements corrective action(s) 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~~ unit's/generating facility's rolling average for R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). After CEA consultation with the BA, and if the CEA approves the request to reset the rolling average(s), the CEA shall notify the BA that the GO may begin a new rolling average(s). In the CEA's notice to the BA, the CEA shall provide the BA with an effective date of the reset time for the rolling average(s). Upon receipt of the notice from the CEA, the BA shall, as soon as practicable, implement the change to the GO's rolling average(s). The first performance during an FME following the CEA's effective date to the BA shall count as the first event in the rolling average(s), and the entity will have an average frequency performance score after 12 successive months or eight events ~~per~~under Requirements R9 and R10 of the Regional Standard.

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1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the ~~Compliance Enforcement Authority~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

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~~CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Balancing Authority shall retain a list of identified FMEs and shall

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retain FME information since its last compliance audit for Requirement R1, Measure M1.

- The Balancing Authority shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The Balancing Authority 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 Balancing Authority shall retain all data and calculations relating to the Interconnection's combined Frequency Response performance, and all evidence of actions taken to increase the Interconnection's combined Frequency Response performance, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each Generator Operator shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each Generator Owner 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~~The CEA shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

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Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six-FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.

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R5.	N/A	N/A	N/A	The Balancing Authority 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 Generator Owner operated with its Governor out of service and did not notify the Generator Operator upon discovery of its Governor out of service.
R8	The Generator Operator notified the Balancing Authority of a change in Governor status between 31 minutes and one hour after the General Operator was	The General Operator notified the Balancing Authority of a change in Governor status more than 1 hour but within 4 hours after the Generator Operator was	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hours but within 24 hours after the Generator	The Generator Operator failed to notify the Balancing Authority of a change in Governor status within 24 hours after the Generator Operator was notified of the discovery of the change.

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	notified of the discovery of the change.	notified of the discovery of the change.	Operator was notified of the discovery of the change.	
R9	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-~~2~~3 Implementation Plan

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Version History

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Version	Date	Action	Change Tracking
1	8/15/2013	Adopted by NERC Board of Trustees	
1	1/16/2014	FERC Order issued approving BAL-001-TRE-1. (Order becomes effective April 1, 2014.)	
2	12/11/2019	Approved by Texas RE Board of Directors	Removed the requirement Governor droop and deadband settings for Steam Turbine(s) of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process and legitimate operating conditions for submitting an FME exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1.

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3			Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA). Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regard to resetting the 12-month rolling average Primary Frequency Response (PFR) performance score. Define PFR performance requirements for Battery Energy Storage Systems (BESS).

Standard Attachments

1. Attachment 1 – 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 Member Representatives Committee (MRC) for consideration. The revision request will be posted in accordance with MRC procedures. The MRC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas

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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.

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Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-~~2~~3
Requirements R2, R9, and R10
Performance Metric Calculations

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I. Introduction

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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,

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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 is maintained by Texas RE and subject to modifications 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 Member Representatives Committee (MRC) for consideration. The MRC shall discuss the revision request in a public meeting~~,~~ and will accept and consider verbal and written comments pertaining to the request. The MRC 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. This value could be negative for BESS to represent the charging capability.

~~In this regional~~ **Maximum Megawatt Governor Control System (MW_{GCS})** for the purposes of this standard, ~~the term~~maximum megawatt control range of the Governor control system MW_{GCS} is calculated from HSL to LSL for BESS and HSL to 0 for all other all generator types.

Design Settings versus real-time Evaluation: Settings and verifications (Requirement R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.

In this Regional Standard the terms "resource" ~~is synonymous with~~and "generating unit/generating facility~~".~~" refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

[1] These spreadsheets are available ~~at www.TexasRE.org.~~ on Texas RE's public website.

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- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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 ~~by the Balancing Authority~~ from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner 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~~PFR 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~~per unit Primary Frequency Response of a resource [P.U.PFR$_{Resource}$] as a ratio between the ~~Adjusted Actual Primary Frequency Response~~adjusted

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actual PFR (APFR$_{Adj}$), adjusted for the pre-event ramping of the unit, and the ~~Final Expected~~final expected Primary Frequency Response (EPFR$_{final}$) as calculated using the ~~Pre~~pre-perturbation and ~~Post~~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~~per unit PFR [P.U.PFR$_{Resource}$] for any ~~Frequency Measurable Event (~~FME~~)~~.

Initial Primary Frequency Response performance requirement

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

Where ~~-~~P.U.~~PFR$_{Resource}$ is~~PFR$_{Resource}$ is the per unit measure of the initial ~~Primary Frequency Response~~PFR of a resource during identified FMEs.

$$\cancel{P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{final}}}$$

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Primary\ Frequency\ Response_{Final}}$$

Where P.U.PFR$_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The ~~Adjusted Actual Primary Frequency Response~~adjusted actual PFR (APFR$_{Adj}$) and the ~~Final Expected Primary Frequency Response~~final expected PFR (EPFR$_{final}$) are calculated as described below.

EPFR ~~Calculations~~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~~actual Primary Frequency Response (APFR$_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

[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.

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$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

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~~actual PFR 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 = (MWT-4 – MWT-60)*0.59

(MWT-4 – MWT-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~~expected Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post-perturbation}$ and the $EPFR_{pre-perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

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$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60\ x\ droop_{max} - deadband_{max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

~~When the frequency is outside the Governor deadband and below 60Hz:~~

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

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$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{\max})}{(60\ x\ droop_{max} - deadband_{\max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The deadbandmax and droopmax 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 net dependable capacity (NDC ~~(Net Dependable Capacity~~) are used interchangeably and the term ~~Capacity~~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~~combined cycle facilities, ~~Capacity~~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$_{\text{final}}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of ~~Capacity~~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

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measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = (EPFR_{ideal} + MW_{adj}) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor\ \times -1$$

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The ~~Rated Throttle Pressure~~rated throttle pressure and the ~~Pressure~~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~~pressure and MW breakpoints where the ~~Rated Throttle Pressure~~rated throttle pressure and MW output, where ~~Rated Throttle Pressure~~rated throttle pressure is achieved, is the first pair and the ~~Minimum Throttle Pressure~~minimum throttle pressure and MW output, where the ~~Minimum Throttle Pressure~~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~~an 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~~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 BESS with capacity that is not expected to provide PFR

$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

$EPFR_{final}$ 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~~Each Generator Owner 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. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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.

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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 ~~by the Balancing Authority~~ from the rolling average calculation by the Balancing Authority 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, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner 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.

This process calculates the ~~Per Unit Sustained Primary Frequency Response~~per unit sustained PFR 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~~final expected PFR (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~~per unit sustained PFR [$P.U.SPFR_{Resource}$] 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~~PFR 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

[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.

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month period, the average of the unit's last 8 sustained ~~Primary Frequency Response~~PFR performances when the unit provided frequency response during ~~a Frequency Measurable Event~~an FME.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$\cancel{P.U.PFR_{Resource} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}}$$

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Reponse_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

P.U.SPFR$_{Resource}$ is the per unit (P.U.) measure of the sustained ~~Primary Frequency Response~~PFR of a resource during identified ~~Frequency Measurable Events~~FMEs. 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~~PFR 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 T=t(0). This is the *RampMW* Sustained adjustment:

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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 T=t(0).*

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 T=t(0). ~~-~~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 (MWT-4 – MWT-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~~The expected sustained PFR (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~~limiting factors each generating units / generating facilities may have and any ~~Power Augmentation Capacity~~power augmentation capacity (PA ~~Capacity~~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~~expected sustained PFR (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$_{pre}$~~ EPFR$_{pre\text{-}perturbation}$ value used in the Initial measure of R9.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

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$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{\max})}{(droop_{\max} \times 60 - deadband_{\max})} \times (HSL - PA\ Capacity) \times (-1)\right]$$

~~When the frequency is outside the Governor deadband and below 60Hz:~~

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{max})}{(droop_{max}\ x\ 60 - deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband\max)}{(droop\max \times 60 - deadband\max)} \times (HSL - PA\ Capacity) \times (-1)\right]$$

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband_{max})}{(droop_{max}\ x\ 60 - deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

Capacity and ~~Net Dependable Capability (~~NDC~~)~~ are used interchangeably and the term ~~Capacity~~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~~combined cycle facilities, determination of ~~Capacity~~capacity includes subtracting ~~Power Augmentation~~power augmentation (PA) ~~Capacity~~capacity, if any, from the original ~~HSL~~MW$_{GCS}$. Other generator types may also have ~~Power Augmentation~~power as 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

$$ESPFR_{final} = ESPFR_{Ideal} + (HZ_{T+46} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

$$ESPFR_{final} = ESPFR_{ideal} + (HZ_{T+46} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of ~~Capacity~~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.)

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ESPFR$_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

$$\cancel{MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PACapacity) \times Steam\ Flow\ Change\ Factor \times (-1)}$$

$$MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Throttle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at MW$_{pre\text{-}perturbation}$

The ~~Rated Throttle Pressure~~rated throttle pressure and the ~~Pressure~~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~~pressure and MW breakpoints where the ~~Rated Throttle Pressure~~rated throttle pressure and MW output where ~~Rated Throttle Pressure~~rated throttle pressure is achieved is the first pair and the ~~Minimum Throttle Pressure~~minimum throttle pressure and MW output where the ~~Minimum Throttle Pressure~~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~~an 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

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rated throttle pressure and resource capacity. An additional sensitivity factor, the ~~Steam Flow Change Factor~~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 BESS with capacity that is not expected to provide PFR

$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

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~~a generating unit/generating facility is operating within 2% of its (~~HSL~~MW$_{GCS}$ – PA ~~Capacity~~capacity and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater~~)~~), or a BESS is operating within 2% or 3 MW of its MW$_{GCS}$ less capacity not expected to provide PFR 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:

$$MW_{pre-perturbation} \geq min[([HSL - PA\ Capacity]\ x\ 0.98),\ ([HSL - PA\ Capacity] - 5\ MW)]$$

$$MW_{pre-perturbation} \geq \min[([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}]\ x\ .98), ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}] - Y\ MW)]$$

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then ~~Primary Frequency Response~~PFR is not evaluated for this FME~~.~~, where Y is 5 MW for generating units/generating facility and 3 MW for BESS.

For frequency deviations above 60 Hz (HzPost-perturbation > 60, if:

$$MW_{pre-perturbation} \le max[(LSL + ([HSL - PA\ Capacity]\ x\ 0.02)), (LSL + 5\ MW)]$$

$$MW_{pre-perturbation} \le \max[(LSL + ([MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}]\ x\ 0.02)), (LSL + Y\ MW)]$$

then ~~Primary Frequency Response~~PFR is not evaluated for this FME~~.~~ where Y is 5 MW for generating units/generating facility and 3 MW for BESS.

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~~MW_{GCS} less PA ~~Capacity~~capacity) or 5 MW~~),~~ for generating units/generating facilities or 3 MW for BESS, 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~~capacity) and greater than 5 MW; and
    b. The BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) and greater than 3 MW; and
    ~~b.~~c. The Expected Primary Frequency $Response_{final}$ is greater than the generating unit/generating facility's available frequency responsive ~~Capacity~~capacity[4]; and
    ~~c.~~d. 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~~MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) as the maximum expected output, the calculated $P.U.PFR_{Resource}$ will not be greater than 1.0.

[4] In this circumstance, when frequency is below 60 Hz, the $EPFR_{final}$ is set to operating margin based on ~~HSL~~MW_{GCS} (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the $EPFR_{final}$ is set to operating margin based on LSL for the purpose of calculating $PUPFR_{resource}$.

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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~~initial and ~~Sustained Primary Frequency Response~~sustained PFR measures.

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Attachment A to
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for
BAL-001-TRE-~~2~~3

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Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

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PA~~=~~ = Power Augmentation

HSL~~=~~ = High Sustained Limit

LSL = Low Sustained Limit

MW_{GCS} = maximum megawatt control range of the Governor control system

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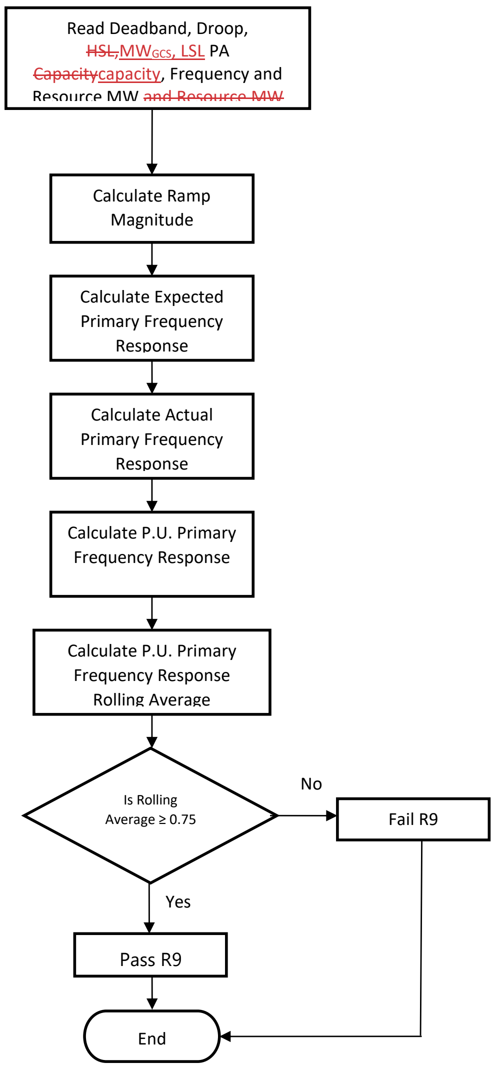

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Pre/Post-Perturbation Average MW and Average Frequency Calculations

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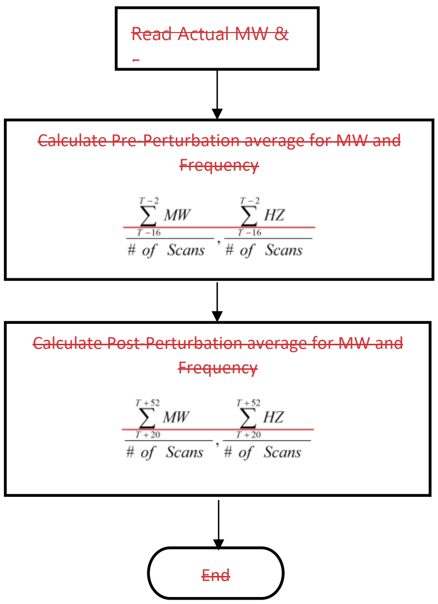

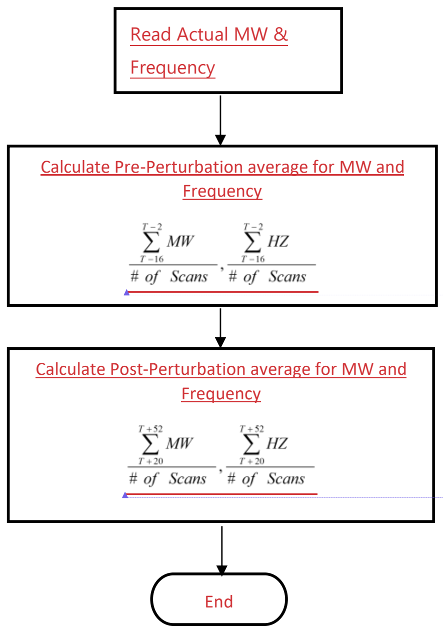

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Ramp Magnitude Calculation

~~Ramp Magnitude = (MW_{T-4} – MW_{T-60})*0.59~~

~~End~~

Ramp Magnitude = (MW_{T-4} – MW_{T-60})*0.59

End

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(MWT-4 – MWT-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.

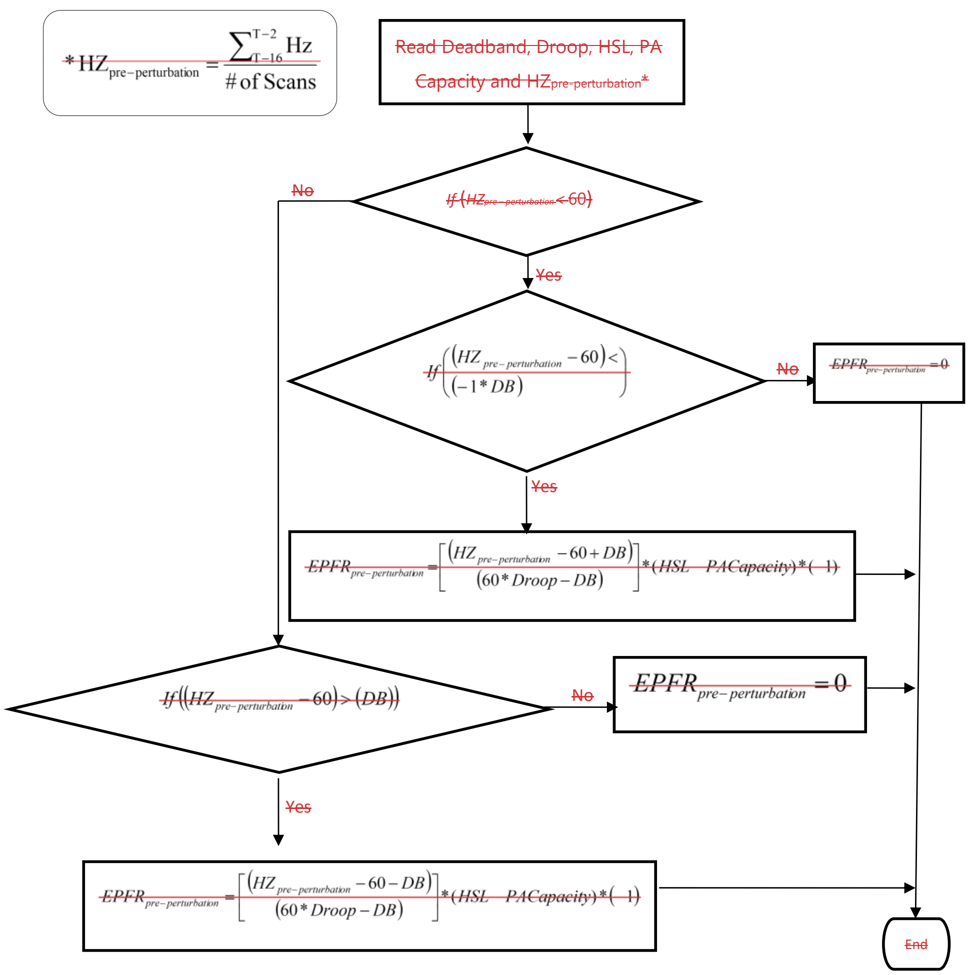
Actual Primary Frequency Response (APFRAdj)

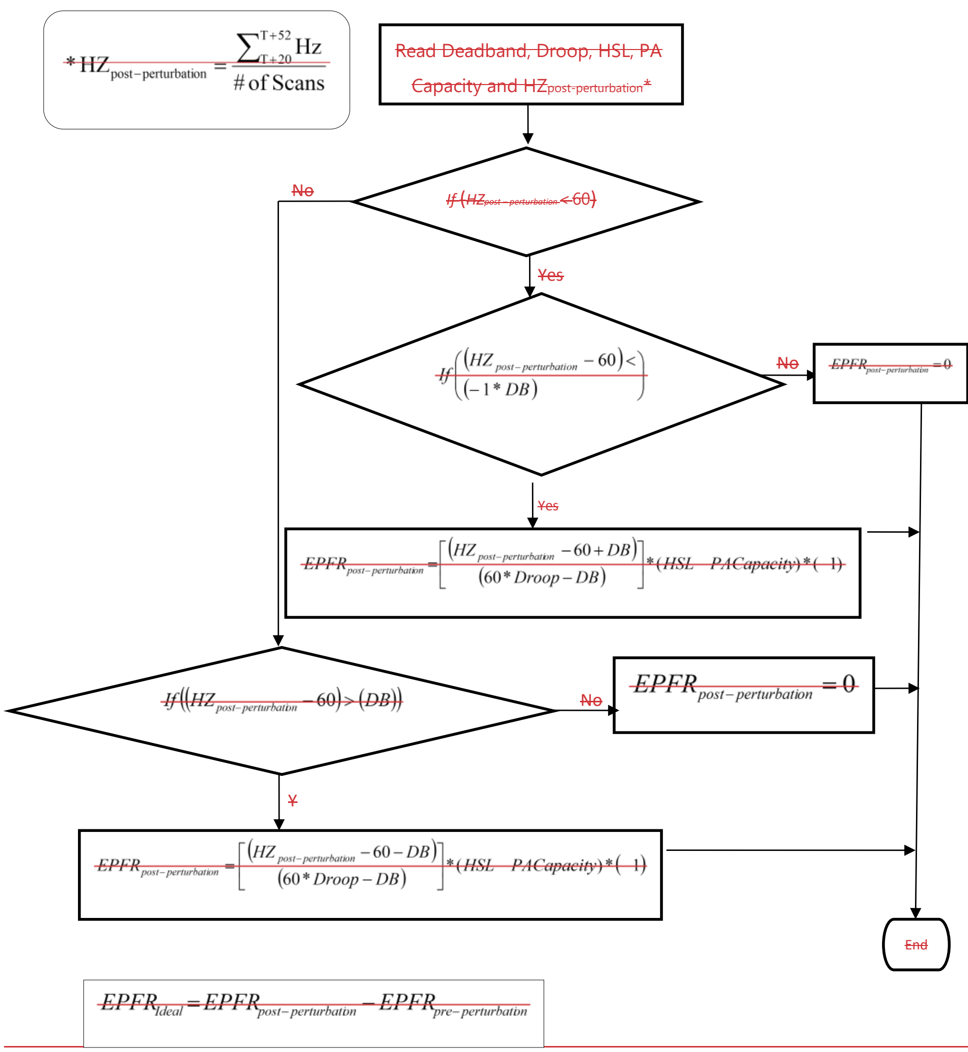
$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

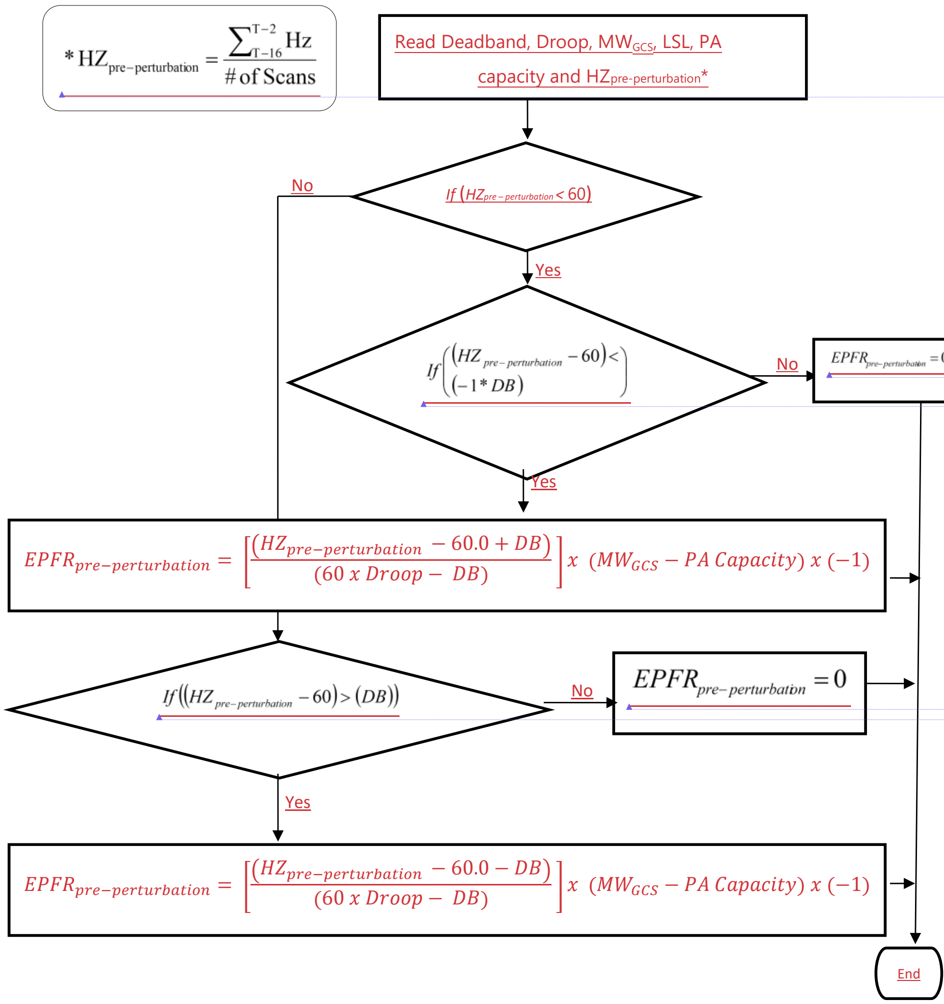
End

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.




