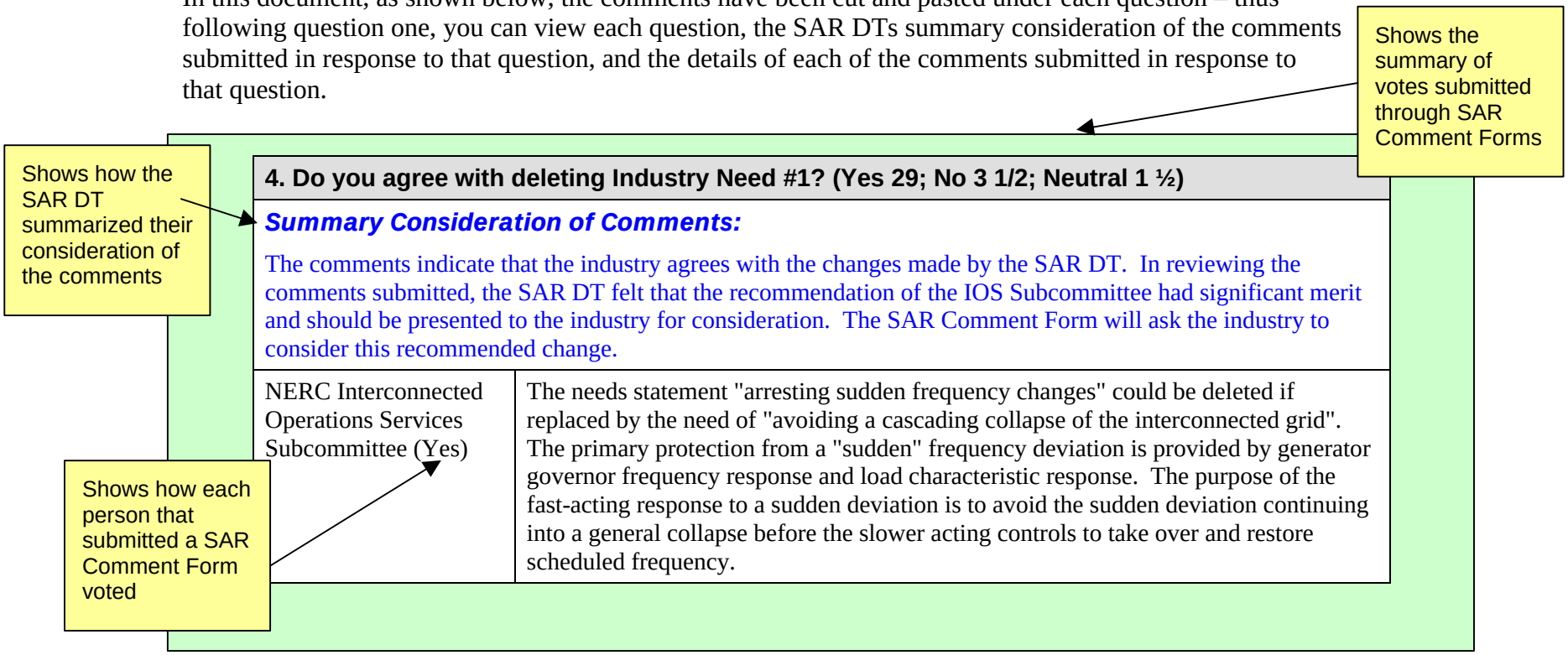
Summary of Comments, Organized By Question Number

Background:

The Balance Resources and Demand SAR was posted for a second public comment period from June 3 through July 12, 2002. The SAR DT asked industry participants to provide feedback on the revisions made to the SAR through a special SAR Comment Form. There were 35 sets of comments submitted via this special SAR Comment Form. The comments can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/BalResDemnd_Comments.pdf

In this document, as shown below, the comments have been cut and pasted under each question – thus following question one, you can view each question, the SAR DTs summary consideration of the comments submitted in response to that question, and the details of each of the comments submitted in response to that question.



The Balance Resources and Demand SAR Drafting Team met and considered each of the sets of responses to the questions posed with the SAR Comment Form. The questions were aimed at gathering feedback on the changes made (or proposed to be made) to the SAR. The SAR DT's consideration of comments is

provided in blue text immediately under each question. In most cases, a single response has been provided to show how the comments were considered.

In some cases, the SAR DT provided a short note to indicate how a unique comment was considered

To make it easier to review the comments, the SAR DT has also provided a copy of the SAR (pages 4-10), showing how the SAR has been changed from the 1st to 2nd postings, and also showing how it has been changed from the 2nd posting to the 3rd posting.

- The comments submitted by industry participants and included in this document were addressing the changes made to the SAR from the 1st to the 2nd posting.
- The comments submitted by industry participants and included in this document were used as the basis for making changes to the SAR for the 3rd posting.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give EVERY comment serious consideration in this process! If you feel there has been an error or omission, you can contact Tom Vandervort in the NERC office. Tom can be reached at 609-452-8060 or at tom.vandervort@nerc.com. Or you can contact the Standards Process Manager, Maureen Long at 305-891-5497 or at spm@nerc.com.

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Changes to the Balance Resources and Demand SAR as a Result of Comments Submitted by Industry Participants

Title	
Original, 2nd Posting and 3rd Posting: Balance Resources and Demand	
Purpose of Standard	
Original	Maintain scheduled frequency within an Interconnection.
2nd Posting	Maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal). The standard requires that Balancing Authorities (BAs) contribute their fair share to maintaining scheduled interconnection frequency
3rd Posting (Combined with Industry Need)	To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal), to prevent unwarranted load shedding and to prevent cascading collapse of the interconnected grid.
Industry Need for Standard	
Original	Load-resource balance is necessary to: 1. Arrest sudden frequency changes in the Interconnection caused by generation failure or load interruption. 2. Maintain Scheduled Frequency in the Interconnection. Frequency Error creates Time Error in the Interconnection. Operating well below 60 Hz can cause underfrequency load shedding. 3. Minimize unscheduled power flows within the Interconnection that can cause operating limit violations. 4. Minimize Inadvertent Interchange accumulation between the Balancing Authority and the Interconnection.
2nd Posting	– Maintain Interconnection scheduled frequency under all conditions, i.e. normal and abnormal – Prevent unwarranted underfrequency load shedding – Control Time Error in the Interconnection
3rd Posting **(Combined with Purpose)**	To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e. normal and abnormal), to prevent unwarranted load shedding and to prevent cascading collapse of the interconnected grid.

Brief Description:	
Original	The Load-Resource Balance Standard requires that each Balancing Authority maintain a close match between its loads and resources in real time. The Standard accomplishes this through four measures that cover various time frames and situations: 1. Frequency Response Measure (FRM) – FRM arrests short-term (0-1 minute) frequency deviation following a sudden mismatch between generation and load. Adherence to the FRM ensures there are sufficient frequency responsive resources that quickly (within seconds) stabilize Interconnection frequency whenever load or generation changes rapidly before operator actions. (Note that FRM does not return the Interconnection to its scheduled frequency, only arrest the frequency change.) 2. Control Performance Measure 1 (CPM1) – CPM1 measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. 3. Control Performance Measure 2 (CPM2) –CPM2 measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled power flows that can cause transmission operating limit violations. 4. Disturbance Control Measure (DCM) –DCM ensures that the Interconnection returns to its scheduled frequency within a defined period following a sudden generation or load change (a "disturbance.") This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.Procedural Requirements: Each Balancing Authority shallhave the necessary AGC facilities at its disposal to calculate an area control error (ACE) value (See Standard Technical Reference document). Each Balancing Authority shall maintain its ACE within specific limits as defined by four measures. FRM CPM1 CPM2 DCM
2nd Posting	Maintain Interconnection frequency performance within a targeted frequency profile as demonstrated through control performance measures. This standard will require the use of a technically defensible mathematical method to enable each Interconnection to disburse control responsibility among its entities to achieve its targeted Interconnection frequency profile.
3rd Posting	Maintain Interconnection frequency performance within a targeted frequency profile as demonstrated through control performance measures. This standard will require the use of a technically defensible mathematical method to enable each Interconnection to disburse control responsibility among its entities to achieve its targeted Interconnection frequency profile. This standard will require that the Reliability Authority monitor system frequency and have the authority to direct actions (to control frequency) that include load shedding.

