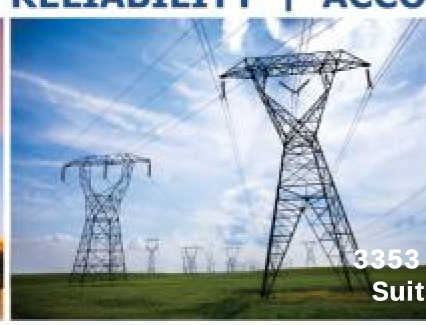
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Review of Bulk Electric System Definition Thresholds

March 2013

RELIABILITY | ACCOUNTABILITY



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Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within the eight Regional Entity boundaries, as shown in the map and corresponding table above. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

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Executive Summary

In March 2012, the Definition of BES Standard Drafting Team (DBES SDT) asked the Planning Committee (PC) to review some of the thresholds in the Bulk Electric System (BES) definition that the DBES SDT identified within the Phase I BES work and to supply technical justifications for the following thresholds:

1. 100 kV bright-line transmission threshold (in the core definition)
2. Generation threshold MVA values associated with single-unit and multiple-unit facilities (in Inclusions I2 and I4)
3. Reactive power threshold (MVA level) (in Inclusion I5)
4. Power flow allowed out of Local Networks (LN) (in Exclusion E3)

After analysis and review, the PC offers the following recommendations to the DBES SDT for consideration:

5. Maintain the 100 kV bright line (core definition).
6. Maintain Inclusions I2 and I4 as currently defined.
7. Maintain Inclusion I5 as currently defined.
8. Use Technical Alternative C, which proposes clarifying changes to the existing Exclusion E3 item (b) as given below in bold:
    a. **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES**
9. Establish a size limit in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section as well as in Appendix 3.

The NERC PC discussed and approved the recommendations in this report and its transmittal to the DBES SDT at its December 2012 meeting. Following the meeting, the PC Executive Committee made further changes based on the discussion by the PC, and the final report was approved by the PC by an email ballot.

1. Introduction

In FERC Order No. 693, the Commission explained that section 215(a) of the Federal Power Act (FPA) broadly defines the bulk power system as:

Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.

The Commission also initially approved NERC's definition of Bulk Electric System, which is an integral part of the NERC Reliability Standards and is included in the NERC Glossary of Terms Used in Reliability Standards[2], as the following:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

In response to the Commission's directive in Order No. 743 that NERC develop a revised definition of Bulk Electric System using NERC's Reliability Standards development process, NERC began work in 2011 to eliminate the Regional and subjectivity contained within the definition. In early 2012, the NERC Board of Trustees approved a revised BES definition and subsequently filed it with FERC under docket RM12-6 and RM12-7. This concluded the Phase I work associated with developing a revised definition.

In its filing, NERC proposed the following core definition of Bulk Electric System:

Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

As stated in the NERC filing, the revised definition of Bulk Electric System:

- removes the basis for regional discretion in the current Bulk Electric System definition;
- establishes a bright-line threshold so that the Bulk Electric System is facilities that operate at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are real power or reactive power resources; and
- contains specific Inclusions (I1-I5) and Exclusions (E1-E4).

During the initial revision of the definition of the Bulk Electric System in Phase I of Project 2010-17, industry stakeholders expressed concerns related to the lack of technical justification associated with the existing thresholds in the definition. Due to time constraints in the Phase I schedule, Phase II of the project was initiated to address the lack of technical justification. As part of this initiative, the DBES SDT asked the PC for assistance in developing technical justification for the thresholds in the revised definition.

1.1 Problem Statement

Properly identified BES Elements are important to the reliability of the interconnected bulk power system. The ability to properly identify BES Elements is dependent on a BES definition that is based on factors directly associated with reliability. The revised BES definition approved by the NERC Board of Trustees and filed with FERC contains historical thresholds from the current BES definition found in the NERC Glossary of Terms and the NERC Statement of Compliance Registry Criteria.[3] These historical thresholds are not currently supported by documented technical justifications.

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[2] http://www.nerc.com/files/Glossary_of_Terms.pdf

[3] On December 20, 2012, FERC issued a Final Rule on *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*: http://www.ferc.gov/whats-new/comm-meet/2012/122012/E-5.pdf

The DBES SDT requested support from the NERC PC (see Appendix 1A and 1B for request authorization) and Operating Committee (OC) to develop technical justifications to assist the SDT in considering revisions to the following thresholds that are part of the current NERC Board of Trustees-approved definition of the BES:

1. 100 kV bright-line transmission threshold (in the core definition)
2. Generation threshold MVA values associated with single-unit and multiple-unit facilities (in Inclusions I2 and I4)
3. Reactive power threshold (MVA level) (in Inclusion I5)
4. Power flow allowed out of Local Networks (LN) (in Exclusion E3)

1.2 Planning Committee Assignments

To complete this request in a timely manner, the PC assigned the development of technical justifications for the thresholds listed above to designated subcommittees of the PC as outlined below:

Technical Justification	Assigned To:
100 kV bright-line transmission threshold	Planning Committee Executive Committee
Generation threshold	Reliability Assessment Subcommittee
Reactive power threshold	System Analysis and Modeling Subcommittee
Power flow allowed out of local networks	System Analysis and Modeling Subcommittee

1.3 Considerations for Technical Justification

The PC, in conjunction with its technical subcommittees, noted that using power flow or dynamic studies may not lead to definitive results and are highly dependent on varying assumptions used in the models, such as generation dispatch, load level, system conditions, etc. Also, other aspects of reliability, such as resource adequacy, reserve margins, voltage support, etc. need to be considered along with performing power flow and dynamic analyses. Therefore, the PC recommended that these studies not be performed at this time in determining technical justification for the above thresholds.

2. Technical Justification for the 100 kV Bright Line

NERC's filing to FERC under docket RM12-6-000 proposed to establish a bright-line transmission threshold so that the "bulk electric system" would include facilities operated at 100 kV or higher if they are Transmission Elements, or connected at 100 kV or higher if they are real-power or reactive-power resources. The DBES SDT asked the PC to provide technical justification for the 100 kV threshold included in the core BES definition or propose a better alternative, if justified (see Appendix 1).

2.1 Alternatives to the 100 kV Bright Line

Several alternatives to the 100 kV bright-line transmission threshold were considered. The alternatives outlined below were selected for further research and consideration.

2.1.1 Technical Alternative A – Surge Impedance Loading (SIL)

Description: Incorporate transmission lines that have a Surge Impedance Loading (SIL) above a specific criteria value (for example, 100 MVA) and for all substations connected to a line that meets this criteria.

Technical Discussion: A key component to the reliability of the power system is the ability to continue to provide service to load not only from nearby generating sources, but also from external sources. This has been the basis for justifying the addition of a number of Extra High Voltage (EHV) transmission facilities throughout North America. To assess the ability of a transmission line to carry load, or the amount of load a transmission line can effectively carry, engineers calculate its Surge Impedance Loading.

SIL is a loading level at which the transmission line attains self-sufficiency in reactive power (i.e., no net reactive power into or out of the line), and is a convenient "yardstick" for measuring relative loadability (or ability of the line to carry load) of long transmission lines operating at different nominal voltages.

For example, considering the SIL alternative, on a per-unit basis, for uncompensated overhead transmission lines, three 500 kV circuits, six 345 kV circuits, or thirty-four 161 kV[4] circuits would be required to achieve the same loadability of a single 765 kV line. Specifically, a 765 kV line can reliably transmit 2,200–2,400 MW (i.e., 1.0 SIL) for distances up to 300 miles, whereas the similarly situated 500 kV and 345 kV lines with bundled conductors can only deliver about 900 MW and 400 MW, respectively, over the same distance.

For short distances, these previous relationships can produce slightly different results, which reflects the thermal capacity of transmission line. The thermal capacity of a transmission line is determined by the number or size of line conductors and terminal equipment ratings. However, SILs for typical compensated overhead lines are two to three times those of uncompensated overhead lines. For underground lines where air is not the insulating dielectric, SILs are three to twelve times that of uncompensated overhead lines, with multipliers increasing as line voltages decrease.

