NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit E1

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II - 2019

RELIABILITY | RESILIENCE | SECURITY




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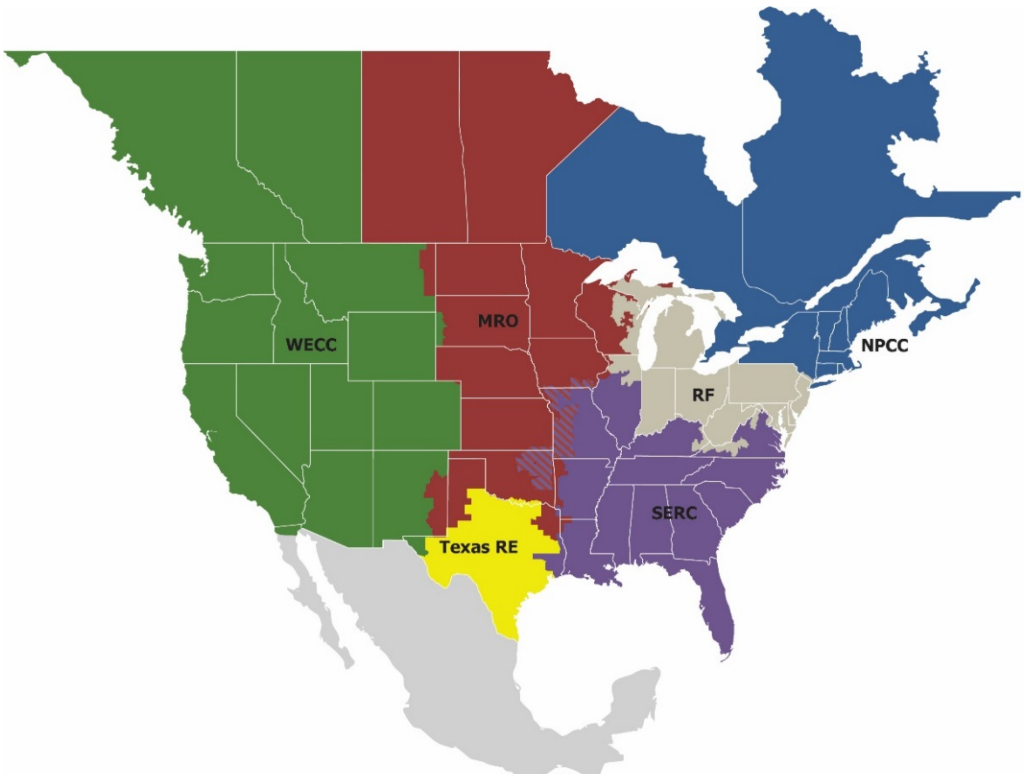
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A request for revisions may be submitted to the ERO or its designee for consideration. The request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used to calculate Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the previous year's evaluation period will be included with the data set by the ERO for determining compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values			
Interconnection	**A Value to Pt C**	**Point C (Low)**	**Point C (High)**
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.08Hz	< 59.92	> 60.08
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 20 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.
4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient

begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

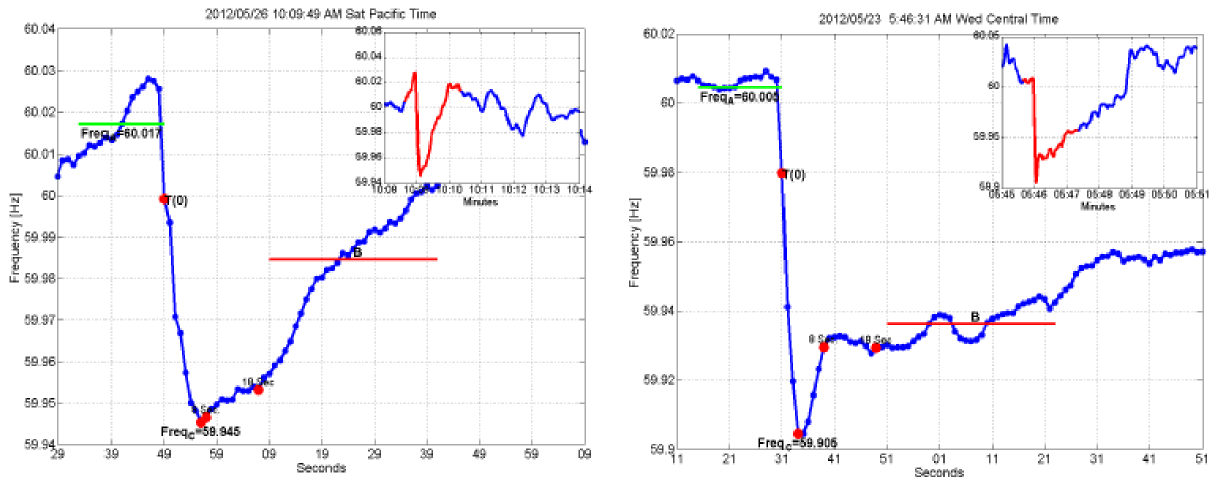


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 20 seconds will not be considered.
6. Frequency excursion events occurring during periods when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Quarterly

The event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each Interconnection. In the first year, the minimum Frequency Bias Setting for each Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each Interconnection, will annually review Frequency Bias Setting data submitted by BAs. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural Frequency Response by more (in absolute value) than 0.2 percentage points of peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW Second Largest Resource Loss = 1400 MW Summation of two largest resource losses = 2900 MW Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW	N-2 RAS event
BA1 Resource Loss A = 1150 MW	
BA1 Resource Loss B = 800 MW	
BA2 Resource Loss A = 1380 MW	
BA2 Resource Loss B = 1380 MW	
BA3 RAS = 1000 MW	N-1 RAS event
BA3 Resource Loss A = 800 MW	
BA3 Resource Loss B = 700 MW	

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

$$IFRO = \frac{(RLPC-CLR)}{(MDF*10)}$$ expressed as MW/0.1Hz

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	**Units**
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-787***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit E2

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Redline

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Version II - 2019

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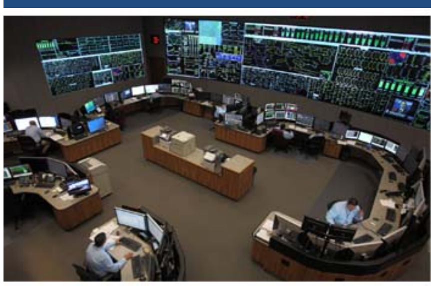