$*HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# \text{ of Scans}}$
Read Deadband, Droop, HSL, PA Capacity and HZpost-perturbation*
If (HZpost-perturbation < 60)
No
Yes
$If\left(\frac{(HZ_{post-perturbation} - 60) <}{(-1 * DB)}\right)$
No
$EPFR_{post-perturbation} = 0$
Yes
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 + DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
$If((HZ_{post-perturbation} - 60) > (DB))$
No
$EPFR_{post-perturbation} = 0$
Y
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 - DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
End
$EPFR_{Ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$



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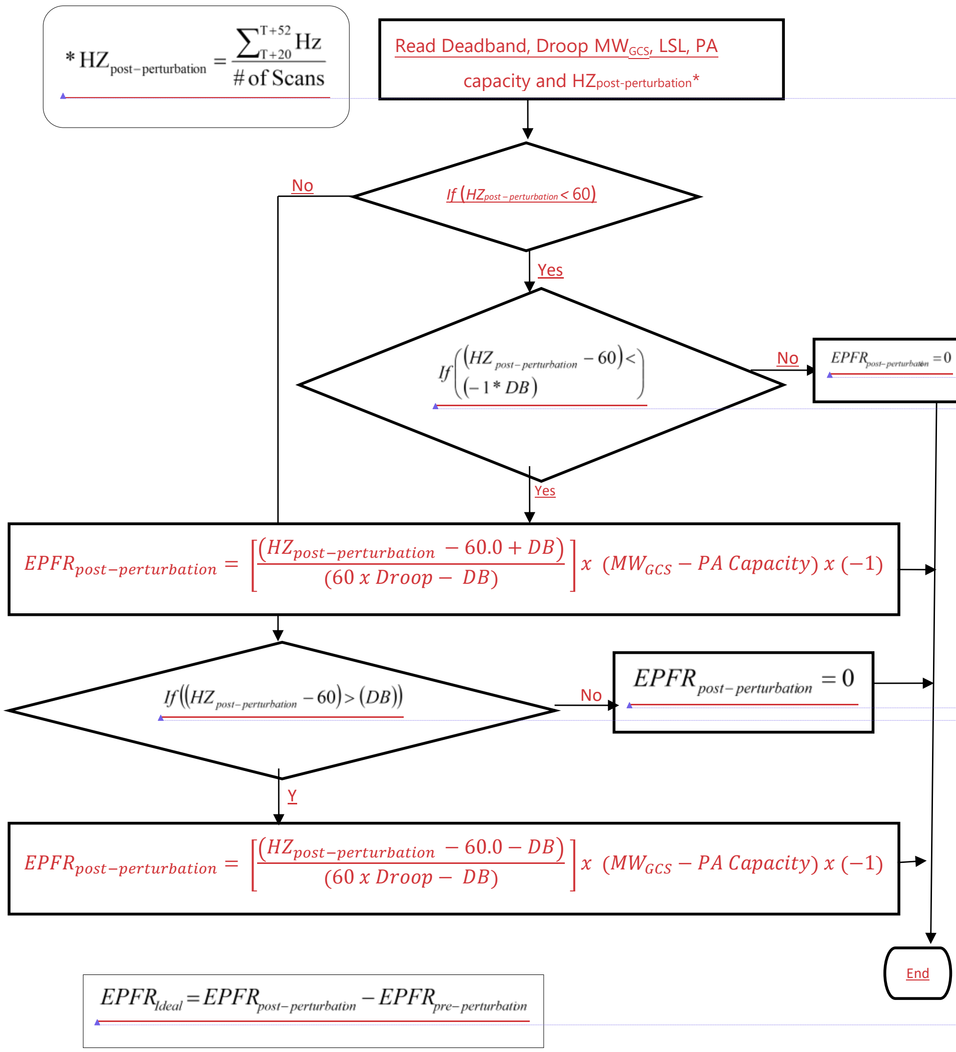

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Adjustment for Steam Turbine

~~Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL,~~

↓

$$\cancel{\%\,Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PACapacity)}}$$

↓

$$\cancel{Steam\ Flow\ Change\ Factor = \frac{\%\,Steam\ Flow}{0.5}}$$

↓

$$\cancel{MW_{Adjustment} = EPFR_{Ideal} * \frac{K}{Rated\ Throttle\ Pressure} * (HSL - PACapacity) * Steam\ Flow\ Change\ Factor * (-1)}$$

↓

~~Throttle Pressure = Interpolation of Pressure curve at $MW_{pre-perturbation}$~~

↓

$$\cancel{EPFR_{final} = (EPFR_{Ideal} + MW_{Adjustment}) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}}$$

↓

~~End~~

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~~Adjustment for Combustion Turbines and Combined Cycle Facilities~~

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}, $MW_{pre-perturbation}$ and $MW_{post-perturbation}$

↓

$$\% \, Steam \, Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA \, Capacity)}$$

↓

$$Steam \, Flow \, Change \, Factor = \frac{\% \, Steam \, Flow}{0.5}$$

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$$MW_{adj} = EPFR_{ideal} \, x \, \frac{K}{Rated \, Trottle \, Pressure} \, x (MW_{GCS} - PA \, Capacity) \, x \, Steam \, Flow \, Change \, Factor \, x(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre-perturbation}$

↓

$$EPFR_{final} = \left(EPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

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Adjustment for Combustion Turbines and Combined Cycle Facilities

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~~Read HSL, PA Capacity, HZ~~ $\cancel{_{post\text{-}perturbation}}$ ~~*~~

$$\cancel{EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60)*10*0.00276*(HSL - PACapacity)}$$

~~End~~

Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right)\, x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

End

0.00276 is the MW/0.1 Hz change per MW of ~~Capacity~~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.)

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Adjustment for BESS with capacity that is not expected to provide PFR

Read MW_{GCS}, capacity not expected to provide PFR

↓

$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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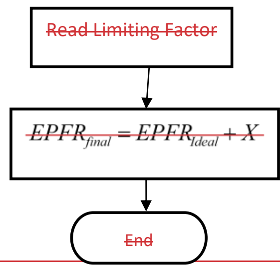

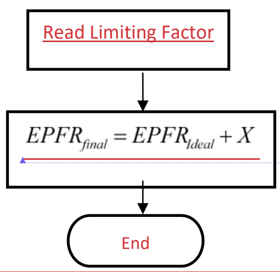

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$$* \, HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} HZ_{Actual}}{\# \text{ of Scans}}$$

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.

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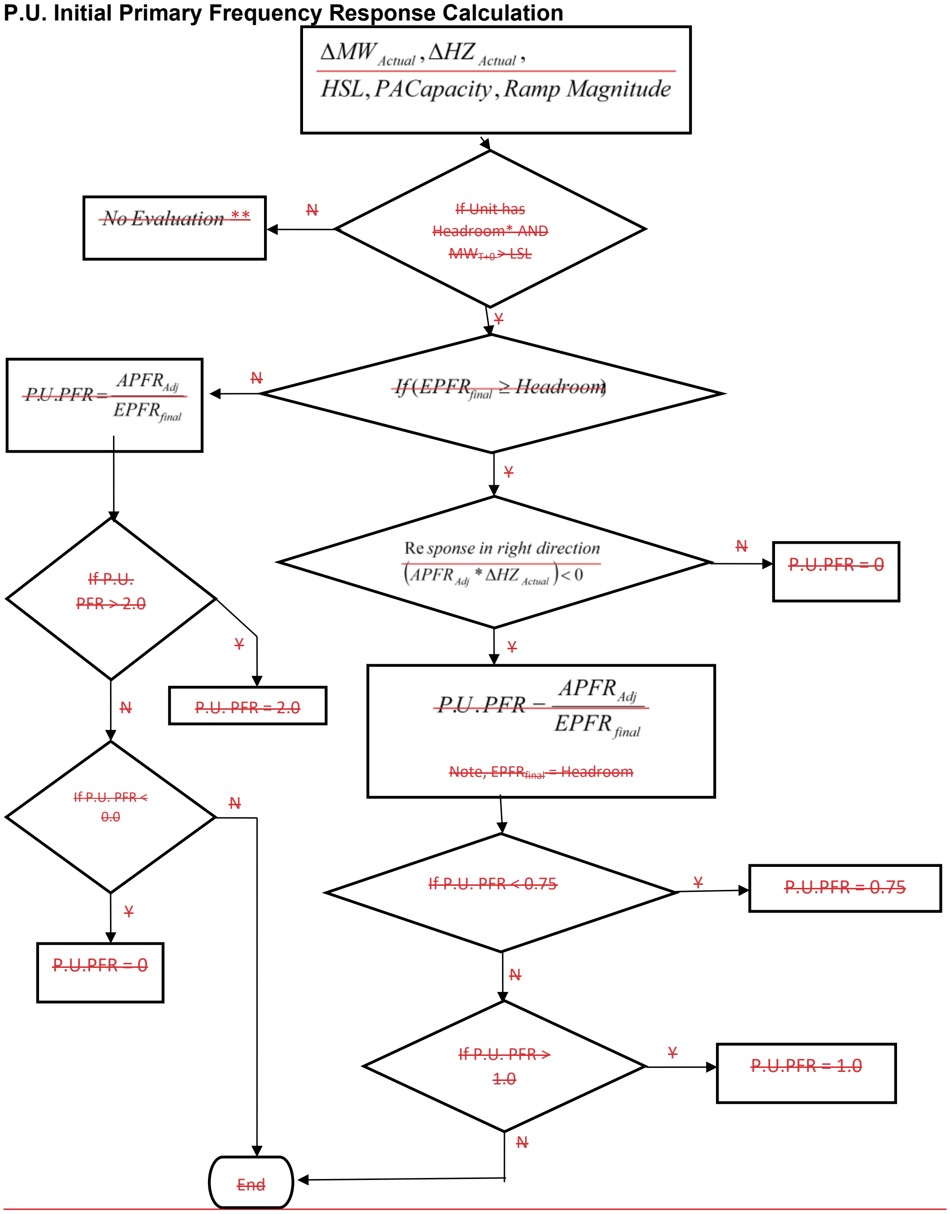
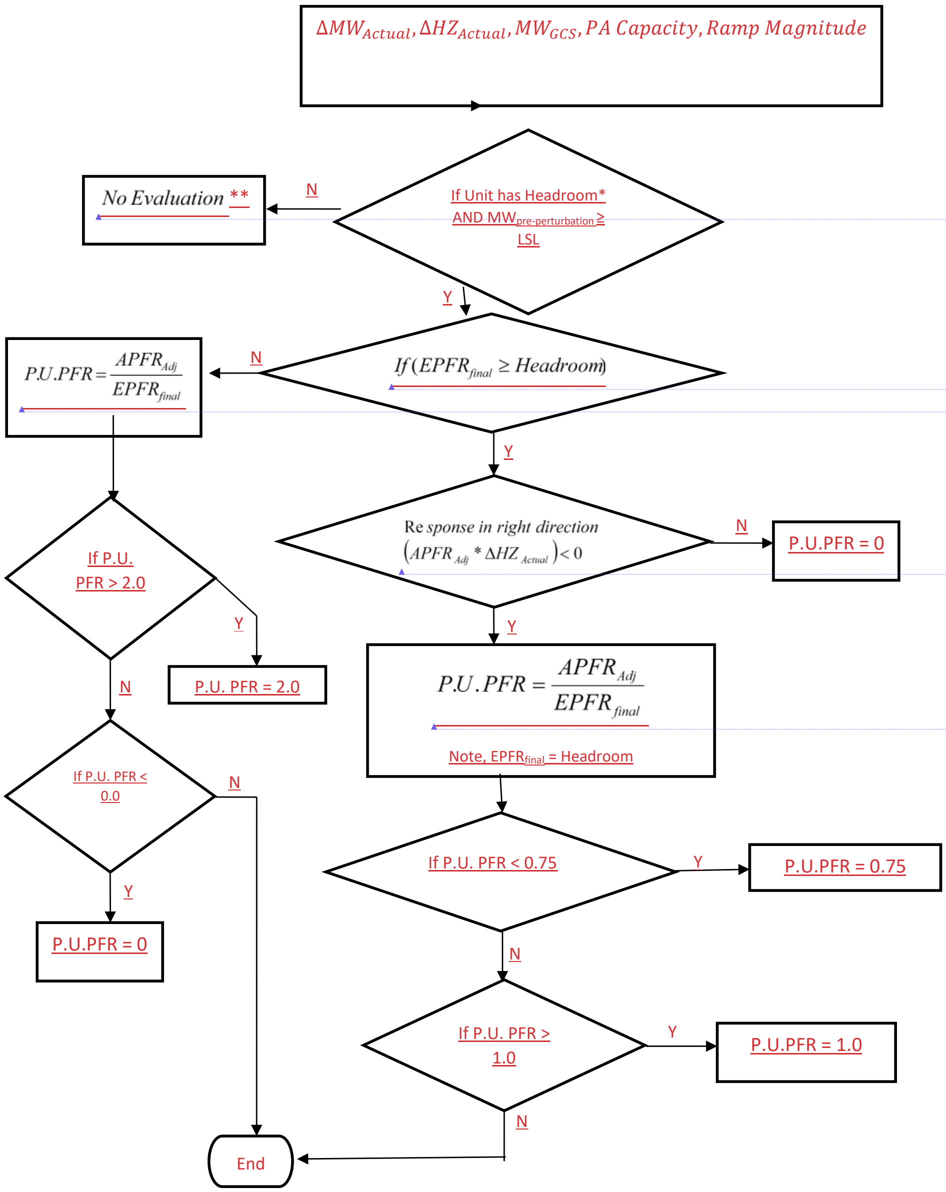
P.U. Initial Primary Frequency Response Calculation





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*Check for adequate up headroom, low frequency events. Headroom must be greater than either ~~5MW~~XMW or 2% of (~~HSL~~MW_{GCS} less PA ~~Capacity~~capacity and additional capacity not expected to provide PFR), 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~~.~~, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

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Check for adequate down headroom, high frequency events. Headroom must be greater than either ~~5MW~~XMW or 2% of (~~HSL~~MW_{GCS} less PA ~~Capacity~~capacity and additional capacity not expected to provide PFR), 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~~.~~, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

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For low frequency events:

$$\cancel{Headroom = HSL - PACapacity - MW_{T-2}}$$

$$Headroom = HSL - PA\ Capacity - capacity\ not\ expected\ to\ respond\ with\ PFR - MW_{T-2}$$

For high frequency events:

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$$\cancel{Headroom = MW_{T-2} - LSL}$$

$$Headroom = MW_{T-2} - LSL$$

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**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.

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T = Time in Seconds

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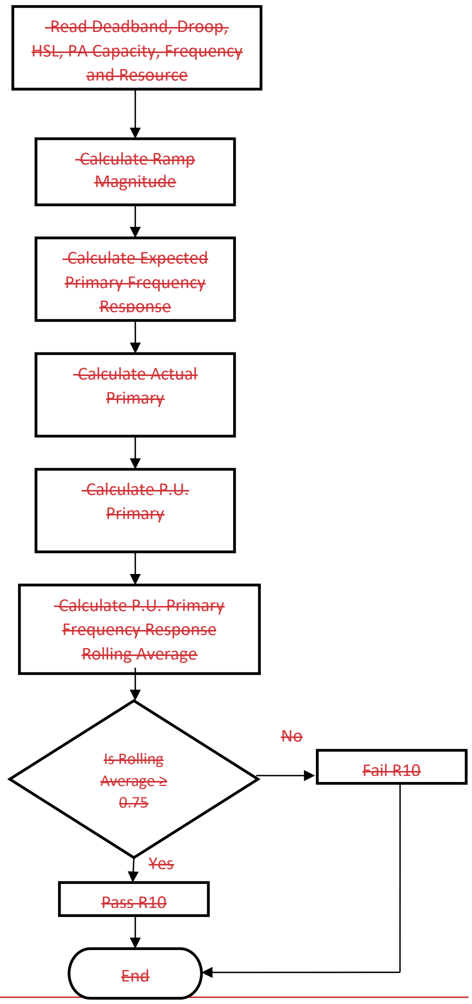
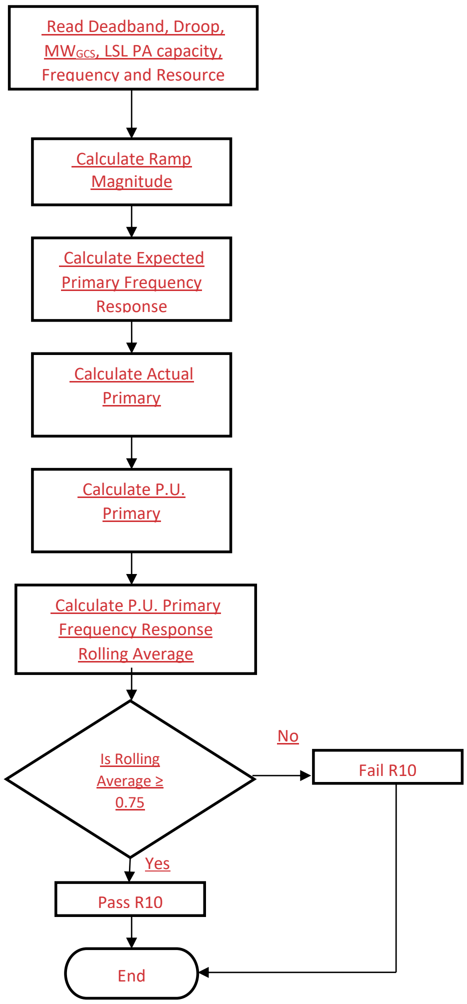
Attachment B to
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for BAL-001-TRE-~~2~~3

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response


~~Read Deadband, Droop, HSL, PA Capacity, Frequency and Resource~~
~~Calculate Ramp Magnitude~~
~~Calculate Expected Primary Frequency Response~~
~~Calculate Actual Primary~~
~~Calculate P.U. Primary~~
~~Calculate P.U. Primary Frequency Response Rolling Average~~
~~Is Rolling Average ≥ 0.75~~
~~No~~
~~Fail R10~~
~~Yes~~
~~Pass R10~~
~~End~~


Read Deadband, Droop, MW$_{GCS}$, LSL PA capacity, Frequency and Resource
Calculate Ramp Magnitude
Calculate Expected Primary Frequency Response
Calculate Actual Primary
Calculate P.U. Primary
Calculate P.U. Primary Frequency Response Rolling Average
Is Rolling Average ≥ 0.75
No
Fail R10
Yes
Pass R10
End

Pre/Post-Perturbation Average MW and Average Frequency Calculations

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~~Read Actual MW & Frequency~~

↓

~~Calculate Pre-Perturbation average for MW and Frequency~~

$$\cancel{\frac{\sum_{T-16}^{T-2} MW_{Actual}}{\#\ of\ \ Scans}, \frac{\sum_{T-16}^{T-2} HZ_{Actual}}{\#\ of\ \ Scans}}$$

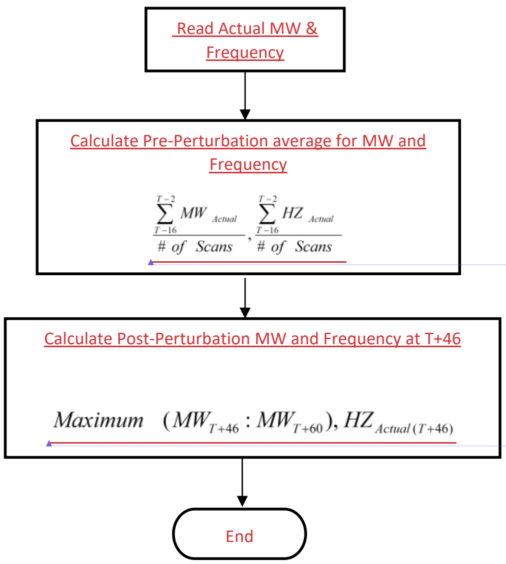
↓

~~Calculate Post-Perturbation MW and Frequency at T+46~~

$$\cancel{Maximum\ \ (MW_{T+46} : MW_{T+60}), HZ_{Actual\,(T+46)}}$$

↓

~~End~~



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Ramp Magnitude Calculation - Sustained

$$\cancel{Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821}$$

~~End~~

$$Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821$$

End

(MWT-4 – MWT-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 (ASPFRadj)

For low frequency events:

$$\cancel{ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}}$$

~~End~~

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$$ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}$$

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For high frequency events:

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$$\cancel{ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}}$$

~~End~~

$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}perturbation} - Ramp\ Magnitude_{Sustained}$$

End

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Expected Sustained Primary Frequency Response Calculation

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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