The relative loadability of the same overhead 765 kV, 500 kV, and 345 kV lines also can be viewed in terms of transmission "reachover," for which a certain amount of power can be transmitted. In the first example, 1,500 MW sent over a 765 kV line would represent a loading of approximately 0.62 SIL, which, according to the loadability characteristic of the transmission line, could be transported reliably over a distance of up to 550 miles.

By contrast, a 345 kV line carrying the same 1,500 MW would operate at 3.8 SIL—this power would be transportable up to approximately 50 miles (assuming adequate thermal capacity). This distance would increase to about 110 miles for a double-circuit 345 kV line.

The generalized line loadability characteristic incorporates the assumptions of a well-developed system at each terminal of the line and operating criteria designed to promote system reliability.[5]

[4] Thirty four 161 kV added to original calculations
[5] Source is American Electric Power System Facts (no endorsement; used posted transmission information)

SIL is a long-accepted indicator of system loadability and capability and is at least one indicator of the reliability of a transmission line. System studies would need to be performed to support a given bright line threshold, such as the 100 MVA mark, with delayed clearing fault simulations occurring while at the same time monitoring for cascading events, extreme frequency excursions, and uncontrolled separation (among other events).

However, calculations from a sample power flow model's branch data indicate that additional stress and stability studies would need to be performed for all interconnections. Follow-up correlation analysis would be necessary to determine whether correlation to SIL exceeds correlation to a voltage level, and to identify the appropriate bright-line SIL threshold for the BES.

A transmission line's SIL is easy to calculate, but the values obtained correspond to a voltage level, which does not provide a better, technically justified alternative to using the 100 kV voltage level. (SIL is proportionate to the square of voltage). SIL would simply be a surrogate to using a bright-line voltage criteria. In addition, transmission lines would still carry portions of power transfers, even though they may be below a certain SIL value, as the SIL value is only an indication of reactive power equilibrium for that line. Virtually all transmission lines above 200 kV would be captured by this criterion for the SIL level. Transmission lines below 200 kV would most likely be included in the BES if the line has series compensation or is built underground, which increases the SIL for those types of lines.

Given that SIL would only be a surrogate for the voltage level of a transmission line, the PC recommends not selecting this method for determining the bright-line threshold in the BES definition.

2.1.2 Technical Alternative B – Short Circuit Values

Description: Incorporate facilities with a short circuit value greater than a specified threshold (e.g., 5,000 MVA).

Technical Discussion: Technical Alternative B to the 100 kV bright-line transmission threshold in the BES definition would be to perform a calculation that reflects the strength of the network at any given location or node (such as a substation bus) using the Short Circuit MVA method. Using this approach, facilities with many sources (either transmission lines or generation sources) would fall under the definition of the BES, given the level of short circuit MVA.

The classical approach and the method defined by ANSI/IEEE are two such industry-accepted methods for calculating short circuits. Both methods assume that the fault impedance is zero (bolted short circuit) and the pre-fault voltage is constant during the evolution of the fault. In actuality, the fault has its own impedance, and the voltage drop, due to the short-circuit current, lowers the driving voltage.[6]

The classical approach is used to calculate the system Thévenin equivalent impedance behind the fault and then to calculate the Short Circuit MVA at the point of the fault. The ANSI/IEEE method for short circuit MVA calculation, which is described in IEEE Std. C37.010-1979[7] and its revision in 1999, is used for high-voltage (above 1000 V) equipment.

In order to include all higher voltage facilities that may be carrying power over longer distances, a bright-line voltage level would also need to be included when using this method. This value could be based on operating and design specifications of the interconnection.

Technical Alternative B is easy to calculate and is completed regularly by industry stakeholders. Calculated Short-Circuit MVA values are normally calculated at substation buses and display the projected fault current at each bus.

However, to use Technical Alternative B as a bright-line criterion in the BES definition, there must also be additional criteria developed to address the inclusion of the associated transmission lines, including transformers connected to those substations (which may include sub-100 kV facilities). Additionally, an MVA threshold value itself would be arbitrary and, therefore, short circuit calculated values would vary, depending on study models, which generators are online, etc. Using this method to identify BES facilities would result in frequent changes and thus be not practical to implement. The PC does

[6] http://ecmweb.com/content/short-circuit-calculation-methods
[7] http://standards.ieee.org/

not recommend the use of the Short-Circuit MVA method as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.3 Technical Alternative C – Substation MVA Rating

Technical Discussion: Include substations with two or more lines connected to a substation with a total rated MVA greater than a specified threshold (e.g., 800 MVA or greater) and any transmission lines with MVA ratings greater than a specified value (e.g., 400 MVA or greater). The total substation MVA value would be the sum of all of the MVA values (or ratings) of the transmission lines connected to a substation and may include sub-100 kV facilities within the substation.

Technical Discussion: Technical Alternative C uses the total connected MVA rating of all lines into substations, regardless of voltage level. The computed MVA would *not* include transformation within the substation, nor would it include generation or load connected to the substation. This method would only include circuits connected to a substation in the determination of the connected MVA value. The connected MVA method would use networked transmission lines, as used in the current BES definition, and would also include lines that connect to the substation via the transmission system. At the same time, it would exclude the following types of transmission lines: radial transmission lines, transmission lines to lower voltage facilities with no transmission sources, loads, and lines connected directly to generation sources. This alternative does not consider the power flow on the lines, but rather their MVA ratings.

Transmission line MVA calculations would then be based on the most restrictive continuous rating of the transmission facility. Continuous ratings would be used since the BES is planned to serve peak load without relying on short-term overload capability. No stability ratings would be used.

Possible advantages of using the total substation-connected MVA alternative over the 100 kV voltage threshold are that the MVA-based determination captures substations with multiple circuits connected to it. (Individual lines are not as important, given the criteria to operate the system at N-1 levels).

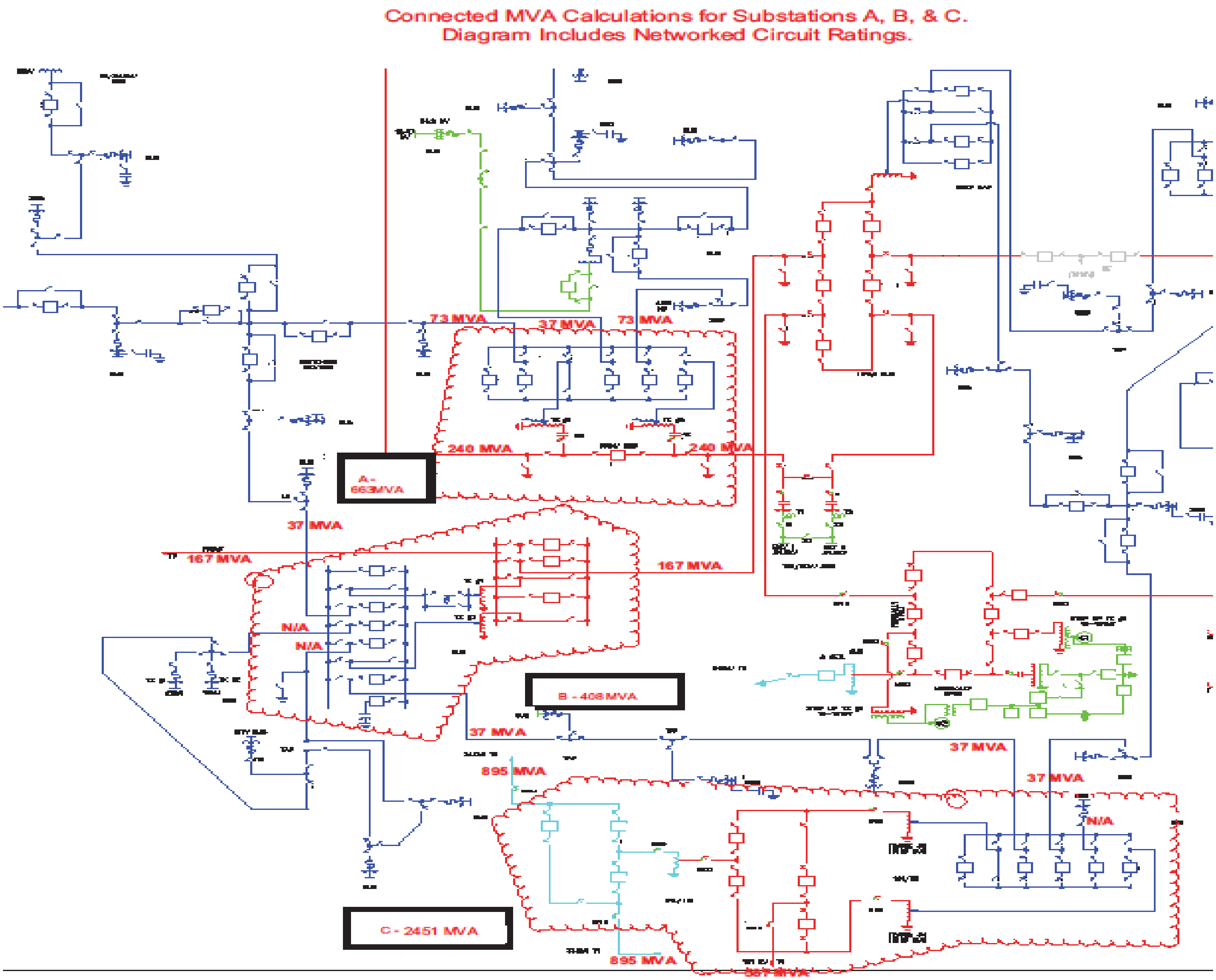
This method also determines the capacity of lower voltage facilities (such as transmission lines operated at voltages less than 100 kV) that are normally closed circuits in lower voltage networks and that contribute reliability benefits to the bulk power system. The connected MVA method may alleviate concerns that facilities operating at voltages less than 100 kV are not considered BES facilities unless they are determined to contribute to the reliability of the local network or interconnection. The connected MVA method also is more efficient to administer, as it reduces the number of inclusions and exclusions necessary to separate BES facilities that contribute to the reliability of network from those that do not (also referred to as non-BES facilities).