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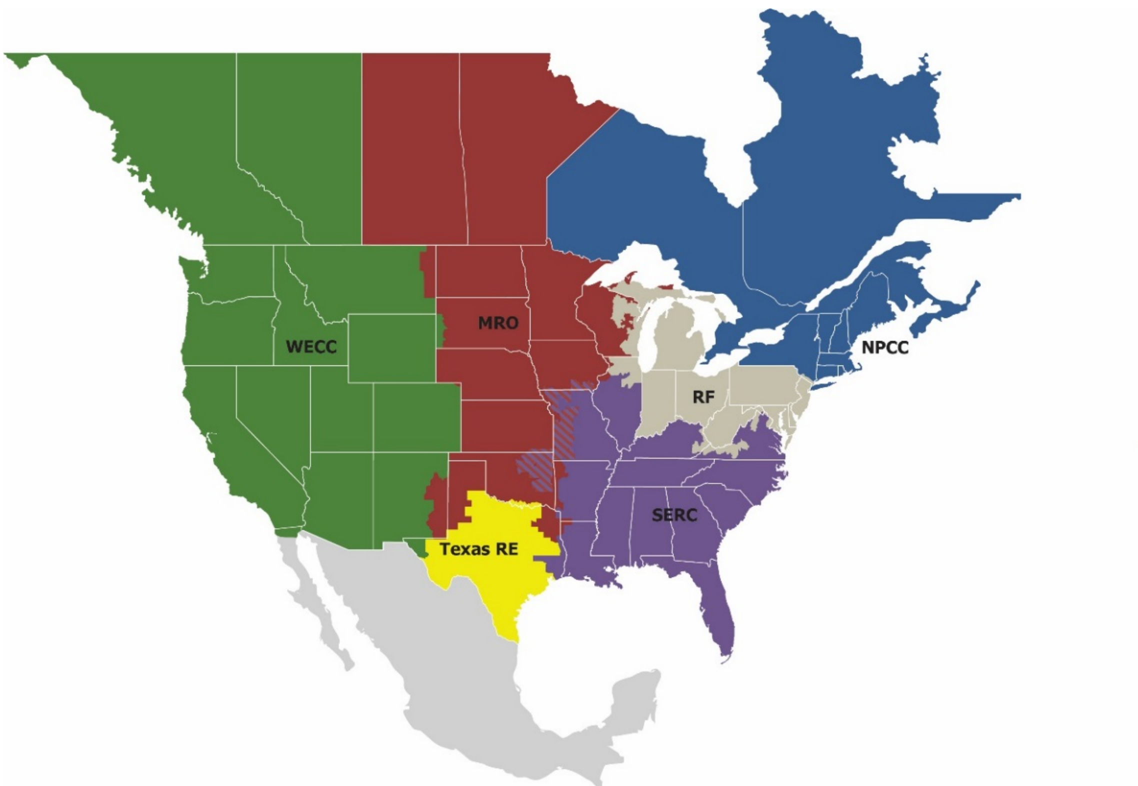

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Introduction

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A ~~Procedure revision~~ request for revisions may be submitted to the ERO or its designee for consideration. The ~~revision~~ request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the ~~revision~~ request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

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Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used ~~by Balancing Authorities (BA)~~ to calculate their Frequency Response to determine:

- Whether the ~~BA~~ Balancing Authority or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS ~~frequency~~ excursion events for analysis. The events that best fit the criteria will be used to support the FRS. ~~-~~The evaluation period for performing the annual Frequency Bias Setting and the ~~Frequency Response Measure (FRM)~~FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. ~~-~~If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the ~~subsequent~~ previous year's evaluation period will be included with the data set by the ERO for determining ~~FRS~~ compliance. ~~This is described later.~~
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within ~~12~~ 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.~~15Hz~~08Hz	< 59.~~90~~92	> 60.~~10~~08
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than ~~18~~ 20 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

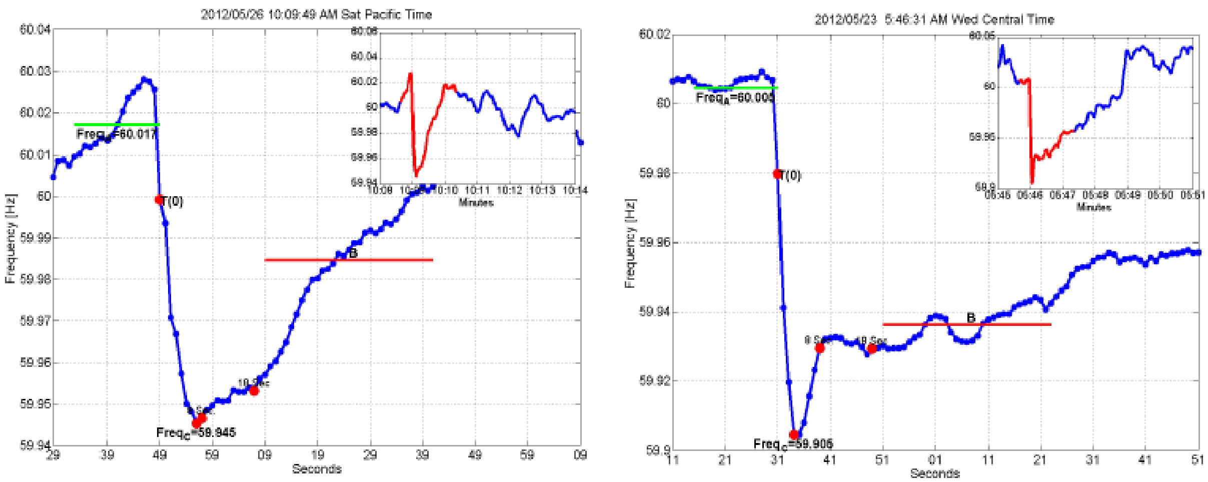

Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within ~~18~~ 20 seconds will not be considered.

6. Frequency excursion events occurring during periods~~:~~ when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

   ~~a. when large interchange schedule ramping or load change is happening, or~~

   ~~b. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.~~

7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:

   a. From the same event quarter of the year.

   b. From an adjacent month.

   c. From a similar load season in the year (shoulder vs. summer/winter)

   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of ~~BAL-003-1~~the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

~~Monthly~~

~~Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".~~

Quarterly

The ~~monthly~~ event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure~~the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*"~~, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS'~~-~~ and Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each ~~Balancing Authority~~BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure. The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-~~1~~2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each ~~interconnection~~Interconnection. In the first year, the minimum Frequency Bias Setting for each ~~interconnection~~ Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an ~~interconnection~~ Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These ~~Balancing Authorities~~BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural Frequency Response by more (in absolute value) than 0.2 percentage points of peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

$$IFRO = \frac{(RLPC-CLR)}{(MDF*10)}$$ expressed as MW/0.1Hz

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-787***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

~~This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).~~

~~The following are the formulae that comprise the calculation of the IFROs.~~

$$\cancel{DF_{Base} = F_{Start} - UFLS}$$
$$\cancel{DF_{CC} = DF_{Base} - CC_{Adj}}$$
$$\cancel{DF_{CBR} = \frac{DF_{CC}}{CB_R}}$$
$$\cancel{MDF = DF_{CBR} - BC'_{Adj}}$$
$$\cancel{ARCC = RCC - CLR}$$
$$\cancel{IFRO = \frac{ARCC}{10 * MDF}}$$

~~Where:~~
~~DF_{Base} is the base delta frequency.~~
~~FStart is the starting frequency determined by the statistical analysis.~~
~~UFLS is the highest UFLS trip setpoint for the interconnection.~~
~~CCAdj is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.~~
~~DFCC is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.~~
~~CBR is the statistically determined ratio of the Point C to Value B.~~

~~DFCBR is the delta frequency adjusted for the ratio of the Point C to Value B.~~

~~BC'ADJ is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~MDF is the maximum allowable delta frequency.~~

~~RCC is the resource contingency criteria.~~

~~CLR is the credit for load resources.~~

~~ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.~~

~~IFRO is the interconnection frequency response obligation.~~

Exhibit F

NERC Staff Report

Interconnection Frequency Response Obligation Determination and Validation: BAL-003-2 SDT Revised RLPC and IFRO Method

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interconnection Frequency Response Obligation Determination and Validation