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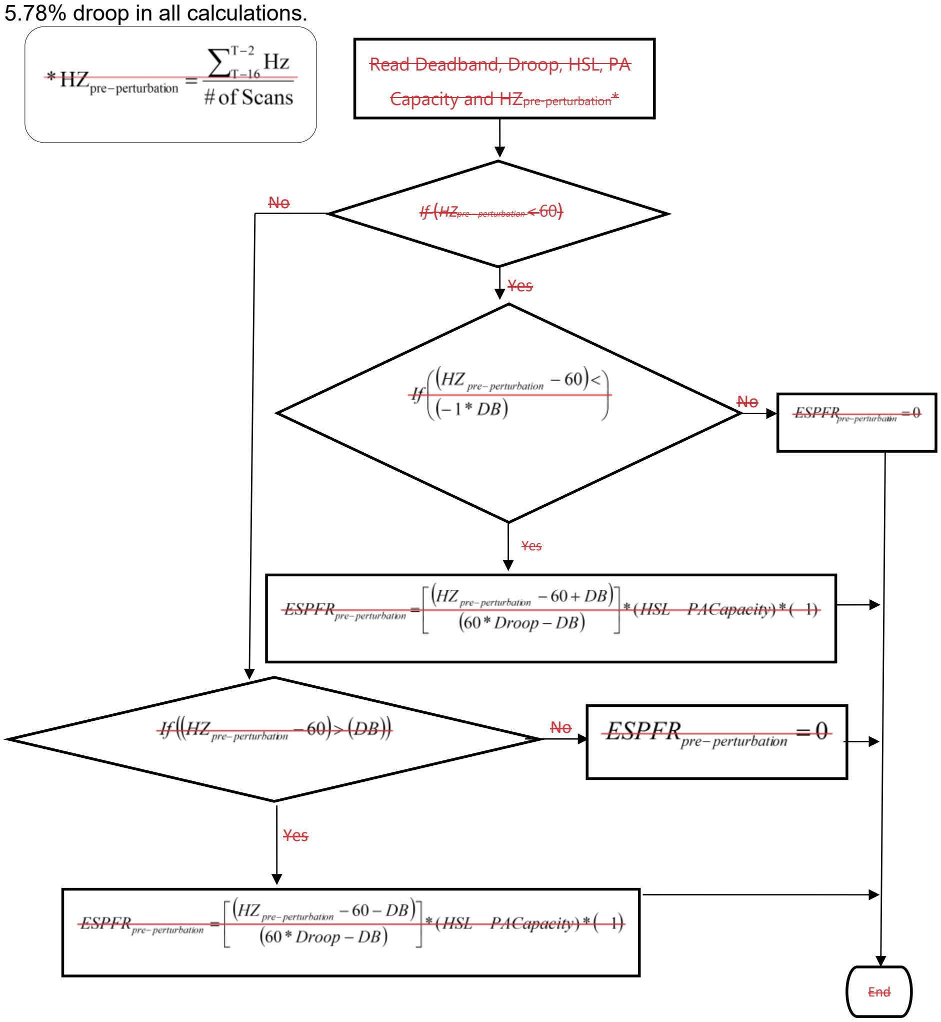
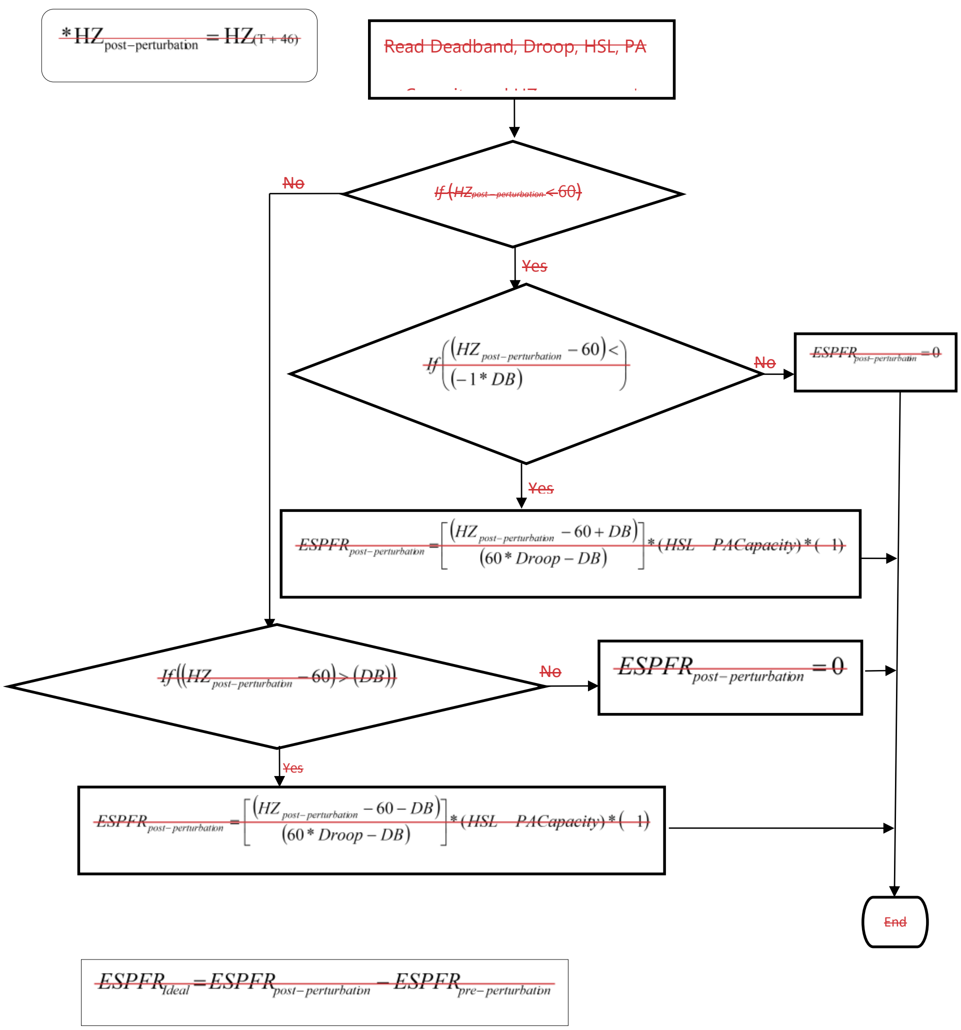
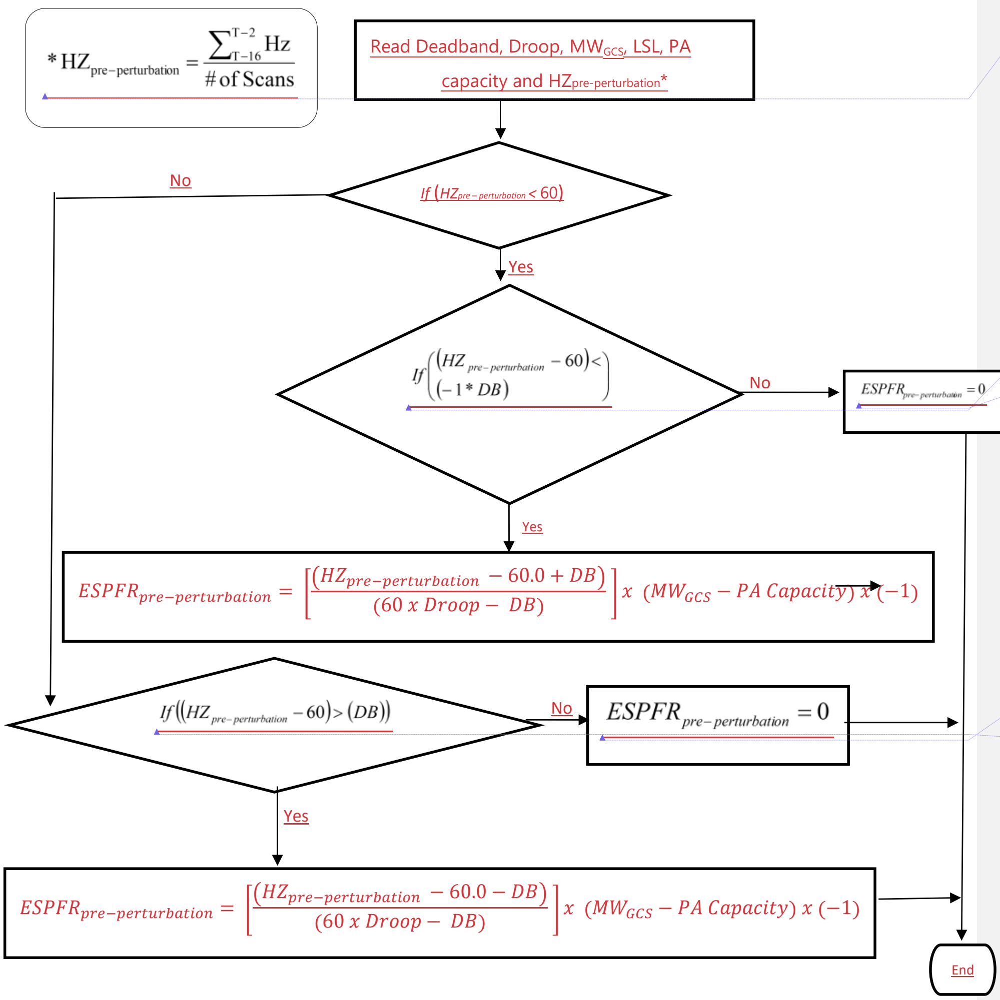
5.78% droop in all calculations.




$*HZ_{post-perturbation} = HZ_{(T+46)}$
Read Deadband, Droop, HSL, PA
$If\ (HZ_{post-perturbation} < 60)$
No
Yes
$If\left(\frac{(HZ_{post-perturbation} - 60) <}{(-1 * DB)}\right)$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 + DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
$If((HZ_{post-perturbation} - 60) > (DB))$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 - DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
End
$ESPFR_{Ideal} = ESPFR_{post-perturbation} - ESPFR_{pre-perturbation}$



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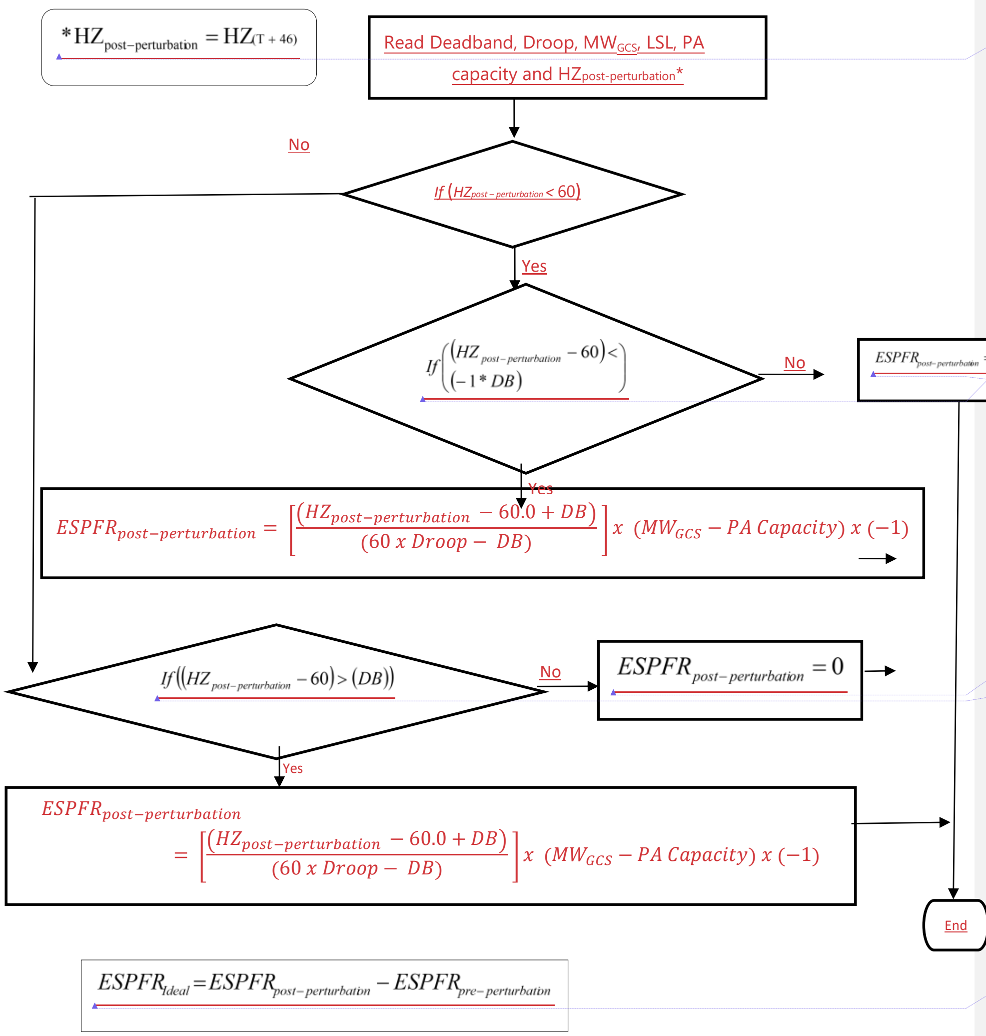

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Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

↓

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x(MW_{GCS} - PA\ Capacity)xSteam\ Flow\ Change\ Factorx(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

↓

$$ESPFR_{final} = \left(ESPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

End

$MW_{post-perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

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Adjustment for Combustion Turbines and Combined Cycle Facilities

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~~Read K(Limiting Factor), Throttle Pressure curve breakpoints, HSL,~~

↓

$$\% \; Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PACapacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{Adjustment} = ESPFR_{Ideal} * \frac{K}{Rated\ Throttle\ Pressure} * (HSL - PACapacity) * Steam\ Flow\ Change\ Factor * (-1)$$

↓

~~Throttle Pressure = Interpolation of Pressure curve at MW~~ $_{pre-perturbation}$

↓

$$ESPFR_{final} = (ESPFR_{Ideal} + MW_{Adjustment}) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

~~End~~

$MW_{post-perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$ESPFR_{final} = ESPFR_{ideal} + (HZ_{post-perturbation} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

End

~~**Adjustment for Combustion Turbines 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 the MW/0.1 Hz change per MW of ~~Capacity~~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 BESS with capacity that is not expected to provide PFR

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Read MW_{GCS}, capacity not expected to provide PFR

$$ESPFR_{final} = Minimum\,(ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

End

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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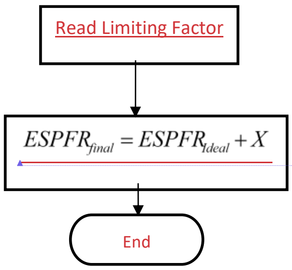
~~Read Limiting Factor~~

$$\cancel{ESPFR_{final} = ESPFR_{ideal} + X}$$

~~End~~



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$* HZ_{Actual} = HZ_{(T + 46)}$

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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.

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P.U. Sustained Primary Frequency Response Calculation

$$*HZ_{Actual} = HZ_{(T+46)}$$

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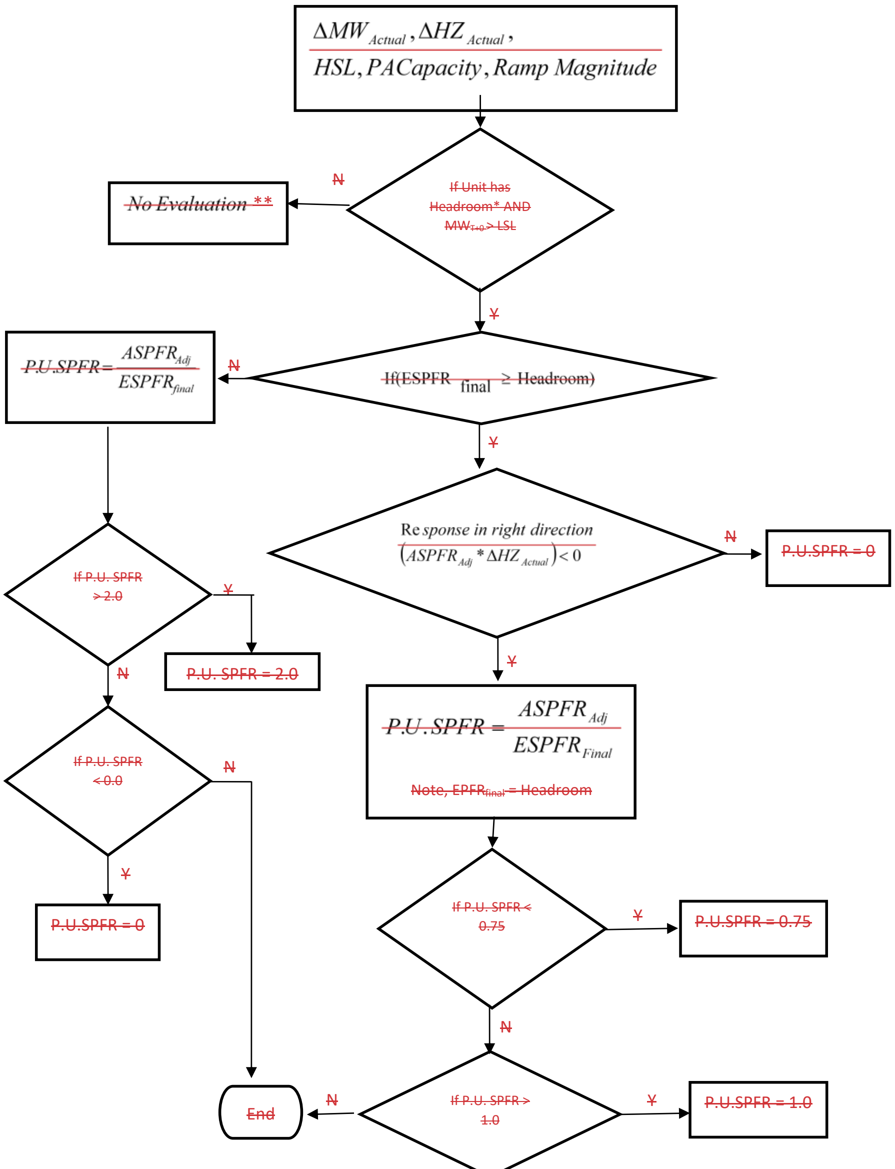
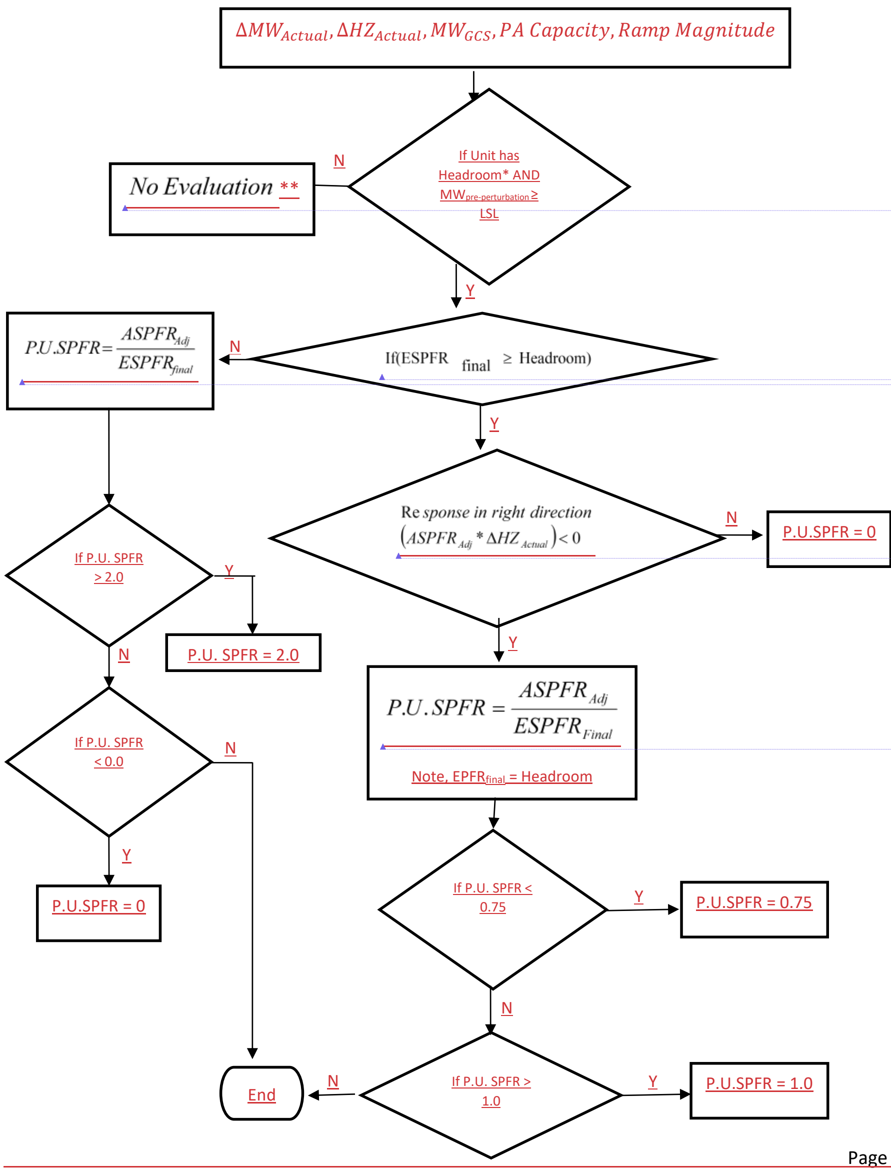

No Evaluation **
If Unit has Headroom* AND MW > LSL
N
Y
If(ESPFR final ≥ Headroom)
Response in right direction
N
Y
P.U.SPFR = 0
If P.U. SPFR > 2.0
P.U. SPFR = 2.0
If P.U. SPFR < 0.0
P.U.SPFR = 0
Note, EPFR final = Headroom
If P.U. SPFR < 0.75
P.U.SPFR = 0.75
If P.U. SPFR > 1.0
P.U.SPFR = 1.0
End



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*Check for adequate up headroom, low frequency events. Headroom must be greater than either ~~5MW~~XMW or 2% of (~~HSL~~MWGCS less PA ~~Capacity~~capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

Check for adequate down headroom, high frequency events. Headroom must be greater than either ~~5MW~~XMW or 2% of (~~HSL~~MWGCS less PA ~~Capacity~~capacity and additional capacity not expected to provide PFR), 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, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

For low frequency events:

$$\boxed{\cancel{Headroom = HSL - PACapacity - MW_{T-2}}}$$

$$\boxed{Headroom = HSL - PA\ Capacity - capacity\ not\ expected\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

$$\boxed{\cancel{Headroom = MW_{T-2} - LSL}}$$

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**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

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Revision History

Version	Date	Action	Change Tracking
1	7/25/2011	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/7/2012	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 FME, and other changes to respond to field trial results, comments, and corrections.
1.1	3/6/2013	Texas RE RSC approves submittal to Texas RE Board	
1.1	4/23/2013	Texas RE Board approves submittal to NERC and FERC	
1.1	9/18/2013	NERC and Texas RE file Petition for approval to FERC	
1.1	1/16/2014	Approved by FERC	
1.2	5/21/2015	Texas RE Board approves revisions to Attachment 2 Primary Frequency Response Reference Document	For clarification and consistency of the equations used in the Attachment, changes performed to: - “T” in the equations refers to the start of the Frequency Measurable Event. - “T-2” nomenclature utilized for clarity rather than “t(-2)” (applicable to numerous equations) - Removed floating x in $EPFR_{final}$ for Steam Turbine equation - Corrected sign convention for Expected Sustained Primary Frequency Response to match the calculation for expected primary frequency response. Corrected Adjusted MW for $ESPFR_{final}$ for Steam Turbine by multiplying -1 to calculate proper value. - On Steam Flow Change Factor removed floating x and reinserted PA ~~Capacity~~capacity. - Clarified Footnote 5 for scenario of high frequency event for setting LSL as operating margin (similar to HSL for low frequency events). - Clarified in flowcharts for both P.U. Initial Primary & Sustained

			Frequency Response Calculations: ○ Unit needs to have Headroom and be above LSL to be scored. ○ Cap $EPFR_{final}$ at value of Headroom on unit - Per RSC 5/11/2015, all references to “Final” were changed to “final”. - Per RSC 5/11/2015, P.U.PFR and P.U.S.PFR removed italics in flowcharts.
1.3	11/14/2016	RSC approves minor changes to Attachment 2 Primary Frequency Response Reference Document	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
1.3	12/07/2016	Texas RE Board approves minor changes to Attachment 2 Primary Frequency Response Reference Document.	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
2.0	12/11/2019	Texas RE Board approves changes to the Attachment.	Removed the requirement for Governor droop and deadband settings for Steam turbines of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process for submitting an exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1. Changed numbering on Attachment 2 to Attachment 1
3.0	TBD		Attachment 1 was updated to align the MW_{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and

			account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.

Implementation Plan

SAR-013 Project to revise Regional Standard BAL-001-TRE-2
Regional Standard BAL-001-TRE-3

Applicable Standard(s)
Regional Standard BAL-001-TRE-3

Requested Retirement(s)
Regional Standard Regional Standard BAL-001-TRE-2

Prerequisite Standard(s)
None

Revision(s) to Glossary of Terms
None

Applicable Entities

- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)
- Exemptions:
    - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from Standard BAL-001-TRE-3.
    - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3.
    - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
This regional standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Retirement Date
Regional Standard BAL-001-TRE-2 shall be retired immediately prior to the effective date of Regional Standard BAL-001-TRE-3 in the particular jurisdiction in which the revised regional standard is becoming effective.