Detailed Description:	
Original	(No Detailed Description Included)
2nd Posting	Detailed Description of New Standard This Standard requires that each Balancing Authority maintain a close match between its resources and demand in real time. The Standard accomplishes this through measures that cover various time frames and situations: Control Performance Measure 1 (CPM1) – CPM1[1] measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. Control Performance Measure 2 (CPM2) – CPM2[1] measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled power flows that can cause transmission operating limit violations. Disturbance Control Measure (DCM) – DCM[1] ensures that the Interconnection returns to its scheduled frequency within a defined period following a sudden generation or load change (a "disturbance.") This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.
3rd Posting	This Standard requires that each Balancing Authority maintain a close match between its resources and demand in real time. The Standard requires that the Reliability Authority monitor system frequency and Balancing Authority activities and direct action when the Reliability Authority determines that the interconnected electric system is at risk. The Standard accomplishes this through measures that cover various time frames and situations: Control Performance Measure 1 (CPM1) – CPM1 measures the Balancing Authority's one-minute average Area Control Error with respect to Interconnection frequency. Compliance with CPM1 helps maintain Interconnection frequency on schedule. Control Performance Measure 2 (CPM2) – CPM2 measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps bound net interchange power flows that can cause transmission operating limit violations. Disturbance Control Measure (DCM) – DCM requires that the deficient BA return to an acceptable balance level within a defined period, following a sudden generation or load change. This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level. (Note: The proposed CPM1 is equivalent to CPS1, CPM2 is the equivalent of CPS2, and DCM is equivalent to DCS, covering identical time horizons. However, the industry may request changes to these measures, through posted comments on this SAR or the draft standard.)

Note – this is the information that was in the footnote for the 2nd posting of this SAR, slightly modified.

Functions			
Original and 2nd Posting		Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	x	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
		Interchange Authority	Authorizes valid and balanced Interchange Schedules
		Planning Authority	Plans the bulk electric system
		Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
		Transmission Owner	Owns transmission facilities
		Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
		Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
		Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
		Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
		Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

3rd Posting	x	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	x	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
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		Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Principles	
Original & 2nd Posting	
x	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
x	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis
Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	yes
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

3rd Posting	
x	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
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x	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
x	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
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Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	yes
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5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

1. Do you agree with retaining the original title? (Industry Responses: Yes 32; No 1; Neutral 2)	
Summary Consideration of Comments: The consensus is agreement with leaving the title alone.	
NERC Interconnected Operations Services Subcommittee (YES)	The IOS Subcommittee agrees with not revising the title. It is sufficiently simple and fits the intent of the standard. Changing "demand" to "load" is too limiting in scope. Use of "requirements" may be technically safe but is overly broad and loses some meaning in describing the focus of the standard - real power balancing.
CA-ISO 2 (NO)	There are several definitions for “demand” in the NERC glossary of terms. The definition of “instantaneous demand”, which I believe we’re talking about here, is “The rate of energy delivered at a given instant”. So then, demand is the measurement of the load, or the rate at which energy is being consumed, not the actual load itself. Another way to look at it is to ask: are we attempting to balance resources with the rate at which the energy is delivered, or the energy usage itself? I believe the answer is that we’re attempting to balance resources with energy usage itself. **Consideration:** *Demand was meant to be BA load plus BA Net Scheduled Interchange. The SDT will include a definition for “demand” in the proposed standard.*

2. Do you agree with the changes that were made to the Purpose? (Industry Reponses: Yes 24 ; No 11)	
Summary Consideration of Comments: The consensus is agreement with the changes that were made but several suggestions were made to delete or clarify the second sentence. The second sentence has been deleted from the revised SAR. Numerous comments recommended specific purposes or needs. The revised *Purpose/Industry Need* either captures the recommendations or the intent of the comments. The SAR has been revised to show that ERCOT expects to have a Regional Difference for one of the measures in this proposed standard (CPM2). WECC expects to have a Regional Difference defining Operating Reserve requirements.	
Allegheny Energy Supply Company (YES)	I do not understand the why the second sentence on the Balancing Authority is required.
Duke Energy Trading and Marketing (Yes)	the term "fair share" is very subjective and could be removed
ERCOT (Yes)	As long as it is recognized that some interconnections have only one Balancing Authority with those responsibilities (second paragraph).
Nebraska Public Power District (Yes)	I did not see the second sentence (about BAs) in the SAR posted on the NERC website. Is it supposed to be there? *The second sentence should have originally appeared in both the SAR and the SAR Comment Form for the second posting of the SAR – however the comments from the industry indicated that the second sentence was unclear and wasn't needed and it is no longer in the SAR..*
We Energies	Define Fair share
California ISO (No)	Please see Yarek Lehr's edits in the Revision Box above
Cinergy - Control Area Operations	I am neutral to the wording of the revised first sentence. The second sentence should be taken out as the purpose should not contain the requirements. A proposed second sentence would be: To set the acceptable control error bounds within which a Balancing Authority must operate to limit negative impact on the Interconnection frequency.
Dominion Virginia Power 2 (No)	Fair Share is too undefined. If included this needs to be much more specific.
Duke Power	The second paragraph refers to the BAs contributing to scheduled frequency, however the BAs do not own

Company (No)	generation so they can not contribute to frequency. The Generator function should be included in this SAR and a performance measure developed (see comment for question #25) to monitor compliance with their submitted schedule and ultimately their contribution to frequency.
Economist (No)	The purpose should be to "limit deviations" from scheduled frequency to within "error bounds" that are just enough to insure against "interconnection failure". "Fair"ness means "FERC approved" and need not be mentioned. Say "range" instead of "profile".
Energy Mark, Inc. (No)	The purpose should be related to preventing the interconnection from experiencing a frequency error condition that will cause interconnection failure. One way of preventing frequency error from reaching unacceptable levels is to operate at a scheduled value and in addition insure that the deviation error from that scheduled value does not reach values large enough to cause an interconnection failure. The revision would be the better of the two choices if the term "profile" was defined to specify the frequency error conditions that will result in interconnection failure. It is not. It has been left undefined. Therefore, the purpose should not be to maintain scheduled frequency, the purpose should be to limit deviations from scheduled frequency to within frequency error bounds that insure reliable interconnection operation. This misdefinition is causing problems with how later decisions are being made.
FRCC (No)	The FRCC OC does not like the second sentence in the revised purpose. BA's contributing fair share seems to be more applicable to the measurement area rather than as a stated purpose.
Illinois Power Company (No)	Illinois Power believes that the purpose must express the specific relationship to reliability. Building off the first sentence of the proposed Purpose IP suggests the following Purpose statement: "Establish meaningful measures that track the performance of Balancing Authorities in maintaining the balance between Demand and Resources so that frequency is maintained within the frequency profile required for reliable system operation." The second sentence of the proposed Purpose statement should be dropped. IP believes that statement does not reflect the purpose, but rather describes a means to accomplish the purpose.
Manitoba Hydro (No)	Manitoba Hydro's main objection to the changes that were made refer to the second line of the revision. We believe that this statement does not belong in the SAR since it defines requirements which could be included in the Standard. The first line of the revised purpose is acceptable.
NERC Interconnected Operations Services Subcommittee (No)	The IOS Subcommittee finds the first sentence of the revision to be acceptable. The second sentence is not acceptable. First, this statement is a weak attempt at a standard, rather than a purpose. Secondly, "fair share" is not defined. The comments described above do not justify adding a concept of "fair share". The purpose of the standard will not be to achieve a "fair share", it will be to maintain frequency within a scheduled profile.

3. Do you agree with the change that was made to eliminate the opening phrase, "Load-resource balance is necessary to . . . "? (Yes 25; No 6; Neutral 4)	
Summary Consideration of Comments: Note: The comments submitted here address the details of the bulleted items rather than the format change addressed by question 3. The consensus of comments did not object to deleting the lead-in phrase. The other comments were evaluated and the intent of the comments incorporated into the *Purpose/Industry Need* language. The SAR DT could not identify a reliability concern with "Time Error in the Interconnection." The SAR DT will ask the industry to identify a reliability issue or concern related to Time Error correction.	
California ISO (Yes)	The third bullet should read "Minimize Time Error in the Interconnection".
CA-ISO 2 (Yes)	The third bullet should read "Minimize Time Error in the Interconnection".
Economist (No)	Arresting "sudden frequency change" must be specified, and that is the exclusive job of Primary Response. "Restoring frequency" so as to maintain it sufficiently within the error bound, must be specified, and that is the exclusive job of Secondary Control, such as Regulation.
Energy Mark, Inc (No)	Resource Demand balance is required to arrest sudden frequency changes caused by resource or demand interruption. This function is performed only by Primary Frequency Control, Frequency Response. If this function is not performed, the interconnection will not get the opportunity to balance resources with demand using other means such as regulation because it will fail before those actions can be applied to correct the imbalance. The purpose of Secondary Frequency Control is to limit normal frequency errors to values such that a sudden frequency change caused by resource or demand interruption is not sufficient to exceed the frequency error limits that bound reliable operations. Therefore, both Primary and Secondary Frequency Control should be addressed by this SAR.

NERC Interconnected Operations Services Subcommittee (No)	The original version is more correct and complete than the revision, although it too is not correct. This process should not result in the level of detail in this SAR being reduced to be comparable with other SARs. It has been expected that this SAR would have more detail early on, since substantial work has already been done in developing concise standards for control performance and disturbance response as part of the NERC compliance program. Eventually all SARs will need more detail. The need statements omit the most obvious and most basic need being addressed by this standard - to maintain frequency within safe limits for the operation of power system equipment and customer equipment. Frequency is ultimately maintained near 60 Hz for one purpose - so generators and other rotating devices don't vibrate themselves to pieces at harmonic frequencies and other frequency-sensitive customer and power system equipment operates properly. In the revision, the first sentence is a repeat of the purpose. The second sentence, to prevent UF load shedding, is marginally valid, but is really a convolution of logic. UF load shedding is installed to retain energized portions of the grid in the event of a major disturbance resulting in a breakup of parts of the system. The purpose of balancing and good frequency control is not to avoid UF load shedding. That is just one constraint that must be observed. If it really was a need being satisfied, 70 Hz would work just fine. The real reasons for good control are a) to protect power system and customer frequency-sensitive equipment and b) to prevent a cascading collapse of the energized grid. These are also reasons that can be generally understood by a broad ballot pool of reliability stakeholders. Everything else is "how". In addition to the two primary justifications of need described in these comments, others that could be included as secondary justifications are: avoid UF load shedding and control time error.