However, the disadvantages of applying the connected MVA method may include challenges to address all possible scenarios (e.g., whether generation facilities with multiple fuel types should be included or excluded). The connected MVA method would require revision to the BES if transmission lines or equipment were uprated.

The connected MVA method could create inconsistent classification of Elements that serve similar purposes (e.g., a transmission line between two major substations would be included; however, if two intervening step-down stations were constructed, the section between the two step-down stations may be excluded even though its function as a transmission path is not changed).

Figure 1 below shows example one-line diagrams of three substations and the summation of MVA of lines interconnecting the substations back to the interconnected system. The MVA interconnection of substations A and B is less than 800 MVA and would not be included in the BES. However, substation C, with an interconnection MVA of 2,451 MVA, would be included.

Figure 1: Connected MVA Calculations for Substations A, B, and C



Because MVA values are essentially arbitrary and reconfiguration could exclude assets with BPS functionality, the PC does not recommend the use of the connected MVA of substation method as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.4 Technical Alternative D – Transfer Distribution Factors

Description: Use transfer distribution factors, such as Power Transfer Distribution Factors (PTDFs)[8] and Outage Transfer Distribution Factors (ODTFs),[9] to determine a bright-line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage (e.g., 3%) would determine which facilities would be considered BES.

[8] Linear methods use PTDF to express the percentage of a power transfer or transaction that flows on a transmission path. PTDF is defined as the coefficient of the linear relationship between the amount of a transaction and the flow on a line or transformer, and the

Technical Discussion: Technical Alternative D would use transfer distribution factors as a bright-line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage (e.g., 1%, 3%, or 5%) would determine which facilities are classified as BES facilities and which facilities are not. The selection of this method to identify bulk system assets has several disadvantages. First, it would require detailed power flow analyses be performed to make the determination, and that method would need to be reviewed periodically (possibly biennially) to account for system changes that would affect the OTDF and PTDF values. Also, it would require a review if lines or equipment were uprated. OTDF values are dynamic and may result in frequent changes to which facilities are classified as BES.

The PC does not recommend the use of transfer distribution factors as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.5 Technical Alternative E – Angular Difference

Description: Determine facilities within the BES by calculating the angular differences between substation buses. The values used in this alternative would be determined by power flow analyses or real-time synchrophasor data gathered from operating phasor measurement units (PMUs).

Technical Discussion: Technical Alternative E suggests using angular differences between substation buses to determine BES and non-BES facilities. This method could use data from power flow analyses or real-time synchrophasor data gathered from phasor measurement units (PMU).[10]

The voltage phasor angle difference between two ends of a transmission line becomes large when the power flow on the line is large or the line impedance is large. Similar relationships are expected to apply to the angle difference between two buses in different areas of a power system.

A large angular difference indicates, in a general sense, a stressed power system with large power flow or increased impedance between the areas. Simulations of the grid before the August 2003 Northeast Blackout showed increasing angle differences between Cleveland and western Michigan, which suggests that large angle differences could be a precursor to a system blackout.

A recent simulation study[11] of potential phasor measurements on the 39-bus New England test system shows that, of several phasor measurements, angle differences were the best in discriminating alert limits and emergency conditions.

The increasing deployment of wide-area measurement of phasor angles spurs interest in finding ways to use phasor angles to determine system stress. Picking one bus in each of two areas and monitoring the phasor angle difference has an inherent problem in that, although the angle difference is generally expected to increase with system stress, many factors contribute to angle difference, including which two buses are chosen and the local power flows within each area. It is then harder to give a specific meaning to the angular difference and specify threshold values that indicate when the angular difference becomes dangerously large.

Angle differences are inherently dynamic and change with generation, load, and transmission conditions instantaneously. The PC could not determine how this method could be used to identify BES facilities. The PC does not recommend the use of angular difference as a replacement for the bright-line transmission threshold identified in the current BES definition.

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incremental percentage of a power transfer flowing through a facility or set of facilities for a particular transfer when there are no contingencies.

[9] OTDF is the percentage of a power transfer that flows through a monitored facility for a particular transfer when the contingent facility is taken out of service.

[10] I. Dobson, M. Parashar, C. Carter, Combining Phasor Measurements to Monitor Cutset Angles, 43rd Hawaii International Conference on System Sciences, January 2010, Kauai, Hawaii. 2010 IEEE.

[11] V. Venkatasubramanian, Y. X. Yue, G. Liu, M. Sherwood, Q. Zhang, Wide-area monitoring and control algorithms for large power systems using synchrophasors, IEEE Power Systems Conference and Exposition, Seattle WA, March 2009.

2.2 Conclusions and Recommendation

Over the years, the industry has widely used the 100 kV threshold that appears in the current BES definition to delineate between transmission and subtransmission facilities in some areas of North America. However, the technical justification for using that voltage level as a bright-line threshold has been missing from the BES definition.

Significant portions of power flow transfers from generation to load centers are carried by facilities operated at 100 kV and above. The 100–299 kV systems support the EHV (i.e., greater than 300 kV) systems during times of normal and emergency operations and contingencies. A significant portion of the total generation in North America is connected at voltages between 100 kV and 299 kV. Each interconnection and its associated entities perform technical analyses (including power flow and dynamics) of their systems along with joint regional and interregional analyses. Most technical analyses model 100 kV and above facilities, and sub-100 kV facilities in certain cases. Contingent and monitored facilities are at the 100 kV and above level in these analyses. See Appendix 2 for detailed statistics and values for each interconnection.

While the PC recommends keeping the 100 kV voltage threshold in the revised NERC definition of the BES, it also recognizes and has considered the inclusion of sub-100 kV facilities in the BES because of the findings and recommendations from the report on the Arizona – Southern California Outages of September 8, 2011. The proposed NERC Rules of Procedure exception process may be used to include pertinent sub-100 kV facilities on a case-by-case basis.

Sub-100 kV facilities, as shown from the interconnection discussions in Appendix 2, may be necessary for the operation of the BES but will need to be considered in the future on a case-by-case basis for inclusion in the BES. Registered Entities and Regional Entities will need to address how to make these determinations going forward.