Implementation Plan

SAR-013 Project to revise Regional Standard BAL-001-TRE-2
Regional Standard BAL-001-TRE-3

Applicable Standard(s)
Regional Standard BAL-001-TRE-3

Requested Retirement(s)
Regional Standard Regional Standard BAL-001-TRE-2

Prerequisite Standard(s)
None

Revision(s) to Glossary of Terms
None

Applicable Entities

- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)
- Exemptions:
    - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from Standard BAL-001-TRE-~~2~~3.
    - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-~~2~~3.
    - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
This regional standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Retirement Date
Regional Standard BAL-001-TRE-2 shall be retired immediately prior to the effective date of Regional Standard BAL-001-TRE-3 in the particular jurisdiction in which the revised regional standard is becoming effective.

Description of Changes to Regional Standard BAL-001-TRE-2
Project SAR-013

General Changes

- Revised BAL-001-TRE-2 to BAL-001-TRE-3

BAL-001-TRE-3 Section	Description	Rationale
A 6 Background	Corrected the typo “measureable” to measurable”	Corrected a typo.
A 6 Background	Added a description of resource to the end of the description. Included the various types that were previously in Requirement Part 6.2. Added Battery Energy Storage System (BESS) to the list of examples.	This revision fulfills one of the objectives of the SAR.
M1	Added “that”	Corrected a typo.
Requirement R2 Footnote 1	Added “Attachment 1” to Primary Frequency Response Reference Document.	This revision specifies the Primary Frequency Response Reference Document is in Attachment 1. It is also to be consistent with Requirements R6, R9, and R10.
R2.3	Changed (8) eight to eight (8).	This is consistent with Requirement R4.
M3	Removed the “per” that should not have been there.	Corrected a typo
Requirement R4	Changed “occurs” to “occur”	Corrected a grammatical error.
Requirement R6	Revised the parent Requirement R6	Clarifies the language.
Requirement Part 6.1	Added “Generating units/generating facilities that are not qualified to provide Operating Reserves and have obtained prior written approval” to Table 6.1.	This revision fulfills one of the objectives of the SAR.
Requirement Part 6.1	Corrected capitalization of Generating unit/generating facility	Clarifies the language.
Requirement Part 6.1 Footnote 2	Added footnote 2: “Refers to ancillary service qualification criteria as required by the Balancing Authority.	This revision fulfills one of the objectives of the SAR.

BAL-001-TRE-3 Section	Description	Rationale
Requirement Part 6.2	Revised the table to only include Combustion Turbine (Combined Cycle) and All other generating units/generating facilities. The other Generator types were moved to Section A Background.	Clarifies the language.
Table 6.2 Asterisk	Changed the asterisk to footnotes 4 and 5: "Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource. Moved this note from an asterisk to the body of Requirement R6.	This revision makes the language consistent.
Requirement Part 6,.3	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
M6	Added "Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz.	This clarifies how Requirement R6 can be measured.
Requirement R9	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
Requirement R10	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
Section C 1.1	Added abbreviation for Compliance Enforcement Authority (CEA)	This change makes it consistent with other NERC Reliability Standards.
Section C 1.2	Revised this section to include more detail on when the reset time frame will occur.	This revision fulfills one of the objectives of the SAR.
Section C 1.3	Abbreviated CEA	This is consistent with the change made in Section C 1.1.
Violation Severity Levels	Corrected formatting for R4	Format correction.
Standard Attachments	Changed font to size 12 to match the rest of the document.	Format correction.

Attachment 1

General

- Changed font size from 11pt to 12pt
- Removed capitalization from “capacity” as it is not defined in the NERC Glossary.

Attachment 1 Section	Description	Rationale
I. Introduction	Revised description of Low Sustained Limit (LSL)	Definition was modified to capture the charging side of the operation curve for BESS units.
I. Introduction	Added description for Maximum Megawatt Governor Control System (MW_{GCS})	Captures the available range of MW response for performance calculations.
	Added the same description of resource and list of examples from Section A Background.	This replaces the previous description of resource and is consistent with the language in the standard.
I. Introduction	Added description for Design Settings versus Real-time Evaluation	To clarify the difference in expectation in minimum design requirements vs operational settings and evaluation.
I. Introduction	Added the revised description of the terms resource and generating unit/generating facility to be consistent with Section A 6 Background.	This revision fulfills one of the objectives of the SAR.
I. Introduction	Revised Footnote 1 to indicate that the spreadsheets are found on Texas RE's public website, rather than a specific link.	This will not need to be updated if the link changes.
II Initial Primary Frequency Response Calculations Requirement R9	Corrected the language for Requirement R9.	This change is to be consistent with the Regional Standard language.
Initial Primary Frequency Response Performance Calculation Methodology	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.

Initial Primary Frequency Response Performance Calculation Methodology	Changed Adjusted Actual to lower case (actual).	This is not a NERC Glossary term.
Initial Primary Frequency Response Performance Calculation Methodology	Changed Final Expected to lower case (final expected).	This is not a NERC Glossary term.
Actual Primary Frequency Response	Changed Adjusted Actual to lowercase (adjusted actual).	This is not a NERC Glossary term.
Actual Primary Frequency Response	Changed Actual to lowercase (actual)	This is not a NERC Glossary term.
Expected Primary Frequency Response (EPFR)	Changed Expected to lowercase (expected).	This is not a NERC Glossary term.
Expected Primary Frequency Response (EPFR)	Revised equations for Expected Primary Frequency Response to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Pre-perturbation Average Hz – Removed capitalization of net dependable capacity.	This term is not defined in the NERC Glossary.

Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Removed capitalization of combined cycle.	This is not a NERC Glossary term.
Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Removed sentence: "The Capacity for wind powered generators is the real time HSL of the wind plant at the time the FME occurred."	The pre-perturbation Average Hz is different than capacity for wind. Statement is no longer needed due to updated definition of MW_{GCS}.
$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities	Revised equations for $EPFR_{final}$ for combustion turbines, combined cycle facilities and steam turbines to change HSL to MW_{GCS}	The equations were revised to align with the definition of MW_{GCS}.
$EPFR_{final}$ for Steam Turbine	Revised equations for $EPFR_{final}$ for combustion turbines, combined cycle facilities and steam turbines to change HSL to MW_{GCS}	The equations were revised to align with the definition of MW_{GCS}.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on rated throttle pressure.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on pressure.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on steam flow change factor.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for BESS with capacity that is not expected to provide PFR	Added this new section to account for BESS.	This intended to be used for energy storage resources with Fast Frequency Response (FFR) capacity without having to define FFR capacity.

III. Sustained Primary Frequency Response Calculations	Corrected the language for Requirement R10 and Part 10.3.	To be consistent with the Regional Standard.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Per Unit Sustained to lowercase (per unit sustained)	This term is not defined in the NERC Glossary.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Final Expected to lowercase (final expected).	This term is not defined in the NERC Glossary.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Frequency Measurable Event to acronym (FME).	The acronym is described in the Introduction paragraph.

Sustained Primary Frequency Response performance requirement	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response performance requirement	Changed Frequency Measurable Event to acronym (FME).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response Calculation	Corrected the equation to reflect P.U.SPFR	Corrected a typo.
Sustained Primary Frequency Response Calculation	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described previously.
Sustained Primary Frequency Response Calculation	Changed Frequency Measurable Event to acronym (FME).	The acronym is described previously.
Actual Sustained Primary Frequency Response, Adjusted	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described previously.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Expected Sustained to lower case (expected sustained)	This term is not defined in the NERC Glossary.

Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed High Sustainable Limit to the acronym (HSL)	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Low Sustainable Limit (LSL) to the acronym.	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Removed capitalization from power augmentation capacity.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Removed capitalization from expected sustained.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Establishing the Ideal Expected Primary Frequency Response	Updated the $ESPRF_{ideal}$ equation to remove the vertical bar.	Corrected a typo.

Establishing the Ideal Expected Primary Frequency Response	Revised the equation to replace HSL with MW_{GCS}.	Equations were revised to align with the definition of MW_{GCS}
Establishing the Ideal Expected Primary Frequency Response	Changed net dependable capacity to the acronym (NDC).	The acronym is described previously.
Establishing the Ideal Expected Primary Frequency Response	Removed the sentence: The capacity for wind powered generators is the real-time HSL of the wind plant at the time the FME occurred.	The pre-perturbation Average Hz is different than the capacity for wind. Statement is no longer needed due to updated definition of MW_{GCS}
Establishing the Ideal Expected Primary Frequency Response	Removed capitalization from combined cycle.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Removed capitalization from power augmentation capacity.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Changed HSL to MW_{GCS}.	Equation was revised to align with the definition of MW_{GCS}
$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities	Revised equations for $EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
$ESPFR_{final}$ for Steam Turbine	Revised equations for $EPFR_{final}$ for Steam Turbine to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}

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$ESPFR_{final}$ for Steam Turbine	Changed rated throttle pressure to lowercase.	This term is not defined in the NERC Glossary.
$ESPFR_{final}$ for Steam Turbine	Changed pressure to lowercase.	This term is not defined in the NERC Glossary.
$ESPFR_{final}$ for Steam Turbine	Changed minimum throttle pressure to lowercase.	This term is not defined in the NERC Glossary.
$ESPFR_{final}$ for Steam Turbine	Changed steam flow change factor to lowercase.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for BESS with capacity that is not expected to provide PFR	Added this new section to account for BESS.	Added this new section to account for BESS.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Changed HSL to MW_{GCS} and added "capacity and additional capacity not expected to provide PFR. Added "or a BESS is operating within 2% or 3MW of its MW_{GCS}	Revised the equations to align with the definition of MW_{GCS} 3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Added the language "and additional capacity not expected to provide PFR" and "less capacity not expected to provide PFR"	This aligns the calculations to ensure that FFR capacity is excluded when identifying conditions where there is limited capacity available to provide PFR.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Revised equations to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Added "where Y is 5 MW for generating units/generating facility and 3 MW for BESS"	This language aligns with ERCOT Operating Guides.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Added "for generating unts/generating facilities or 3 MW for BESS"	3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Added: The BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) and greater than 3 MW; and	3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed HSL to MW_{GCS}.	revised to align with the definition of MW_{GCS}
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	To #2 – Added "MW_{GCS} less PA capacity and additional capacity not expected to provide PFR"	This aligns the calculations to ensure that FFR capacity is excluded when identifying conditions where there is limited capacity available to provide PFR.

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed initial and sustained to lower case.	These terms are not defined in the NERC Glossary.

Attachment A

- Added LSL = Low Sustained Limit
- Added MW_{GCS} = maximum megawatt control range of the Governor control system
- Made conforming changes to the flowcharts to align with Attachment 1
- Removed capitalization from "capacity" as it is not defined in the NERC Glossary.
- Added the flowchart for Adjustment for BESS with capacity that is not expected to provide PFR.
- Updated the verbiage under P.U. Initial Primary Frequency Response Calculation to include additional capacity that is not expected to provide PFR.
- Updated the formula for low frequency events.
- Added Adjustment for BESS with capacity that is not expected to provide PFR,

Attachment B

- Made conforming changes to align with Attachment 1
- Removed capitalization from "capacity" as it is not defined in the NERC Glossary.
- Added the flowchart for Adjustment for BESS with capacity that is not expected to provide PFR.

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Work Plan
Project SAR-013 Revisions to Regional Standard BAL-001-TRE-2

The Standard Drafting Team (SDT) and the Manager, Reliability Standards Program (RSM) developed the following work plan for Project SAR-013 Revisions to Regional Standard BAL-001-TRE-2. This work plan lays out the steps for revising Regional Standard BAL-001-TRE-2 in accordance with Texas RE's Regional Standards Development Process (RSDP) document.

Milestone	Anticipated Date	Location	Comments
Standard Drafting Team Kick-off Meeting • The SDT shall elect the permanent chair and vice chair.	12/19/2024	Webinar	
RSM and SDT develop a work plan.	1/21/2025	Webinar	
SDT has first working meeting • SDT drafts the work product	2/7/2025	Webinar	
Work plan delivered to the MRC.	2/19/2025	Hybrid MRC Meeting at Texas RE	
Subsequent SDT meeting(s) to draft the work product	Q2 2025	Webinar /Possible Hybrid Meeting	
MRC approves the work product to be posted for a public comment and ballot period.	9/17/2025	Hybrid MRC Meeting at Texas RE	
The RSM shall post the work product for a 45-day public comment period with the ballot period occurring in the last 15 days.	9/22/2025 – 11/6/2025	N/A	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	9/22/2025	N/A	
The SDT shall meet to discuss comments received within 30 days of the conclusion of the posting period. During the meeting, the SDT shall: • prepare responses to comments received; and • prepare a "modification report".	12/3/2025 12/12/2025 12/16/2025	Webinar	

SDT Meeting to finalize revisions to proposed Regional Standard BAL-001-TRE-3	3/10/2026	Webinar	
Quality Review	March 16 – April 3, 2026	Via Email, Texas RE's External Sharing Site	
MRC approves the work product to be posted for an additional public comment and ballot period.	May 13, 2026	Hybrid MRC Meeting at Texas RE	
Additional Ballot and Comment Period - The RSM shall post the work product for a 45-day public comment period with the ballot period occurring in the last 15 days.	May 14 - June 29, 2026	Via Email/Posted on Website	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	May 14, 2025	Via Email	
The SDT shall meet to discuss comments received within 30 days of the conclusion of the posting period. During the meeting, the SDT shall: • prepare responses to comments received; and • prepare a "modification report". • Approve the work product for final ballot	July 20, 2206	Webinar	
When the ballot passes in accordance with section 4.12 and 4.13, the RSM shall conduct a final ballot.	July 20 – August 4, 2026	Via Email/Posted on Website	
Once the final ballot final ballot, the MRC shall approve the final Work Product to be provided to the Texas RE Board for action.	September 16, 2026	Virtual MRC and Board Meeting	
The Work Product shall be posted at least seven days prior to action by the Texas RE Board.	September 9, 2026	N/A	
If deemed appropriate, the Texas RE Board will adopt the work product.	September 16, 2026	Virtual MRC and Board Meeting	
The RSM will submit the work product to NERC.	Subsequent to Texas RE MRC and Board Approval	Via Email	
Once the Work Product is approved by FERC, the RSM shall send	TBD	N/A	

notification of the effective date to Texas RE stakeholders.			

Regional Standard BAL-001-TRE-3 Additional Ballot Results Ballot Period Ended June 29, 2026					
	No. in ballot pool	Affirmative	Negative	Abstain	No Ballot
System Coordination and Planning	1	1	0	0	0
Transmission and Distribution	4	3	0	0	1
Cooperative Utility	1		0	0	1
Municipal Utility	1	1	0	0	
Generation	6	5	0	0	1
Load-serving and Marketing	1		0	0	1
Totals	14	10	0	0	4

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Ensuring electric reliability for Texans

Standard Drafting Team's Responses to Comments
Additional Comment Period: May 14 – June 29, 2026
Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

Question 1	**Regional Standard BAL-001-TRE-3: In Section A. 6. Background, the SDT revised the description of the terms "resource" and generating unit/generating facility for clarity. In addition, it moved examples from Requirement R6 to this section. Do you agree with the change?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes	Constellation agrees with defining the term "resource" in the background instead of Requirement 6. Please note ERCOT IBRWG posting from January 17th, 2025, a curtailment to low output including down to 0 MW prevents a generator of certain technology types from being able to respond to a frequency event. Please consider adding an exclusion and expectations, that includes timeline for submitting exclusion paperwork requests, due to operational limitations for the technology types that cannot respond to a frequency event when concurrently being curtailed.	Thank you for your comment. The drafting team has determined that this is out of scope for this project. There are ongoing discussions during ERCOT's Performance Disturbance Compliance Working Group (PDCWG) and Inverter-Based Resource Working Group (IBRWG) on this topic.

Question 2	**Regional Standard BAL-001-TRE-3: The SDT made revisions to Requirement R6: it moved the asterisk language to the requirement language, revised the table in Requirement R6.2 since it moved the examples of resources to the background section, and added some information to Measure M6. The SDT had previously revised the language to account for including a provision for a resource that is not qualified to provide operating reserves and accounting for BESS. Do you agree with these changes?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes	There is relief available for wider deadband settings for certain units. An example of where this may be used is when you have a Mechanical Hydraulic Control (MHC) unit that cannot meet the 17 mHz criteria and is not economically justified to upgrading to Electro-Hydraulic Control (EHC) unit.	Thank you for your comment.

Question 3	**Attachment 1: Primary Frequency Response Reference Document: The SDT updated the attachment to include language for capacity not expected to provide PFR in order to accurately account for expected frequency response. The SDT also included an equation for $EPFR_{final}$ and $ESPFR_{final}$ for BESS with capacity not expected to provide PFR and associated flowcharts to attachment A and B to the Primary Frequency Response Reference Document. Do you agree with the changes to Attachment 1?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes		

Question 4	**Do you have any additional comments for the standard drafting team?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No		

Marie Potter, Constellation Energy Generation, LLC	Yes	Continued conversation and consideration are needed on how to better align the ERCOT protocols with how renewable resources naturally perform. It seems there is an opportunity to add additional market changes to better convey expected WGR PFR and scoring criteria during events surrounding ERCOT curtailment events especially with respect to renewable resources. For example, if a site was curtailed or had the curtailment lifted immediately prior to a frequency event. This creates a scenario in which the wind turbines need to go through a “startup” phase to return to normal operations. The WGR to ERCOT has an LSL of 0 MW and RST of ‘ON’, while the HSL is the forecast. In the event of the curtailment to 0 MW, the WGR must shut down the facility but cannot telemeter shut down as a normal resource would because there would not be an outage ticket, and ERCOT would not have a way to communicate when the curtailment may be lifted. When ERCOT lifts a curtailment and issues a new base point above 0 MW, the WGR will then re-enable the turbines to re-engage and return to normal operations. At that point it would be practical to expect PFR. Potentially there is an opportunity to leverage the “Non-Frequency Response Capability” that combined cycles use for the periods in which the WGR is going through a startup, returning from an ERCOT curtailment. Further collaboration with	Thank you for your comment. The drafting team has determined that this is out of scope for this project. There are ongoing discussions during ERCOT’s Performance Disturbance Compliance Working Group (PDCWG) and Inverter-Based Resource Working Group (IBRWG) on this topic.

		ERCOT and affected stakeholders would be beneficial. To reiterate, per ERCOT IBRWG posting from January 17th, 2025, a curtailment to low output including down to 0 MW prevents a generator of certain technology types from being able to respond to a frequency event. ERCOT has confirmed that “wind resources cannot respond to frequency requirements while curtailed to zero output”. ERCOT has added the scenario of curtailment as “an additional exclusion to the BAL-001-TRE-2 PFR exclusion process.” With this additional exclusion ERCOT requires formal exclusion paperwork to be submitted for each PFR event within 30 days of the event.	

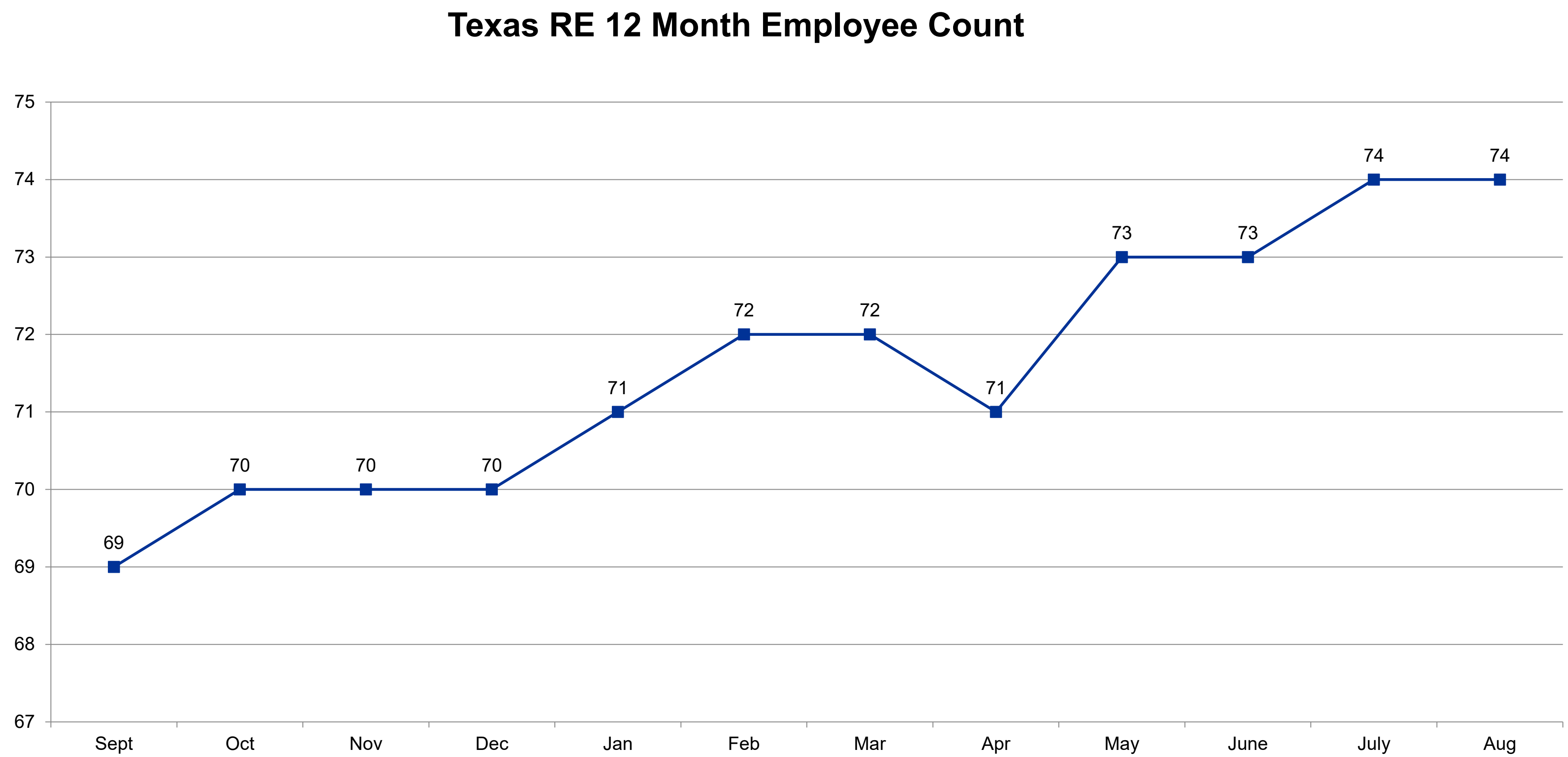
Regional Standard BAL-001-TRE-3 Final Ballot Results
Ballot Period Ended August 4, 2026

	No. in ballot pool	Affirmative	Negative	Abstain	No Ballot
System Coordination and Planning	1	1	0	0	0
Transmission and Distribution	4	3	0	0	1
Cooperative Utility	1		0	0	1
Municipal Utility	1	1	0	0	
Generation	6	5	0	0	1
Load-serving and Marketing	1		0	0	1
Totals	14	10	0	0	4

Human Resources Report

Board of Directors Meeting
September 16, 2026

August 2026 Staffing Report



	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug
Net Staffing Change	0	1	0	0	1	1	0	-1	2	0	1	0
Month End Employee Count	69	70	70	70	71	72	72	71	73	73	74	74

75 FTEs in 2026 Business Plan and Budget

New Hires (June - August)

- CIP Cyber & Physical Security Analyst
- Manager, Accounting
- Senior Accountant
- Manager, Communications & Training

One Vacancy as of August 31, 2026

- BI Analyst & Data Solutions Lead (contract)