4. Do you agree with deleting Industry Need #1? (Yes 29; No 3 1/2; Neutral 1 ½)	
Summary Consideration of Comments: The comments indicate that the industry agrees with the changes made by the SAR DT. In reviewing the comments submitted, the SAR DT felt that the recommendation of the IOS Subcommittee had significant merit and should be presented to the industry for consideration. The SAR DT will ask the industry to consider this recommended change.	
NERC Interconnected Operations Services Subcommittee (Yes)	The needs statement "arresting sudden frequency changes" could be deleted if replaced by the need of "avoiding a cascading collapse of the interconnected grid". The primary protection from a "sudden" frequency deviation is provided by generator governor frequency response and load characteristic response. The purpose of the fast-acting response to a sudden deviation is to avoid the sudden deviation continuing into a general collapse before the slower acting controls to take over and restore scheduled frequency.
Economist (No)	Arresting "sudden frequency change" must be specified, and that is the exclusive job of Primary Response. Resource demand balancing requires the use of both Primary and Secondary Control. Both must be included in any SAR to address resource demand balancing.
Energy Mark, Inc. (No)	Resource demand balancing requires the use of both Primary and Secondary Control. Both must be included in any SAR to address resource demand balancing.
WECC (No)	I believe balancing resources and demand is required to arrest sudden frequency changes during abnormal conditions. The standard developed from the SAR should include the "arrest frequency" requirement.

5. Do you agree with the modifications made to Industry Need #2? (Yes 27; No 6; Neutral 2)	
Summary Consideration of Comments: The FERC SMD NOPR identifies inadvertent imbalance as a commercial issue rather than a reliability issue. The responses to this question seem inconclusive and the SAR DT couldn't identify a reliabity-related need for Time Error Correction. Given the new information from the SMD and the mixed comments submitted, the SAR DT will ask the industry to identify any reliability-related need for Time Error Correction.	
Manitoba Hydro (Yes)	The emphasis should be that underfrequency will not occur when resources and demand are in balance. An underfrequency load shedding operation should only occur for severe system disturbances where system collapse would most likely occur without the load shedding. Control of frequency would minimize opportunity for operating security limit violations. Would the Standard apply to a system which was isolated from the Interconnection?
NERC Interconnected Operations Services Subcommittee (Yes)	As stated previously in the response to #3, avoiding UF load shedding is a secondary justification and a boundary condition of balancing resources and demand. The primary justifications are for the safety and proper operation of frequency-sensitive power system and customer equipment, as well as to avoid cascading collapse of the interconnected grid. To get the logic straight - UF load shedding is what you do when balancing does not work, it is not the reason you have balancing in the first place. UF load shedding is the backstop or safety net when the balancing does not work, it is not a boundary for "good" control.
WECC (Yes)	The SAR should make clear the requirement to arrest frequency deviations to prevent unwarranted underfrequency load shedding for underfrequency conditions and to mitigate overfrequency conditions in a sufficient time frame and controlled manner to prevent undesirable results.
Dominion Virginia Power 2 (No)	Why does it say "unwarranted load shedding?" Does this mean there is also warranted load shedding? The reference to unwarranted or warranted should be explained more or eliminated. Warranted load shedding is load shedding that is designed to occur in a controlled manner to preserve the integrity of the interconnected electric systems and can be included in commercial contracts such as with large industrial or commercial customers. Unwarranted load shedding is load shedding that is unintended or uncontrolled and is indicative of a failure to meet reliability requirements.
Economist (No)	Frequency error during normal operations needs to be limited only to the extent that, when disturbances do occur, the disturbances do not cause interconnection failure. "Maintaining" frequency sufficiently within the error bound must be specified, and that is the exclusive job of Secondary Control, such as Regulation. This SAR attempts to limit the interconnection's exposure to underfrequency collapse without trying to identify "How".

Energy Mark, Inc. (No)	The real reason to limit the frequency error during normal operations is to insure that the joint probability of normal and disturbance frequency error does not lead to interconnection failure. The joint probability of a frequency error that exceeds the reliability limits can only be determined by considering joint consequences of Primary and Secondary Frequency Control actions. In other words, the starting frequency error value for a disturbance, as determined by Secondary Control, may have as great an influence on the risk of interconnection failure as the size of the change in frequency caused by the disturbance, as determined by Primary Control.
Illinois Power (No)	The first phrase of the proposed need says, with the exception of two words, exactly the same thing as the proposed Purpose. Preventing unwanted underfrequency load shedding is not a need either. It would be a result of meeting this standard. IP also does not believe controlling time error creates a need for this standard. IP proposes that the true need for this standard is to "Avoid extended operation above or below desired frequency (60Hz), at the limits of reliable operation."
Potomac Electric Power Company (No)	Time Error is not a reliability issue. In fact, the correction of time error forces a compensating frequency offset (error). The industry should determine as a commercial issue whether time error should continue to be corrected.

6. Do you agree the SAR should not specifically address over frequency? (Yes 18; No 12; Neutral 5)	
Summary Consideration of Comments: The comments indicate that both under and over frequency are important considerations in this SAR. Although it appears that there are 12 "no's", many of the comments submitted with a "no" indicate a need for overfrequency – the SAR DT feels that the response was mixed because of the 'double negative' included in the question. Please refer to No. 4, Summary Consideration of Comments (above). The SAR was changed to say: Prevent frequency-related cascading collapse of the interconnected grid.	
Allegheny Energy Supply Company (Yes)	Conrol of Frequency implies both under and over.
CA-ISO 2 (Yes)	Balancing addresses both under and over frequency implicitly.
Midwest ISO (Yes)	To be sure my understanding is correct, the Yes vote assumes you mean that there is no need in the standard to differentiate between low and high frequency. Both extremes have reliability impacts. If what you're stating is that there should be no standard for high frequency, this vote should be changed to No.
NERC Interconnected Operations Services Subcommittee (Yes)	Yes, but only if the focus was on protecting equipment and avoiding a cascading collapse - then both over and under frequency conditions would be addressed. Equipment damage or improper operation and cascading collapse could result from an over or under frequency condition. Reference the IOS Subcommittee response to comment #3.
Dominion Virginia Power 2 (No)	From past experience it is apparent that CPM1 and CPM2 are not controlling frequency well. In fact, occurances of over frequency have greatly increased since the adoption of CPS as opposed to operation under the older A1 and A2 standards. It is not clear if this is because the industry has changed or if CPS does not mandate tight control. Although less likely to cause major problems, it is conceivable that if system frequency is very high and a large load trips the result could be very bad. We believe, therefore, that the standard does need to address this.
Duke Power Company (No)	Overfrequency should be addressed.
Duke Energy Trading and Marketing (No)	Overfrequency is also a condition that should be addressed

ECAR (No)	The SAR should specifically address over frequency. The reason we recommend that the SAR address over frequency is that the Eastern Interconnect has a problem during minimum load periods with high frequency. That is why we continue to see fast time during the off peak periods. We believe the reason that this is happening is that companies are not bringing their units to minimum during the off peak period for various reasons. We feel eliminating high frequency from the SAR would be giving tacit approval to continue to allow high frequency operation during the off peak periods.
Economist (No)	Even if the risk of failure due to overfrequency is smaller than the risk of failure due to underfrequency.
Energy Mark, Inc. (No)	The risk of failure due to overfrequency is smaller than the risk of failure due to underfrequency, but it is the joint risk that is of interest. Decisions on reliability should include both the greater risk of underfrequency failure and the lesser risk of overfrequency failure as part of the total risk that must be managed.
Entergy Nuclear Northeast, Inc. (No)	The SAR revised Need #1 (page 4) addresses "Maintain Interconnection scheduled frequency under all conditions...". Doesn't schedule frequency have an upper as well as lower limit. If we want the SAR to only address underfrequency the Need #1 should make that statement.
Michigan Electric Coordinated Systems (No)	Over frequency does have ramifications and needs to be addressed.
Nova Scotia Power Inc (No)	Over frequency results in thermal damage to transformers and generators and is a long term reliability concern.It should be a consideration in the Org Standard.
We Energies	Frequency outside the specified range should be addressed, both over and under.

