FERC Reliability Technical Conference
Panel I: 2016 State of Reliability

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It is my great privilege and honor to respond to specific questions raised by this panel. Thank you for this opportunity. The comments provided are strictly mine and do not represent positions taken by any other parties. However, they are result of many R&D years with my collaborators, and their direct or indirect input is greatly appreciated.

I first make several general comments, and then respond to specific questions raised by the Commission in light of these comments.

General comments

Need to relate mandatory standards with their quantifiable relevance to reliable and efficient BPS operation--Given a very complex nature of operating BPS, it is often difficult for non-utility industry participants to appreciate the need for mandatory standards of one kind or the other. Because they are viewed as additional cost to the basic electric energy services, it is necessary to have a way to directly interpret their relevance for reliable and efficient operation. We suggest that it is, therefore, necessary to work on evolving mandatory standards so that this becomes possible.

One way forward would be to establish general, relatively simple, framework based on common transparent and quantifiable metrics and protocols. The framework should be based on straightforward physical and economic principles. To achieve this, it is necessary to base today's standards on unifying principles of electric power system operations subject to end users' quality of service (QoS) specifications. This is a tall order, given that today's system operation is a complex mix of various methods under various assumptions.

For the basic framework to work (ensure reliable service at well-understood value to all) it must be designed to account for complex spatial and temporal interdependencies within a multi-layered multi-temporal architecture of the emerging electric energy systems. The complex multi-layered spatial boundaries create well-known "seams" problems; these problems are not only between Balancing Authorities (BAs), they exist within a BA between Transmission System Owners (TSOs), Distribution System Owners (DSOs); between utility-owned and non-utility-owned parts of the system. To overcome this problem, all components must provide information about their ability to contribute and their needs for reliable service using common interaction variables between themselves and the rest of the system. Second, in order to manage highly dynamic system reliably, a family of well-organized temporal standards is necessary. These needs are described next. We identify key open problems which require solutions. Finally, we take the liberty to propose possible solutions based on our long-term R&D findings.

***Need for distributed, multi-layered standards*--** Technological and organizational industry changes have led to BPS architecture with "nested" Balancing Authorities (BAs) [Ref. 1]. Each group of components responsible for participating in reliable service at value is called an intelligent Balancing Authority (iBA) [Ref. 2]. For example, non-utility-owned parts of the system with their own sub-objectives are often embedded inside today's BAs and are hard to align with the utility objectives. To account for their effects, more granular standards for all BPS members must be established. Clear characterization of their roles in balancing the system during both normal and abnormal conditions is required. NERC reliability standards recognize this emerging architecture evolution, and have been geared toward setting mandatory rules for both utility-owned and non-utility-owned generators. These should be extended to all groups of components within BPS in accordance with well-defined principles.

Key open technical problem comes from lacking technical foundations for relating certain BPS operating problem (loss of synchronism, for example) to the mandatory requirements on specific equipment and its physical controllers (primary frequency reserve in the case of loss of synchronism); much serious industry effort is under way to solve this problem [Ref.3]. However, since it is fundamentally impossible to uniquely map a specific BPS reliability problem to the technical requirements which must be met by the components themselves, many such on-going industry efforts will still face the fundamental problem of how to justify the technical requirement set by the mandatory standard.

This problem can be overcome by requiring all components to provide information themselves about their ability to participate in reliable service, and the system operators to use this information to minimally coordinate them on-line so there is no system-level problem. Moreover, if components also provide the cost associated with their participation in reliable service, it also becomes possible for system operators to manage the system efficiently without deteriorating system-level reliability.

To do this systematically, without biasing certain technologies and participants, we propose that common variables and metrics must be used and that these must be replicable and quantifiable. Higher-level iBA entities must be responsible for meeting standards expressed in terms of the same types of variables and metrics. The key role of higher level iBA is to minimally coordinate its member iBAs so that their own metrics are met.

***Need for dynamic, multi-temporal standards*—** The well-established approach to power balancing in the past has been "horizontal", namely the slowest generators are scheduled first, and the faster ones are scheduled closer to real time to supply system-level demand. This has been possible because the system demand has been quite stationary and predictable. Feed-forward (ahead of time) scheduling of generation is done so that the only feedback (automation) needed is to regulate frequency in response to hard-to-predict imbalances in between scheduling intervals (AGC, by the BAs) and primary stabilization in response to fast small deviations in near real time (primary control, by the governors, AVRs and PSSs primary controllers of generators).