BAL-003-2 SDT Revised RLPC and IFRO Method

November 2019

RELIABILITY | RESILIENCE | SECURITY




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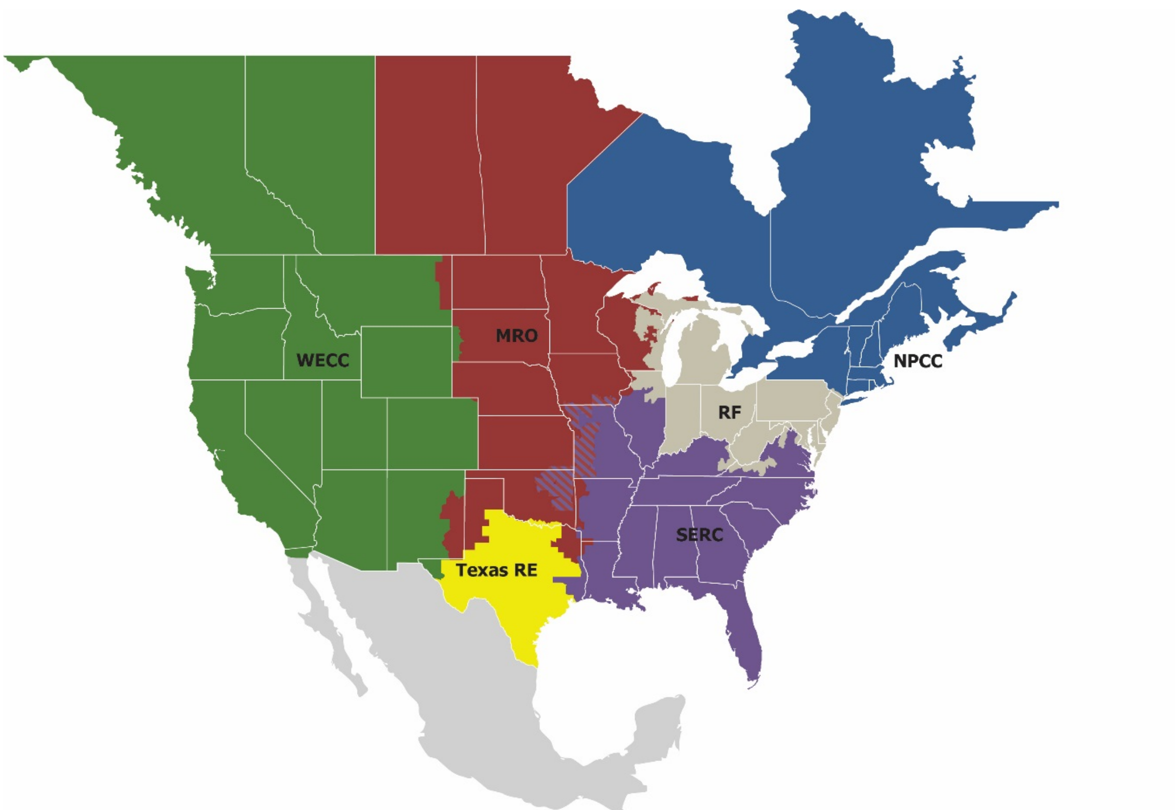
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The BAL-003-2 Standard Drafting Team (SDT) has proposed revisions to *Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting*[1] that would modify how the Interconnection Frequency Response Obligation (IFRO) will be determined. This report describes the proposed changes to the method of determining the resource loss protection criteria (RLPC) and shows how those proposed changes would be reflected in the IFROs. This report also documents how the proposed changes in IFROs were validated by NERC staff using dynamic simulations to assure that those levels of response are adequate to protect the respective Interconnection. The processes and analysis methods for the proposed changes and their validation are documented herein.

Eastern Interconnection

The BAL-003-2 SDT recommended a reduction in the Eastern Interconnection (EI) RLPC from 4,500 MW to 3,209 MW with the resulting IFRO phased in over three increments following annual evaluation of each previous reduction. The initial reduction in IFRO would be from the current 1,015 MW to 915 MW/0.1 Hz followed by subsequent reductions to 815 and 764 MW/0.1 Hz. The 4,500 MW value was recommended in the *2012 Frequency Response Initiative Report*[2] and was the largest resource contingency event in the previous ten years at the time of the report.

The August 2007 event that led to the initial EI RLPC involved nine generators across three states, resulted in a loss of 4,457 MW, and a frequency nadir of 59.863 Hz. The subsequent NERC *Event Analysis Report* identified root causes and major contributory factors in addition to entity-specific and industry-wide recommendations to improve reliability. As a result of the event, the Regional Entity initiated a compliance violation investigation (CVI) that led to an entity settlement agreement to resolve alleged violations of requirements in four NERC Reliability Standards and a mitigation plan that was completed on June 30, 2010. Since the recommendations set forth in the *2012 Frequency Response Initiative Report* the largest resource loss event in the EI has been 2,344 MW in April 2013.

The 3,209 MW value was determined by the SDT and is the sum of the two largest single contingencies (N-1) in the EI at the time of their review as shown in **Appendix B**. Dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz.

Western Interconnection

The BAL-003-2 SDT recommended an increase in the Western Interconnection (WI) RLPC from 2,626 MW to 2,850 MW with the resulting IFRO increasing from 858 to 1,018 MW/0.1 Hz.

The 2,850 MW value was determined by the SDT and is the remedial action scheme (RAS) resource loss, which is initiated by multiple (N-2) contingency events and is larger than the sum of the two largest single contingencies (N-1) in the WI at the time of the SDT review as shown in **Appendix B**. Dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz.

Texas Interconnection

The BAL-003-2 SDT recommended no change in the Texas Interconnection (TI) RLPC of 2,750 MW with the IFRO decreasing slightly from 381 to 380 MW/0.1 Hz.

.

The 2,750 MW value was determined by the SDT and is the sum of the two largest single contingencies (N-1) in the TI at the time of their review as shown in **Appendix B**. Dynamic simulations successfully validated a TI IFRO as low as 378 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz.

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

[2] https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Introduction

This document describes the proposed changes to the method of determining the RLPCs and shows how those proposed changes would be reflected in the IFROs and how those revised IFROs would be tested using dynamic simulation to assure that those levels of response are adequate to protect the Interconnection. The processes and analysis methods for the proposed changes and their validation are documented herein.

Background

Frequency support is recognized as an essential reliability service. The NERC *Reliability Standard BAL-003-1.1* is intended to require sufficient frequency response from the Balancing Authorities (BAs) to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. *Reliability Standard BAL-003-1.1* is intended to provide consistent methods for determining the amount of frequency response needed in each Interconnection as well as measuring frequency response performance. The standard applies to all BAs or the Frequency Response Sharing Group (FRSG) if the BA is a member of an FRSG.

The RLPC is the respective Interconnection design resource loss in MW; it is used to determine the IFRO. An "N-2" event is defined as a single initiating event that leads to multiple electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double-circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection except for the EI. In the EI, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the under frequency load shedding (UFLS) safety net is not activated for the largest N-2 event. The previous BAL-003 IFRO method determined that the largest N-2 event should not precipitate an UFLS event. The original basis for determining the RLPCs and IFROs was prescribed in the *2012 Frequency Response Initiative Repor*t[3] and annually updated in the *Frequency Response Annual Analysis* reports.[4]

The BAL-003-2 SDT is proposing revisions to *Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting*[5] that would modify how the RLPCs and IFROs will be determined.

[3] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[4] The most recent of which is the 2018 report. https://www.nerc.com/comm/OC/Documents/2018_FRAA_Report_Final.pdf

[5] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

Chapter 1: Study Scope and Method

Chapter 1 will discuss the proposed changes in determination of each Interconnection RLPC in addition to the methods used to validate the resulting IFROs.