7. Do you agree the SAR should not eliminate the reference to time error correction? (Yes 21; No 8; Neutral 6)	
Summary Consideration of Comments: The FERC SMD NOPR identifies inadvertent imbalance as a commercial issue rather than a reliability issue. The responses to this question seem inconclusive and the SAR DT couldn't identify a reliabity-related need for Time Error Correction. Given the new information from the SMD and the mixed comments submitted, the SAR DT will ask the industry to identify any reliability-related need for Time Error Correction.	
CA-ISO 2 (Yes)	However, as mentioned before, "Minimize" is more appropriate than "Control".
Duke Power Company (Yes)	Reference to time error should remain.
Duke Energy Trading and Marketing (Yes)	Time error correction is part of good control and its reference should be kept
Economist (Neutral)	Only some customers need it. It is an optional service to customers.
Energy Mark, Inc. (Neutral)	The answer to this question relates to the ongoing value that interconnection time has to our customers. This becomes solely an economic decision.
Midwest ISO (Yes)	Although time error is a secondary measure of interconnection health, it is worth monitoring. Also, nobody knows for sure exactly what would be impacted by releasing the control of time.
NERC Interconnected Ops Services Subcommittee (Yes)	Time error correction is a benefit of controlling the balance of resources and demand, albeit a secondary benefit.
Cinergy - Control Area Operations (No)	I believe more research is needed to determine if time-error accumulation is detrimental to the industry. If economics drives units to run at night and frequency remains at some acceptable level above 60 Hz, is that a problem? Right now the only problem may be trying to correct for it later.
Manitoba Hydro (No)	Time error correction is not viewed as a reliability issue and if required at all should be developed as a separate Standard from this one.
Nebraska Public Power District (No)	Todays clocks are not dependent on frequency. The esxisting use of time error correction lacks technical justification. If there is another reason for this process it should be identified and included in the process with an appropriate name.

8. Do you agree with deleting Industry Need #3? (Yes 29; No 4; Neutral 2)	
Summary Consideration of Comments: There are two other SARs where unscheduled power flows may be addressed: "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" SAR and "Monitor and Assess Short Term Reliability – Operate Within Limits" may both have some components that address unscheduled power flows – one would establish acceptable limits and the other would require operating within those limits. The industry's responses indicate support to delete the respective Industry Need #3.	
California ISO (Yes)	But Transmission Operator should be added as a monitoring entity along with the Reliability Authority in the justification statement
CA-ISO 2 (Yes)	The Transmission Operator or Reliability Authority should be added as a monitoring entity.
ECAR (Yes)	Load-resource balance or imbalance is not the primary cause of operating limit violations and operating limit violations should be part of a SAR on transmission system operation, not a SAR on load resource balance.
Economist (Yes)	Location and transmission-safety limits are not directly a Balancing Authority issue. They are a constraint on and not an objective of the Balancing Authority's actions. Unscheduled flows can be caused by control balancing, not just by imbalance: they can be caused by the Balancing Authority in the normal pursuit of its objectives. Transmission safety limits place a locational constraint on what resources the Balancing Authority can use to balance the system. Transmission safety is the Transmission Operator's function that constrains the Balancing Authority's actions. The Balancing Authority cannot itself exercise this function, determine its own constraints.
Energy Mark, Inc. (Yes)	It is not a Balancing Authority function.
Manitoba Hydro (Yes)	Manitoba Hydro believes that this "Industry Need" is important and could provide reliability benefits by reducing the occurrence of larger amounts of unscheduled power flow. This function belongs in SAR"Monitor and Assess Short Term Transmission Reliability - Operate Within Limits" since the Balancing Authority will not have the appropriate data to accomplish this need.
NERC Interconnected Operations Services Subcommittee (Neutral)	Unscheduled flows can be caused by many factors, one of which can be control imbalances. Preventing unscheduled flows, however, does not itself justify why we need to balance resources and demand - the reasoning is too stretched in this case.
Duke Energy Trading and Marketing (No)	Inadvertent energy is an issue to be addressed by the SAR.
Midwest ISO (No)	Managing unscheduled power flows the primary reason for such a standard, much more so than time error and much more probable then UF load shedding. System separation and potential damage would likely occur

	well before any UF load shedding.

Nebraska Public Power District (No)	Unscheduled power flows caused by inadvertent energy could lead to large unscheduled power flows on flowgates. Since the inadvertent energy is not tagged, there is no way to get it off the flowgate. The TP or flowgate owners won't know where this flow is coming from. Therefore, the balancing standard or some other standard needs to include a requirement to keep unscheduled flows off flowgates.

9. Do you agree with deleting Industry Need #4? (Yes 28 ; No 6; Neutral 1)	
Summary Consideration of Comments: The industry respons indicated support to delete the respective Industry Need #4. The FERC SMD NOPR identifies imbalance as a commercial issue rather than a reliability issue. The SAR DT infers this to mean inadvertent imbalance. If proper control is maintained, a byproduct may be some inadvertent energy, but this does not appear to be a reliabilty issue. NERC expects to participate with NAESB in the development of standards that involve both commercial and reliability components.	
California ISO (Yes)	However, the CAISO feels that Inadvertent Interchange Accumulation between Balancing Authorities and the Interconnection is an important point that needs to be addressed in the Standards process.
Duke Energy Trading and Marketing (Yes)	The NERC JIITF recommended to the NERC RS and NERC OC that the frequency component of inadvertent be addressed by the SAR. CPM1 may already address the issue.
NERC Interconnected Operations Services Subcommittee (Yes)	Inadvertent is an after-the-fact settlement mechanism and provides the least tangible justification for the standard of the reasons in the original version. Inadvertent may be an indicator or measure of performance, but it is not necessarily a good statement of purpose for balancing resources and demand.
We Energies (Yes)	Replace with " allow for reasonable variations in resource control to achieve scheduled frequency"
Duke Power Company (No)	Inadvertent needs to be addressed in one of the 11 proposed standards and this standard appears to be the one that is most appropriate. The word "manage" should be used instead of "minimize".
ECAR (No)	Industry Need #4 should not be deleated. The reason it should remain in the SAR is that one of the primary reasons for balancing load and generation is to make sure that Control Areas do not rely on the Interconnection by importing unscheduled power during periods of high cost power.
Economist (No)	It presumes that FERC can define "inadvertent interchange" well enough to take care of it appropriately in market designs. That contradicts NERC's claim to be the reliability authority because, if not "defined" properly, the product "inadvertent" cannot be priced properly and becomes a reliability issue. If not NERC, then who can define "inadvertent interchange" such that reliability won't suffer? Furthermore, no designs are being planned by FERC for markets between RTOs, only within RTOs, and inadvertent will occur only between RTOs if the RTO becomes the Balancing Authority. So inadvertent interchange risks falling through the cracks or "seams". Need #4 should address "inadvertent", not just "inadvertent accumulations". If not addressed in the "what", inadvertent must be addressed in the "how" since it is an indicator of Balancing Authority performance and impacts frequency performance.

Energy Mark, Inc. (No)	The choice to delete Inadvertent as a reliability consideration can only be made in consideration of how it is managed within the markets. If the resource demand balance components of Inadvertent are managed correctly within the market, then it does not need to be addressed within this SAR. If the reliability components are not addressed adequately within the market design, then reliability will only be able to be maintained by addressing Inadvertent within the SAR.
Michigan Electric Coordinated Systems (No)	Need to retain Need 4 from original version, since no other SAR is addressing Inadvertent.
Midwest ISO (No)	The wording could be improved. The accumulation of inadvertent over the long term is not as significant a concern as the bounding of hourly control. Assuming something close to the existing CPS is implemented, it is possible to have extremely large hourly inadevertents and still get good CPS (as long as accumulations only happen in under 10% of the hours and the accumulations are random with respect to frequency.

10. Do you agree with the changes that were made in making the Brief Description more general, and moving the details to the Detailed Description? (Yes 30; No 2; Neutral 3)	
Summary Consideration of Comments: The industry's responses indicate support for the change that moved the details to the *Detailed Description*.	
Allegheny Energy Supply Company (Yes)	The standard should cover the details.
Duke Power Company (Yes)	As a part of breaking this out into two sections, the Detailed Description section needs to become more specific. In general, Revision 2 of the SAR became more general. The SAR should be more specific.
Economist (Yes)	Say "range" instead of "profile". In the original definition 2 of CPM1 say "relative to" instead of "with respect to".
ERCOT (Yes)	The brief description only is preferred; however, wording changes are needed. In the second sentence, strike "mathematical" and strike "to disperse control responsibility among its entities".These are "hows" and may not fit in a competitive market or single BA environment. Striking these words do not take away from the standard.
NERC Interconnected Operations Services Subcommittee (Neutral)	Now there is very little difference between the brief description and the purpose or need.
Oncor (Yes)	The brief description is preferred; however, wording changes are needed. In the second sentence, strike "mathematical" and strike "to disperse control responsibility among its entities".These are "hows" and may not fit in a competitive market or single BA environment. Striking these words do not take away from the standard.
Illinois Power Company (No)	Illinois Power believes it would be clearer to just have a "Description" section. The introductory paragraph could provide an overview with the details following.
Wisconsin Public Power Inc.	The word 'disburse,' as used in the brief description, is misapplied, as it implies the distribution of funds. 'Assign,' 'allocate' or simply 'distribute' would be more appropriate.