Key new challenge —These historically practiced temporal hierarchies underlying power balancing are currently challenged as both net load and new technologies connected to the system often exhibit previously unseen temporal fluctuations.

Proposed technical solution-In order to bring some order to balancing power over time by the most effective technologies, it is essential to think of standards as "dynamic" standards [Ref. 4,Ref. 5]. All components connected to BPS are responsible for providing specifications about their ability to participate in balancing power at certain rate and over certain time horizon. If this information is provided, it becomes then the responsibility of system operators to request the right amount of power at the right rate from technologically very diverse components. For technical details on such dynamic standards, see [Ref.4, Ref.5].

Possible Dynamic Monitoring and Decision Systems (DyMoNDS) framework for Reliable, Efficient and Clean Electricity Service

The idea of having common metrics and protocols within a consistent general framework raises the key technical question regarding the existence and nature of such common variables and metrics.

To account for complex multi-layered BPS spatial architecture, we first must think of a BPS as comprising many electrically interconnected heterogeneous iBAs [Ref.1, Ref.2,Ref.6]. Each BPS member (component, or group of components, physically connected to the grid) must belong to an intelligent Balancing Authority (iBA).

To account for complex multi-temporal dynamics, the required information must be in terms of temporally-organized metrics relevant for the entire range of operating problems.

Definition of intelligent Balancing Authority (iBA) –A group of cooperative components within the BPS freely bundled according to its own objectives and subject to its own technical constraints. In order to be part of BPS it must: (a) provide information about its ability and needs in terms of variables and metrics common to all other iBAs; and, (b) must participate in protocols determined by the higher-level iBAs, ultimately responsible for reliable service at today's BA levels and higher.

The proposed general framework is named Dynamic Monitoring and Decision Systems (DyMonDS) framework. It is based on straightforward on-line information exchange between iBAs according to a simple protocol that lower level iBAs must provide information to the higher level iBAs to which they are electrically connected. The higher-level iBAs, in turn, have the responsibility and authority to minimally coordinate their iBA members. Each IBA has its own "DyMonDS" defined as follows:

Definition of DyMonDS—Information processing unit responsible for providing information about its common metrics and QoS. The unit is equipped with sensors, automation, computer applications in support of their own decision making so that it is capable of meeting its own specifications. These are characterized in terms of common interaction variables (intV) and Quality of Service (QoS).

Definition of Common Interaction Variable (intV)-- An interaction variable z_i(t,T) between component i and the rest of the system is characterized as a set of physical variables comprising incremental stored energy E_i(t,T), power p_i(t,T) and rate of change of power dp/dt_i(t,T) which an iBA can produce or which it needs.

Definition of Common Metrics-- The general metric represents *bounds on common variable intV*.

Definition of Quality of Service (QoS)--- Each iBA specifies limits on voltage delta v_i(t,T) and delta f_i(t,T) frequency deviations acceptable.

Shown in Figure 1 is a sketch of DyMonDS-based SCADA. It can be seen that DyMonDS framework is basically next generation SCADA system required to implement protocols for on-line information exchange in support of reliable and efficient service at specified QoS. It can also be seen that multi-layered, multi-directional and multi-temporal information exchange becomes key to systematic operations and control.