Many and varied interconnection studies indicate that 100 kV is the proper threshold needed for BES reliability. Additionally, none of the alternatives considered in the PC's analysis provides a convincing technical justification for change from the bright-line threshold.

The PC recommends maintaining the 100 kV bright line (core definition) without enhancement or changes.

3. Technical Justification for Generator Thresholds

In the Phase 1 Bulk Electric System definition filing, Inclusion I2 of the BES definition provides the following statement:

> "Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above."

The filing also states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating resources. The Phase 1 filing notes that a "basic tenet that was followed in developing the [revised definition] was to avoid changes to Registrations . . . if such changes are not technically required for the [revised definition] to be complete."

While Inclusion I2 specifies "generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above," the NERC Registry Criteria specifies a "direct connection" to the bulk power system.

Also in the Phase 1 Bulk Electric System filing, Inclusion I4 of the BES definition provides the following statement:

> "Inclusion I4 identifies as part of the bulk electric system dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above."

NERC stated in its Phase 1 filing that the goals of Inclusion I4 were to accommodate the effects of variable generation on the Bulk Electric System. It further states that even though Inclusion I4 could be considered subsumed in Inclusion I2 (generating resources), NERC believes it is appropriate "to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity" as a separate inclusion criteria.

3.1. Capacity Breakdown

For its reliability assessments, NERC collects two different types of capacity data to classify generators on the bulk power system: 1) nameplate/installed capacity, and 2) seasonal rated capacity.

The nameplate (or installed) capacity of a generation resource is defined as the maximum output (usually in MW) the resource can achieve under specific conditions designated by the manufacturer. Nameplate capacity usually does not include resource uprates (i.e., upgrades made to the generator to increase output) or derates and capacity reductions for station or auxiliary services and loads.

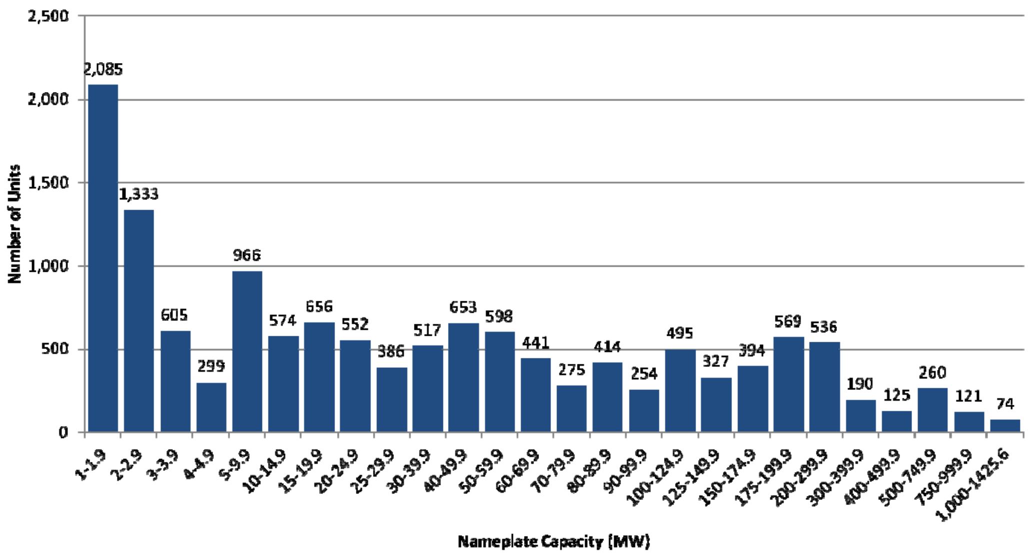
The net capacity (for both summer and winter seasons) is the maximum output (MW) a generator can supply to system load at the time of summer or winter peak demand. The net capacity includes resource uprates (upgrades) and/or derates and capacity reductions for station/auxiliary services. However, net capacity values can be impacted by market conditions, environmental regulations, and other factors.

Based on data from the 2010 Long-Term Reliability Assessment, there are approximately 13,699 generating resources in the United States that can be broken down into different classes based on the capacity (MW) of the resource.

- Less than 10 MW: 5,288 resources (39%)
- Between 10 MW and 99.9 MW: 5,320 resources (39%)
- Between 100 MW and 499.9 MW: 2,636 resources (19%)
- Greater than 500 MW: 455 resources (3%)

Figure 2 shows an aggregation of nameplate capacity of generating resources (MW) by the number of units.

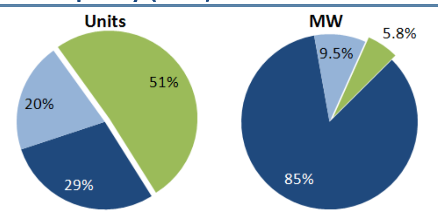
Figure 2: Number of Generating Units by Nameplate Capacity (MW)[12]



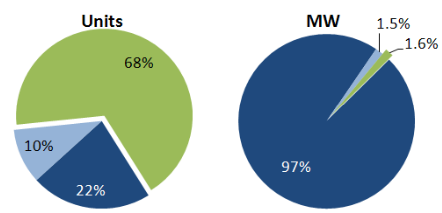
Further analysis was developed to identify the amount capacity and number of units currently in the BES (in the U.S. only) based on the EIA-860 form. In addition to the current threshold level, a two other thresholds were developed as a reference to understand what the associated impacts would. These included setting a threshold for plants and units that were above 20 MW and another for 75 MW. The analysis is included below:

Figure 3a: Number of Generating Units by Nameplate Capacity (MW)[13]

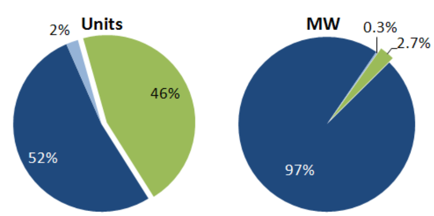
	Category	BES	Color	Units	MW
75/75 Units	Units ≥ 75	BES UNITS		3,942	945,330.1
	Units < 75 that are part of Plants ≥ 75	BES PLANTS		2,767	105,470.8
	Units < 75 that are part of Plants < 75	NOT BES		6,984	65,289.1
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**51.0%**	**5.8%**



	Category	BES	Color	Units	MW
20/20 Units	Units ≥ 20	BES UNITS		7,170	1,082,161.0
	Units <20 that are part of Plants ≥ 20	BES PLANTS		4,472	16,350.7
	Units < 20 that are part of Plants < 20	NOT BES		2,051	17,578.3
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**15.0%**	**1.6%**



	Category	BES	Color	Units	MW
75/20 Units	Units ≥ 20	BES UNITS		7,170	1,082,161.0
	Units < 20 that are part of Plants ≥ 75	BES PLANTS		302	3,252.9
	Units < 20 that are part of Plants < 75	NOT BES		6,221	30,676.1
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**45.4%**	**2.7%**



[12] Data source is 2010 Long-Term Reliability Assessment
[13] Data source is 2010 Long-Term Reliability Assessment

The analysis shown in Figure 2a used the following assumptions:

- EIA-860 Data (2011 Existing Unit Level Information)
  - Covers the 48 U.S. States
  - Nameplate Rating
  - Excludes Inoperable Units (i.e., mothballed)
  - Excludes units less than 1 MW (≈1,600 MW, 2,800 Units)
  - Excludes units “not connected to the transmission grid” (≈5,000 MW)

3.2 Alternatives to the 20/75 MVA Threshold

The PC explored multiple alternatives regarding the generator thresholds contained in the proposed Bulk Electric System definition and selected the following five alternatives for further analysis and consideration:

3.2.1 Technical Alternative A

Description: All generation resources directly connected to the bulk power transmission system, regardless of capacity value (MW), generator size (MVA), or voltage at the point of interconnection, to be considered part of the BES. This alternative would not include photovoltaic resources or wind turbines connected directly to distribution systems.

Technical Discussion: Setting a small capacity value of generator resources for modeling with well-defined points of interconnection at BES voltage levels would not require significant changes in the way generation is recognized in simulation models. The difficulties associated with representing small generation resources at defined points of interconnection are those of developing and maintaining reliable datasets of resource performance in an operational environment.