Proposed Determination of RLPCs

The BAL-003-2 SDT is proposing to change the method used to determine the Interconnection RLPC in accordance with the following process:

> NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 remedial action scheme (RAS) event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.
>
> BAs determine the two largest resource losses for the next operating year based on a review of the following items:
>
> - The two largest balancing contingency events due to a single contingency that is identified by using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). An abnormal system configuration is not used to determine the RLPC
> - The two largest units in the BA Area, regardless of shared ownership/responsibility
> - The two largest RAS resource losses (if any) that are initiated by single (N-1) contingency events
>
> The BA provides these two numbers determined above as Resource Loss A and Resource Loss B.
>
> The BA should then provide the largest resource loss due to RAS operations (if any) that is initiated by a multiple contingency (N-2) event. Note that RLPC cannot be lower than this value. If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.
>
> The calculated RLPC should meet or exceed any credible N-2 resource loss event.
>
> The host BA (or planned host BA), where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.
>
> Direct current (dc) ties to asynchronous resources, such as dc ties between Interconnections or the Manitoba Hydro Dorsey bi-pole ties to northern asynchronous generation. These dc lines, such as the Pacific DC Intertie (PDCI), which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bipole high-voltage dc system is a single contingency.

Based on initial review of data submitted to the BAL-003-2 SDT the proposed RLPC for each Interconnection is shown in **Table 1.1** and **Appendix B**.

Determination and Validation of Revised IFROs

Using the proposed RLPC values to recalculate the IFROs, the IFROs should be modified from those calculated in the *2017 Frequency Response Annual Analysis*[6] report as shown in **Table 1.1**. Both the maximum delta frequency and the credit for load resources (CLR) used in these calculations are from that report.

Table 1.1: Revised IFROs

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
Max. Allowable Delta Frequency	0.420	0.280	0.405	0.947	Hz
Proposed Resource Contingency Protection Criteria	3,209	2,850	2,750	2,000	MW
Credit for Load Resources	N/A	N/A	1,209	N/A	MW
Proposed IFROs	**-764**	**-1,018**	**-380**	**-211**	**MW/0.1 Hz**
Implemented 2017 IFROs	-1,015	-858	-381	-179	MW/0.1 Hz

Case Selection Process and Desired Attributes

Proper powerflow base case selection is essential to the process of IFRO validation especially since not all contingency elements of the proposed RLPCs are necessarily feasible for any single load level, resource dispatch, or inertia level. A balance must be struck between load levels, resource mix in the dispatch and the attendant inertia levels, and the contingencies against which the RLPCs are based.

With conventional synchronous generating resources, the lower the load level is the lower the generation dispatch, resulting in lower inertia and lower primary frequency response. Therefore, case selection would gravitate toward light-spring conditions. However, with today's high levels of photovoltaic inverter-based resources (IBRs), a lower inertia situation may occur in the middle of the day. Since photovoltaic IBR peak output is in the middle of the day with a growing portion "behind the meter," the net load that must be served by conventional generation resources is far lower than in the past, resulting in lower inertia levels. That situation is further complicated by blending higher penetrations of wind resources and the seasonal variability of water for hydroelectric generation, particularly in the WI.

For instance, loading on the California Oregon Interface (COI) and the Pacific DC Intertie (PDCI) must be high enough to arm and trigger the highest levels of generation tripping for the RAS to validate an IFRO based on an RLPC that includes the Pacific Northwest RAS in the WI. These conditions only exist during high water flows of spring runoff. However, high levels of hydro generation come with much higher levels of synchronous generation with a resultant higher inertia than would be seen in an equivalent light-load fall condition with lower water flows and lower hydro generation output.

Similarly, in the TI, very high levels of wind resource penetration result in counter-intuitive dispatch patterns that are sometimes constrained by ramping requirements for conventional generators and potential over-frequency conditions.

[6] https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf

Procedure for Case Detuning

As built, each base case has its own inherent interconnection frequency response measurement (IFRM) linked to the dispatch and resource mix. That inherent case dispatch must be adjusted to match the proposed IFRO level in order to test the RLPCs at that frequency response level.

The following procedure was used on each case:

1. For the base case, determine the inherent IFRM for the contingencies in the RLPC and calculate the margin from the inherent Point C nadir to the highest level of UFLS for the Interconnection.
2. Reduce the frequency responsive reserves (FRRs) on the system by detuning the governors of the frequency responsive resources until the $IFRM_{A-B}$ equals the proposed $IFRO_{A-B}$. Perform this activity in several steps.

$$IFRM_{A-B} = \frac{MW\ Loss\ (RLPC)}{10*(Freq\ A - Freq\ B)} \leq Proposed\ IFRO_{A-B}$$

3. Determine the IFRM and calculate the margin from Point C nadir to UFLS for each detuning level.
4. When the case has been detuned to the level where $IFRM_{A-B}$ is equal to or less than the proposed $IFRO_{A-B}$ in absolute terms, evaluate whether the resulting Point C is higher than the Interconnection UFLS setting. If the Point C nadir is greater than the Interconnection UFLS then the proposed $IFRO_{A-B}$ is validated. If the resulting Point C is below the UFLS setting, reverse the detuning steps until Point C is above the UFLS setting and note the IFRM. The IFRO for that Interconnection must then be limited to that response level.
5. Graphically plot the frequency profiles for the base case and each detuning level showing the margins to the Interconnection UFLS set point.

IFROs and IFRMs are negative numbers because the change in MW output should be in the opposite direction as the change in frequency. For convenience purposes, references in this report to IFROs and IFRMs will often be in terms of absolute value.

It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Chapter 2: IFRO Validation for Each Interconnection

Chapter 2 details the approach for case selection, identifying desired case attributes, the results of each detuning step, and the process for validation of the proposed IFROs through time domain simulation. Results and key findings are summarized in this chapter.

Eastern Interconnection

This analysis is a validation of the proposed IFRO for the EI using a Light Load Base Case. The 2018 Year Operating Base Case was developed by incorporating actual governor response data and modeling parameters obtained from the Generator Owners and Generator Operators during survey processes. This data was incorporated during the building process for the 2018-LL Light Load Dynamics Base Case.

Interconnection Characteristics

Table 2.1 shows the statistical EI load and inertia characteristics based on the 2018 FERC Form 714 submittals (2017 data) and 2018 inertia data collected for essential reliability services (ERS) measurements as well as the base case attributes.

Table 2.1: Eastern Interconnection Characteristics

Interconnection Load	MW
10th Percentile Interconnection Load	265,004
90th Percentile Interconnection Load	416,188
Peak Load	564,733
Interconnection Inertia	**GW-seconds**
10th Percentile Interconnection Inertia	1,302
90th Percentile Interconnection Inertia	1,851
Base Case Attributes	
Base Case Load (MW)	325,181
Base Case Inertia (GW-seconds)	1,506
Base Case Frequency Responsive Reserves (MW)	26,619

Selected Base Case Description and Attributes

The EI frequency response is resilient under peak load conditions due to the amount of dispatched generation resulting in a large system inertia. The 2018-LL Light Load Dynamics Base Case was the only case studied for the IFRO analysis because this case models a relatively light load low inertia operating scenario.

Dispatch and Case Modifications

The base case did not include sufficient loading on the Dorsey bipole terminals to meet the recommended RLPC criteria, so the Manitoba dc tie-line Base Case set value was increased from 710 MW to 1,732 MW. To accommodate this change in power flow, Henday Generation was increased to provide a source for the increased Dorsey bipole set value. Additional generation was reduced in Area 600, and the net load was reduced by 600 MW in the Manitoba Hydro assessment area. The EI IFRO evaluation was performed by detuning the governor performance in the base case. The amount of FRRs on the system was decreased in successive steps until it approached the proposed IFRO of

764 MW/0.1 Hz for a loss of the RLPC of 3,209 MW. The resulting nadir was then compared to 59.5 Hz, the highest EI UFLS set point.