11. Do you think the Brief Description should be revised to include the following: "Balancing Authorities are expected to maintain sufficient resources (i.e., regulation, AGC, Contingency Reserve, DSM, etc.) to stabilize the system following an unexpected event." (or similar language) (Yes 15; No 18; Neutral 2)	
Summary Consideration of Comments: There is no consensus on whether to add these elements to the Brief Description. Half the comments indicated that these elements addressed the "How" not the "What" and the SAR DT agrees with this assessment. Therefore, the suggested change was not made to the SAR.	
CA-ISO 2 (Yes)	Yes, as this is the responsibility of the Balancing authority
Economist (Yes)	Include Frequency Response in the list. Only Frequency Response "stabilizes" the system. The resources listed "restore" the system to normal frequency range after a disturbance, but only once Frequency Response has stabilized the system by containing and ending the disturbance.
Energy Mark, Inc. (Yes)	The resources listed are insufficient to stabilize the system following an unexpected event without Frequency Response.
We Energies (Yes)	Change "unexpected event" to disturbance and define same.
Duke Power Company (Neutral)	AGC does not belong.
Midwest ISO (Neutral)	As long as the description is not too prescriptive, it is fine.
Dominion Virginia Power 2 (No)	It should be revised but with several modifications. We believe the requirement should be more forceful, saying the BA "shall" maintain sufficient resources. Also, we believe the phrase "to stabilize the system following an unexpected event" should be rephrased to stress that the requirement is to prevent the system from slowly progressing into a position where it is easier for an unexpected event to cause problems.
Duke Energy Trading and Marketing (No)	The requirement may be difficult for all BA's to implement given the current structure of the industry.
Entergy Nuclear Northeast, Inc. (No)	This should be incorporated into the Detailed Description.
ERCOT (No)	This is a "How". Keep standards to "What".
FRCC (No)	The FRCC does not believe this belongs in the brief description however, believes this statement should be added as the second sentence introducing the detailed description.
Illinois Power Company (No)	This directly addresses the how, which should not be included in the SAR or the standard.

Manitoba Hydro (No)	The above statement deals with specific details related to a specific operating time increment and does not belong in the "Brief Description" of the SAR.
Mirant Americas Energy Marketing (No)	Don't think this is necessary. The detailed description covers this (referenced measures).
NERC Interconnected Operations Services Subcommittee (No)	This may be stepping into how compliance with the standard is achieved, rather than the standard itself. The desired outcomes are measured by CPM1 and 2 and DCM, not the availability of the resources listed.
Nova Scotia Power Inc (No)	These comments may belong in the Org Std, but are not required in the SAR.
Oncor (No)	This is a "How". Keep standards to "What".
Potomac Electric Power Company (No)	This suggestions is a "How," not a "What."
WECC (No)	Specific requirements should be included in the Detailed Description.

12. Do you agree with the changes that were made in deleting FRM? (26 Yes; 5 No; 4 Neutral)	
Summary Consideration of Comments: The industry's responses affirm the previous posting's support to remove FRM from the SAR. Note: The NERC Resources Subcommittee will assess the technical need for Frequency Response Measure (FRM). If a technical need for this measure exists, a separate SAR addressing FRM may be initiated.	
California ISO (Yes)	At this point in time, the CAISO has very strong concerns regarding the ability to measure FRM in the interconnection.
CA-ISO 2 (Yes)	Measuring FRM and enforcing compliance would be difficult.
WECC (Yes)	It is not clear what FRM is intended to measure or how it is to be measured. It seems somewhat duplicative of CPM1.
WE Energies (Yes)	only as long as "generator goveners and under-frequency load shedding type equipment" requirements are established in the "physical interconnection requirements" standard.
ERCOT (Neutral)	FRM may be an appropriate measure in some cases, but more work needs to be done in its definition.
Duke Energy Trading and Marketing (No)	The recent frequency excursions in the Eastern interconnect demonstrate the need for a frequency response measurement. The SAR committee may want to revisit the effectiveness of the current standard.
Economist (No)	FRM is the most important standard. Without FRM the other standards are ineffective and NERC can close up shop.
Energy Mark, Inc. (No)	The deletion of the FRM Standard demonstrates a significant misunderstanding of how frequency is controlled on an interconnection. Unlimited Secondary Frequency Control resources cannot assure interconnection reliability if there is insufficient Frequency Response to provide the Secondary Control resources the opportunity to respond before interconnection failure. Secondary Control cannot assure reliability without Primary Control.
Midwest ISO (No)	The frequency response of the Interconnections is declining. At some point there will be a reliability problem. The standard does not have to be onerous, but should start to benchmark performance and flag those entities not carrying something close to a reasonable share of their responsibility. It is easy to calculate this performance from the same raw data as the CPM1.
NERC Interconnected Operations Services Subcommittee (No)	Frequency response capability and the measure of frequency response performance is an absolute must for reliability and must be included in a NERC reliability standard. Going back to the underlying basis for balancing, protecting equipment and avoiding a system collapse, frequency response capability is the ability to arrest a sudden, large frequency deviation to prevent a collapse, while slower acting controls can respond. Even if one argues that interconnections are so large that frequency response capability has a diminished value, that is certainly not the case in an islanding condition. Frequency responsiveness has been demonstrated in historical events to enable an islanded system to remain energized during a major disturbance condition.

13. Do you agree with leaving the description of CPM1 intact? (Yes 27; No 6; Neutral 2)	
Summary Consideration of Comments: The last version of the SAR provided clarifying information in a footnote. Based on comments received, the SAR DT refined the footnote and moved the information from the footnote to the body of the text. The industry's comments indicate that most entities want a measure that is the same as or similar to CPS1 (CPM1). The current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment.	
FRCC (Yes)	This is part of the new detailed description, not the brief description.
NERC Interconnected Operations Services Subcommittee (Yes)	There is a need to retain the method used in calculating CPM1, but review the expected performance level (e.g. epsilon) for each interconnection based on reliability need.
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
Midwest ISO (Neutral)	Could not see the footnote in the document.
Dominion Virginia Power 2 (No)	A comment on this and the following sections. CPS, CPM, DCS and other measures do not accomplish control in themselves. They simply measure what has happened after the fact. The tools to really match resources to demand are things such as AGC. Currently Policy 1 states that "all units of consequential size shall be equipped for AGC". We believe that this requirement needs to be clearly stated in the detailed description section of the SAR, as well as detailing other mechanisms available to control system frequency. This SAR has received significant indsutry comments indicating that the SAR should address "What", not "How".
Duke Power Company (No)	The last sentence, "Compliance with CPM1…." should be deleted. The measure (e.g. CPM1) is how well the BAs comply with a STANDARD of maintaining the one-minute ACE with respect to interconnection frequency. The intent of CPM1 is to measure how well a BA helps maintain interconnected frequency on schedule.
Economist (No)	The CPM1 frequency range should be based on more than history. It should be derived from some agreed definition of measurable reliability.

Energy Mark, Inc. (No)	The current CPS1 is based upon historic frequency experience. It is not enough to do things the way they have always been done in the past. This opportunity should be taken to consider whether the standard can be directly linked to physical reliability limits that are not based solely on historical experience, or the standard continues to be based on the way things were done in the past. This is a unique opportunity to demonstrate that NERC is a dynamic and changing institution willing to consider new approaches to reliability. The Standards Development Process ensures that all industry participants have an opportunity to identify and present alternate methods for consideration by the industry as a whole. If you are aware of an alternate method for accomplishing what is achieved through CPM1, the SAR DT encourage you to submit this for consideration by the industry during the Standard Drafting stages of this process.
Manitoba Hydro (No)	The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining control performance.
WE Energies (No)	As the industry evolves, the control area will be redifined and managing the balance of resources and load may be done by other means, this measure should not be prescribed based on the historical methods used, doing so now is beyond the scope of this SAR process.

14. Do you agree with leaving the description of CPM2 intact? (Yes 25; No 8; Neutral 1)	
Summary Consideration of Comments: The last version of the SAR provided clarifying information in a footnote. Based on comments received, the SAR DT moved the information from the footnote to the body of the text. The industry's comments indicated that most entities want a measure that is the same as or similar to CPS2 (CPM2). The current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment. The revised SAR clearly indicates that ERCOT has a proposed Regional Difference with CMP2 and this has been included in the revised SAR	
FRCC (Yes)	This is part of the new detailed description, not the brief description.
Midwest ISO (Yes)	This assumes the CPM2 remains intact. CPS2 was a safety valve to prevent large flows which could occur within the CPS1 envelope. The standard, if developed, should state whether it applies to single control area interconnections (it would appear moot).
NERC Interconnected Operations Services Subcommittee (Yes)	There is a need to retain the method used in calculating CPM2, but review the expected performance level (e.g. epsilon) for each interconnection based on reliability need.
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
ERCOT (Neutral)	CPM2 would not apply to a single BA Interconnection.
Oncor (No vote completed)	CPM2 would not apply to a single BA Interconnection.
California ISO (No)	As written, the description of CPM2 concentrates on USF and ignores the fact and impact of unintended power flows. The CAISO feels that the description would be more accurate were it to read **"**Control Performance Measure 2 (CPM2) – CPM2[1] measures the Balancing Authority's 10-minute average Area Control Error. Compliance with CPM2 helps minimize unscheduled and/or unintended power exchange between Balancing Authority and Interconnection."
Cinergy (No)	The CPS2/CPM2 limits the number of times a Balancing Authority can impact transmission operating limits with unscheduled power flows, but does nothing to restrict the magnitude of those flows. A Balancing Authority with a 50 MW CPM2 limit, can have an ACE average of -1000 MW for <10% of the measured periods and meet the CPM2. The BA can also score well on CPM1 if frequency averages positive during those times. A new measure should be looked into that will address imbalance when it is detrimental to the scheduled frequency beyond an allowable threshold no matter if it is related to a unit outage, loss of resource, or any other factor.