Future system studies will most likely be concerned about the cumulative behavior of new “classes” of generation, where a class is made up of a large number of very small generating resources (which could include different types of resources from rooftop solar systems). These generating resources will most likely have the following characteristics:

- no readily identifiable point of interconnection with the BES;
- capacity that will be combined with demand from nearby loads; and
- generating resources making up the class will be so small, their locations and ownership so diverse, and their technical details so varied, that explicit representation within system models in the traditional equipment-based sense will be impossible.

There may be areas where the aggregate output and the operating performance of small generating resources are essential to maintaining BES reliability.

In 1997, WECC began recognizing motor behavior as it found that a large amount of its load was electric motors. Recent technical reference paper on the FIDVR phenomenon[14] is developing modeling of new classes of load whose cumulative behavior is of great importance to the grid. The approach recognizes that it is necessary to represent the basic physical characteristics of device class but that it is impractical to get this representation by modeling individual facilities.

It would be a natural extension of composite load modeling to recognize that a class, or classes, of distributed small generating resources can have a cumulative impact on the reliability of the BES. The PC does not consider setting a small (e.g., 1 MW) generator threshold to be practical from engineering and administrative perspectives. Therefore, the PC does not recommend this alternative.

[14] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf

3.2.2 Technical Alternative B

Description: Technical Alternative B would require the development of either a uniform generator performance criterion or the development of a uniform method to assess a generator's potential impact on the reliability of the BES and determine whether a generator should be considered part of the BES or excluded from the BES.

Technical Discussion: The draft whitepaper "Generation Exclusion Below 75 MVA in BES Definition – Position Paper" developed by the BES Standard Drafting Team was considered in this assessment. Various case studies identified in the paper only considered steady-state conditions, in effect testing the deliverability of the resources dispatched in place of the generation being removed. It would be expected to find minimal issues using this method. And, if this method or a similar method is applied to select large generating resources, the results are expected to be similar.

Several experts in the field of dynamic simulation studies, including John Undrill, PhD,[15] were consulted on potential methods to determine a generation threshold based on a study of dynamic simulations. These methods would require the development of specific criteria based on engineering judgment that could vary between interconnections. Based on the confluence of feedback from technical experts, no clear technical rationale was identified to establish a minimum generator threshold criterion. Therefore, the PC does not recommend this alternative.

3.2.3 Technical Alternative C

Description: Technical Alternative C would change the proposed Inclusion I2 to include all generating resource(s) whose nameplate ratings are greater than 20 MVA. This would include generating resources where the generator terminals through the high-side of the step-up transformer(s) are connected at a voltage of 100 kV or above.

Technical Discussion: The PC considered enhancing Inclusion I2 of the proposed BES definition by eliminating the distinction between individual and aggregate generating facilities and selecting a single bright-line registration criterion, such as 20 MVA. This would modify the proposed Inclusion I2 as shown below and remove Inclusion I4:

> *"Inclusion I2 consisting of generating resources(s) with individual or aggregate nameplate rating greater than 20 MVA including the generator terminals connected through the high side of the step-up transformer(s) at a voltage of 100 kV or above."*

From a policy perspective, a single criterion of 20 MVA is greater than the data requirements currently imposed by the U.S. Energy Information Administration Form EIA-860,[16] which collects generator-level specific information about existing and planned generators at electric power plants with 1 MW or greater of combined nameplate capacity. In addition, a 20 MW generator threshold value is supported by FERC in Order 2006[17] and by NERC GADS.[18]

The PC has concluded that there is no technical rationale for having a generator threshold value for a single resource and a different threshold value for a group of resources at a plant or facility. The potential impact to the BES for the loss of a single generating resource or a plant or facility at the same generation level would be similar. Therefore, the same generation threshold should apply to a single generating resource as to a plant or facility. However, there is also no technical rationale that has been identified at this time in order to establish a single generator threshold value, whether that value represents a single unit or a total plant. Therefore, this alternative is not recommended.

3.2.4 Technical Alternative D

Description: Technical Alternative D would seek to define BES generation resources based on physical or contractual characteristics.

[15] John Undrill, PhD is an IEEE Fellow, a member of the National Academy of Engineering: http://www.nae.edu/42087.aspx and is a Research Professor at the Arizona State University School of Electrical, Computer, and Energy Engineering: http://engineering.asu.edu/ecee/eceeresearchfaculty

[16] Form EIA-860 detailed data request: http://www.eia.gov/electricity/data/eia860/index.html

[17] Standardization of Small Generator Interconnection Agreements and Procedures Docket No. RM 02-12-000 paragraph 75: http://www.ferc.gov/eventcalendar/files/20050512110357-order2006.pdf

[18] NERC GADS' minimum reporting threshold is greater than or equal to 20 MW starting in January of 2013.

Technical Discussion: The PC considered Technical Alternative D in an effort to define BES generation resources based on their physical or contractual characteristics. These characteristics include:

- Generation resource connection voltage to the BES;
- Capacity obligations of the generation resource;
- Nameplate capacity of the generation resource (using U.S. Energy Information Administration (EIA) reporting threshold of greater than 1 MW);
- The inertia constant of the generation resource; and
- Using Adequate Level of Reliability metrics to determine generation resource contributions to reliability.

The PC determined that establishing a generator threshold criterion based on characteristics that may change over time or characteristics that may be considered vague would not be practical and would lack technical merit. Therefore, the PC does not recommend this alternative.

3.3 Recommendation for Generator Thresholds

The PC recommends maintaining the currently proposed Inclusion I2 that consists of generating resources with gross individual nameplate rating greater than 20 MVA or gross plant or facility aggregate nameplate rating greater than 75 MVA, including the generator terminals through the high side of the step-up transformer(s) connected at a voltage of 100 kV or above.

The PC also recommends maintaining the currently proposed Inclusion I4, which identifies as part of the Bulk Electric System dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating), utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

The PC has not found a superior technical justification to support a different threshold.

In making these recommendations, the PC recognizes that the technical impact on reliability of a given amount of generation at a single point in the bulk power system is the same whether the generation comes from a single unit or is the combined output of a total plant. The PC also realizes that it would be impossible to determine a single megawatt threshold that would apply universally. For example, based on the functions a generator provides, reactive capability and voltage stability support, and on the characteristics of other generation located within the same region, a 20 MW unit in Florida may not be necessary for the reliability of the bulk electric system, whereas a 20 MW unit in Quebec may. Therefore, the PC recommends that in addition to maintaining the current 20/75 MVA thresholds, the results of applying this portion of the BES definition should be closely monitored to evaluate the number of inclusions and exclusions, as well as technical exception requests, and use the results of this evaluation to consider future adjustments to these thresholds.

The PC supports having different MW thresholds for the size of single units and for the combined output of plants. Further, given the unit sizes and numbers of units shown in Figure 2a above, the PC believes that the 20 MVA threshold for single units is still appropriate, as it encompasses over 97 percent of the capacity in the U.S. Based on EIA-860 data (2011 existing unit level information for the U.S.), the current 20/75 MVA thresholds will initially exclude approximately 31,000 MW of capacity from the bright-line definition, which represents 2.7 percent of the total capacity. Raising the unit threshold to 75 MVA would exclude an additional 35,000 MW of capacity, bringing the total capacity excluded from the bright-line definition to 65,000 MW, which represents 5.8 percent of the total capacity in the U.S. Similar results can be assumed if Canadian resources are included in the analysis.

Generators in the 20 to 75 MVA range significantly contribute to the voltage and reactive support of the system; this is also true for sub-20 MVA units. The PC also recognizes that there may be situations in which representing units and plants below the 20/75 MVA thresholds in modeling studies is critical to the accuracy of those studies. Many such units are small combustion turbines or low-head hydro units. The small hydro units tend to be older, 0.85 power factor machines, giving them strong reactive support capabilities. Excluding such units from powerflow and dynamics studies can result in changing flow patterns, potential overloads, and understating transfer capabilities. For instance, the many small hydro units in Maine contribute significant voltage support and stability contributions in the calculations of transfer capability from New Brunswick into New England; removing them from the calculations reduces that transfer capability.