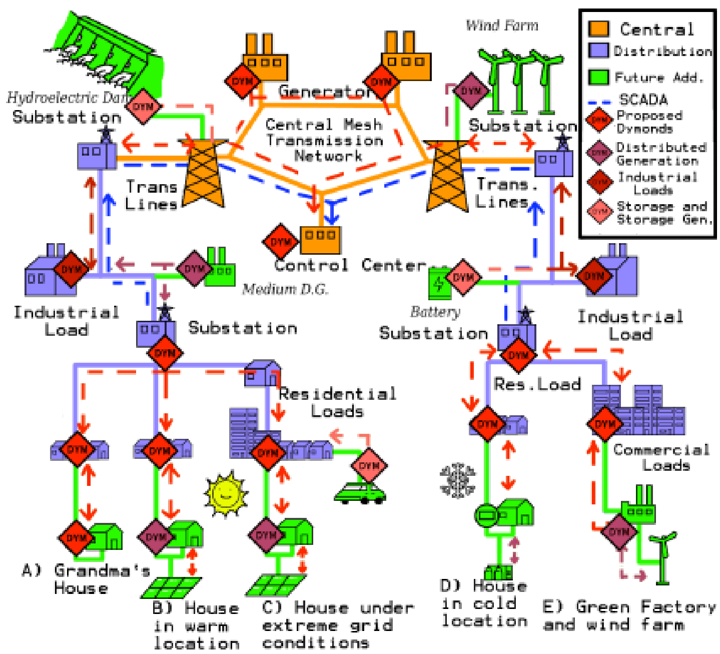

Figure 1 DyMonDS-based next generation SCADA [Ref.2, Ref.6]

Several important observations regarding proposed DyMonDS framework

Natural outgrowth of today's operations --- Proposed metrics and protocols underlying DyMonDS are direct extensions of well-known Area Control Error (ACE) used in Automatic Generation Control (AGC). The extensions are two-fold: An ACE-like interaction variable is introduced to characterize any given component connected to a BPS and intV must be defined over carefully-organized temporal horizons T so that all operating problems are managed using these variables [Ref. 6]. The basic technical idea is that the instantaneous power must balance at several rates and that users must have desired QoS. In AGC power balances every 10 minutes by responding to ACE (incremental energy, average power over this period) and frequency at the BA level is specified QoS. Very similar extensions can be introduced for specific dynamic problems of concern to NERC. In our answers to specific questions we illustrate this under Part b.

Possible to interpret all NERC requirements in terms of common variables and metrics—This fact is critical. Recent CMU provisional patent [Ref. 6] offers unified modeling by transforming current dynamic modeling into multi-layered modeling. Original variables of any dynamic component can be represented in this new space as comprising its intV and the remaining internal states. It is shown that components must know their internal states to design their sensing and control so that they can operate within the specified metrics. On the other hand, higher-level inter-area dynamical model does not have to know internal technological details nor models. Higher-level iBA can minimally coordinate its interconnected components so that no reliability problems of any sort occur. This model is fundamentally critical for moving forward in this vastly multi-layered industry.

No requirement on one size fits all -- Reliability problems of concern to engineers can be managed by the smallest iBAs themselves, or by the higher-level iBAs. How is this done depends on the available control at different level iBAs, as well as on their interest to explore new solutions. Even the boundaries of iBAs can be created in a bottom up way as long as each iBA follows the proposed protocol.

Implications of using DyMonDS framework on innovation

Explicit incentives to select right technology-Assuming a general framework as proposed, it becomes possible to innovate at well-understood value to those doing it. The BPS members have clear options between implementing technologies to meet the metrics/standards themselves, or in cooperation with other iBA members. Higher level iBA can coordinate its members by either allocating technical responsibilities or by having market incentives in an IT-enabled DyMonDS environment. A quantifiable binding burden of proof is set on all BPS members to meet their metrics measured in terms of interaction variables or pay to iBA for doing it on their behalf. The incentives shift to the level of granularity needed to assess what may be the most effective technology (software and hardware) to which BPS members. In particular, iBAs quickly recognize that for them to meet their metrics it is essential to operate in a much more flexible way than it is currently done. We point out that for this to be implemented much innovation is needed in software for enabling on-line reliable operation. Instead of ERO mandating provision of, say, specific primary frequency reserve, or voltage control, or deployment of FACTS, iBAs will utilize these so that their performance metrics are met in the most effective ways.

Recommended software innovations— For DyMonDS framework to become reality, it is necessary to enhance both automation embedded into components/iBAs and computer applications currently used by the system operators. Decisions on how to operate BPS on-line as conditions vary are currently based on system operators' knowledge about the specifics of their part of the system and on the off-line analyses under different assumptions. In particular, today system operators base their decisions on the worst-case contingency studies. We recommend that NERC and Commission would do well to move toward corrective reliability management with minimal required reserve for non-time critical contingencies. This means that, instead of operating during normal operations conservatively so that in case contingency happens no system-level problems occur, it is necessary to have software which, after a contingency occurs, quickly decides on what are the best adjustments on the remaining functional equipment. This mode of operation is likely to become unavoidable because of higher presence of hard-to-predict worst-case scenarios created by larger variations in net demand as seen by the BPS operators. In our Part b. response we illustrate potential value of an extended AC OPF, for example, when determining rule on reactive power support.