Duke Power Company (No)	The last sentence, "Compliance with CPM2…." should be deleted. The measure (e.g. CPM2) is how well the BAs comply with a STANDARD of maintaining the ten-minute average ACE.
Exelon	Eliminate “minimize unscheduled power flows” and replace with “control or bound” net interchange (as expressed in the ACE calculation) Use “bound net interchange” in the revised SAR Unscheduled power flows are not a part of this SAR but should be included in the SAR that addresses Operating Limits.
Economist (No)	The CPM2 measure is superseded by the SAR "Monitor and Assess Short-Term Transmission Reliability--Operate within Limits" per question 8 above and the deletion of Need #3. Deleted Need #3 was the justification for CPM2. Furthermore, CPM2 has been scientifically proven [Sasaki & Enomoto, IEEE Transactions on Power Systems, Oct. 2001, pp. 476-81; Sasaki & Enomoto, IEEE Transactions on Power Systems, 2002] to be no better than controlling to ACE alone which has already been replaced by CPS1.
Energy Mark, Inc. (No)	The CPM2 measure is based on the concept of maintaining a historic frequency profile without specifically linking that profile to any reliability objective. It does nothing but maintain history.
Manitoba Hydro (No)	Same comment as in 13 (The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining control performance.)
WE Energies (No)	As the industry evolves, the control area will be redefined and managing the balance of resources and load may be done by other means, this measure should not be prescribed based on historical methods used, doing so now is beyond the scope of this SAR process.

15. Do you think that CPM2 should be changed to be a 60-minute average rather than a 10-minute average? (Yes 2; No 31; Neutral 1)	
Summary Consideration of Comments: The industry comments indicate that the measure should remain at 10 minutes. However, the current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment. ERCOT has requested a Regional Difference to the CMP2 measure. The SAR DT endorses the ERCOT request and included ERCOT's exemption from CPM2 in the *Regional Differences* section of the revised SAR..	
Cinergy (Yes)	Possibly. During the development of CPS1, a CPS60 was discussed that would consider both frequency and ACE (unlike the current CPS2) and help achieve the desired frequency performance by having both a 1 minute and 1 hour criteria. I believe this should be looked into further.
Allegheny Energy Supply Company (No)	10 min. allows corrective actions to be taken sooner.
Duke Energy Trading and Marketing (No)	The recent frequency excursions observed in the Eastern Interconnect indicate that CPM2 should not be measured with a longer interval.
Economist (No)	All failures are the consequence of much shorter-interval duration. Only economic/cost advantages have proven [Jaleeli & VanSlyck, Report to EPRI on CPS and IO Procedures, RP-3555-10, Aug. 1996] to derive from a 60-minute measure (of CPS1) because it randomizes control behavior over time and between Control Areas. Economic motives alone are sufficient to prompt participants to control to a 60-minute average within a tighter range than the short-interval average. So NERC need not implement a 60-minute average, even for CPM1. Promoting economic efficiency is not NERC's job but FERC's job, and FERC is supposed to leave economically efficient choices as much as possible to the market participants themselves rather than make them mandatory or build them into market rules, let alone reliability rules.
Energy Mark, Inc. (No)	Before the CPM2 measure is changed to a 60-minute average, it should be demonstrated that there is a reliability risk associated with a 60-minute average frequency control error. There has been no linkage even closely related to interconnection failures resulting from such long-term averages deviations in frequency control. All failures are the consequence of much shorter interval deviations.
Entergy Nuclear Northeast, Inc. (No)	We should identify and correct frequency problems as timely as possible. Large frequency transients which last seconds, which may squew the average, should be addressed as a special case.
ERCOT (No)	CPM2 would not apply to a single BA Interconnection.
Manitoba Hydro (No)	Same comment as in 13 (The proposal to include reference to CPM1 should not be included in item #2 of "Brief Description" because it pre determines that CPM1 will be a measure in the new Standard. The Standard drafting team should be provided the opportunity to investigate alternative methods of defining

	control performance)
Midwest ISO (No)	The No vote assumes you mean to take the average of the 60 one-minute ACE values. Extremely poor performance in the first 30 minutes of an hour could be negated by extremely poor performance in the opposite direction the last 30 minutes. However, if you mean that an hourly CPS1-based metric were used, it could be acceptible.
Michigan Electric Coordinated Systems (No)	The original requirement is a better measure of real time performance.
NERC Interconnected Operations Services Subcommittee (No)	This proposal might be considered in a future revision, but has not been substantiated. Much work has gone into developing the approach using a 10-minute average. Any alternative should be subject to substantial research first.
Nebraska Public Power District (No)	Ten minutes seems more appropriate for monitoring frequency.
Oncor (No Vote Provided)	CPM2 would not apply to a single BA Interconnection.
WECC (No)	In terms of frequency control and inadvertent interchange control, 60 minutes is far too long a period to have any meaning.

16. Do you agree with leaving the description of DCM intact? (Yes 24; No 8; Neutral 2)	
Summary Consideration of Comments: The consensus of the industry responses was to keep DCM. The next posted SAR Comment Form asks the industry for feedback on the unresolved issue of whether there is a need for a standard that fills the time gap between CPS1 (CPM1) and CPS2 (CPM2).	
WECC (Yes)	It should be left as is unless and until someone develops a better measure.
Cinergy (No)	The DCM (if similar to DCS) does not ensure that the Interconnection returns to its scheduled frequency, it ensures that a Balancing Authority's impact on scheduled frequency will be limited to some prefined period (15 minutes) when in a disturbance condition related to a loss of generation or loss of load.
Duke Power Company (No)	The last sentence, "Compliance with DCM…." should be deleted. The measure (e.g. DCM) is how well the BAs comply with a STANDARD of maintaining the ten-minute average ACE.
Economist (No)	Redundant with CPM1. Overkill. The CPM1 Standard already measures disturbance recovery.
Energy Mark, Inc. (No)	The CPM1 Standard also measures disturbance recovery.
Entergy Nuclear Northeast, Inc. (No)	See agree with items 17 and 18 recommendations.
Manitoba Hydro (No)	Same comment as in 13. The present DCM performance measure is insensitive to sytem impact on Interconnection performance which is not ideal. The Standard drafting team should be given free rein to review these criteria and develop what is most appropriate to ensure Interconnection Reliability.
Michigan Electric Coordinated Systems (No)	Adopt language from Question 18.
NERC Interconnected Operations Services Subcommittee (No)	See our comments in 18.
Midwest ISO (Neutral)	There is a need for a standard that fills the time gap between CPS1 and CPS2. The problem is the DCM and DCS are too narrow in scope. The current policy 1 gives about 7 reasons for carrying reserves. They all equate to restoring ACE following an unplanned event. The present DCS just measures a subset of these. There is evidence that some control areas are operating for extended periods with ACE well beyond their reserve requirement but take no immediate action because the deficiciency does not fit the definition of a "reportable event". The way the DCS is crafted, it is acceptible to have a -500 ACE due to failure to commit sufficient resources and wait for a reserve call before deploying 100 Mw of reserves, get back to -400 and pass the standard. ACE is ACE and should be brought back into balance no matter what the cause.

17. Do you think the description of DCM should be changed to include the language, "DCM ensures that the Interconnection helps minimize unscheduled power flows and return its Area Control Error to an acceptable level? (Yes 6; No 27; Neutral 2)	
Summary Consideration of Comments: The consensus of the industry's comments is to leave this language out of the DCM description.	
Cinergy (Yes)	With the addition "..unscheduled power flows due to the sudden unplanned loss of load or generation and . . . ."
California ISO (No)	USF, associated with DCM, would be a secondary consideration and should be addressed in a SAR relating to Transmission Operators.
CA-ISO 2 (No)	DCM is to insure that the Balancing Authority maintains reliability above reducing USF or inadvertent.
Dominion Virginia Power 2 (No)	As stated above, these measures do not ensure power flows will be balanced. They are simply measures of other system controls which may or may not result in correct actions.
Economist (No)	Unscheduled power flows are not "minimized". They are "optimized" according to a pricing mechanism that incents participants to keep frequency on average within a NERC-established reliability range. Move the word "help" from "helps minimize" to "helps ensure" so that the proposed change reads: "DCM helps ensure that the Interconnection minimizes unscheduled power flows and returns its Area Control Error to an acceptable level"
Energy Mark, Inc. (No)	Before including the minimization of unscheduled power flows as a reliability instead of an economic problem, it must be demonstrated that unscheduled power flows are a reliability problem and the Balancing Authority is the proper participant to address the problem.
Midwest ISO (No)	Is the proposed wording correct? How would a DCM cause an INTERCONNECTION to help minimimize its ACE and unscheduled flow? Do you mean Control Area, if so, the vote can be changed to yes.
NERC Interconnected Operations Services Subcommittee (No)	See our comments in 18.
Nova Scotia Power Inc (No)	Wording in the posting is ok.
Oncor (No)	CPM2 would not apply to a single BA Interconnection.
Potomac Electric Power Company (No)	The "Interconnection" does not have an Area Control Error.
WECC (No)	DCM is not about what the Interconnection can do, but what the Balancing Authority must do.