Outstanding Workplace Culture Happenings

June - August

- World Cup Events
- Harassment Prevention Training
- Lunch-N-Learns
- Ice Cream Freeze Off
- Hawaiian Shirt Day

Upcoming Events

- Company-wide Training – Leading Across Boundaries
- CPR Training
- College Colors Day
- Company-wide Murder Mystery Team Building Event
- Thanksgiving Luncheon
- Holiday Party

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2026 Regional Risk Assessment
Board of Directors Meeting
September 16, 2026

Regional Risk Assessment

Regional Risks Register

- **Grid Transformation**
  - **Integration of Large Loads *(primary risk)***
  - **IBR Ride-through**
  - **Inaccurate Resource Modeling**
  - **Energy Availability**
  - **Provisions of Ancillary Services from a Changing Resource Mix *(upgraded)***
- **Resilience to Extreme Events**
  - **Extreme Weather Response**
  - **Critical Infrastructure Interdependencies**
  - **Facility Ratings**
  - **Workforce Changes *(new for 2026)***
- **Cyber and Physical Security**
  - **Remote Connectivity**
  - **Supply Chain**
  - **Physical Security**
  - **Artificial Intelligence**
  - **Cloud Security *(new for 2026)***

Risk Analysis and Prioritization

Impact or Consequence

How could a typical event affect BPS reliability?	
Severe	Widespread effects across North America
Major	Widespread effects across an RC area
Moderate	Widespread effects across multiple entities or a portion of an RC area
Minor	Effects on one entity
Negligible	Small or non-existent effects

- **Combined effort between RAPA and CMEP teams**
- **Data sources include:**
  - **NERC RISC Risk Priorities report**
  - **Texas RE ARP and NERC SOR**
  - **NERC CMEP IP**
  - **ERCOT**
  - **Violations/AOC's/Recommendations**

Likelihood

What is the reasonable probability that the event will occur?	
Almost Certain	Mandatory Controls – No NERC Reliability Standards in place for mitigation Emerging Trends – Increasing trends have been identified Event History – Widely publicized/documented events have been recorded
Likely	Mandatory Controls – No NERC Reliability Standards in place for mitigation Emerging Trends – Some trends have been identified Event History - Publicized events have been recorded
Possible	Mandatory Controls – NERC Reliability Standards in place for limited mitigation Emerging Trends – Some trends have been identified Event History – Moderate or no documented events have been recorded
Unlikely	Mandatory Controls – NERC Reliability Standards in place for mitigation Emerging Trends – Some trends have been identified Event History – Minimal or no documented events have been recorded
Very Unlikely	Mandatory Controls – NERC Reliability Standards in place for mitigation Emerging Trends – No trends have been identified Event History – No documented events have been recorded

Public

Regional Risk Assessment

Consequence/Effect				Likelihood: 1 Very Unlikely	2 Unlikely	3 Possible	4 Likely	5 Almost Certain
Widespread effect	ERO	5	Severe					
Widespread effect	Interconnection	4	Major		Extreme Weather Response	Energy Availability Supply Chain Gas Supply Restrictions During Cold Weather Physical Security	***Disorganized Integration of Large Loads*** IBR Ride-through	
Widespread effect	Large TOP/GOP	3	Moderate		Artificial Intelligence Facility Ratings	Inaccurate Resource Modeling **Provision of Essential Reliability Services from a Changing Resource Mix** **Workforce Changes** Remote Access		
Local Entity	Small TOP/GOP	2	Minor			**Cloud Security**		
Small	Single Facility	1	Negligible					

Primary Regional Risk

- **Integration of Large Loads**

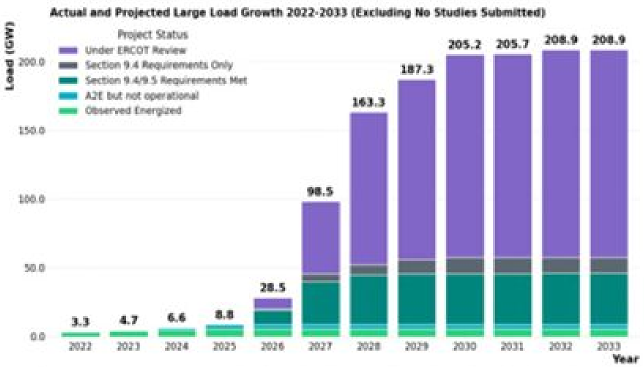
Upgraded Risk from 2025

- **Provisions of Essential Reliability Services from a Changing Resource Mix**

New Risks for 2026

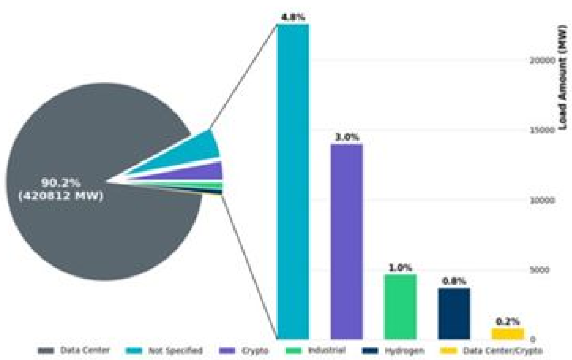
- **Cloud Security**
- **Workforce Changes**

Large Load Integration Risks

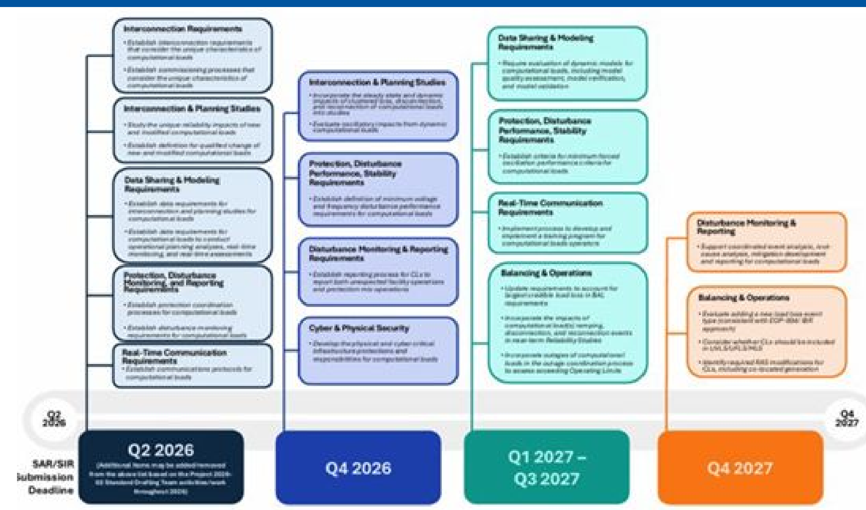


Project Status	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Under ERCOT Review	0.0	0.0	0.0	0.0	8.1	52.9	111.0	131.2	147.7	148.2	151.1	151.1
Section 9.4 Requirements Only	0.0	0.0	0.0	0.0	1.5	5.7	7.2	10.4	11.8	11.8	11.8	11.8
Section 9.4/9.5 Requirements Met	0.0	0.0	0.0	0.0	10.1	31.0	36.1	36.8	36.8	36.8	37.1	37.1
A2E but not operational	0.0	0.4	1.8	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Observed Energized	3.3	4.3	4.8	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Total (GW)	3.3	4.7	6.6	8.8	28.5	98.5	163.3	187.3	205.2	205.7	208.9	208.9

Large Load Project Distribution by Type



- Primary risk for the Texas RE region
- 36 GW of new loads by 2030 with approved planning studies and that have met ERCOT planning guide requirements
- Additional 148 GW of load under ERCOT review could interconnect by 2030
- 90% of new load requests are data centers
- Risk Mitigation Measures
  - NERC ROP changes to define Computation Load Entity
  - NERC standard roadmap for large loads



New Risks

Workforce Changes

- Aging demographics
- Loss of institutional knowledge
- Increasing system complexity
- Insufficient staffing/expertise on cyber security

- Risk Mitigation Measures
  - Training for system operations
  - BES cyber systems training, access management, and security awareness

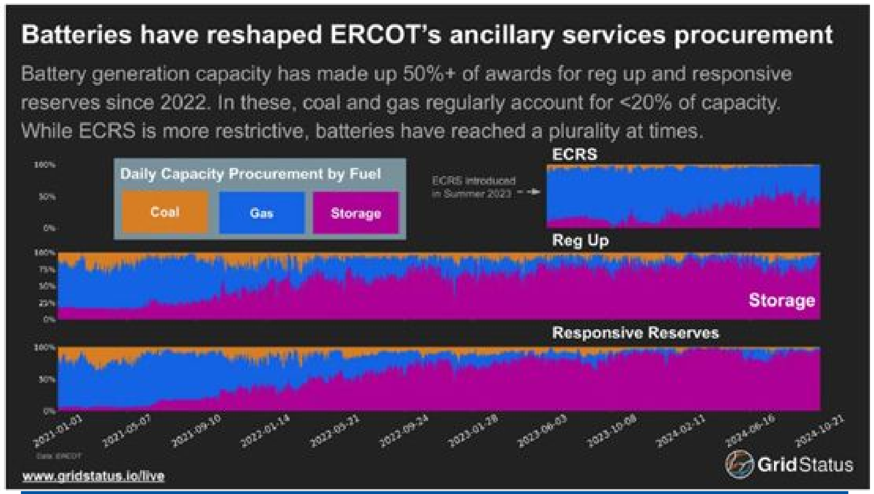
Cloud security

- Dependency on 3rd party platforms
- Increasing reliance on common cloud service providers with shared infrastructure dependencies
- Increased exposure of critical data within cloud-based systems
  - Data breaches
  - Incorrectly configured cloud settings
  - DoS attacks
  - Supply chains

- Risk Mitigation Measures
  - Project 2023-09 Risk Management of 3rd party Cloud Services

Public

Provisions of Essential Reliability Services from a Changing Resource Mix



ERCOT Market Rule Changes in Progress	
Introduction of Mitigation of ESRs	NPRR1255
Establishing Advanced Grid Support Service as an Ancillary Service	NPRR1278
Add Energy Storage Resource (ESR) State of Charge (SOC) Information to the Ancillary Services Capacity Monitor	NPRR1326
Establish an Incentive Program for Advanced Grid Support	NPRR1333
Dispatchable Reliability Reserve Service Ancillary Service with Energy Storage Resource Participation	NPRR1340

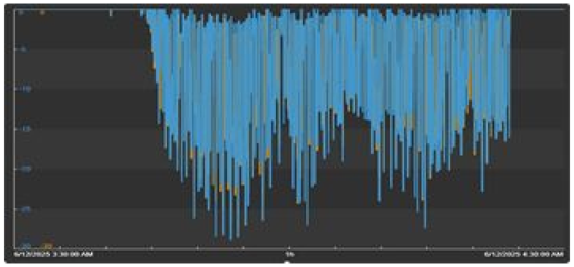
- **Increased reliance on ESRs for critical ancillary services**
- **ERCOT market rules for Advanced Grid Support**
- **Risk Mitigation Measures**
  - **Standards related to:**
    - **Interconnection requirements for IBRs**
    - **Studies to assess reliability impact of new IBR interconnections**
    - **IBR models**
    - **IBR Ride-through**
    - **IBR protection system coordination**
    - **Frequency control performance**
    - **Balancing contingency event performance with increased ESR participation**
  - **ERCOT market rule changes**

Inverter-Based Resource Risks

IBR Standards Planned for 2026	
Operational Studies Planning Studies	Project 2025-03 Project 2025-04
Ride-Through Revisions	Project 2025-05
Verification of Generator Models	MOD-026-2

Event Type	# of events in 2024	# of events in 2025
IBR Ride-Through Events	7	12
IBR Oscillation Events	35	24

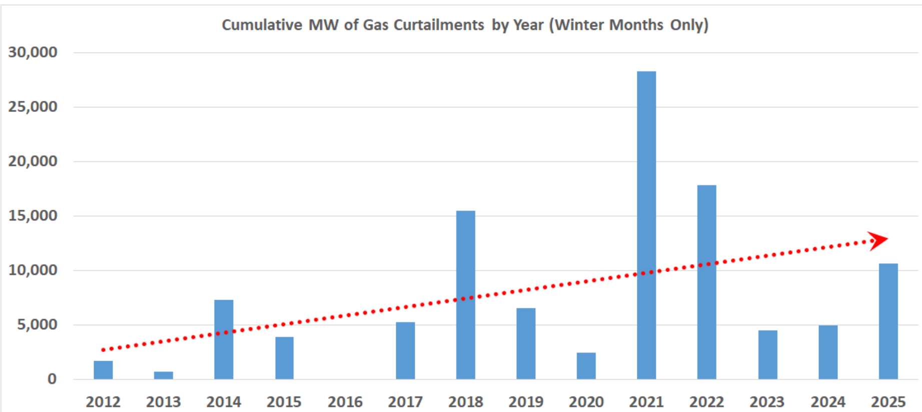
Year	Count of Hours with Renewable Penetration > 70%
2023	1
2024	39
2025	163
2026 YTD	321

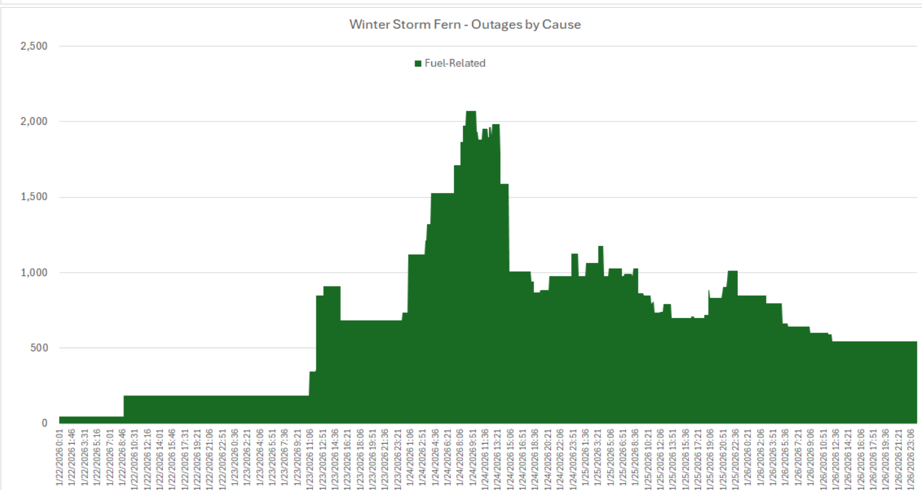


- Increased reliance on IBRs to meet load
- FERC Order 901 projects
- NERC Alert on IBR model quality
- Category 2 IBR registration Implementation
- No IBR ride-through events in 2024/25 > 500 MW

- Risk Mitigation Measures
  - Standards related to:
    - Interconnection requirements for IBRs
    - Studies to assess reliability impact of new IBR interconnections
    - IBR models
    - IBR ride-through
    - IBR protection system coordination
    - Frequency control performance
    - Balancing contingency event performance with increased ESR participation

Gas Supply Restrictions During Cold Weather

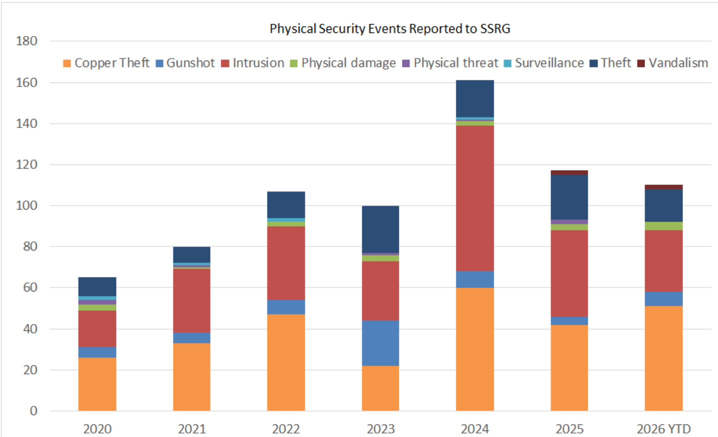




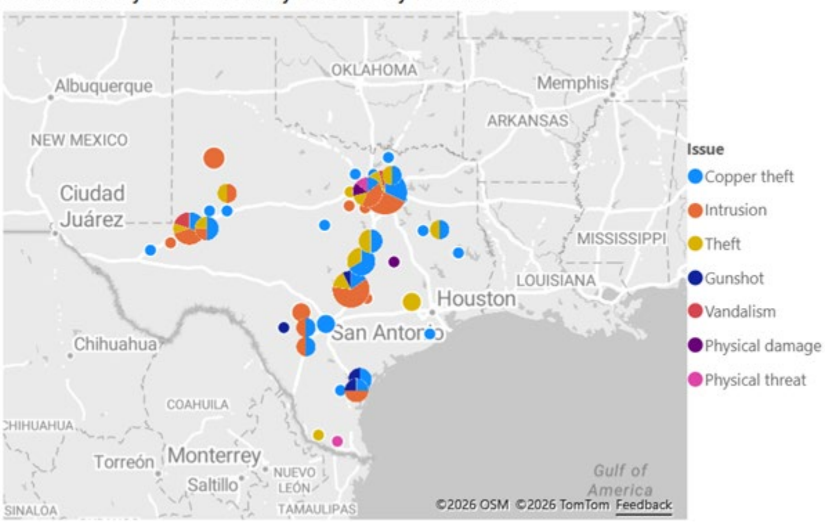
- Cumulative MW impact from gas curtailments increased in 2025, however, larger than normal increases were observed in summer and fall months

- Risk Mitigation Measures
  - Standards related to:
    - Identification of critical natural gas infrastructure loads
    - GO plans to mitigate operational limitations for fuel supply and inventory concerns
  - Proposed Standards and ERCOT Rules:
    - NPRR1335 Implementation of PUCT Changes to Firm Fuel Supply Service
    - NPRR1346 Updates to the Fuel Oil Price

Physical Security Risks

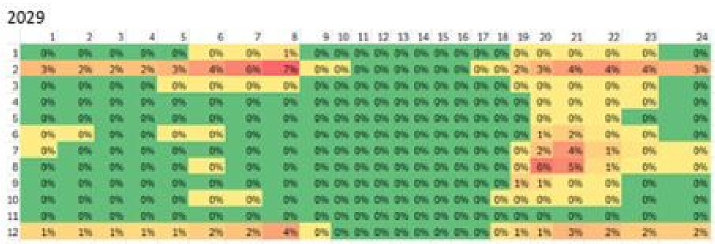


Count of Physical Security Events by Location



- **Increasing trends in physical security incidents**
  - **Intrusions**
  - **Copper theft**
  - **Ballistic damage**
- **Risk Mitigation Measures**
  - **Standards related to:**
    - **Risks to the reliable operation of the BPS as the result of a Physical Security Incident**
    - **Risks to the reliable operation of the BPS as they relate to physical security programs**
    - **Risks to the reliable operation of the BES as the result of increased Physical Security events related to low impact assets**
  - **Proposed Standards and ERCOT Rules:**
    - **Project 2021-03 CIP-002**
    - **NPRR1334 Revision to Cybersecurity Incident Notification**

Energy Availability Risks



Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
* Provides the 2024 ProbA Results for Comparison			

New Resources Approved for Commercial Operation in 2025

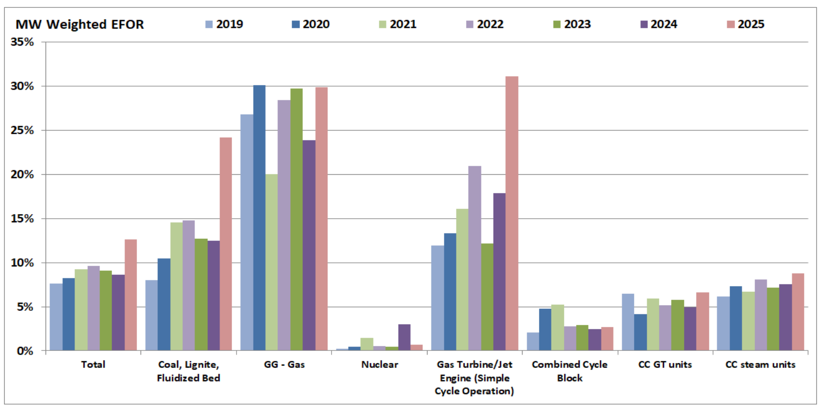
Fuel Type	Total MW	Average # Days to Connect (from FIS to COD)	Median # Days to Connect	Minimum # Days to Connect	Maximum # Days to Connect
Battery	6,291	625	479	200	1,535
Solar	5,998	845	714	330	1,829
Fuel Oil	439	75	75	34	115
Wind	1,463	1,119	844	692	2,858

- NERC Wide Area Energy Assessment Studies
- NERC Probabilistic Assessment Studies

- Risk Mitigation Measures
  - BAL-007 Implementation: plan to address forecasted Energy Emergencies in the near-term time horizon
  - TEF Projects
  - Proposed Standards and ERCOT Rules:
    - Project 2025-03 Operational Studies
    - Project 2025-04 Planning Studies
    - Project 2024-02 Planning Energy Assurance
    - NPRR1320 Reserve Margin Reporting and Miscellaneous Changes for the Report on Capacity, Demand, and Reserves in the ERCOT Region (CDR)
    - NPRR1328 Establishment of Generation Firming Program
    - NPRR1320 Reserve Margin Reporting and Miscellaneous Changes for the CDR

Public

Supply Chain Risks



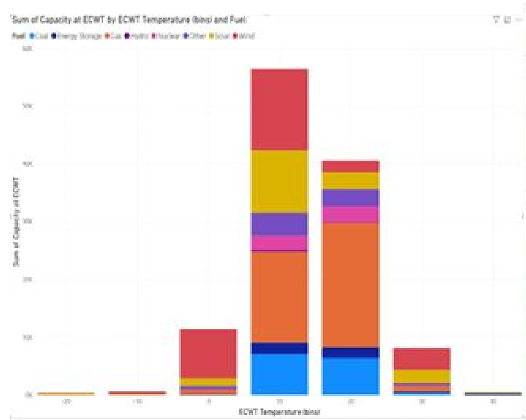
- Persistent supply chain and workforce challenges are impacting risk mitigation and response capabilities
  - Extended outages on two coal units, one for 14 consecutive months and another for 18 months (ongoing)
  - A single fire-related substation equipment failure, Circuit and associated 345 kV auto remain out ~ 18 months)
- Software supply chain cyber security challenges

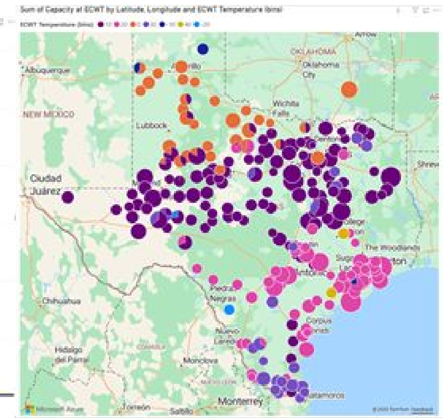
- Risk Mitigation Measures
  - Standards related to:
    - Implementation of Supply Chain policies and procedures
    - Transmission planning criteria for extended facility outages > one year
  - Proposed Standards and ERCOT Rules:
    - Project 2025-06 Supply Chain Risk Management
    - Project 2022-05 CIP-008 Reporting Threshold