Results and Key Findings

The BAL-003-2 SDT recommended a reduction in the EI RLPC from 4,500 MW to 3,209 MW with the resulting IFRO phased in over three increments following evaluation of each previous reduction. The initial reduction in IFRO would be from the current 1,015 to 915 MW/0.1 Hz followed by subsequent reductions to 815 and 764 MW/0.1 Hz.

EI Findings

Dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz. This is 11 mHz above the EI UFLS of 59.500 Hz.

The base case had a total Interconnection load of 325,181 MW and inertia of 1,506 GW-seconds with 26,619 MW of FRR at the EI recommended droop setting[7] of 5%. Loss of the proposed RLPC of 3,209 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.890 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.974 Hz was statistically determined in the 2017 FRAA report. The settled frequency of Value B was 59.897 Hz resulting in a calculated $IFRM_{A-B}$ of 4,161 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in **Table 2.2 and Figure 2.1**. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 23,741 MW, or 7.30% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 2,099 MW/0.1 Hz and a minimum Point C frequency nadir of 59.817 Hz.
- For detuning Level 2, the amount of FRR was reduced to 11,682 MW, or 3.59% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,352 MW/0.1 Hz and a minimum Point C frequency nadir of 59.728 Hz.
- For detuning Level 3, the amount of FRR was reduced to 4,832 MW, or 1.49% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 956 MW/0.1 Hz and a minimum Point C frequency nadir of 59.601 Hz.
- For detuning Level 4, the amount of FRR was reduced to 2,114 MW, or 0.65% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 787 MW/0.1 Hz and a minimum Point C frequency nadir of 59.511 Hz.

[7] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

Table 2.2: Eastern Interconnection Detuning Summary					
	Base Case	**Detune1**	**Detune2**	**Detune3**	**Detune4**
EI Load (MW)	325,181	325,181	325,181	325,181	325,181
On-line Generation (MW)	330,236	330,236	330,236	330,236	330,236
EI Inertia (GW-sec)	1,506	1,506	1,506	1,506	1,506
FRR (MW @ 5% droop)	26,619	23,741	11,682	4,832	2,114
FRR % Load	8.19%	7.30%	3.59%	1.49%	0.65%
RLPC (MW)	3,209	3,209	3,209	3,209	3,209
Starting Freq Pt A (Hz)	59.974	59.974	59.974	59.974	59.974
Min Freq Pt C (Hz)	59.890	59.817	59.728	59.601	59.511
Time Min Freq (sec)	5.867	18.971	23.160	36.015	40.401
Settled Freq Value B (Hz)	59.897	59.821	59.737	59.638	59.566
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)*	915/815/764	915/815/764	915/815/764	915/815/764	915/815/764
$IFRM_{A-B}$ (MW/0.1 Hz)	**4,161**	**2,099**	**1,352**	**956**	**787**

* The proposed EI IFRO will be reduced in three increments pending evaluation of the previous reduction.

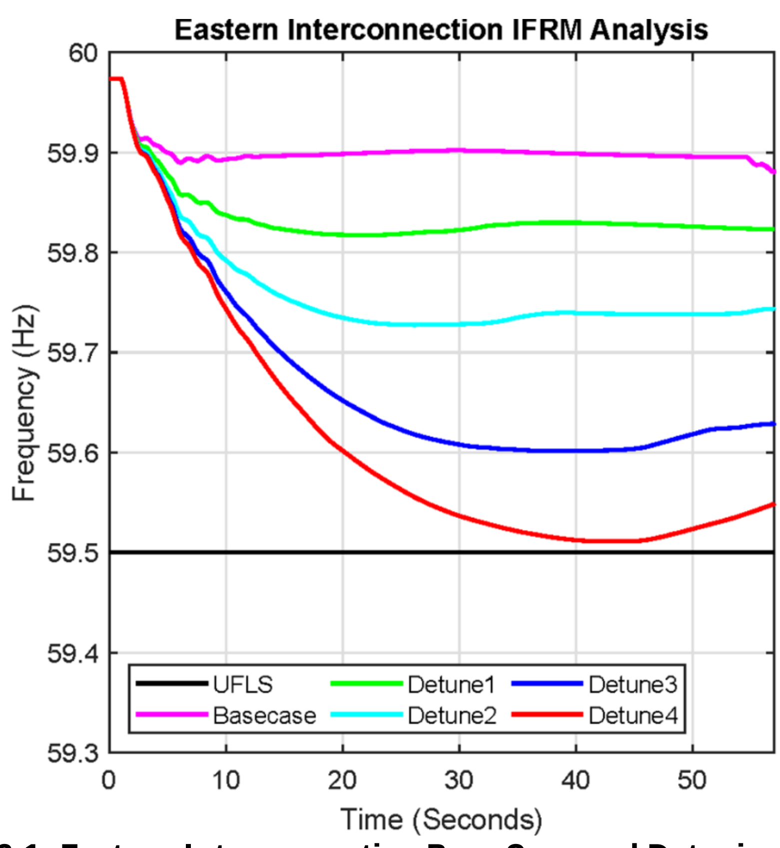


Figure 2.1: Eastern Interconnection Base Case and Detuning Graphs

Conclusion

The aforementioned dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz; which is 11 mHz above the EI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Western Interconnection

This analysis is a validation of the proposed IFRO for the WI. The WI proposed RLPC was selected by the SDT to be the Northwest Remedial Action Scheme (RAS). Previously two Palo Verde (2PV) nuclear units were used as the RPLC for the WI. In this study the 2PV simulation was also performed as a sensitivity analysis.

Interconnection Characteristics

Table 2.3 shows the statistical load and inertia characteristics for WI based on the 2018 FERC Form 714 submittals (2017 data) and inertia data collected for essential reliability services measurements as well as the base case attributes.

Table 2.3: Western Interconnection Characteristics	
Interconnection Load	
10th Percentile Interconnection Load (MW)	75,758
90th Percentile Interconnection Load (MW)	119,273
Peak Load (MW)	170,862
Interconnection Inertia	
10th Percentile Interconnection Inertia (GW-seconds)	540
90th Percentile Interconnection Inertia (GW-seconds)	695
Base Case A Attributes: RLPC = RAS	
Base Case Load (MW)	82,634
Base Case Inertia (GW-seconds)	527
Base Case Frequency Responsive Reserves (MW)	50,689
Base Case B Attributes: RLPC = 2PV	
Base Case Load (MW)	108,245
Base Case Inertia (GW-seconds)	674
Base Case Frequency Responsive Reserves (MW)	24,118

Selected Base Cases Description and Attributes

Two cases were developed for the 2018 operating year. Case A was developed with a State Estimator Node Breaker Case for April 7, 2017, 0600 UTC. The RLPC is the Northwest RAS with a loss of 2,850 MW. Case B is the 2019 Light Summer Planning Case. The RLPC is two Palo Verde units (1 and 3) with a combined loss of 2,775 MW.