Also, to avoid time-critical problems, it is essential to ensure that iBAs have sufficient embedded automation to transiently stabilize equipment in response to large sudden changes, including faults. Humans can only act at limited speed. Theoretical state of the art designs are known for designing nonlinear controllers of several types so that closed-loop primary dynamics are stable within the specified bounds on interaction variable (metrics). Manufacturers need to implement such controllers. Otherwise, the system will experience previously unseen oscillations such as sub-synchronous control instabilities (SSCI) [Ref. 7,Ref.8]. NERC should require testing of equipment automation prior to deploying to the system so that the dynamic standards are met as measured in terms of metrics set on interaction variables.

<u>Minimal information exchange and internal privacy-</u> Relevant for availability requirement of certain databases, the model used by an iBA to ensure that the specified metrics are feasible by means of their own primary control design is a very detailed model of specific technologies. The higher-level model is only in terms of interaction variables of all iBAs within the BPS; it is, therefore, sufficient to coordinate actual power outputs for stabilizing system-level performance without knowing full detail of internal models and parameters. The bounds on interaction variables (metrics) can vary in operations, the higher level iBA simply selects the actual value of the interaction variable for all of its iBA members so that no system-wide operating problems occur. For reliable service to be implemented at the BPS level, it is necessary to only exchange information about interaction variables between the iBAs and their higher level iBA. It is not essential for the highest BPS level operating entity to know much detail about the specifics of technologies embedded within the lower-level iBAs. This observation sets the basis for a new multi-layered approach to ensuring reliability by:

- Requiring non-uniform specifications of all iBAs in terms of their own interaction variables; these variables are common to all iBAs. Achievable bounds on interaction variables (metrics) must be guaranteed and tested by the iBA itself at each rate of response of interest. This requires full knowledge of local iBA only.
- Requiring higher-level iBAs to minimally coordinate the actual values of interaction variables so that bounds on interaction variable at their level are also met. This does not require full knowledge if local iBAs comprising the higher-level iBA. Only bounds on their interaction variables are needed.

Much the same way as AGC of each BA (formerly control area) is characterized in terms of its own Area Control Error (ACE), each iBA is characterized in terms of its own interaction variable with the rest of the system; and has much autonomy to decide on technologies and means of meeting the AGC standard.

Potential effects on economics for reliable service- We suggest that DyMonDS framework gives lots of flexibility to save while observing reliability. Members within each iBA are free to decide on how to implement their specified metrics and to cooperate to make the most out of their resources. Savings within any given iBA happen through cooperation. Savings across same-level iBAs are achieved either through minimal coordination or through competition depending on the tradeoffs of potential gains and complexity of communications implementation. Notably, iBAs compete within the BPS for their members. A well-designed electricity market is ultimately DyMonDS framework in which technical and economic signals are communicated and aligned [Ref. 9]. For this to happen, common IntV and metrics must also have the cost specified.

In closing-- We humbly suggest to the Commission and NERC to further consider the proposed DyMonDS framework. It is not too late to re-think principles of mandatory standards for reliability and establish a general framework according to such principles. Such an approach is likely to make the overall process systematic and easy to quantify and monitor. We have developed at CMU a Smart Grid in a Room Simulator (SGRS) in collaboration with NIST which can be used as a means of demonstrating DyMoNDS-enabled BPS performance and for comparing it with the effects of today's mandated standards [Ref. 10]. We point out that the proposed framework is not suggested lightly; we have simulated many of its aspects using real-world models of electric grids in two Azores Islands. This work started in response to the challenging question of how would one minimize the use of expensive fossil fuel without increasing long-term electricity service cost and without affecting QoS [Ref. 11]. I strongly believe that we could extend these concepts to enable BPS reliable operations at reasonable long-term cost.