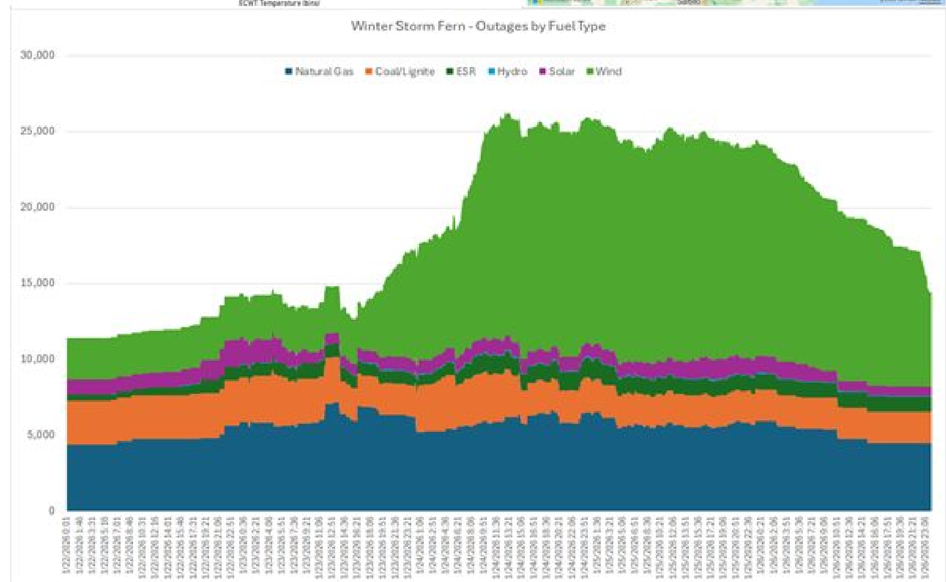
Extreme Weather Response Risks

- ECWT data collection
- EOP-012 constraint declarations
  - Wind blade/solar panel icing
  - Wind cold weather packages
  - CT inlet air icing

- Risk mitigation measures
  - Standards related to:
    - TOP and BA emergency operating plans
    - GOP cold weather plans
  - Proposed Standards:
    - Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather







TEXAS RE

Chief Engineer’s Report

Board of Directors Meeting
September 16, 2026

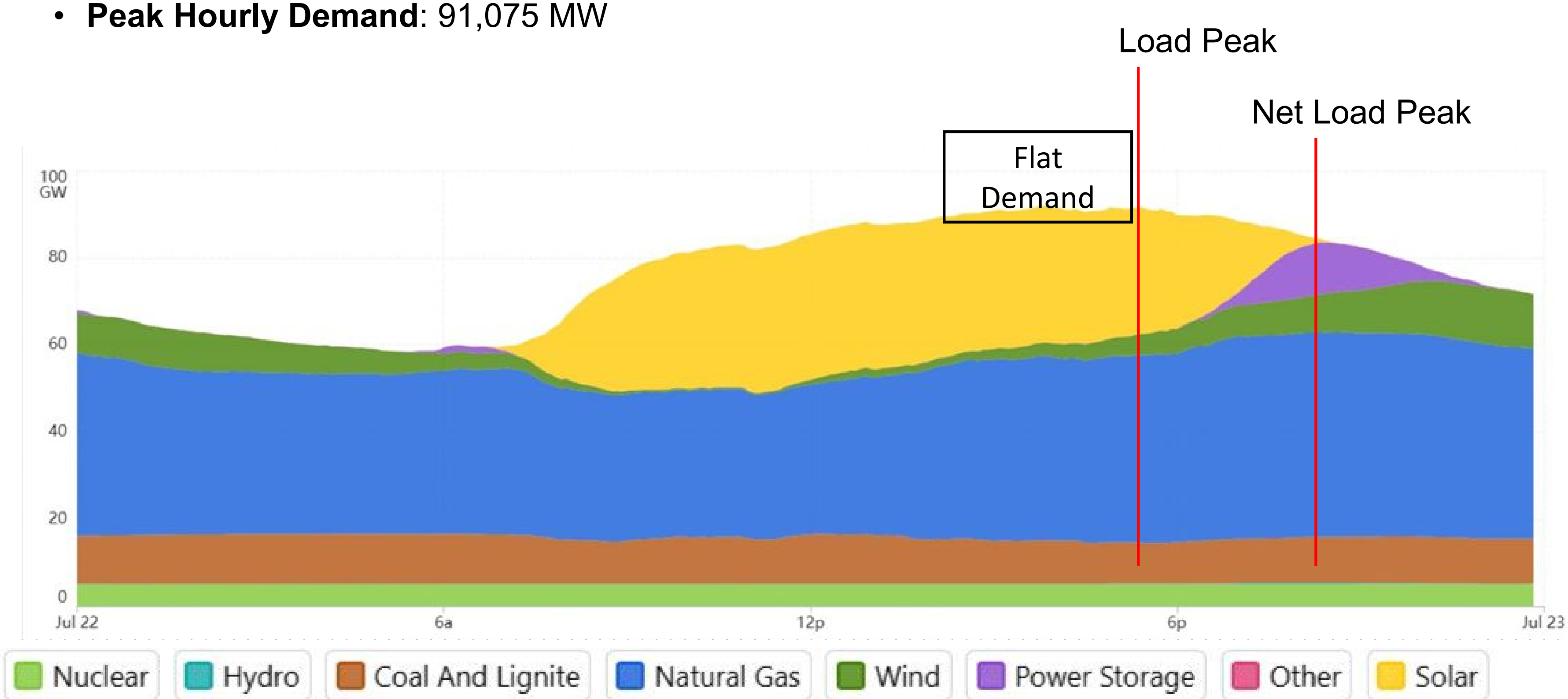
Public

Topics

- Summer Performance Review
- Large Computational Loads Update
- Inverter-Based Resources Activities
- Extremes and Critical Infrastructure Work
- Teaching at ERCOT's Operator Seminar

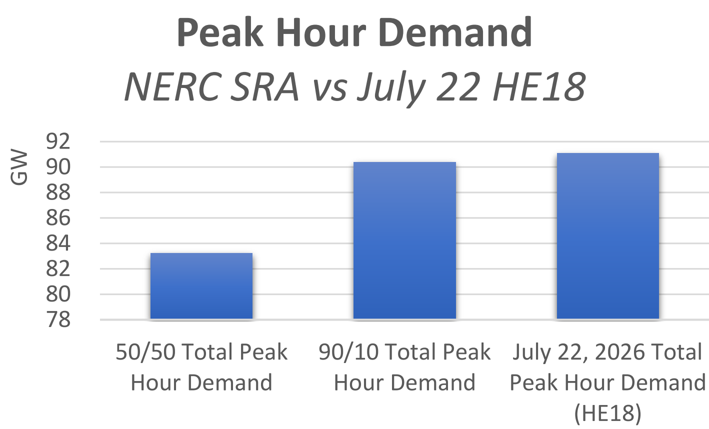
July 22, 2026, Record Demand

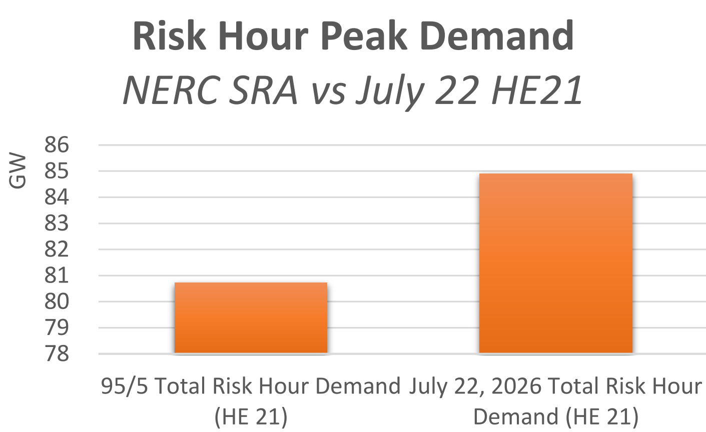
- **Peak Hour**: HE18
- **Peak Hourly Demand**: 91,075 MW

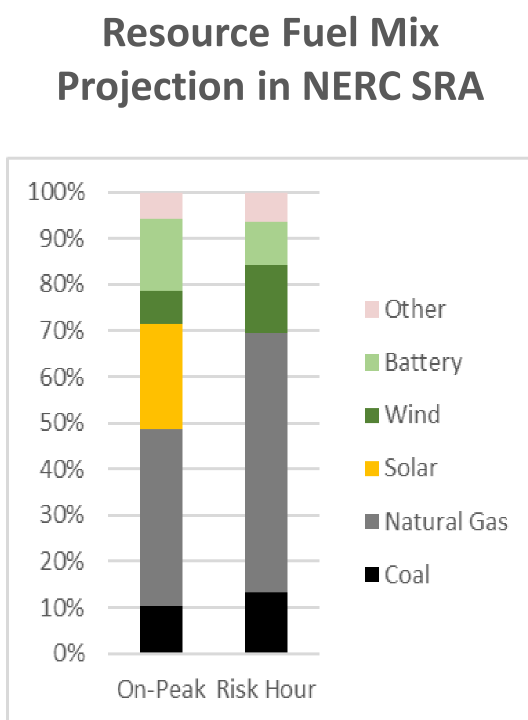


Source: GridStatusio.com

July 22 Peak vs. NERC's Summer Reliability Assessment (SRA)

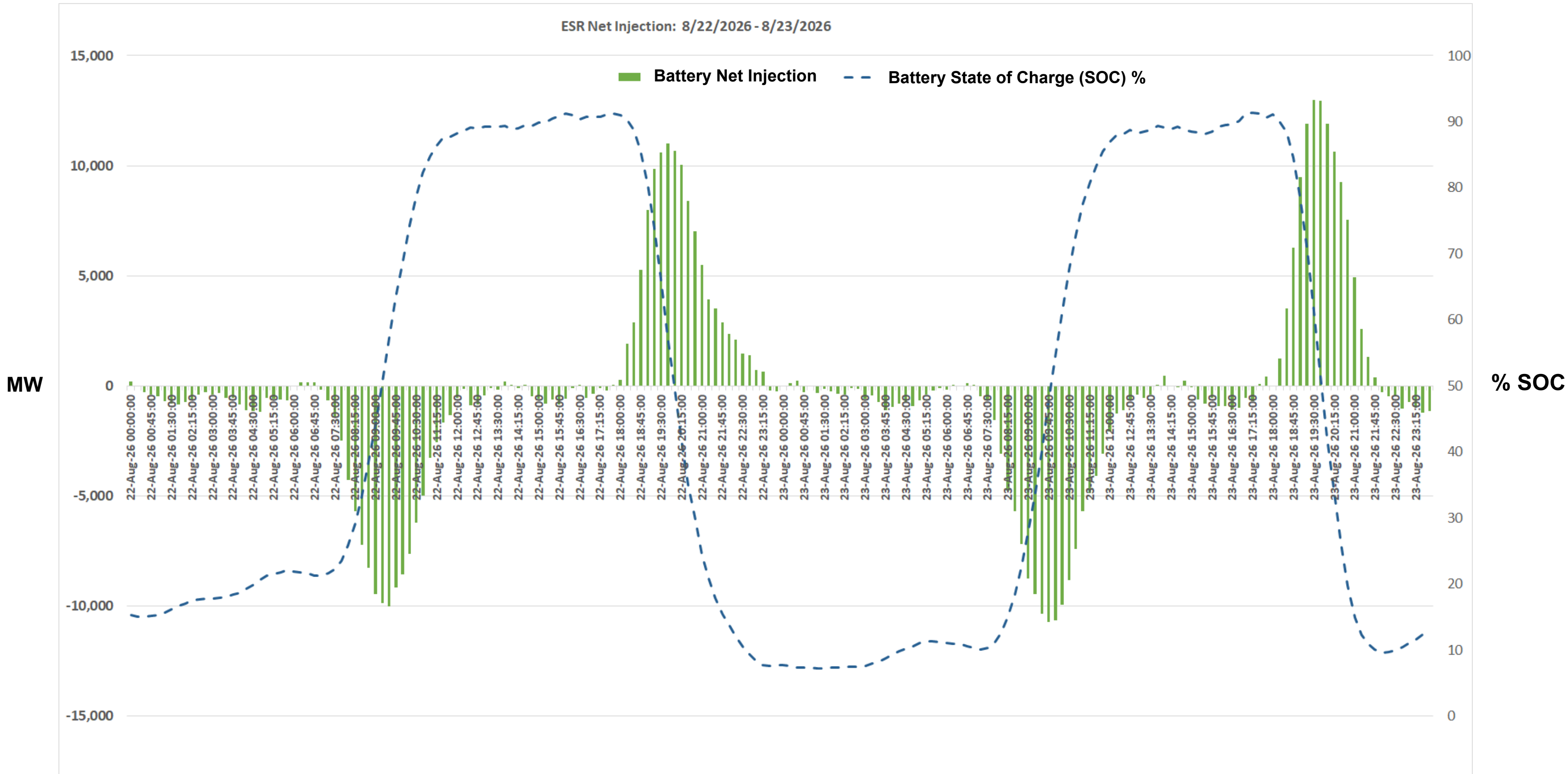






Source: NERC 2026 SRA

Battery Energy Storage (BESS) Cycling August 22-23



BESS are performing well this summer – and carrying over 50% of Physical Responsive Capability

Data Center Growth and Developments

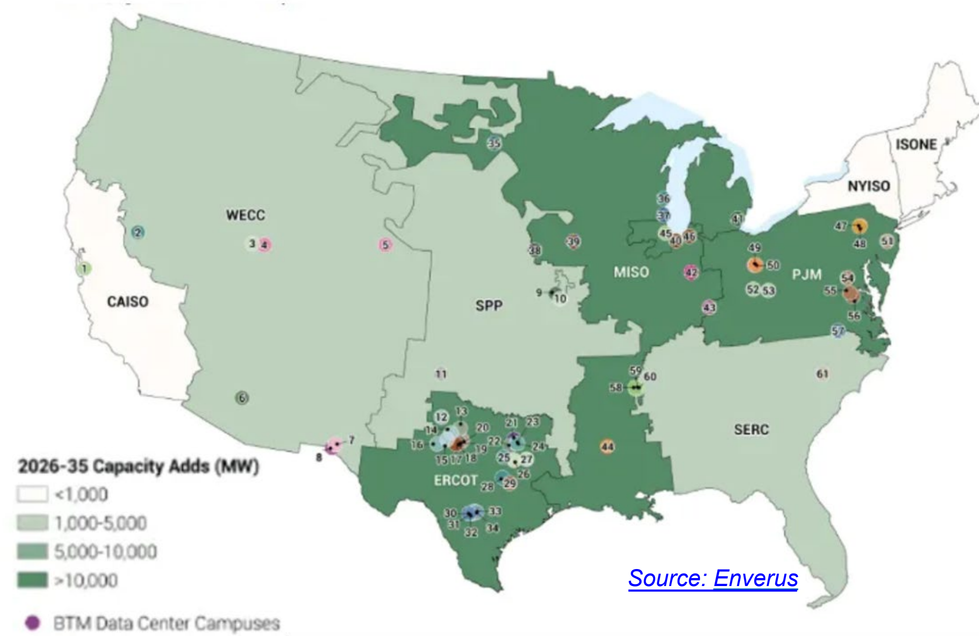
FERC's June 22 Orders direct other RTO/ISOs to develop interconnection plans like Texas' Senate Bill 6 and PUCT Orders

- Faster study processes that weed out speculative loads
- Protection against cost shifting
- Support for co-location and self-generation
- Enhanced flexible load operation
- Studies coordinating loads, generation, and transmission

State-directed auditing of data centers will take place before ERCOT's 'batch zero' interconnection studies.

Reliability concerns with facility ride-through and power cycling need solutions; work is in progress to identify and mitigate

High Confidence Data Center Projects – One Analyst's View



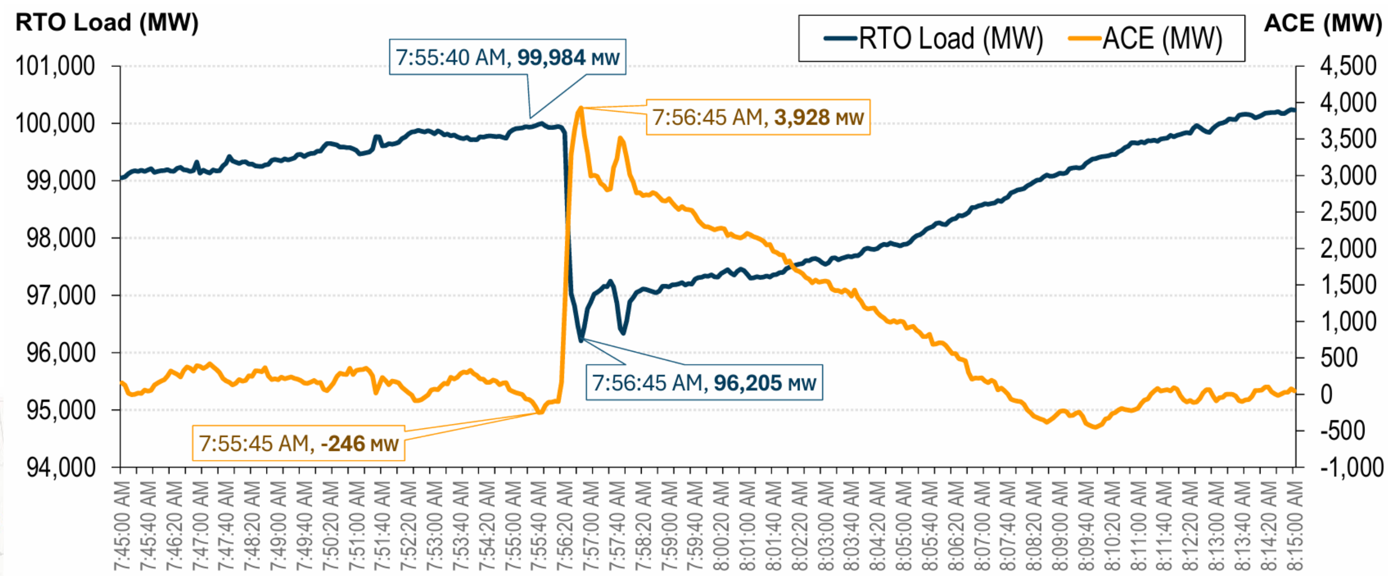
Source: Enverus

Key items - NERC's Large Load Action Plan in Q3:

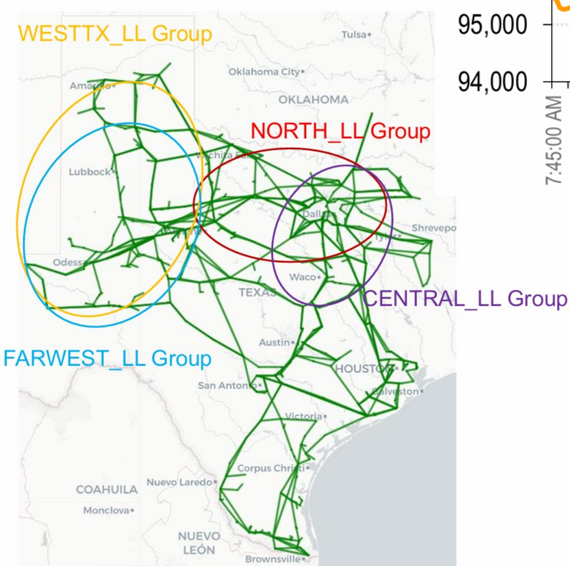
- NERC Essential Action Alert Responses Received
- Data Center Load Modelling Technical Reference published and workshop scheduled for September 15-16
- Registry Criteria for Large Computational Loads posted along with three draft Standards, August 19 – September 18

Data Center Ride-Through (RT) of Transmission Faults

On Wednesday, July 22, at 07:56 approximately 3,800 MW of load transferred to back-up power during a 230 kV transmission line fault, the largest load transfer PJM has experienced.



Source: PJM



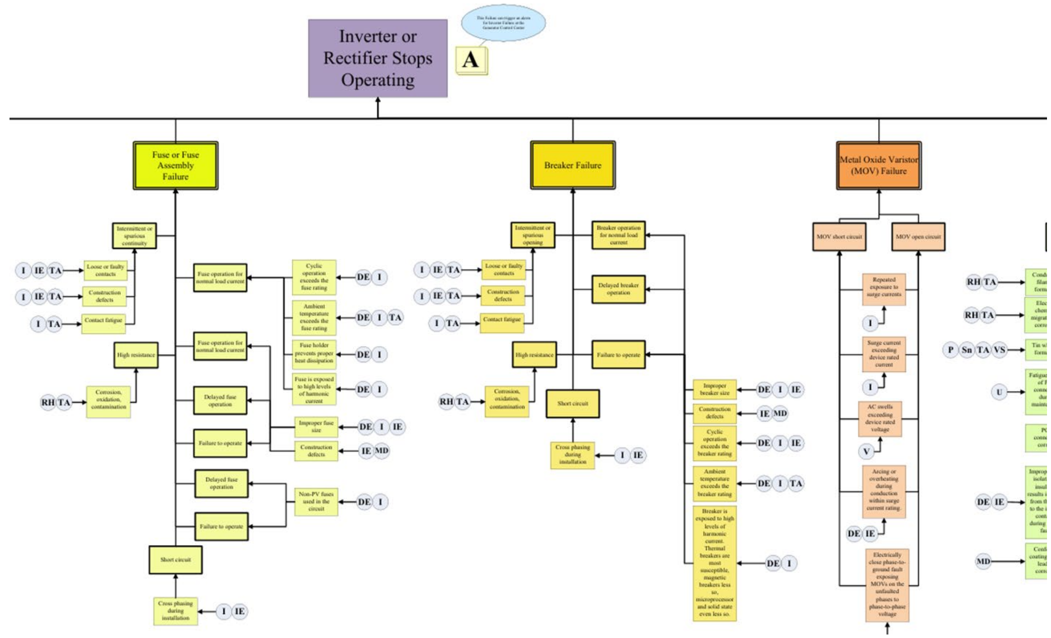
Source: ERCOT

- ERCOT studies of similar events found that four groups of large loads (LL) without RT capability could disconnect, leading to voltage collapse when a group's load exceeds 3200 MW.
- PUCT approved ERCOT's NOGRR282 establishing RT requirements for large loads coming into the system. NERC's new LL disturbance whitepaper suggests this as a model for all.