WE Energies (No)	The "minimize unscheduled power flows" implies a schedule??? We don't know what that is yet!! and is beyond the stated industry need.

18. Do you think the description of DCM should be changed to include the language: "DCM ensures that the deficient system returns to an acceptable balance level within a defined period, following a sudden generation or load change. " (Yes 16; No 13; Neutral 6)	
Summary Consideration of Comments: The industry's responses did not indicate consensus on the need for this change. The SAR DT discussed the various recommendations and drafted language to be more technically specific. This revised DCM language included in the latest version of the SAR states: DCM requires that the deficient BA return to an acceptable balance level within a defined period, following a sudden generation or load change. This measure requires the responsible Balancing Authority to quickly return its Area Control Error to an acceptable level.	
Cinergy (Yes)	With the wording change "..following a sudden unplanned loss of generation or load. . ." I believe the wording should also reflect that the DCM ensures that a Balancing Authority's impact on scheduled frequency will be limited to some window (15 minutes) when in a disturbance condition related to a loss of generation or loss of load.
Duke Power Company (Yes)	The first sentence "DCM ensures that the Interconnection…." should be replaced with the sentence from above "DCM ensures that the deficient system…."
NERC Interconnected Operations Services Subcommittee (Yes)	This description is the most accurate, except that DCM does not "ensure" anything - it tells someone how well they performed. DCS measures the effectiveness of a deficient system in returning to an acceptable balance within a defined period. This statement is preferable to 16, 17 or 19.
Midwest ISO (Neutral)	See the earlier comments that this definition appears to be too narrow. There are other things that cause a large ACE value that should be corrected.
Nova Scotia Power Inc (No)	Wording in the posting is ok.
Oncor (No)	CPM2 would not apply to a single BA Interconnection.
WECC (Yes)	This description more clearly indicates who is responsible.
WE Energies (No)	Already stated in the 2nd sentence of the origional.

19. Do you think that DCM should be dropped because it isn't linked to a frequency profile and can't be easily measured? (Yes 4; No 31)	
Summary Consideration of Comments: The industry's responses indicate that DCM should not be dropped from this SAR. However, the current version of the SAR provides the Standards Drafting Team flexibility to modify the existing CPS1, CPS2 and DCS measures. If the industry wants changes to these existing measures, the changes can be suggested and addressed when the draft standard is posted for public comment.	
Allegheny Energy Supply Company (No)	DCM is needed to protect generation equipment from damage during a disturbance.
Cinergy (No)	I stated "NO" only because I believe we need a standard that will drive a Balancing Authority to take corrective action in real time, whenever its operations are impacting the scheduled frequency beyond some pre-defined bounds in consideration of ACE and frequency. The DCM is the closest criteria we have for requiring corrective action when imbalance is impacting the Interconnection.
Entergy Nuclear Northeast, Inc. (No)	Agree with items 17 and 18.
Manitoba Hydro (Yes)	DCM is not an analytical measure of performance and not sensitive to the impact that the disturbance has on the Interconnection. An attempt should be made to develop a DCM which accounts for the impact of the disturbance on the Interconnection frequency performance. It is possible that CPM1 and CPM2 could be modified in such a way to eliminate the need for DCM altogether.
Midwest ISO (No)	Your premise is incorrect. A large ACE does impact the frequency profile and is not that difficult to measure via an hourly CPS metric.
NERC Interconnected Operations Services Subcommittee (No)	DCM is an important element of bounding the balancing of resources and demand.
WECC (No)	DCS is "easily measured." There is no reason to think DCM will be any more difficult.

20. Do you agree this SAR should only have functions for the Balancing Authority? If you think other functions should have performance measures, please identify those measures and their associated functions in the comments. (Yes 24; No 7; Neutral 4)	
Summary Consideration of Comments: This SAR, as originally written, addressed functions that apply just to the BA. Based on the industry's comments, the description has been revised to include the Reliability Authority's (RA) oversight of this function. The following additions were made to support the addition of the RA function: – Added to the Brief Description: The RA needs to have the authority to direct actions (to control frequency) that include load shedding. – Added to the Detailed Description: The Standard requires that the RA monitor system frequency and BA activities and direct action when the RA determines that the interconnected electric system is at risk. For all other functions, the SAR DT are unsure if there will be measures and compliance elements beyond those identified for the BA and the RA. Additional functions may be identified as the standard is developed.	
Duke Energy Trading and Marketing (Yes)	Frequency and AGC effectiveness should also be measured. The functions in this section of the SAR are the functions defined in the Functional Model. (Reliability Authority, Balancing Authority, Interchange Authority, Planning Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Load Serving Entity, Distribution Provider, Purchasing Selling Entity and Generator)
Economist (Yes)	Other SARs should address the means to provide the Balancing Authority with the necessary resources to meet the requirements of this SAR.
Energy Mark, Inc. (Yes)	Other SARs should address the requirements to provide the Balancing Authority with the necessary resources to meet the requirements of this SAR.
ERCOT (Yes)	Better to keep this focused at this level for now. However it is important to develop additional standards involving provision of ancillary services, as these may be provided by generators, scheduling entities, and marketers not part of the balancing authorities organization.
Nebraska Public Power District (Yes)	It is th BA's responsibility to have the appropriate arrangements in place to satisfy the requirements of this SAR.
WE Energies (Yes)	Need to recognize interdependency of other functions. This gets to the heart of Who has the obligations and responsibilities for the "energy adequacy" of the system. I do not believe this is agreed upon in the industry. The Provider of Last Resort for serving load shall be ultimately responsible although may deligete to a service entity to carry out, or must be able to perform the function itself.

Midwest ISO (Neutral)	We agree that the BA has the primary responsibility and should be held to some standard. Since CPM and the other standards are the ultimate desired outcome, generators (or loads) self-providing or selling ancillary services (or IOS) should be held to similar standards.
California ISO (No)	The Balancing Authority plays an integral role in responding to the requests of and working in cooperation with the Transmission Operators, Reliability Authority, and Interchange Authority and as such, reference or linkage to these cannot be eliminated.
CA-ISO 2 (No)	The Balancing Authority plays an integral role in responding to the requests of and working in cooperation with the Transmission Operators, Reliability Authority, and Interchange Authority and as such, reference or linkage to these cannot be eliminated.
Duke Power Company (No)	Apply to Generator, LSE, PSE functions. These functions need to have a requirement to meet the schedules given to the BAs, either in this standard or another. The performance measures- for compliance with the standard- for these functions would need to be developed and clearly defined. These performance measures should be stated in this or the applicable standard.
Manitoba Hydro (No)	This SAR should have functions for the Reliability Authority as well as the Balancing Authority since the Reliability is the highest level Authority and has responsibility for implementing transmission loading relief procedures which may impact Balancing Authority function. The Reliability Authority should be aware of any network balancing issues in the Balancing Authorities within its footprint of responsibility so if problems arise in one Balancing Authority another Balancing Authority can help the one in trouble if required for interconnection reliability. An example of this type of function is the Reserve Sharing Pool where several balancing Authorities share their operating and spinning reserves.

Michigan Electric Coordinated Systems (No)	In Michigan SAR would apply to IA, Generators and PSE. CPS1, CPS2 and DCS sanctions/penalties would be allocated to the entities performing these functions. Michigan structure needs to be allowed for in SAR. The Functional Model assigns tasks to specific "functions". The functional titles used in the Functional Model may or may not match the titles used by any single entity. At some time in the future, there will be a process whereby each entity will register with NERC and identify the "functions" it wants to be recognized as performing. From NERC's perspective, the "functions" in the Functional Model are the functions for which the industry ist developing standards. Thus, whatever an entity's structure, if that entity registers to perform the "balancing authority " tasks, that entity will be considered the Balancing Authority and will be expected to comply with all sections of all standards that are developed for the BA. Note that an entity may perform more than one function. While this SAR currently indicates that there needs to be measures such as CPM1, CPM2 and DCM, the industry has an opportunity to review and comment on the appropriateness of these measures. The determination of appropriate compliance for each measure will be accomplished during the Standard Drafting stage of this process. All compliance elements will be publicly posted and will be revised so they represent what the industry wants. There is, therefore, no guarantee that the compliance currently in effect for CPS1, CPS2 and DCS will be the compliance elements associated with the proposed standard.
NERC Interconnected Operations Services Subcommittee (No)	Omitting the requirement that all generators, loads, and transmission facilities must be metered into one and only one balancing area results in a standard that is incomplete and doomed to failure. As a simple case, generators could serve loads, while synchonized to the grid, without being part of a balancing area. The functional model breaks down if all energized facilities are not part of a balancing area. This most basic requirement cannot be left to regulations, contracts, or other forms of rules for generators and loads. This statement is in the current Operating Policy 1, and along with the BA's obligation to balance resources and demand to meet CPM1, CPM2, DCM, and FRM, this statement is a cornerstone of the proposed new standard: "All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area". This comment was submitted in the first posting of the SAR and appears to be lost in the analysis provided above. Furthermore, the IOS Subcommittee, as documented in the IOS Reference Document, believes that IOS Supplies have specific obligations associated with real-time balancing. To the extent that balancing obligations apply to IOS Suppliers, the applicable functions should be checked. For example, the definitions shown in the table indicate that generators and PSEs may have IOS responsibilities. Certification requirements for the BA are expected to contain language that includes requirements for metered boundaries and authority within those bounaries.