Response to Specific Questions Raised by the Commission Panel 1

a. Primary accomplishments and new future issues

Planners, operators and transmission owners have continued to work hard to ensure no major loss of service at the BPS levels. They are to be congratulated for this. As pointed out by all participating in this panel, the system has performed well; this has been mainly accomplished by a heavy reliance on a combination of mandatory standards for reliability and the engineering expert knowledge. However, the industry has remained short of having a unifying framework in support of systematic transitioning from voluntary to mandatory standards; as a result the process has been extremely time consuming and hard to follow. Perhaps the main challenge has been the lack of simple transparent metrics and protocols underlying evolution of standards. In our General Comments we provide a detailed discussion of this issue and propose a possible framework for moving forward. Our basic recommendation is that a systematic approach to innovating today's engineering tools and computer applications should be given major attention when defining reliability standards in such complex systems. It is well-known that the complexities are not only technical, but economic, organizational and societal. Aligning all of this requires systematic framework.

Furthermore, ensuring reliable service by strictly planning more equipment (transmission, generation) and not changing the way the infrastructure is used in the actual operations will fall short of ensuring reliable service at any reasonable cost as uncertainties seen by the BPS operators increase. In particular, relying on off-line analyses and putting the burden of proof on operators to make on-line decisions will result in many situations previously unseen by them and in hard-to-foresee wide-spread blackouts. We strongly recommend that Commission and NERC consider enhanced decision-making tools beyond the ones currently used. Improvements are needed to facilitate on-line decisions by system operators; computer applications capable of managing events on-line as they occur, instead of relying solely on the worst-case reserves are critical. Similarly, fast automation capable of avoiding time critical events (fast control and protection) must be deployed; humans can only act at certain speed.

b. Assessment of the effectiveness of NERC's reliability activities and related industry efforts

The Commission and NERC have issued several dockets related to reliability services. They all share common challenges described in my General Comments. In particular, various activities have been concerned with various specific technical requirements and have not addressed these requirements in direct relation to their impact on reliable system operations. We have seen a sequence of dockets which are hard to interpret by those who are not intimately familiar with the power system operations. This situation begs questions regarding the need for these services and the amounts mandated. As explained in our General Comments above, this is simply because at present the industry does not have general model-based framework which in a transparent way explains how the BPS operates and why are certain standards needed.

The proposed Dynamic Monitoring and Decision Systems (DyMonDS) framework offers a relatively straightforward thinking about how is very complex BPS operated. It is as simple as having to balance power (deliver produced power to the locations needed) at the fast rate. The faster the rate at which the power balances, the less deviations in system frequency and voltages. So, the natural common variables for defining metrics are in terms of integrals of power (incremental energy), power and rate of change of power. Everyone can understand this. Moreover, the Quality of Service (QoS) is courtesy to the BPS end users, and should not be explicit in determining system-level requirements. It is these two observations, together with lots of theoretical foundations work, which should begin to set the basis for common metrics and protocols. Once this is understood, one begins to avoid all together difficult details regarding exact protection standard settings, or specifications for frequency reserves (primary and secondary) and voltage/reactive power support complications. These should be internal to those operating the system on-line as information about common metrics is made available and updated on line. It is no longer possible to operate the system reliably for the worst-case scenario which is probably never to happen. What is needed are methods for resilient on-line operation.

To illustrate, we briefly discuss some recent activities by the Commission in light of our general comments:

The debate regarding essential reliability services --the first Docket No. RM16-1, November 2015 about exemption for wind generators from providing reactive power--- It does not appear plausible to provide meaningful incentives for this support without having interactive protocols in place to select out of many different options the ones which are most effective as seen by the higher level iBAs. For example, given metrics, AC OPF obtains the most effective reactive power support [Ref.12]. As a rule, the result of AC OPF based voltage dispatch is never for all iBAs to provide the same reactive power support. The question of reactive power support is particularly thorny one for several reasons. To start with, based on the discussion in general comments, no common metrics are needed in terms of reactive power. Instead, only QoS measured in terms of acceptable voltage deviations explicitly enter the proposed protocol. Also, a closer look into controllers for generators and other equipment (including power converters) shows that none of these control directly reactive power, they control voltage. Therefore, it is needed that BPS members provide information on common metric specifications as well as ranges of acceptable voltage deviations and not worry about reactive power support specifications. Some of the BPS members would require higher level voltage dispatch coordination if they are not capable of supporting their own voltage, and other iBAs will be capable and willing to adjust their voltages within relatively large ranges, and, therefore, help out other parts of the system.