Inverter-Based Resources (IBR) Developments

FERC Order 901 Standards

Large Inverter Failure Modes & Mechanisms

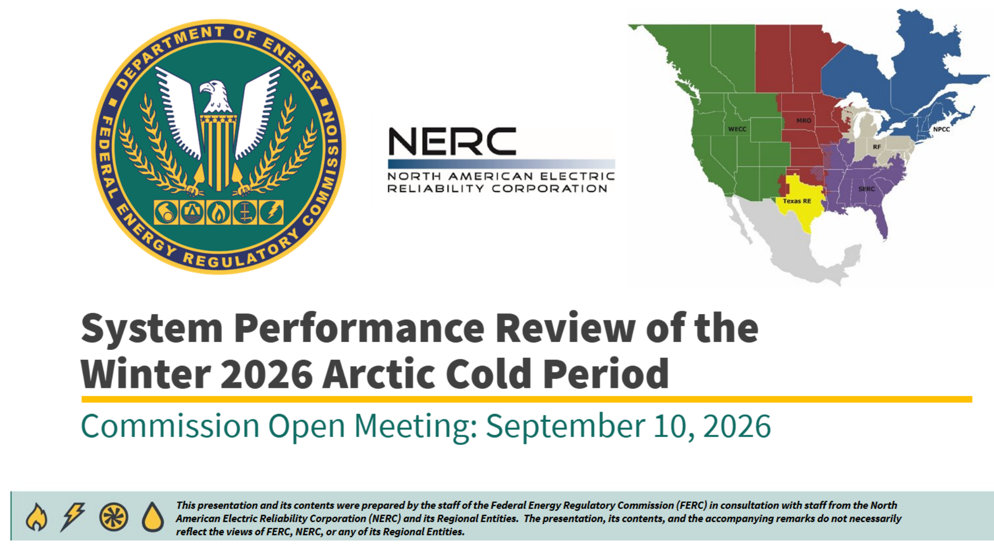


Assisting IBR Integration

Resilience to Extreme Events and Critical Infrastructure Interdependencies

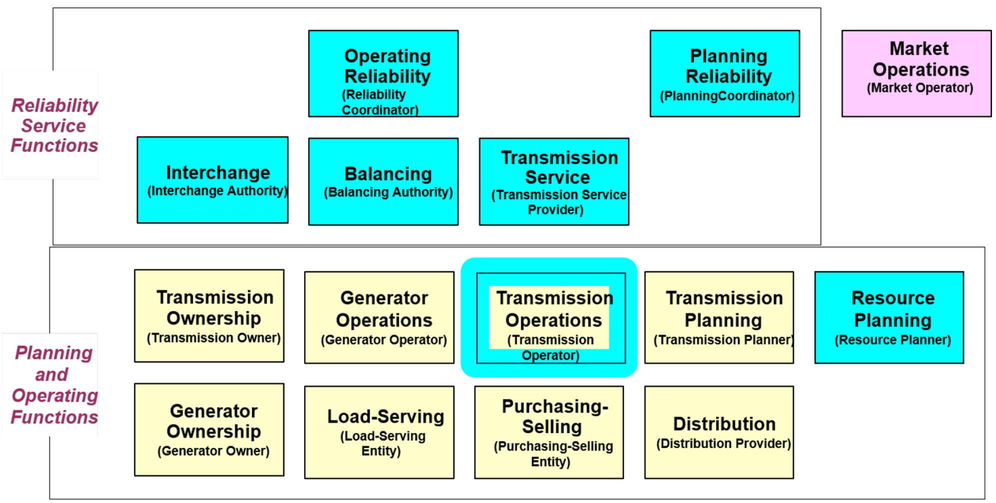
Texas RE and NERC activities:

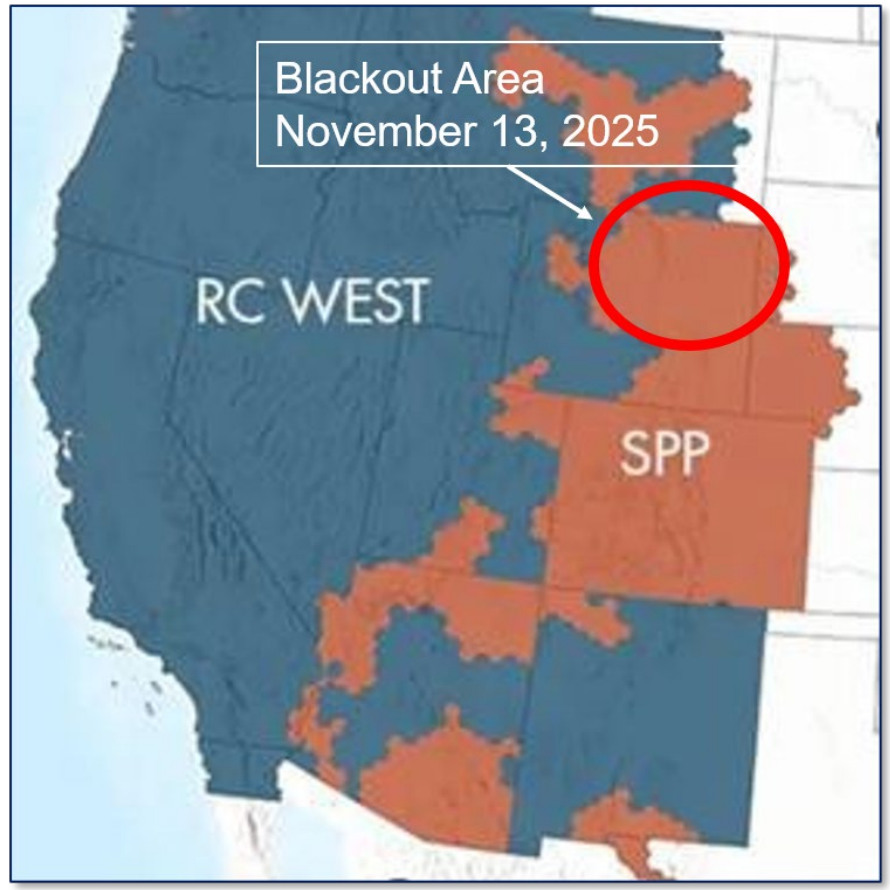
- Upcoming ERO-FERC report on Winter 2026 for September 10 FERC Open Meeting
- Winter preparedness workshop August 19, 2026; NERC webinar September 17, 2026
- Wildfire guideline drafting in progress
- Participation in Texas Division of Emergency Management Blackstart Exercise during August
- Hosting EISAC VISA exercise August 4-6
- Cyber and physical security engagements with state and federal agencies and outreach through newsletter and Talk with Texas RE
- Ongoing development of ERO-wide energy assessments for inclusion into NERC Long Term Reliability Assessments



Messaging for ERCOT's 2026 Operations Training Seminar

- Reviewed NERC Functional Model and Entity Roles and Responsibilities
- Stressed need for coordination and communication and authority in normal and emergency conditions
- Taught with practical example from recent event





CIP and O&P Compliance Monitoring and Risk Assessment Report

Board of Directors Meeting
September 16, 2026

2026 ERO Enterprise Long-Term Strategy

- ENERGY
- SECURITY
- ENGAGEMENT
- AGILITY AND SUSTAINABILITY


Critical Infrastructure Protection Compliance Monitoring

Public

Q2 2026: Texas RE*view* Newsletter

Articles

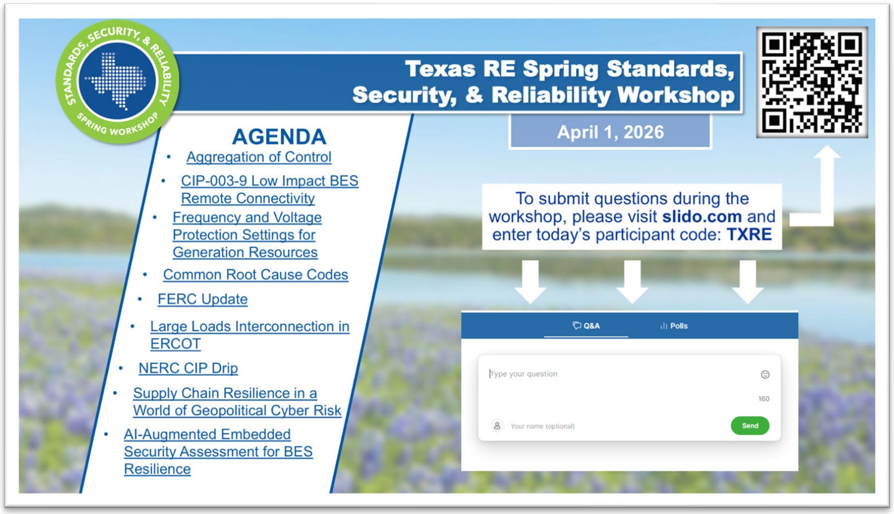
- CIP-012 Remote Connectivity
- Cybersecurity Best Practices
- Physical Security: CIP-014-3
- Access Management

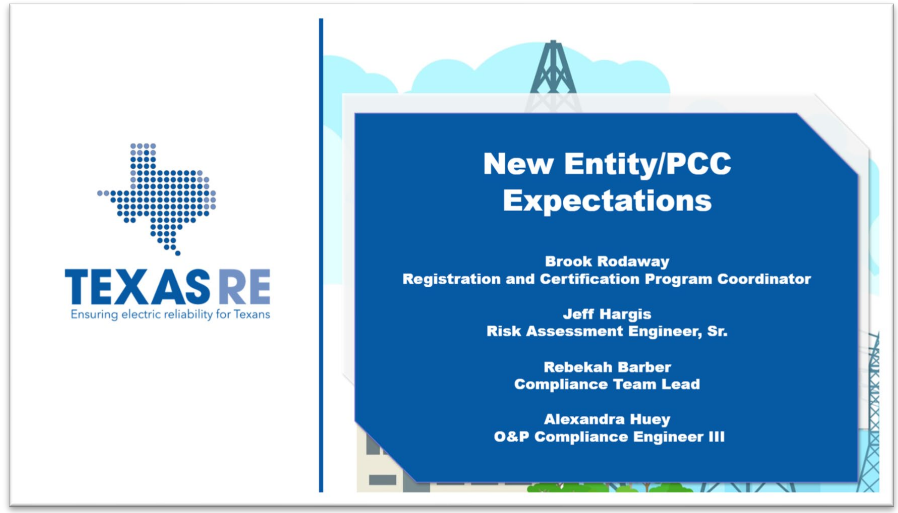
Q2 2026: CIP Working Group (CIPWG)

Ask Texas RE Presentations

- 2026 CMEP IP Risk Element - Remote Connectivity: CIP-012-2 R1
- 2026 CMEP IP Risk Element - Physical Security: CIP-014-3 R4 R5
- 2026 CMEP IP Risk Element - Grid Transformation: CIP-004-7 R6

Q2 2026: Workshop, Webinar, Training, and Conference Highlights





Operations and Planning Compliance Monitoring

Q2 2026: Texas RE*view* Newsletter

REview
Newsletter

Articles

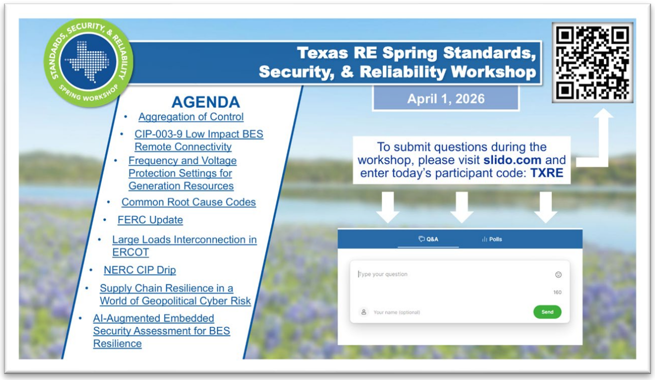
- PRC-028 & PRC-029 IPs and Data Submittals
- FAC-008 Inventory Change Management
- Extreme Weather Reliability and Compliance

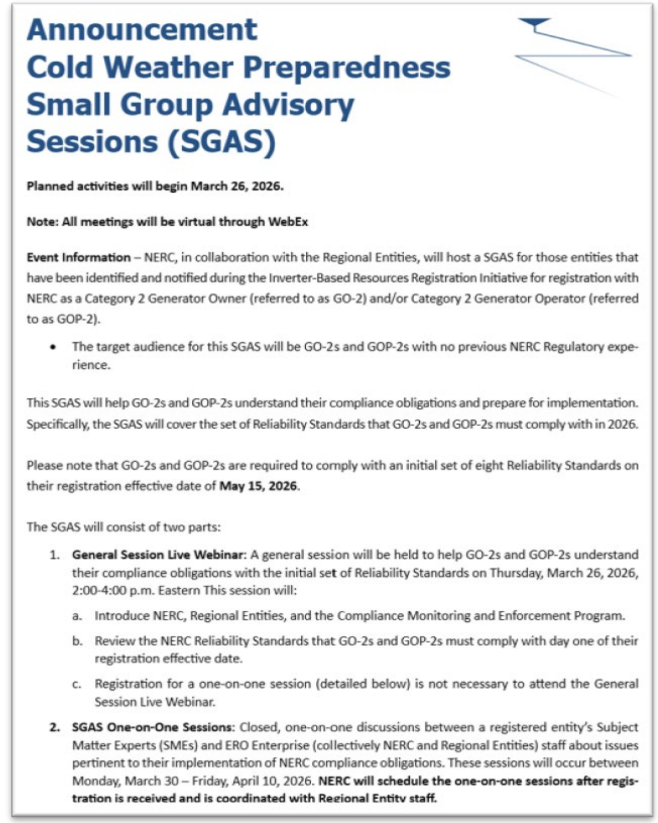
Q2 2026: NERC Standards Review Forum (NSRF)

Ask Texas RE Presentations

- FAC-008: Inventory Change Management
- EOP-011-4: Emergency Operations
- MOD-032: Large Load Integration

Q2 2026: Workshop, Webinar, Training, and Conference Highlights





Announcement
Cold Weather Preparedness Small Group Advisory Sessions (SGAS)

Planned activities will begin March 26, 2026.

Note: All meetings will be virtual through WebEx

Event Information – NERC, in collaboration with the Regional Entities, will host a SGAS for those entities that have been identified and notified during the Inverter-Based Resources Registration Initiative for registration with NERC as a Category 2 Generator Owner (referred to as GO-2) and/or Category 2 Generator Operator (referred to as GOP-2).

- The target audience for this SGAS will be GO-2s and GOP-2s with no previous NERC Regulatory experience.

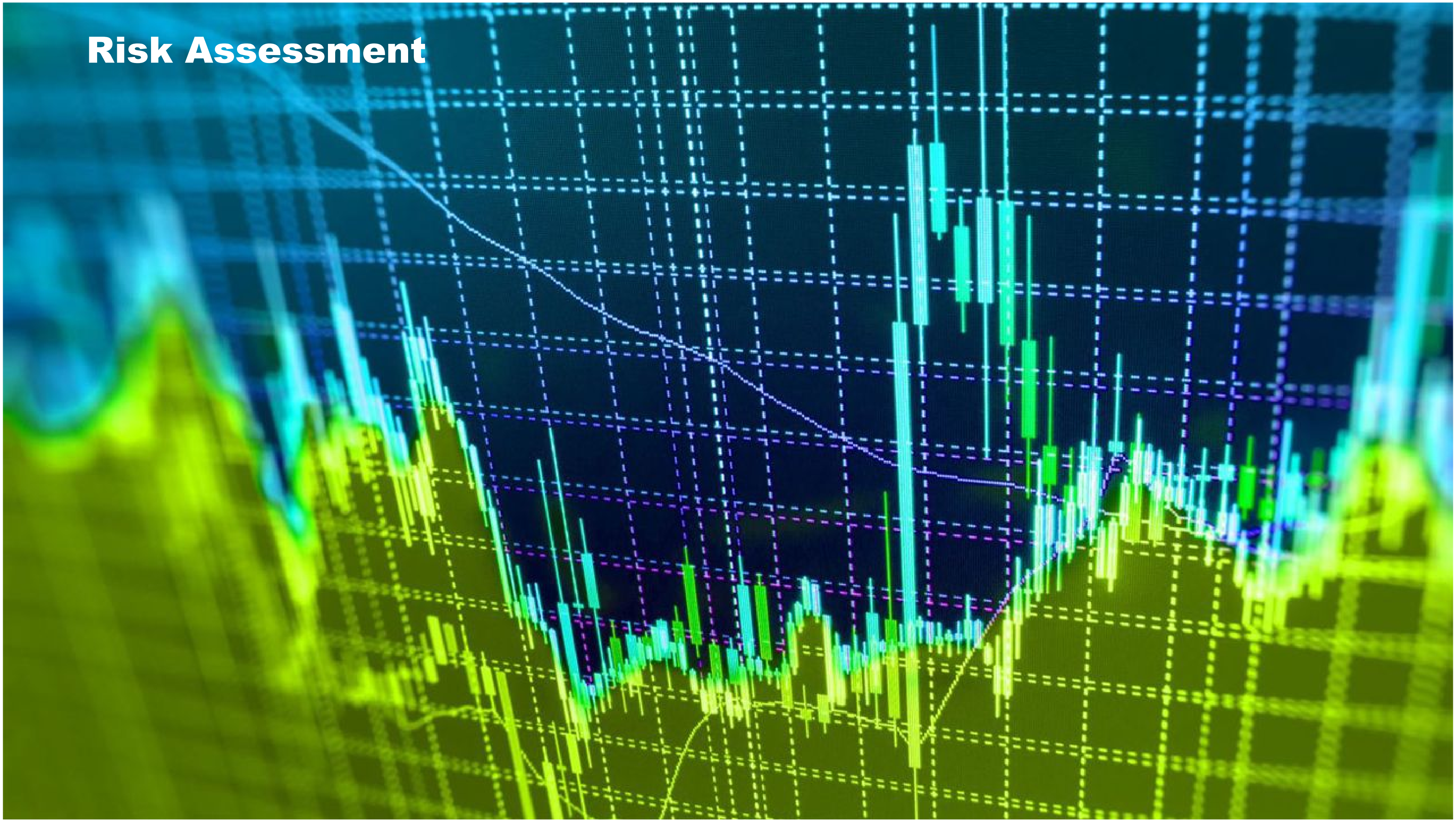
This SGAS will help GO-2s and GOP-2s understand their compliance obligations and prepare for implementation. Specifically, the SGAS will cover the set of Reliability Standards that GO-2s and GOP-2s must comply with in 2026.

Please note that GO-2s and GOP-2s are required to comply with an initial set of eight Reliability Standards on their registration effective date of **May 15, 2026**.

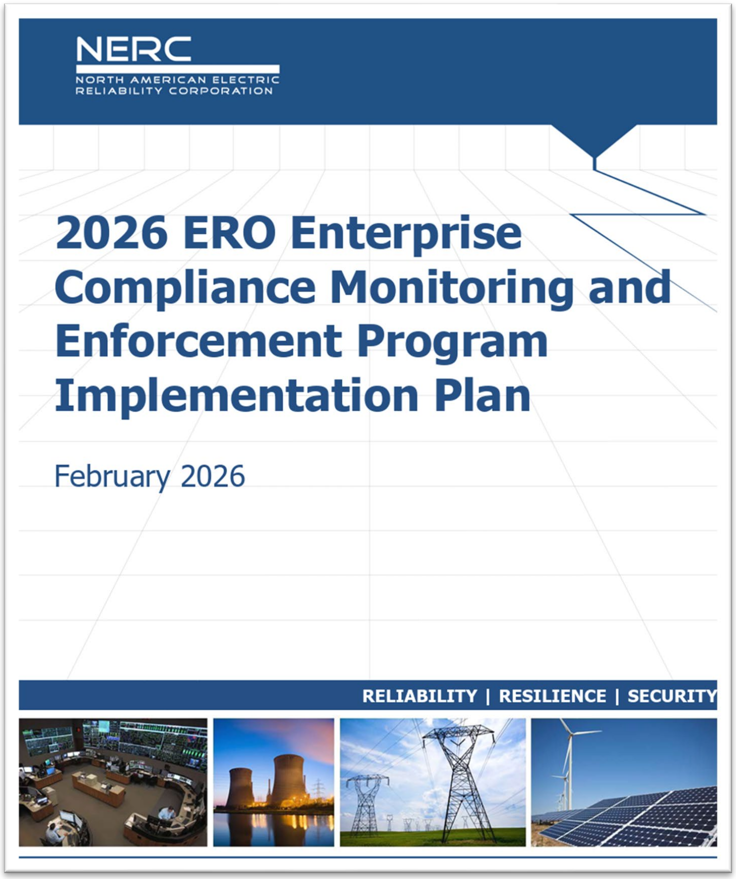
The SGAS will consist of two parts:

1. **General Session Live Webinar**: A general session will be held to help GO-2s and GOP-2s understand their compliance obligations with the initial set of Reliability Standards on Thursday, March 26, 2026, 2:00-4:00 p.m. Eastern This session will:
   a. Introduce NERC, Regional Entities, and the Compliance Monitoring and Enforcement Program.
   b. Review the NERC Reliability Standards that GO-2s and GOP-2s must comply with day one of their registration effective date.
   c. Registration for a one-on-one session (detailed below) is not necessary to attend the General Session Live Webinar.
2. **SGAS One-on-One Sessions**: Closed, one-on-one discussions between a registered entity's Subject Matter Experts (SMEs) and ERO Enterprise (collectively NERC and Regional Entities) staff about issues pertinent to their implementation of NERC compliance obligations. These sessions will occur between Monday, March 30 – Friday, April 10, 2026. **NERC will schedule the one-on-one sessions after registration is received and is coordinated with Regional Entity staff.**

Risk Assessment



2026 Risk Assessment Strategy: CMEP IP


NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2026 ERO Enterprise Compliance Monitoring and Enforcement Program Implementation Plan

February 2026

RELIABILITY | RESILIENCE | SECURITY

- Remote Connectivity
- Supply Chain
- Physical Security
- Grid Transformation
- Facility Ratings
- Extreme Weather Response
- Communication Protocols & Operating Instructions

Q2 2026: Texas RE*view* Newsletter

Articles

- Align Risk Questionnaire Update
- Grid Transformation Risk Element

Q2 2026: NERC Standards Review Forum (NSRF)

Ask Texas RE Presentations

- Risk Assessment Using MIDAS

Q2 2026: Workshop, Webinar, Training, and Conference Highlights

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TEXAS RE

Enforcement Report

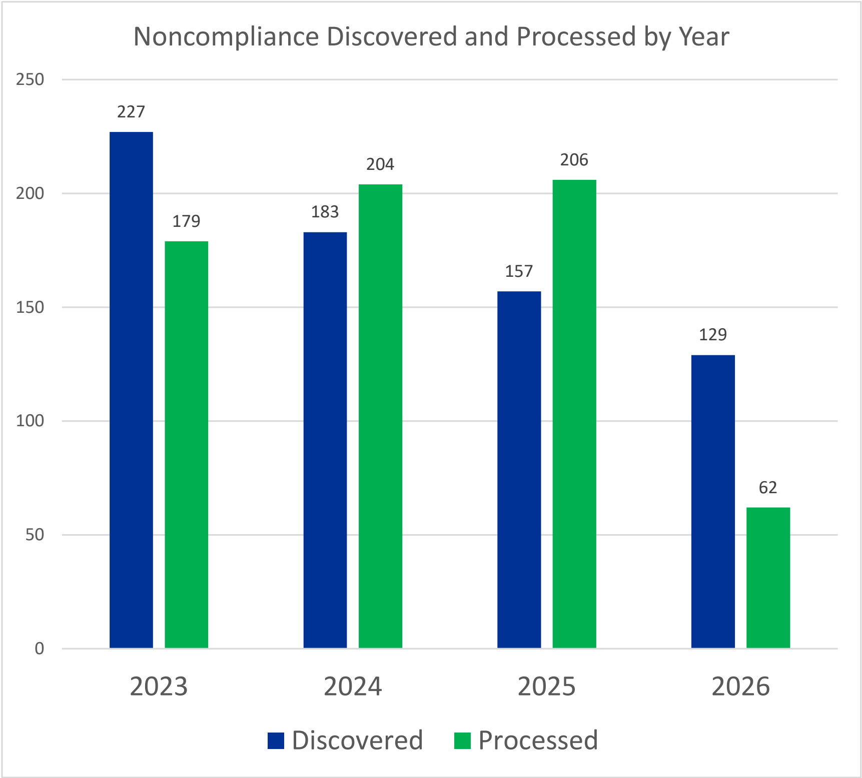
Board of Directors Meeting
September 16, 2026