Finally, it would be impossible to determine a single MVA threshold that would apply universally under all conditions and in all situations. The threshold above which generators are necessary for reliable operation of the interconnected system would vary for different reliability concerns; e.g., voltage regulation versus rotor angle stability versus frequency response. In addition, for any given reliability concern, the threshold would vary depending on the characteristics of the system to which the generators are connected.

Therefore, the PC recommends that in maintaining the current 20/75 MVA thresholds, if owners of units above 20 MVA believe that they do not have a material impact on the reliability of the bulk power system, the NERC Rules of Procedure provide a mechanism to request an exception. The results of applying this portion of the BES definition should be closely monitored to evaluate the number of inclusions and exclusions, as well as technical exception requests, that occur and use the results of this evaluation to consider future adjustments to these thresholds.

4. Technical Justification for Reactive Device Threshold

4.1 Background

Inclusion I5 specifically includes reactive devices in the definition of Bulk Electric System, Phase 1 as follows:

> **I5** – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

Inclusion I5 does not possess a threshold in terms of reactive resource sizing. As a result, all reactive resources connected at 100 kV or higher are automatically included in the BES definition regardless of their nameplate rating if they are not excluded in E4. This results in devices such as STATCOMs, SVCs, and reactive devices connected to the tertiary windings of BES transformers being included.

Neither the core definition nor Inclusion I5 provides a threshold for reactive device exemption; however, Exclusion E4 provides an exemption for reactive devices installed specifically for customer reactive support.

> **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use.

The System Analysis and Modeling Subcommittee (SAMS) was tasked with determining an appropriate reactive threshold for excluding some reactive devices from the BES.

Consideration of reactive support and its control are fundamental to the operation of the BES; however, many reactive resources are located on sub-100 kV systems (e.g., the low side of power transformers in subtransmission or distribution substations), where they can more effectively supply the reactive demands of the load, and where they are often less expensive to install and maintain. Reactive resources compensate for the reactive demands of loads by correcting their power factor. Load power factor correction offsets or eliminates the reactive demand of these loads on the BES so that the BES is only required to provide real power to the load. While sub-100 kV reactive resources may not necessarily be integral to BES operation, they still decrease reactive demands on the BES, which benefits the reliability of the BES by reducing losses, supporting voltage, and freeing up capacity on the transmission system.

Furthermore, some reactive resources are connected at varying voltage levels (including sub-100 kV). Their primary function is to provide reactive support and voltage control. These reactive resources have a direct impact on the reliable operation of the BES, and it is important to consider them as integral components of the BES.

4.2 Alternatives to the Zero-Mvar Threshold under Consideration

The PC explored multiple alternatives regarding the reactive device thresholds contained in the proposed Bulk Electric System definition and selected two alternatives for further analysis and consideration.

4.2.1 Technical Alternative A

Description: This alternative would provide a threshold for excluding reactive devices sized below a value based on the generator inclusion threshold (Inclusion I1). Since generators below 20/75 MVA are excluded, a similar or related threshold could be to exclude reactive devices with Mvar capabilities equal to those of a 20 MVA generator.

Technical Discussion: The PC considered a threshold for reactive resources for exemption from the BES based on the typical reactive output of a 20 MVA machine (i.e., using generator bright-line criteria in Phase 1 of BES project).

Currently, 20 and 75 MVA thresholds exist for the inclusion of generation resources depending upon individual unit or aggregate plant nameplate capacities, respectively. A similar approach could be taken for reactive resources; by examining the reactive capability of a 20 MVA generator, say 0.8 per unit nameplate at maximum capacity, a value of 12 Mvar could be selected. Alternatively, if the range of typical reactive output is considered, say at 0.85 power factor, a value of 10.5 Mvar could be selected.

However, without a clear technical justification for the generator threshold, and considering potential inconsistencies between the two thresholds given that generators and reactive devices have different primary objectives, extending the generator threshold to reactive resources does not have a sound technical basis. Reactive resources are not installed for the same reason that generation is installed (i.e., providing real power to support loads), and they are typically only installed as required for voltage support of reliable power system operation. Therefore, the PC does not recommend this alternative.

4.2.2 Technical Alternative B

Description: This alternative examines the deployed reactive resources as modeled in interconnection power flow modeling cases to determine whether there is a bright line to be drawn between load-compensating resources and BES-supporting resources.

Technical Discussion: In examining transmission system power flow models, reactive devices installed with the sole intent of supporting local load power factor are typically netted into the load as non-BES Elements. Other devices are modeled explicitly so that the effect of their statuses can be taken into account when performing system studies. By reviewing the system modeling cases and evaluating the size of devices present in the model, a lower limit might be determined for the reactive devices that directly support reliable BES operation.

When corresponding with generator thresholds, simply selecting a class of reactive devices based on their distribution throughout the transmission system does not provide a sound technical justification for the selection of a threshold. However, the Eastern Interconnection Reliability Assessment Group modeling case demonstrated that if a reactive threshold of 10.5 Mvar were selected (corresponding to the previously mentioned generator threshold of 20 MVA at 0.85 power factor) roughly 5% of the reactive devices less than 10.5 Mvar would be directly connected at 100 kV and above (exclusive of generators). This 5% represents a small but significant number of reactive devices—significant because they provide critical voltage support to the reliability of the bulk power system.

It is difficult to discern whether a small reactive device is required for reliability or for other purposes. Therefore, applying the BES exception process to exclude a subset of this relatively small class of Elements on a case-by-case basis is preferable to providing a blanket exclusion for all reactive devices of this class. Further, it is consistent with a bright-line approach.

Also, the interconnection modeling cases may not show the detail of all reactive resources on the transmission system. This is attributed to equivalencing and reactive supply/load netting within the model. As a result, the cases may be unreliable sources of data for obtaining the actual number and sizes of reactive devices physically installed on the interconnected transmission system. It can be argued that even load-netted reactive devices could have a significant impact on BES reliability if placed in or out of service inappropriately.

Therefore, the PC does not recommend this alternative.

4.3 Conclusion and Recommendation

Reactive resources do not serve the same primary purpose as generating resources and are typically installed at BES voltages as needed to support reliable BES operation. Inclusion I5, in its current state, provides an inherent bright-line distinction between devices installed to support the BES and devices installed at lower voltages to supply the reactive component of the load (e.g., load power factor correction). Inclusion I5 includes any reactive resource directly connected at 100 kV or above, regardless of its design, configuration of its connecting facility, or planned operation.

The PC agrees that devices included by Inclusion I5 are installed to support the BES and therefore should be included. A threshold of zero Mvar for exemption is recommended since reactive devices of all sizes can be installed for the purpose of meeting the NERC TPL standards, and a zero-Mvar threshold ensures that all reactive resources connected at BES voltages (including those located in radial systems and local networks) are included.

Reactive resources connected at 100 kV or higher can be excluded on a case-by-case basis through the BES exception process in the Rules of Procedure. This is consistent with other components of the bright-line BES definition (e.g., generation and blackstart units) in that the potential exists for standalone BES Elements. Furthermore, Exclusion E4 provides for exemption of end-use customer-owned devices, which should capture most—if not all—of the reactive resources installed at BES voltages for the purposes of power-factor correction (i.e., not explicitly installed to support reliable BES operation).

Proposing a non-zero Mvar threshold for exemption or including reactive resources below 100 kV would add unnecessary complexity to the current bright-line inclusion. The current wording of Inclusion I5, taken in tandem with Exclusion E4, provides clear guidance on what is considered integral to BES reliability.

Therefore, the PC recommends maintaining the current threshold stated in Inclusion I5.

5. Technical Justification for Power Flow Out of Local Networks

5.1 Background

Exclusion E3 provides an exemption for “local networks” in the definition of Bulk Electric System, Phase 1 as follows:

> **E3** – Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
>
> - Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
> - Power flows only into the LN, and the LN does not transfer energy originating outside the LN for delivery through the LN; and
> - Not part of a flowgate or transfer path: The LN does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Québec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL).