We stress that requiring each iBA to provide unity power factor is pointless for variety of reasons as we have documented in the past studies for industry [Ref.13]. Instead, much the same way as with other on-line corrective actions, as conditions vary the available resources are adjusted by the coordinating entities to ensure that a BPS as a whole does not experience voltage “collapse” problems. We have documented in excruciating details how this can be done for the case of NYCA [Ref. 13]. It was shown, for example, that on a hot summer day approximately 1GW power can be delivered beyond what is being delivered from Niagara to NYC by implementing voltage dispatch [Ref. 14]. Similar studies have shown that in PJM even after retiring major power plants the system can be operated reliably if on-line systematic voltage dispatch is practiced when dispatching real power [Ref. 15]. The infamous PV curve can become much more forgiving (allow for larger transfers) when voltage dispatch is implemented, as shown for the case of ERCOT [Ref.16].

Unfortunately, my discussions over the past decade with many leading engineers have clearly demonstrated that deployment of any new software creates a risk in its own right and, moreover, no direct incentives exist to do so. As a result, sub-optimal utilization of available resources takes place and, at the same time, the threat of voltage collapse is not eliminated; at least a dozen major blackouts worldwide have been caused by poor management of available reactive power resources, and not by their shortage. It was shown that the blackout of 2003 could have easily been avoided by on-line corrective actions despite the specific triggering event [Ref.17].

However, if there are no bids in terms of financial incentives this is hard to do since higher level iBAs won’t have a quantifiable way of allocating cost of meeting reliability performance by diverse smaller iBAs. Of particular importance are incentives to lower level iBAs and transmission and distribution owners to help support voltage by their higher level iBAs. Adjusting tap changer setting and AVR settings in NYCA BPS (and/or) the neighboring systems would be a major means of directing more power from clean hydro to NYC. Serious economic studies must be done to compare the effects and cost of such BPS solutions (dominated by economies of scale) to the solutions envisioned by NY REV (deployment of many small-scale DERs).

Provision and Compensation of Primary Frequency Response, Docket No. RM16-6, February 2016 is particularly straightforward to discuss in light of our proposed reliability metrics. To start with, we highlight that frequency deviation is a rather poor indicator of power imbalance-related instabilities. Recall that even in steady state AGC is in response to power imbalance known as ACE, and not in response to frequency deviation. Long ago adjusting frequency bias was a major job for at least one engineer. A single frequency bias in iBAs comprising highly heterogeneous technologies (with large and smaller, or no, inertia) is a non-starter and therefore an impossible job for designers of mandatory standards. Instead, we propose to specify metrics in terms of feasible ranges of power and rates of change of power. Determining the amount of primary frequency response can only be done if protocol is in place to specify which components are likely to cause how much sudden power change (either because they fail to operate or they have insufficient means of responding fast to follow desired rate of power changes).

Finally, selecting sources of primary frequency control should be revisited in somewhat serious way. It is our understanding that current industry effort is putting all its thinking into determining the bandwidth of governor response needed to have adequate primary frequency response [Ref. 3]. We stress that governor would quickly break if it were to serve the purpose of saving a generator from loss of synchronism following sudden rate of change of power output and being required to respond to it. Instead, AVR, PSS, SVC,FACTS, fast storage, such as flywheels and batteries (as the last resource because of their excessive cost) can all contribute in major ways to transiently stabilizing BPS response and preventing loss of synchronism. For this to be implemented, these potential suppliers of primary frequency response should make their metric known to the higher level iBA, which, in turn would assess which disturbances can the system withstand. Instead of reducing power transfers and making ranges of operating conditions more conservative prior to these disturbances, the higher level iBAs should solicit sufficient supply for stabilization across all these newly emerging technologies. While they may appear too costly to implement, it is possible to asses an optimal level of investment in fast power-electronically switched controllers whose cost pays off by operating the system efficiently during normal operations [Ref. 18]. It is at this critical time scale that PMU-based monitoring and wide-area control schemes may become essential, this is to be determined by the higher-levels iBAs. We stress that there exists fundamental difference between special protection schemes (SPS) on one side, and wide-area fast control schemes. The objective of protection is to disconnect the equipment, and the objective of fast control is to support the system operation even when protection would have had to disconnect it otherwise. A recommended case study is to take the case of SSR controller proposed in [Ref. 19] and compare to SPS in AEP for protecting the system against SSR [Ref. 20].