Case A: On-line generation profile from the energy management system (EMS) snapshot April 7, 2017, 0600 UTC

- RLPC Simulation = High-water semi-light load trips of the PDCI and activation of the RAS
- Interconnection Load = 82,634 MW
- Interconnection Inertia of 527 GW-sec and Interconnection Load of 82.6 GW
- Base Case Frequency Responsive Reserve (FRR) = 50,689 MW

Case B: **2019 Light Summer Planning Case**

- RLPC Simulation = 2,775 MW for the trip of two Palo Verde nuclear units.
- Interconnection Load = 108,245 MW
- Interconnection Inertia = 674 GW-seconds
- Base Case Frequency Responsive Reserve (FRR) = 24,118 MW

Case A: Results and Key Findings

The BAL-003-2 SDT recommended an increase in the WI RLPC from 2,626 MW to 2,850 MW with the resulting IFRO increasing from 858 to 1,018 MW/0.1 Hz.

WI Finding
Dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz; this is 34 mHz above the WI UFLS of 59.500 Hz.

The base case had a total Interconnection load of 82,634 MW and inertia of 527 GW-seconds with 50,689 MW of FRR and 61.3% of total Interconnection load at the recommended WI droop setting of 5%. Loss of the proposed RLPC of 2,850 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.615 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.966 Hz was statistically determined in the *2018 FRAA* report. Settled frequency Value B was 59.785 Hz resulting in a calculated $IFRM_{A\text{-}B}$ of 1,581 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.4 and Figure 2.2. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 46,037 MW, or 55.71% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,477 MW/0.1 Hz and a minimum Point C frequency nadir of 59.597 Hz.
- For detuning Level 2, the amount of FRR was reduced to 41,288 MW, or 49.97% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,382 MW/0.1 Hz and a minimum Point C frequency nadir of 59.581 Hz.
- For detuning Level 3, the amount of FRR was reduced to 34, 145MW, or 41.32% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,098 MW/0.1 Hz and a minimum Point C frequency nadir of 59.555 Hz.
- For detuning Level 4, the amount of FRR was reduced to 31,028 MW, or 37.55% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,013 MW/0.1 Hz and a minimum Point C frequency nadir of 59.534 Hz.

Table 2.4: Western Interconnection Detuning Summary – NW RAS

	Base Case	Detune1	Detune2	Detune3	Detune4
WI Load (MW)	82,634	82,634	82,634	82,634	82,634
On-line Generation (MW)	85,453	85,453	85,453	85,453	85,453
WI Inertia (GW-sec)	527	527	527	527	527
FRR (MW @ 5% droop)	50,689	46,037	41,288	34,145	31,028
FRR % Load	61.34%	55.71%	49.97%	41.32%	37.55%
RLPC (MW)	2,850	2,850	2,850	2,850	2,850
Starting Freq Pt A (Hz)	59.966	59.966	59.966	59.966	59.966
Min Freq Pt C (Hz)	59.615	59.597	59.581	59.555	59.534
Time Min Freq (sec)	6.517	6.567	6.654	8.967	8.967
Settled Freq Value B (Hz)	59.785	59.773	59.759	59.706	59.684
Proposed $IFRO_{A\text{-}B}$ (MW/0.1 Hz)	1,018	1,018	1,018	1,018	1,018
$IFRM_{A\text{-}B}$ (MW/0.1 Hz)	**1,581**	**1,477**	**1,382**	**1,098**	**1,013**

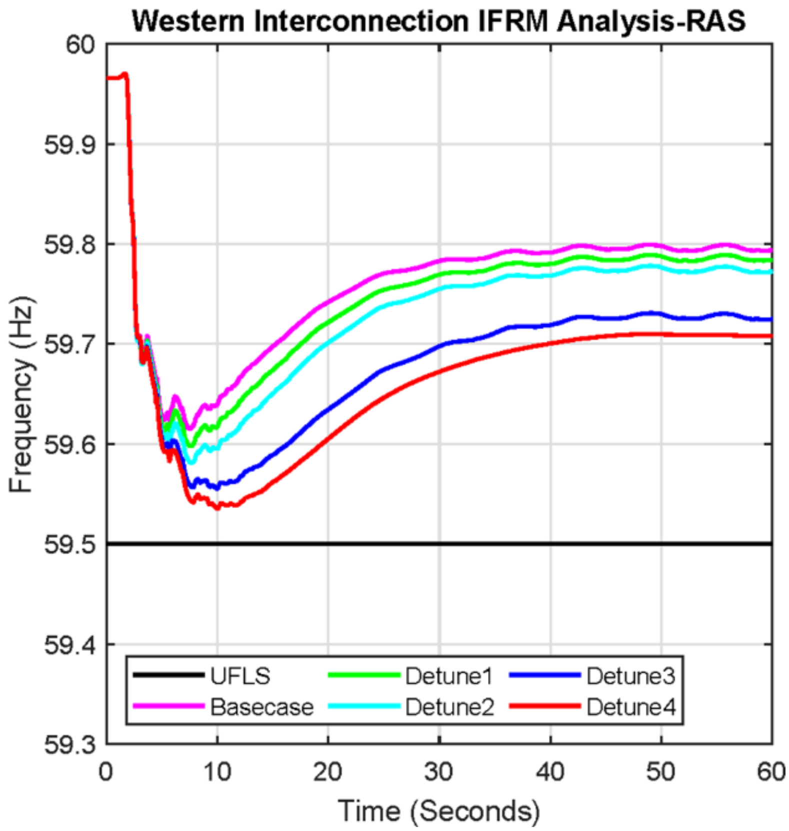


Figure 2.2: Western Interconnection Base Case and Detuning Graphs

Conclusion for Case A

The aforementioned dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz; this is 34 mHz above the WI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Case B: Results and Key Findings

Case B is a sensitivity analysis using a WI RLPC of 2,775 MW for the loss of two Palo Verde units. The purpose of this analysis is to simulate a contingency in the southern part of the WI in addition to the Northwest RAS simulated in Case A. The aforementioned proposed IFRO of 1,018 MW/0.1 Hz is used for validation purposes.

The base case had a total Interconnection load of 108,245 MW and inertia of 674 GW-seconds with 24,118 MW of FRR at the recommended WI droop setting of 5%. Loss of the proposed RLPC of 2,775 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.681 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.966 Hz was statistically determined in the *2018 FRAA* report. Settled frequency Value B was 59.810 Hz resulting in a calculated $IFRM_{A\text{-}B}$ of 1,770 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.5 and Figure 2.3. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 22,467 MW, or 20.76% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,600 MW/0.1 Hz and a minimum Point C frequency nadir of 59.670 Hz.
- For detuning Level 2, the amount of FRR was reduced to 19,558 MW, or 18.07% of Interconnection load; resulted in a calculated $IFRM_{A\text{-}B}$ of 1,316 MW/0.1 Hz and a minimum Point C frequency nadir of 59.648 Hz.

- For detuning Level 3, the amount of FRR was reduced to 16,212 MW, or 14.98% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,082 MW/0.1 Hz and a minimum Point C frequency nadir of 59.626 Hz.
- For detuning Level 4, the amount of FRR was reduced to 15,180 MW, or 14.02% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,010 MW/0.1 Hz and a minimum Point C frequency nadir of 59.611 Hz.