The intent of defining an LN is to provide an exemption for components of transmission systems that were installed to improve the level of service to retail customer Load. An LN’s design and operation is intended to be such that, at the points of connection to the BES, the LN’s effect on the BES is similar to that of a radial system (i.e., as in Exclusion E1), particularly with regard to the fact that in aggregate, real power flow always flows from the BES into the LN. Any re-distribution of parallel flows into the LN from the BES will be negligible compared to the load being served by the LN. Furthermore, since the primary purpose of an LN is to improve the level of service to retail customer Load, and not to support the reliable operation of the interconnected BES, the separation of an LN from the BES shall not diminish the reliability of the BES.

In other words, an LN can effectively be treated in the same way as a radial system but with multiple feeds that enhance local reliability or meet customer requirements, and as such, the characteristics of an LN should match those of a radial system as closely as possible.

The wording of Exclusion E3 raises two issues related to the phrase “power only flows into the LN”:

1) The wording “power only flows into the LN” can be strictly interpreted as meaning that *no* power will flow out of *any* connection point of the LN, at *any* time. While power may not flow out of an LN during normal conditions (e.g., LNs are not permitted to wheel power), the potential exists for parallel flows following a contingency event (i.e., single, double, etc.).
2) The following questions also arise: Should there be a distinction between real and reactive power flow? Does the limitation that “power only flows into the LN” also imply that reactive power is absorbed by the LN at all points of interconnection and at all times?

With regard to these issues, the PC was tasked with providing a threshold for permissible flow out of an LN, along with appropriate time duration for outward flows and the associated system conditions. Specifically, the problem statement is:

> “It is anticipated that the technical justification will consist of interconnection-wide studies that target the surrounding BES Elements at the connection points of the subject LN. The studies would utilize the criteria currently established within the definitions of Adequate Level of Reliability[19] and Adverse Reliability Impact[20] to determine the appropriate

[19] From the NERC Glossary of Terms, *Adverse Reliability Impact*: “The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.”

values for the thresholds associated with the potential power flow out of the LN. The final analysis should indicate the amount of acceptable parallel flow through an LN where a loss of the LN or portions of the LN would not result in a reduction of the reliability of the surrounding interconnected Transmission network."

In addition to the issues described above pertaining to the allowable flow through an LN, the PC concluded that the BES definition would greatly benefit from a bright-line distinction for the maximum allowable size (i.e., a maximum MW load limit) of an LN, and in such a way that a system cannot be subdivided into multiple adjoining LNs. In other words, the definition should not allow multiple LNs to be directly tied to one another, nor should it allow for LNs to be embedded or nested within one another. If large amounts of load are not properly taken into account across an interconnection due to exclusion as LNs, then significant impacts to BES reliability—such as frequency stability issues and system operating limit violations—could result due to separation of an LN from the BES.

Prior to the adoption of the Phase 1 BES definition, there were significant regional differences in both the definition of BES and its application that permitted exclusions for portions of a load-serving transmission network. The Phase 1 definition's Exclusion E3 for LNs is intended to standardize this exclusion for systems that are often referred to as "load pockets" along with the Transmission Elements that connect them (assuming that the Transmission Elements are all operated at voltages of at least 100 kV but less than 300 kV, and assuming the underlying generation inclusions and exclusions are met). However, the interaction between an LN and the BES needs to be carefully considered. Providing exclusion for LNs regardless of size could lead to the exclusion of very large networks, which could affect BES reliability. The loss of large networks could have far-reaching, interconnection-wide system impacts.Selecting a bright line for load that can be served by an LN will limit the unintended consequences of such exclusions, and, if needed, the exception process in the Rules of Procedure provides a path for exemption of larger LNs.

5.2 Alternatives to the Zero Power Flow Limitation under Consideration

The PC explored multiple alternatives regarding power flow out of LNs contained in the proposed Bulk Electric System definition and selected three alternatives for further analysis and consideration.

5.2.1 Technical Alternative A

Description: This alternative would propose an acceptable amount of outward power flow for LNs that would be consistent with generation limits set forth elsewhere in the BES definition.

Technical Discussion: The PC considered generation limits set forth elsewhere in the BES Phase 1 definition to define an acceptable amount of outward power flow for LNs. For example, applying a limit on outward flow from an LN corresponding with the 75 MVA embedded generation maximum would provide consistency with the radial system Exclusion E1.

With radial systems, the outward flow of power will always occur at a single connection point on the BES. However, with an LN, outward flow of generation may occur at any terminal on the LN. Without knowing or considering the internal conditions within the LN, outward flows may lead to unpredictable impacts to the overlying BES. Furthermore, without a clear technical justification for the generator threshold, extending this threshold to LNs does not have a sound basis.

Therefore, the PC does not recommend this alternative.

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[20] Currently under development for inclusion in the Glossary of Terms, *Adequate Level of Reliability*: "The intent of the set of NERC Reliability Standards is to deliver an Adequate Level of Reliability defined by the following bulk power system characteristics:

- The system is controlled to stay within acceptable limits during normal conditions.
- The system performs acceptably after credible contingencies.
- The system limits the impact and scope of instability and cascading outages when they occur.
- The system's facilities are protected from unacceptable damage by operating them within facility ratings.
- The system's integrity can be restored promptly if it is lost.
- The system has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components."

5.2.2 Technical Alternative B

Description: This alternative considers the use of outage transfer distribution factors (OTDFs) to define a threshold for an acceptable amount of through-flow on LNs.

Technical Discussion: OTDFs represent the percentage of a power transfer that flows through the monitored facility for a particular transfer when the facility is switched out of service after a contingency. In relation to an LN, the monitored facilities would include the terminals of the LN, and the contingent facilities would include BES Elements in parallel with the local network. The Flowgate Methodology described in MOD-030-2 sets a 5% threshold for OTDF, in conjunction with other criteria for including a monitored facility as a flowgate. In a similar fashion, an OTDF of 5% or less could be selected as a reasonable threshold for defining the permissible flow through an LN upon the occurrence of a BES contingency, and subsequently for determining a reasonable amount of flow out of an LN.

While computation of OTDFs and related factors are commonplace calculations and well-understood, such factors do not necessarily form a bright line for exclusion from the BES; the permitted flow computed in the OTDF will depend on the contingent Element and will be heavily dependent upon system conditions. Appropriate system conditions and contingencies would need to be specified. This would complicate the definition and completion of supporting analysis and potentially lead to inconsistencies in the application of this approach.

Therefore, the PC does not recommend this alternative.

5.2.3 Technical Alternative C

Description: This alternative would use the existing definition, along with clarifications, to identify the circumstances under which power is expected only to flow into an LN.

Technical Discussion: This alternative relies on the existing Exclusion E3 and, while preserving the concept of an LN, proposes clarification without confusing the bright-line distinction between an LN and the BES. The recommended changes to Exclusion E3 item (b) are given below in bold:

- **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**

The PC considered specifying that both real and reactive power must flow into the LN. The "**real** power" clarification is recommended to align with the recommendation on Inclusion I5 for an appropriate reactive device threshold; if all reactive devices connected directly at 100 kV and above are included in the BES definition, then their impact to reliability will be accounted for independently of Exclusion E3. In this case, an LN may deliver some reactive power to the BES in the same way that, under some conditions, a load-serving distribution network delivers reactive power to the BES.

The PC recommends adding the words "**from every point of connection to the BES**" for clarity. If real power flows out of the network at any interconnection point under normal conditions or single-contingency conditions, then at least some portion of the LN is being used to transfer power to the overlying BES network. The portions of a proposed LN that allow parallel flow must be removed from the LN, and the remaining portions of the proposed LN should be further studied to ensure that they do not participate in such flows.

Limiting the study of a proposed LN "**for the system as planned**" (i.e., over the planning horizon) is recommended. This allows some flexibility for outward flow under abnormal or unplanned conditions.