As a side note, principles for secondary frequency reserve are straightforward to determine, following the same general metrics. As an illustration of possible standards for ensuring small signal stable frequency response and frequency regulation within the pre-specified threshold is just an example of the more general principle proposed [Ref. 21].

In short, we strongly recommend taking a step back and setting up systematic principles for primary frequency support protocols according to the general proposed metrics, instead of struggling with tightening up the requirement for governor response.

Please notice that sufficient flexibility ought to be given to both existing and new resources when attempting to implement consistent protocols and standards. The response given to me during a recent presentation at CA-ISO is very supportive of the proposed metrics and protocols [Ref. 22]. Two basic takeaways from that meeting are: Both engineers and market folks understand power, rate of change of power, and incremental stored energy. Our findings so far are that it is sufficient to have multi-temporal metrics in terms of these variables only without being too concerned about the type of technology and its details.

All the other Commission events (Ride-Through Requirements for Small Generators, Docket No. RM16-8, March 2016; NERC Reliability Standard for Geomagnetic Disturbances, TPL-007-1; FERC Docket No. RM15-11, May 2015; FERC proposed directive for new requirements Docket No. RM15-14, July 2015)

should be assessed in light of common general framework for reliable services proposed here.

FERC proposed non-public access for Commission staff
Docket No. RM15-25, September 2015

Relevant for availability requirements of certain databases, the model used by an iBA to ensure that the bounds on interaction variable are feasible by means of their own primary control design is a very detailed model of specific technologies. The higher-level model is only in terms of interaction variables of all iBAs within the BPS; it is, therefore, sufficient to coordinate actual power outputs for stabilizing system-level performance without knowing full detail of internal models and parameters. The bounds on interaction variables can vary in operations, the higher level iBA simply selects the actual value of the interaction variable for all of its iBA members so that no system-wide operating problems occur. For reliable service to be implemented at the BPS level, it is necessary to only exchange information about interaction variables between the iBAs and their higher level iBA. It is not essential for the highest BPS level operating entity to know much detail about the specifics of technologies embedded within the lower-level iBAs. This observation sets the basis for a qualitatively different multi-layered approach to ensuring reliability by:

- Requiring non-uniform specifications of all iBAs in terms of their own interaction variables; these variables are common to all iBAs. Achievable bounds on interaction variables (metrics) must be guaranteed and tested by the iBA itself at each rate of response of interest. This requires full knowledge of local iBA only.
- Requiring higher-level iBAs to minimally coordinate the actual values of interaction variables so that bounds on interaction variable at their level are also met. This does not require full knowledge if local iBAs comprising the higher-level iBA. Only bounds on their interaction variables are needed.

c. What metrics have been, or should be, developed to define whether reliability, in whole or in part, is improving? How can we assess if the risk of blackouts is increasing or decreasing and, if increasing, due to what causes? Can a quantitative risk analysis be used?

Reliability is not a single number! It should be measured in terms of how are specified metrics and QoS met by BPS members and by the higher-level iBAs. If BPS members specify their common metrics (bounds on stored energy, power and rate of power change) they are capable of providing or needing, as well as their own QoS acceptable, it is up to higher-level iBAs to implement these according to their least cost metric (a combination of fuel cost, environmental impact and risk of not serving); here, again, iBAs metrics are measured using the same variables as for their members. A quantitative risk analyses depends on how is the system operated, and the effects of operating practices should be looked into very carefully. Proactive protocols should be put in place to enable implementation of desired reliable service within the multi-layered BPS.

Coordinating protocol for ensuring reliable service becomes the one of computing the actual value within the ranges specified by the metrics of BPS members and sending the commands to them to implement at different rates relevant for specific technical problems. Dynamic standards are fundamentally families of multi-temporal requirements as follows:

To avoid sub-synchronous electromagnetic and electromechanical oscillations –each iBA must specify range of power needing/producing at the rate relevant for this dynamic phenomenon, say specifications must be set for response within the split second time intervals[Ref. 23].