Enforcement Processing Priorities

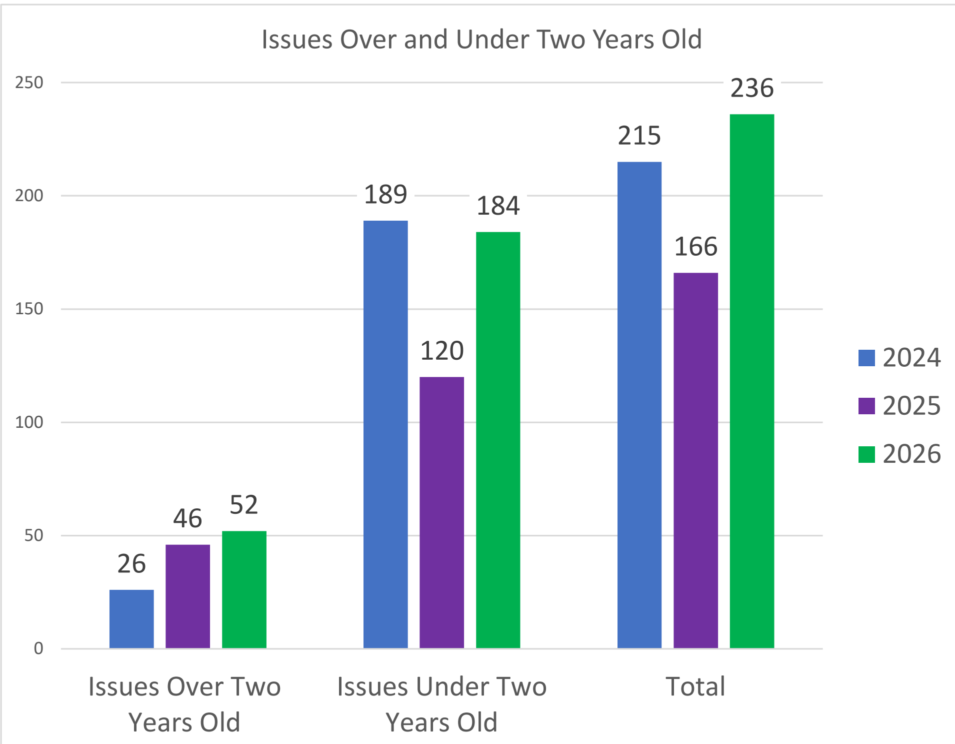
Streamlining disposition of minimal risk issues

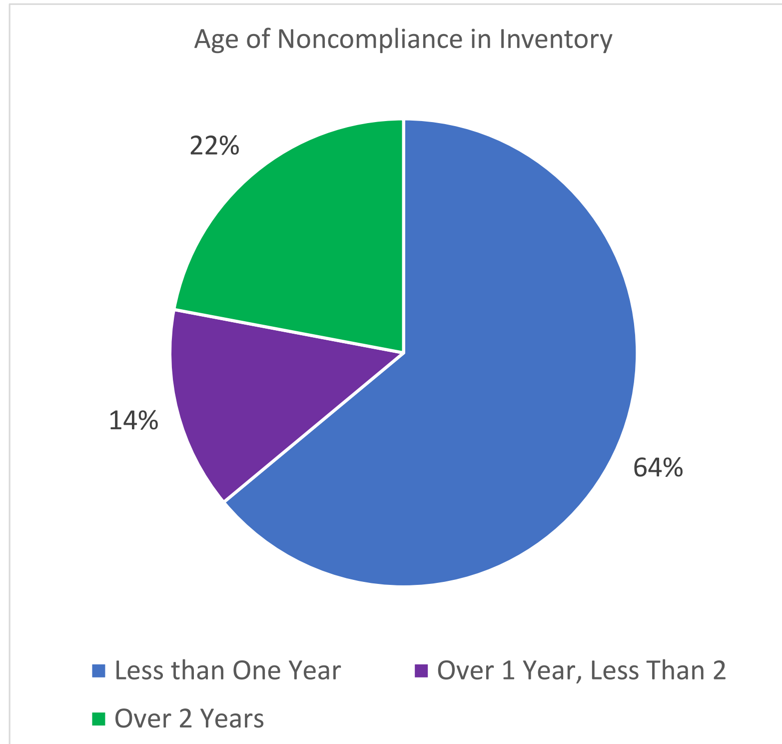
Working to promptly assess mitigating activities to ensure reasonableness and effectiveness

Focus on mitigating and resolving higher risk issues



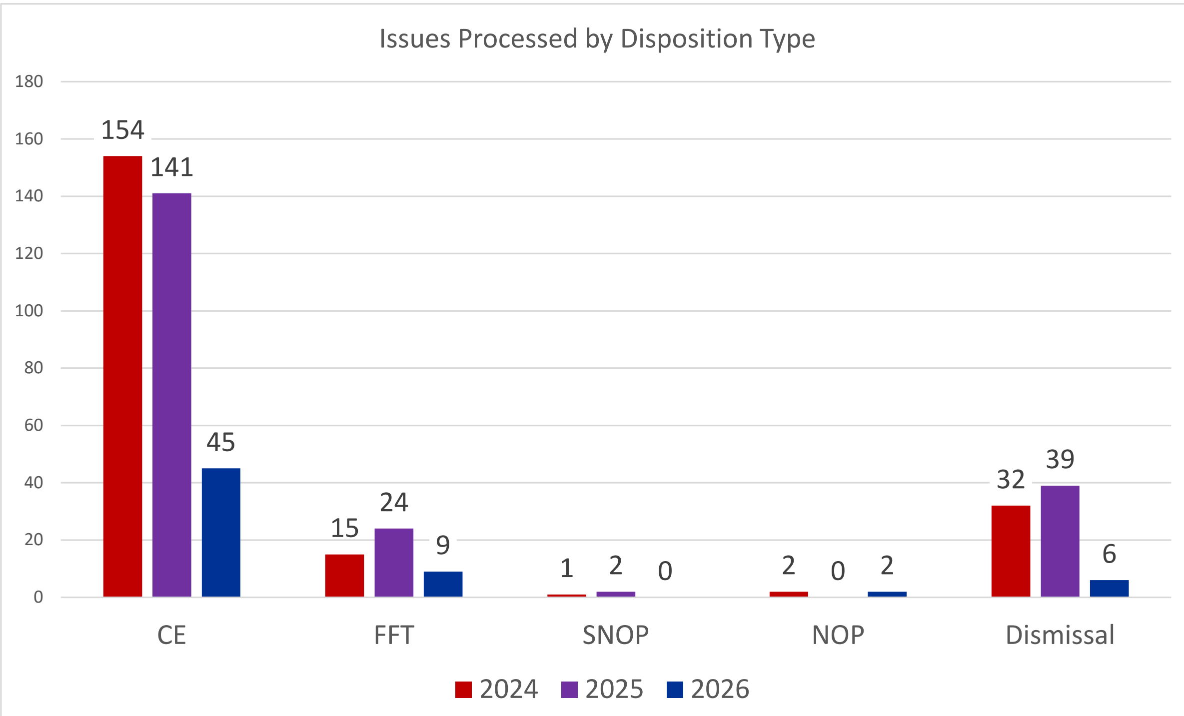
Addressing Aging Inventory

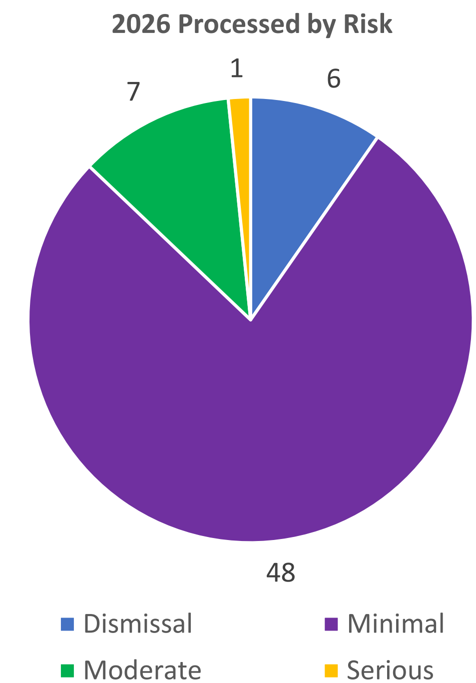




Enforcement Year-to-Date Dashboard

Public





TEXAS RE

Registration Report

Board of Directors Meeting
September 16, 2026

Registration Initiatives

Inverter-Based Resource Registration Initiative

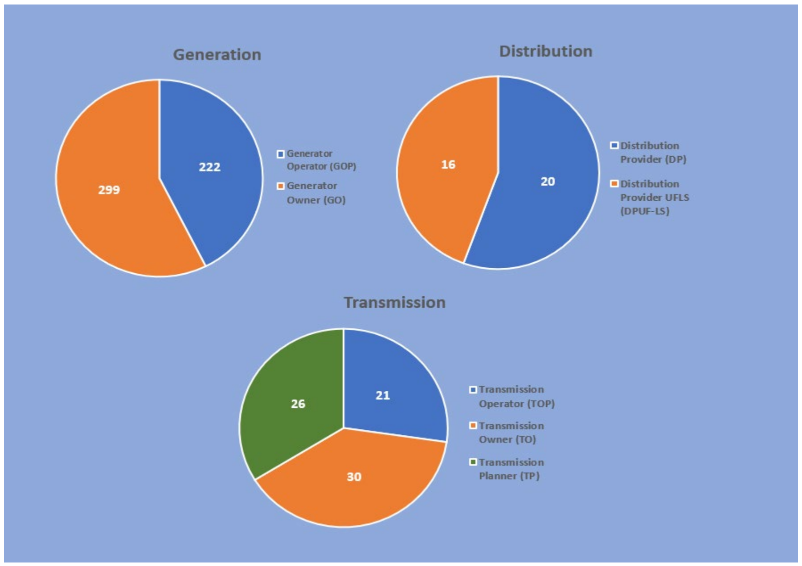
- Texas RE registered 30 Category 2 Generator Owners and 21 Category 2 Generator Operators on May 15, 2026
- Texas RE completed all required registration analysis ahead of schedule

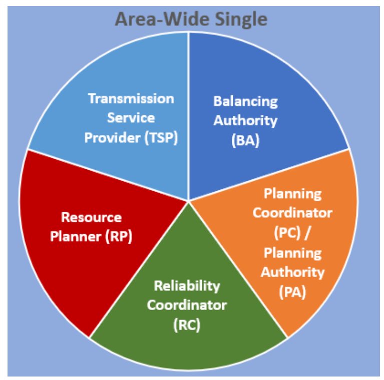
Large Computational Loads

- Proposed changes to Registry Criteria are open for comment until September 18, 2026
- More information to come!

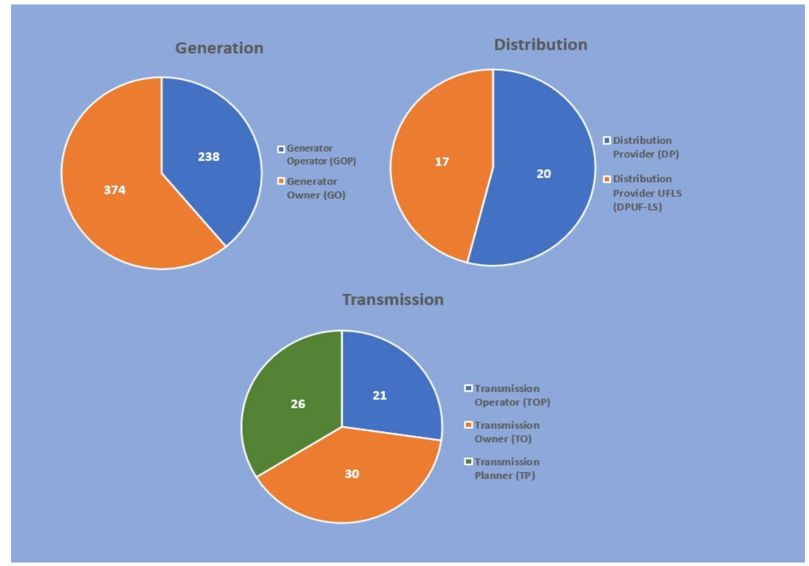
Number of Registered Entities by Function – Texas RE Region

387 Registered Entities | 634 Functions
As of August 1, 2025





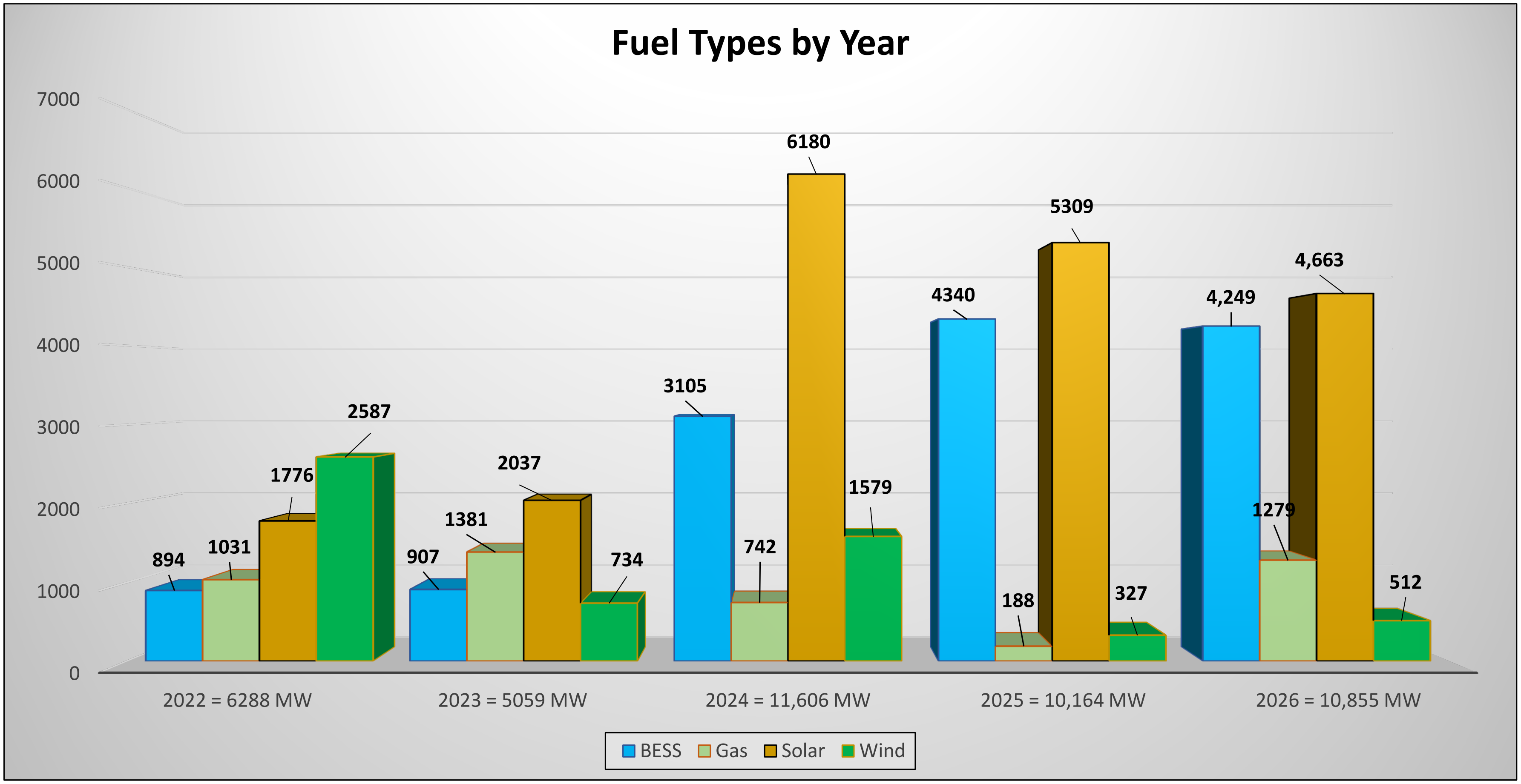
463 Registered Entities | 726 Functions*
As of August 1, 2026



Over 20% of all Texas RE registered entities participate in the Coordinated Oversight Program

***This includes 30 Category 2 GOs and 21 Category 2 GOPs that were registered as a result of the Inverter-Based Resources Registration Initiative**

Registered Generation by Fuel Type



Registration Change Activity by Entities and Functions – 2026

Registration Changes by Entity

Type of Activity	# of Entities
Deactivations	8
Additions	72
Entity Name Changes	4

Includes only registration activities requiring a revision to the NERC Registry between January 1 – August 1, 2026

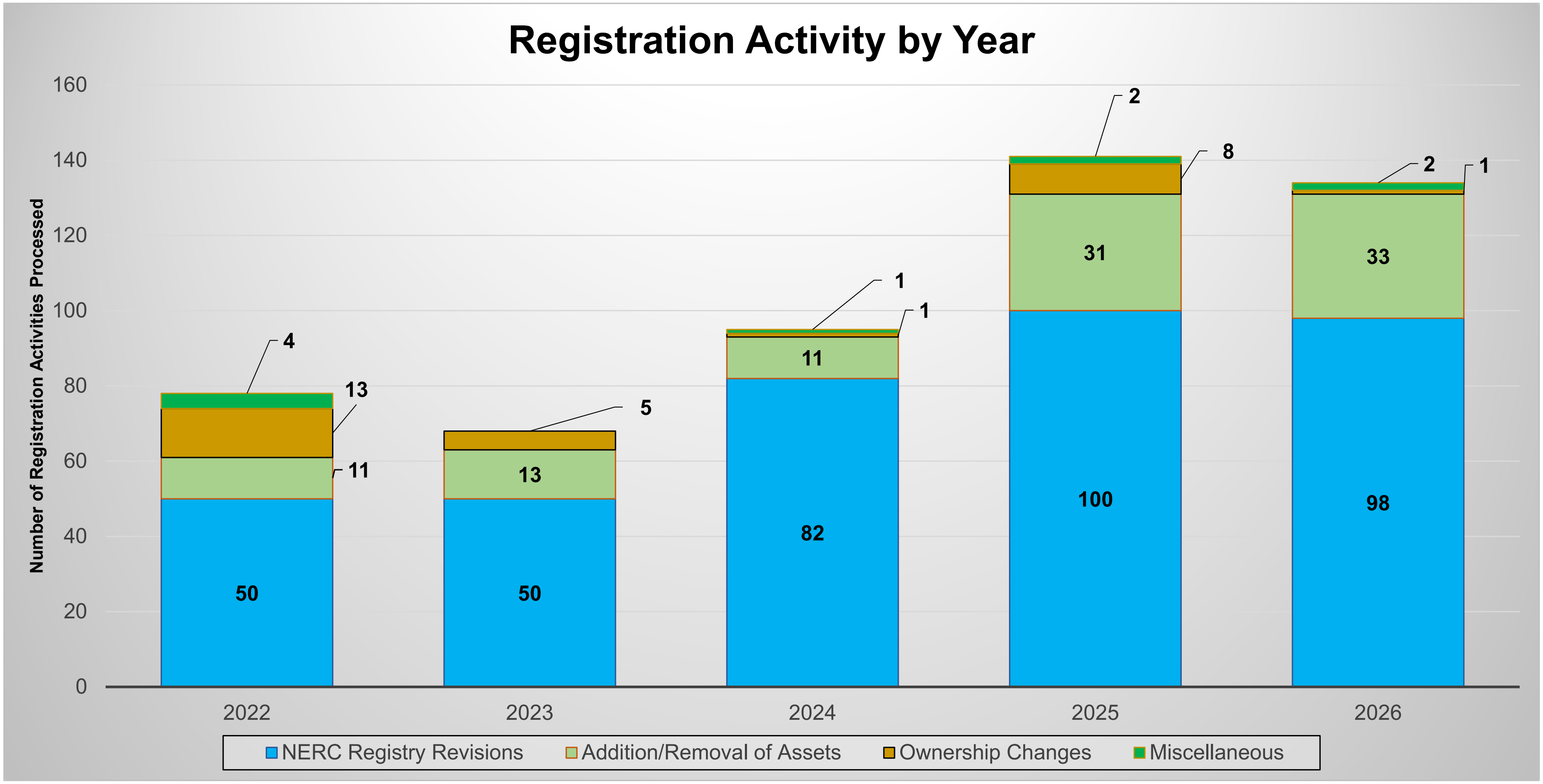
Registration Changes by NERC Function (Note: entity may have more than one function)

Type of Activity	DP	DP UFLS	GO	GOP	TO	TOP	TP	Total Functions
Deactivations	0	0	0	8	0	0	0	10
Additions	0	1	56	32	0	0	0	89
Entity Name Changes	0	0	2	2	0	0	0	4

10,855 MW* New Generation | **512 MW Wind** | **4663 MW Solar** | **4249 MW Battery Storage** | **1279 MW Gas**

***The total amount of MW includes facilities that added generation to existing registrations**

Growth in Registration Activity



Certification/Certification Review Updates

Status Updates

Current Certification Activities

1 Certification

2 Certification Reviews

3 Lesser Activities

Completed Activities in 2026

1 Certification Review

4 Lesser Activities

TEXAS RE

Reliability Services Report

Board of Directors Meeting
September 16, 2026

Public

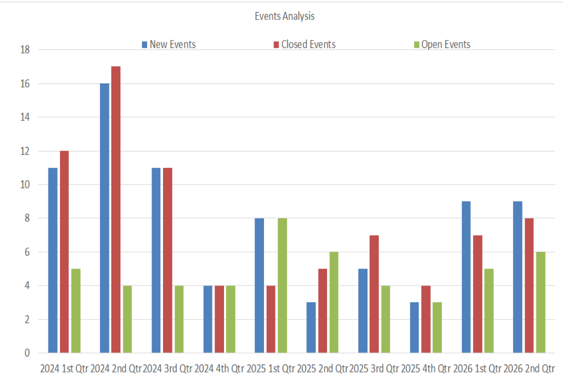
Key Activities in Q2 2026

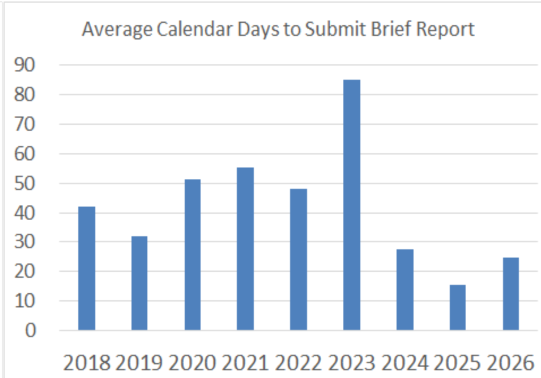
- Scope completed for 2026 Energy Assessment
- LTRA data submission and data quality review
- MAST frequency study scope development
- 2026 Regional Risk Assessment underway
- RAPA Oversight and ERM Updates

Public

Reliability Services Functional Dashboard as of August 1, 2026

EVENTS ANALYSIS





SITUATIONAL AWARENESS

Through 8/1/2026

Category	OE-417 Submission	EOP-004 Submission
Physical/cyber Threat	3	
System Separation or Islanding		
Loss of Firm Load		
Public Appeals		
Loss of Monitoring	6	1
Control Center Evacuation		
Loss of > 50k Customers		
Fuel Supply Emergency		
Damage/Destruction of Facility	5	2
Generation Loss		
Transmission Loss	2	

PERFORMANCE ANALYSIS

On-Time Section 1600 Reporting Status as of 8/15/2026

	2025 Q3	2025 Q4	2026 Q1	2026 Q2
TADS	100%	100%		
GADS	100%	100%	100%	97%
MIDAS	99%	97%	97%	
Wind GADS	96%	92%	76%	76%
Solar GADS	92%	94%	75%	70%

- >90%
- >80% and < 90%
- <80%

*Q2 data due on 8/15 for GADS-Conventional, Wind and Solar

** Q2 data due 8/31 for MIDAS

Q2 data reporting in progress

RELIABILITY ASSESSMENTS

Region	LTRA Quality	LTRA Timeliness	WRA Quality	WRA Timeliness	SRA Quality	SRA Timeliness
MRO						
NPCC						
RF						
SERC						
TEXAS-RE						
WECC						

Public

Grid Reliability Dashboard as of August 1, 2026