WECC (No)	Reliability Coordinator should have oversight authority. Planning authority should have responsibility to plan the system to comply with the resource/demand balancing requirements. The other functions (generator, load serving entity, transmission provider, etc.) have a secondary responsibility to help ensure that compliance with the resource/demand balancing requirements is achieved.

21. Do you agree with leaving the Reliability Principles as originally identified? (Yes 18; No 10; Neutral 5)	
Summary Consideration of Comments: There is no consensus on whether to change the Reliability Principles. The reliability principles can be interpreted broadly or narrowly and no single interpretation seems to have more technical merit than another. The SAR DT added all recommended principles to the revised SAR.	
NERC Interconnected Operations Services Subcommittee (Yes)	Yes, only one box is required and # 2 works the best.
Duke Energy Trading and Marketing (No Vote Provided)	Our version of the SAR had no boxes checked and therefore we agree or disagree.
California ISO (No)	Please see response to Question #22, below.
CA-ISO 2 (No)	Please see response to Question #22, below.
Manitoba Hydro (No)	Manitoba Hydro believes that Reliability Principle #7 should be added to the applicable Principles because resource and demand balance can have a significant impact on the reliability of the Interconnection.
Nova Scotia Power Inc (No)	# 3 should be added
WE Energies (No)	I believe all 7 Reliability Principles apply to the function of a BA and are needed to meet this standard as the primary role of the BA.

22. Do you agree Reliability Principles #3 and #5 should be added to this SAR? (Yes 14; No 13; Neutral 7)	
Summary Consideration of Comments: There is no consensus on whether to change the Reliability Principles. The reliability principles can be interpreted broadly or narrowly and no single interpretation seems to have more technical merit than another. The SAR DT added all recommended principles to the revised SAR.	
California ISO (Yes)	The CAISO also feels that Reliability Principles #' 4 & 6 are applicable in this SAR.
CA-ISO 2 (Yes)	Reliability Principles #' 4 & 6 are applicable in this SAR.
Duke Power Company (Yes)	Reliability Principle #6 should be added also.
Duke Energy Trading and Marketing (No vote provided)	Our response depends on the application of the SAR. If the SAR is to apply to both RA and BA, would agree.
Entergy Nuclear Northeast, Inc. (No)	Agree with item 21.
ERCOT (No)	These belong in other SAR's, but they are still important. Hopefully we will develop some means to link or at least cross-reference these situations.
Michigan Electric Coordinated Systems (Yes)	Also add Principle 6
Nova Scotia Power Inc (No)	add #3 only
WECC (Yes)	I believe all the reliability principles apply.

23. Do you agree the SAR should be revised to incorporate these objectives? {Yes 7 and 3 yes votes for the first half of this question; No 18 and three no votes for the second half of this question; Neutral 7)	
Summary Consideration of Comments: There is not industry consensus to change the SAR to include this language.	
Allegheny Energy Supply Company (Yes)	In addition, limit dip to insure generation equipment is protected from damage.
WECC (Yes)	If UFS is underfrequency load shedding, I agree to the extent that it should not cause unwarranted underfrequency load shedding. I am not sure of the intent of the second comment, but it should be covered by DCM if it's referring to the period following a disturbance.
Economist (Yes/No)	Yes to the first. No to the second.
Energy Mark, Inc. (Yes/No)	I agree with the first, I do not agree with the second.
National Grid USA (Neutral)	IF no other industry standard explicitly states frequency limits where ALL balancing authorities will initiate some form of corrective action, then we believe that industry limits should be include in this document for they are essential in returning the interconnection to normal.
Duke Power Company (No)	Should not be revised.
Duke Energy Trading and Marketing (No)	Underfrequency is addressed in the Industry Need for standard issue. See comment for 25.
Manitoba Hydro (No)	There are many systems where it would be impossible to implement performance requirements related to item 1. In many systems underfrequency load shedding is implemented as the least cost solution to ensure that the underfrequency is minimized to a level where a system blackout does not occur. The second bullet is a desirable objective which all systems should try to get to within the practical limits of money and resources.
Midwest ISO (No)	The No vote is because two different objectives were bundled. The UF load shedding is may already be included depending on the votes to earlier questions. We agree that this is important, but again, two objectives were bundled. The"specied time" assumes a DCS-like standard.

24. Do you agree the SAR should be revised to include checking control error? (Yes 9; No 21; Neutral 6)	
Summary Consideration of Comments: There is not industry consensus to include this change in the SAR.	
Cinergy (Yes)	As long as the components of each can be compared to determine if the error between real-time and ATF was due to metering, scheduling, control, and so on.
Economist (Yes)	This can eliminate inadvertent resulting from incorrect metering.
Energy Mark, Inc. (Yes)	The above should end ….inadvertent developed due to incorrect metering.
Midwest ISO (Yes)	The standard is meaningless if ACE is misstated.
Wisconsin Public Power Inc. (Yes)	In addition, the standard should be expanded so as to prevent individual Balancing Authorities from 'leaning on the interconnection' by operating with significant positive values of Area Control Error during periods of when this poses difficulty for neighboring Balancing Authorities. This is a matter of reliability, and the existing Control Performance Standards are not adequate to achieve this result.
WE Energies (Neutral)	Need to account for adequate metering and communication ckts in the interconnection standard, this standard may or yet another new SAR may establish the "maintenance" requirements. This should be addressed in the Certification Requirements for these Functions.
Duke Power Company (No)	Should not be revised.
Duke Energy Trading and Marketing (No)	Should already be reflected in the CPM standards.
ERCOT (No)	This may belong in another SAR that covers control and data collection systems
Manitoba Hydro (No)	It was unclear what this comment was intended to address.
NERC Interconnected Operations Services Subcommittee (No)	Some would argue inadvertent is a reliability issue and others would say it's a settlement issue if you have the other performance measures in place. There should be an explicit justification of why checking control error is necessary for reliability if it is to be included. The JIITF had a good concept - what is really needed for reliability is a continuous feedback loop to incent good performance in real time, not an after-the-fact settlment method.
Potomac Electric Power Company (No)	Inadvertent interchange, while a measure of control performance, is a commercial issue.

WECC (No)	I believe "checking" of control error is inherent in CPM 1 & 2. Details such as checking average interchange against metered interchange are a matter of self-interest on the part of the BA because inadvertent must be tracked and repaid to the Interconnection.

25. Do you agree the standard should include a more quantifiable definition of the term, "disturbance?" (Yes 13; No 18; Neutral 4)	
Summary Consideration of Comments: There is no consensus to modify the SAR to include this definition. The Standards Drafting Team will have responsibility for defining terms used in the proposed standard.	
Nebraska Public Power District (Yes)	The standard should include a definition of a disturbance for reporting purposes. The SAR does not need this definition.
WECC (Yes)	It could include a specific magnitude of frequency deviation that may necessarily be specific to each Interconnection.
Midwest ISO (Neutral)	If you have a DCS-like standard, there would have to be some objective way of knowing what constitues a measureable event. As noted earlier, ACE should be maintained within some general bounds, no matter what the cause.
Mirant Americas Energy Marketing (Neutral)	The term "disturbance" should be better defined (more specific). However, this need not be done in this standard. Could be part of NERC standards glossary.
Duke Energy Trading and Marketing (No)	Disturbance may be difficult to quantify – but the operator ought to recognize one when it occurs. That is why we support having trained professionals operate the system.
FRCC (No)	However, the FRCC OC believes the standard drafting team will need to be clear when DCM applies when they are drafting the words for the standard itself.
Illinois Power (No)	The SAR should not include detailed definitions. This should be left to the development of the standard
NERC Interconnected Operations Services Subcommittee (No)	There exists today in the NERC vernacular no less than three definitions of "disturbance". Adding another is not going to help. What should be done is a SAR should be submitted to form a single NERC Glossary that goes through the consensus process and is maintained to support the other standards.
WE Energies (No)	Develop a Glossary of Terms applicable to all standards.