To avoid loss of synchronism --each iBA must specify range of power needing/producing at the rate relevant for this phenomenon. These are typically rates relevant for ensuring critical clearing time following major loss or major sudden dip in power generated or consumed [Ref. 24]. For example, an iBA could be a wind power with storage and conventional generator jointly managing loss of synchronism when a fault occurs in their part of the grid [Ref. 25].

To avoid small signal instabilities specifications of the proposed metric must be made for the time responses so that they do not trigger under-/over-frequency and voltage [Ref. 26].

To ensure frequency and voltage regulation the existing ACE metric must be specified for minutes to 10 minutes [Ref. 4,Ref.5]; in systems with continuously fluctuating DERs the existing ACE must be enhanced and it becomes a dynamic metric [Ref. 26].

To ensure that ramping rates important for balancing power when dispatch is performed it is important to specify the proposed metric for time intervals over which dispatch is being done [Ref. 27].

The more granular metrics over time, the smoother system-level response is achievable. Adding to currently observed time scales the new shortest time scale which brings about the assurance that no power electronics-related electromagnetic instabilities would be created in response to extremely sudden changes, could be an excellent starting point for ensuring reliable service at value by all entities.

Specific recommendations for transparent regulatory rules in support of effective reliability standards

When/if iBAs fail to meet their specifications by not responding to the coordinating entities the reasons may be multiple. They could range from having failures in their own hardware components and/or failures in their embedded DyMonDS implementation. Part of the protocol is that they must notify higher level coordinating iBA and this entity should have stand-by ready methods to modify the commands to the remaining iBAs according to the well defined performance objective at the aggregate level. Similar interactive protocol must exist between all layers.

Monitoring whether the metric are implemented becomes the objective of enforcing reliability standards. An important technical detail is that if all (groups of) component(s) are required to participate in enabling reliability than one could consider enriching the protocols to specify two types of metrics: The first metric is to operate according to the best possible specified metrics, and the second metric is to be specified for abnormal conditions when some components fail to meet the specified metric for normal operation.

We observe that the specifications of iBAs multi-temporal metrics must be made prior to the iBA connecting to a BPS. The on-line commands, on the other hand, are issued in a feed-forward way at the rate determined by the higher level iBAs. The committed/required metric is implemented by the lower level iBA.

We point out that the technical problem of higher level iBA coordination so that the system as a whole does not experience instability problems at particular rate and to also ensure that system frequency and voltage remain within pre-specified bounds requires serious attention by both industry and academia. It is truly a solvable problem. As an example of control area computing how much power (secondary frequency reserve) and at which rate so that the system frequency settles to within the pre-specified threshold epsilon can be found in [Ref. 21]. It is extremely important to observe that this is not possible to answer unless all BPS members and iBAs specify their demand for frequency reserve to compensate likely deviations from dispatched power and all iBAs providing frequency reserve specify their ability to do so in terms of above proposed metrics. Similar extension is needed to all metrics within the multi-temporal family for each iBA, independent from the specific technology or ownership.

Specific recommendations for transparent electricity market designs in support of reliability service at value

Parts of the large complex bulk electric power systems which are operated as electricity markets naturally lend themselves to participating in reliable service at value by being required to specify the same technical metric. In addition to specifying the technical metric they would be required to participate in a family of multi-temporally clearing markets by providing supply and demand bid curves for [E_i(t,T)^min; E_i(t,T)^max]; range of power [p_i(t,T)^min; p_i(t,T)^max] and rate of change of power [dp_i(t,T)/dt^min; d p_i(t,T)/dt^max] capable of either producing or needing during the time T of interest. The role of higher level iBAs then becomes the one of not only ensuring that the technical metric is implemented according to their coordinating commands, but also that the cost of ensuring reliability is optimized. For transactive energy control to work such specifications will become essential.

Specific recommendations for combining technical standards and market design rules

Notably, the proposed reliability metrics are expressed in terms of common variables [E_i(t,T)^min; E_i(t,T)^max]; range of power [p_i(t,T)^min; p_i(t,T)^max] and rate of change of power [dp_i(t,T)/dt^min; dp_i(t,T)/dt^max] capable of either producing or needing during the time T of interest for both reliability and for defining market derivatives hybrid solutions are possible. Given this important fact, hybrid solutions are possible in which existing iBAs may meet technical standards while the newly deployed technologies can be selected by the electricity markets to best align the cost and technical performance.

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