Table 2.5: Western Interconnection Detuning Summary – 2PV

	Base Case	Detune1	Detune2	Detune3	Detune4
WI Load (MW)	108,245	108,245	108,245	108,245	108,245
On-line Generation (MW)	111,782	111,782	111,782	111,782	111,782
WI Inertia (GW-sec)	674	674	674	674	674
FRR (MW @ 5% droop)	24,118	22,467	19,558	16,212	15,180
FRR % Load	22.28%	20.76%	18.07%	14.98%	14.02%
RLPC (MW)	2,775	2,775	2,775	2,775	2,775
Transmission Losses (MW)	433	433	433	433	433
Starting Freq Pt A (Hz)	59.966	59.966	59.966	59.966	59.966
Min Freq Pt C (Hz)	59.681	59.670	59.648	59.626	59.611
Time Min Freq (sec)	7.079	7.192	9.267	11.704	11.816
Settled Freq Value B (Hz)	59.810	59.794	59.757	59.711	59.693
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)	1,018	1,018	1,018	1,018	1,018
$IFRM_{A-B}$ (MW/0.1 Hz)	**1,770**	**1,600**	**1,316**	**1,082**	**1,010**

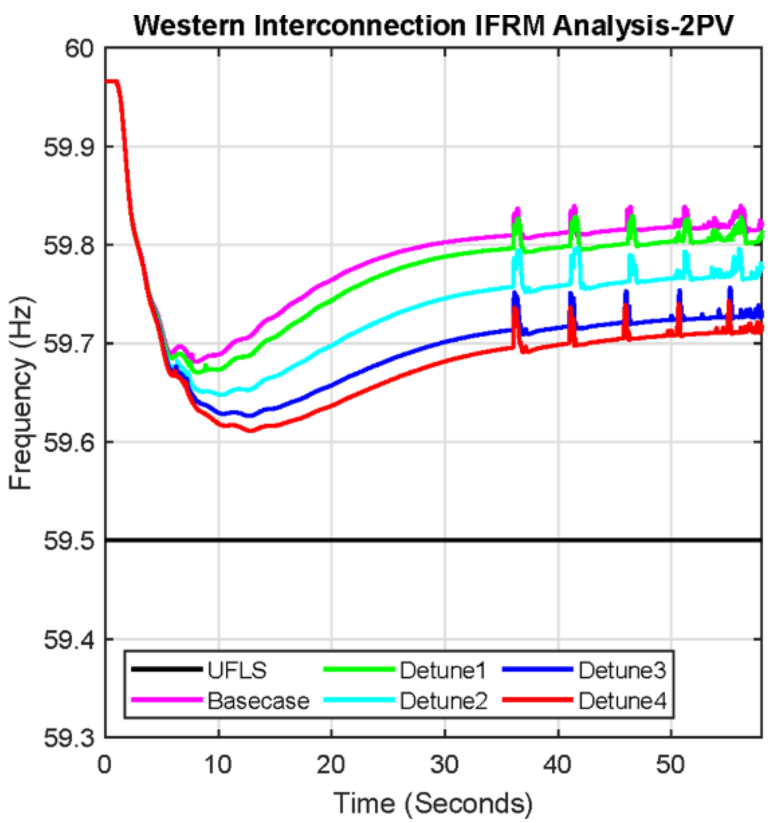


Figure 2.3: Western Interconnection Base Case and Detuning Graph

Figure 2.3 shows spikes beyond 30 seconds during the simulation that are attributed to the need, when simulating the loss of 2 Palo Verde units, to adjust the planning case prior to simulation in an attempt to match average system inertia conditions. Such adjustments may create interactions with widespread small MVA generating units across the planning case that are usually netted. The simulation graph (Figure 2.3) demonstrates those interactions. Additionally, many of those units are modeled at the sub-transmission buses with the parameters from the machine test results or other databases. Due to such modeling the small units can create numerical "blips" after a large disturbance pushing them into an operating range allowable by the model but not tuned to represent the unit's response.

Conclusion for Case B

The aforementioned dynamic simulations successfully validated a WI IFRO as low as 1,010 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.611 Hz; this is 111 mHz above the WI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Texas Interconnection

This analysis is a validation of the proposed IFRO for the TI using a Light Load Base Case. The 2021 Light Spring Year Base Case was developed by adapting the 2021 High Wind Case using the generation dispatch and load profile from an EMS snapshot.

Interconnection Characteristics

Table 2.6 shows the statistical TI load and inertia characteristics based on the 2018 FERC Form 714 submittals (2017 data) and inertia data collected for essential reliability service measurements as well as the base case attributes.

Table 2.6: Texas Interconnection Characteristics	
Interconnection Load	
10th Percentile Interconnection Load (MW)	30,347
90th Percentile Interconnection Load (MW)	55,074
Peak Load (MW)	73,473
Interconnection Inertia	
10th Percentile Interconnection Inertia (GW-seconds)	181
90th Percentile Interconnection Inertia (GW-seconds)	337
Base Case Attributes	
Base Case Load (MW)	27,400
Base Case Inertia (GW-seconds)	143
Base Case Frequency Responsive Reserves (MW)	4,537

Selected Base Case Description and Attributes

The 2021 Spring Light Case with Interconnection inertia of 143 GW-sec and Interconnection load of 27.4 GW was used for the base case. The on-line generation profile and dispatch scenario from the EMS snapshot were used.

Other Cases Considered

Initially, the 2021 High Wind Case that was provided to represent a high wind generation dispatch and corresponding load level greater than the Minimum Case but lower the Summer Peak Case. However, the spinning reserve in that was considered high and it has 209 GW-sec of interconnection inertia.

Dispatch and Case Modifications

Replace the generation values of the 2021 HW by the provided EMS snapshot and scale the load down from 53 GW to 27.4 GW.

Results and Key Findings

The BAL-003-2 SDT recommended no change in the TI RLPC of 2,750 MW with the IFRO decreasing slightly from 381 to 380 MW/0.1 Hz.

TI Findings

Dynamic simulations successfully validated a TI IFRO as low as 378.1 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz; this is 2 mHz above the TI UFLS of 59.300 Hz.

The base case had a total Interconnection load of 27,400 MW and inertia of 143 GW-seconds with 4,537 MW of FRR, 16.56% of total Interconnection load, at the Texas RE recommended droop setting of 5%. Loss of the proposed RLPC of 2,750 MW with the load resources credit of 1209 MW that triggered at 59.7 Hz were simulated using the base case and resulted in a minimum Point C frequency nadir of 59.526 Hz versus an Interconnection UFLS of 59.300 Hz. The starting frequency of 59.968 Hz was statistically determined in the 2017 FRAA report. Settled frequency Value B was 59.790 Hz resulting in a calculated $IFRM_{A-B}$ of 886.3 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.8 and Figure 2.4. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 3,540 MW, or 12.92% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 709.9 MW/0.1 Hz and a minimum Point C frequency nadir of 59.485 Hz.
- For detuning Level 2, the amount of FRR was reduced to 2,538 MW, or 9.26% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 592.2 MW/0.1 Hz and a minimum Point C frequency nadir of 59.438 Hz.
- For detuning Level 3, the amount of FRR was reduced to 1,486 MW, or 5.42% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 432.4 MW/0.1 Hz and a minimum Point C frequency nadir of 59.345 Hz.
- For detuning Level 4, the amount of FRR was reduced to 482 MW, or 1.76% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 378.1 MW/0.1 Hz and a minimum Point C frequency nadir of 59.302 Hz.

Table 2.8: Texas Interconnection Detuning Summary

	Base Case	Detune1	Detune2	Detune3	Detune4
TI Load (MW)	27,400	27,400	27,400	27,400	27,400
On-line Generation (MW)	31,850	31,850	31,850	31,850	31,850
TI Inertia (GW-sec)	143	143	143	143	143
FRR (MW @ 5% droop)	4,537	3,540	2,538	1,486	482
FRR % Load	16.56%	12.92%	9.26%	5.42%	1.76%
RLPC (MW)	2,750	2,750	2,750	2,750	2,750
Load Resources Credit (MW)	1,209	1,209	1,209	1,209	1,209
Starting Freq Pt A (Hz)	59.968	59.968	59.968	59.968	59.968
Min Freq Pt C (Hz)	59.526	59.485	59.438	59.345	59.302
Time Min Freq (sec)	2.404	3.337	5.775	6.567	6.867

Table 2.8: Texas Interconnection Detuning Summary					
	Base Case	Detune1	Detune2	Detune3	Detune4
Settled Freq Value B (Hz)	59.790	59.751	59.708	59.612	59.560
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)	380	380	380	380	380
$IFRM_{A-B}$ (MW/0.1 Hz)	**866**	**710**	**592**	**432**	**378**

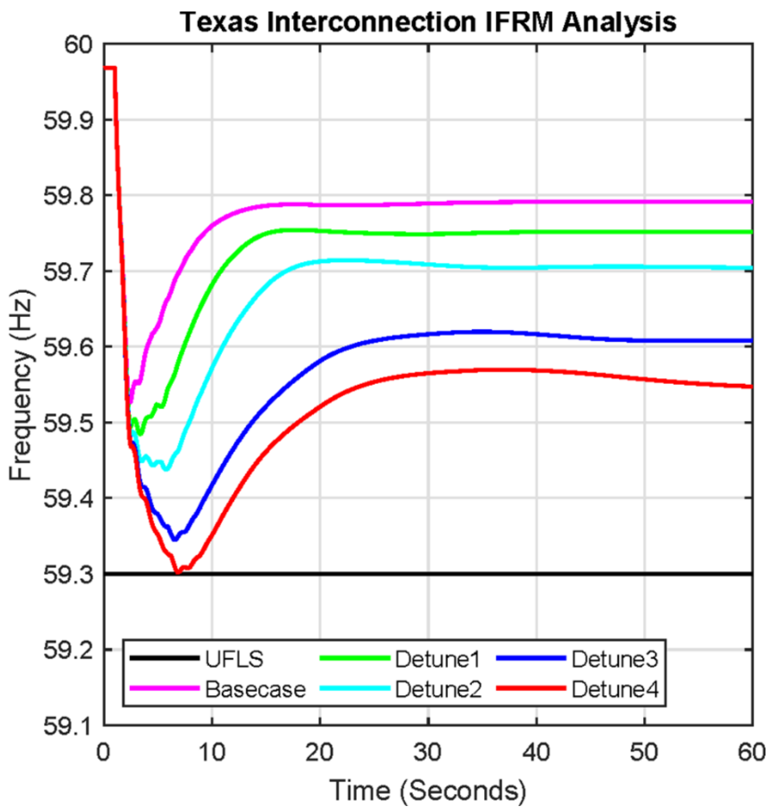


Figure 2.4: Texas Interconnection Base Case and Detuning Graphs

Conclusion

The aforementioned dynamic simulations successfully validated a TI IFRO as low as 378 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz; this is 2 mHz above the TI UFLS of 59.300 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Appendix A: Definitions

Note that IFROs and IFRMs are negative numbers because the change in MW output should be in the opposite direction as the change in frequency. For convenience purposes, references in this report to IFROs and IFRMs will be in terms of absolute value.

Interconnection Frequency Response Obligation: IFRO is the minimum amount of frequency response that must be maintained by an interconnection in order to avoid activation of the first stages of UFLS.[8]

Value A: The average pre-disturbance frequency for the period T-16 through T+0 seconds

Value B: The post-disturbance frequency for the period T+20 through T+52 seconds is defined as the settled frequency response.

Point C: The point at which the frequency decline of an event is arrested, often called the nadir.

Interconnection Frequency Response Measurement: IFRM is the measured frequency response of the interconnection calculated as:

$$IFRM_{A-B} = \frac{MW\ Loss}{10 * \Delta f_{A-B}}$$

Where:

MW Loss = Resource or Load Output immediately prior to the start of the event

Δf_{A-B}= Change in frequency from Value A to Value B Change in frequency from Value A to Value B

Resource Loss Protection Criteria: RLPC was originally determined in the *2012 Frequency Response Initiative Report*[4] and are shown in **Table A.1**.

Table A.1: Original RLPCs

Interconnection	RLPC Description	MW	Criteria
Eastern	2007 EI Frequency Event	4,500	Largest Resource Event in Last 10 Years
Western	Loss of 2 Palo Verde Units	2,740	Largest N-2 Resource Loss Event
ERCOT	Loss of South Texas Project	2,750	Largest Total Plant with Common Voltage Switchyard
Québec		1,700	Operating Loss Criteria

[8] IFRO is described in detail in the *2012 Frequency Response Initiative* Report at: http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Appendix B: Interconnection RLPC Values

Based on initial review, the numbers below are representative of the RLPC for each Interconnection proposed by BAL-003-2 SDT.

Eastern Interconnection:
Present RLPC = 4,500 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1,732 MW
RESOURCE LOSS B = 1,477 MW
Proposed RLPC = 3,209 MW

Western Interconnection:
Present RLPC = 2,626 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1,505 MW
RESOURCE LOSS B = 1,344 MW
N-2 RAS = 2,850 MW
Proposed RLPC = 2,850 MW

ERCOT:
Present RLPC = 2,750 MW   Load Credit = 1,209 MW
RESOURCE LOSS A = 1,375 MW
RESOURCE LOSS B = 1,375 MW
Proposed RLPC = 2,750 MW

Quebec Interconnection:
Present RLPC = 1,700 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1,000 MW
RESOURCE LOSS B = 1,000 MW
Proposed RLPC = 2,000 MW

Appendix C: Calculation of IFRO Values

The IFRO is calculated using the RLPC as shown in Table C.1

$$\text{IFRO} = \frac{(\text{RLPC-CLR})}{(\text{MDF*10})} \quad \text{expressed as MW/0.1Hz}$$

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Table C.1: Interconnection Frequency Response Obligation					
	Eastern	**Western**	**ERCOT**	**HQ**	**Units**
Max. Delta Frequency	0.420	0.280	0.405	0.947	Hz
Resource Loss Protection Criteria	3,209	2,850	2,750	2,000	MW
Credit for Load Resources	0	0	1,209	0	MW
Calculated IFRO	-764*	-1018	-380	-211	MW/0.1Hz

* The proposed EI IFRO will be reduced in three increments pending evaluation of the previous reduction.

Exhibit G

Proposed Resource Loss Protection Criteria

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control Error (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal

The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.

- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resources losses. DC lines, such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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Exhibit H

Standard Drafting Team Roster

Project 2017-01 Modifications to BAL-003-1.1

Standard Drafting Team Roster

Name	Company	
David Lemmons	Ethos Energy Group	Chair
Rich Hydzik	Avista	Vice-chair
Thomas V. Pruitt	Duke Energy	Member
Greg Park	Northwest Power Pool	Member
Danielle Croop	PJM Interconnection	Member
Daniel Baker	Southwest Power Pool	Member
Sandip Sharma	ERCOT	Member
William (Bill) Shultz	Southern Company	Member
Antonio Franco	Gridforce	Member
Joshua Boone	LG&E and KU Services Co.	Member
Jessica Tang	IESO	Member
Laura Anderson	NERC - Standards Developer	NERC Staff
Darrel Richardson	NERC - Principal Technical Advisor	NERC SME
Bob Cummings	NERC - Senior Director	NERC SME
Brad Gordon	NERC - Manager	NERC SME
Candice Castaneda	NERC - Legal	
Lauren Perotti	NERC - Legal	