The "**single contingency**" wording is also recommended for clarity. The intent would be to study single contingencies on the BES outside of the LN, as well as contingencies within the LN, and to monitor the LN for any outward flow under these conditions. The PC understands that the system is *planned* for multiple contingencies; however, the expectation of real-time performance for multiple contingencies under myriad unplanned system operating conditions is much more difficult to define. The study of multiple contingencies requires closer examination of credible contingencies. To avoid creating a very complex LN definition, the PC selected "single contingency," because existing NERC Reliability Standards call for the system to be *operated* to single-contingency conditions. Including a single-contingency requirement would imply that the definition of LN would hold under NERC-mandated operating conditions. The threshold is zero power out of the LN—what is being clarified are the conditions under which that threshold applies.

The single-contingency load flow test should not be burdensome to administer. First, contingency analysis is required to be performed annually as part of the TPL requirements. The purpose of basing the determination on the planning horizon is to preserve the bright line so that the facilities can be characterized as they are planned to be operated. Clarifying the definition in such a manner avoids the need to constantly reclassify Elements in response to the myriad of operating conditions that may occur on the system.

5.3 Conclusion and Recommendation

The PC recommends using Technical Alternative C, which proposes changes that clarify the existing Exclusion E3. The recommended changes to Exclusion E3 item (b) are given below in bold:

> **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**

The PC further suggests that a size limit be established in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section, as well as in Appendix 3.

5.4 Further Considerations for Limits on the Size of Local Networks

In determining the connected MVA bright-line value for the size of LNs, NERC Reliability Standard EOP-004[21] Disturbance Reporting could be used as a starting value for inclusion or exclusion. Attachment 1 of EOP-004 indicates the magnitude of firm demand loss during disturbances that are of concern and require reporting to NERC. Attachment 1's relevant text is as follows:

> Equipment failures/system operational actions that result in the loss of firm system demands for more than 15 minutes, as described below:
>
> - Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
> - All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

A review of interconnection facilities serving approximately 300 MW of load determined that the system consisted of 800–900 MVA of interconnection capability to maintain the reliability of the interconnected system. This capability over the load value is usually installed for N-1 planning criteria, and support of this assumption is justified in a review of average circuit loadings on the system.

As an example, an entity with a peak load of approximately 4,500 MW calculated an average circuit loading on their system to be approximately 23.6%. Using this average circuit-loading approach determined that an additional 1,271 MVA of interconnecting MVA capacity would be required to serve 300 MW of load. Using 800 MVA for substations with interconnecting capability is a conservative estimate.

As another example, transmission lines with 400 MVA of transfer capability would calculate to the approximate values:

- 2,000 amps at 115 kV
- 1,674 amps at 138 kV

[21] NERC Reliability Standard EOP-004: http://www.nerc.com/files/EOP-004-1.pdf

- 1,434 amps at 161 kV
- 1,004 amps at 230 kV
- 670 amps at 345 kV

The selection of 400 MVA for a single-circuit bright-line test is that most system configurations do not rely on a single circuit to serve 300 MW of load, but rather use multiple, lower rated facilities. Therefore, a rating above 300 MVA would be appropriate for a single transmission line.

The PC suggests the addition of a gross load limit in the form of another qualifier under Exclusion E3:

- The gross load served by the LN is less than 300 MW.

The addition of this limit on local networks will ensure that the systems that support metropolitan areas will not be excluded by default. As with other bright lines established in the BES definition (e.g., 100 kV core definition and 20/75 MVA generator thresholds), this specific number was selected to clearly categorize networks and Elements to prevent significant adverse impacts to the BES in a way that can be applied consistently across power systems, Regions, and interconnections. The PC identified the 300 MW limit based on a preponderance of evidence presented by a cross section of regional representation that is supported by the following data points:

- U.S. Department of Energy Electric Disturbance Events form OE-417[22] and NERC Standard EOP-004 provide a bright-line criteria of 300 MW for reporting load loss.
- The typical upper limit of a radial system reported by SAMS members was approximately 100 MW. The upper limit on the maximum consequential load loss reported by SAMS members was less than 300 MW.
- Examination of 100–300 kV line ratings across the interconnections shows that the majority are rated less than 300 MW (see Table 2 and Appendix 3). Flows on transmission lines are typically a fraction of the line rating (i.e., this is an upper bound), and the system is required to tolerate the flow shifts created by a single contingency (i.e., a line outage); therefore, an LN should not have the potential to induce a greater shift in flow.

Table 2: Summary Statistics for Branches in 2010 Power Flow Models

	Mean (MW)	Median (MW)	Standard Deviation. (MW)	Maximum (MW)	Minimum(MW)	Percent of lines rated < 300 MW (%)
ERAG	266.6	216.0	181.6	1800.0	7.0	73.9
WECC	233.9	159.0	202.5	3031.1	12.0	76.1
ERCOT	289.1	228.0	144.6	1220.0	12.0	62.4

Even for zero outward power flow as allowed in the LN definition, this 300 MW load limit could entail a change in flow of up to 300 MW on the terminals of the overlying BES (i.e., a 300 MW swing between two terminals of the LN). A very simple illustration based on an actual network is provided in Appendix 3. The BES and higher voltage networks and are depicted in red, and a lower voltage network to be considered as an LN is depicted in blue.

[22] The Electric Emergency Incident and Disturbance Report (Form OE-417) collects information on electric incidents and emergencies. The Department of Energy uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes. http://www.oe.netl.doe.gov/oe417.aspx

6. Recommendations

After analysis and review, the PC offers the following recommendations to the DBES SDT:

- Maintain the 100 kV bright line (core definition).
- Maintain Inclusions I2 and I4 as currently defined.
- Maintain Inclusion I5 as currently defined.
- Use Technical Alternative C, which proposes clarifying changes to the existing Exclusion E3 item (b) as given below in bold:
  - **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**
- Establish a size limit in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section, as well as in Appendix 3.

Appendix 1A: Request from the BES SDT to the PC

From: Heidrich, Peter
To: "Mark Lauby"; Jeff Mitchell; "jcastle@nyiso.com"; Crisp, Ben; "bowet@pjm.com"
Cc: "Ed Dobrowolski"; "Lawson, Barry R."
Subject: FW: Project 2010-17 DBES Phase 2 Problem Statements - Revised
Date: Monday, February 27, 2012 1:13:43 PM
Attachments: bes_phase2_problem_statement_20120223_r1_clean.pdf

Dear Sir:

Additionally, the DBES SDT would like an opportunity to review the 'technical assistance project outline' for accuracy and completeness prior to presentation at the Joint OC/PC/CIPS Meeting.

Therefore, when you complete your review of the 'problem statements' and draft the outline document, please forward a draft copy of the outline to me. The SDT is prepared to conduct a timely review of the outline as not to interfere with the scheduling of the presentation to the Joint OC/PC/CIPC.

Thank you,

Peter A. Heidrich
Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7994 - office
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813-289-5646 - fax

From: Heidrich, Peter
Sent: Monday, February 27, 2012 12:04 PM
To: 'Mark Lauby'; 'jeff.mitchell@rfirst.org'; 'jcastle@nyiso.com'; Crisp, Ben; 'bowet@pjm.com'
Cc: 'Ed Dobrowolski'; Lawson, Barry R.
Subject: Project 2010-17 DBES Phase 2 Problem Statements - Revised

Dear Sir:

The Project 2010-17 DBES SDT meet the week of February 20th and discussed the initial 'problem statements' provided for consideration by the leadership of the Technical Committees. Following discussion and review of the comments submitted during the initial posting of the phase 2 SAR, revisions were made to the 'problem statements'. Attached you will find the revised the 'problem statements' which include additional language speaking to potential sources of technical information (provided by industry) that the Technical Committees may consider for possible analysis.

The SDT is in no way promoting a particular type of analysis or study to be conducted. The potential sources of technical information are being forwarded to the Technical Committees to support the characteristics of 'openness' and 'transparency' advocated through the Standard Development Process.

If you are in need of any additional information or clarification surrounding the issues identified in the attached document, please do not hesitate to ask.

Thank you,

Peter A. Heidrich
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FRCC
Florida Reliability Coordinating Council, Inc.

Appendix 1B: Authorization and Problem Statement from the BES Definition SDT (NERC Standards Project 2010-17, Phase II)

A1.1 Background:

The ERO has the obligation to identify the Elements necessary for the reliable operation of the interconnected Transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards. The NERC Board of Trustees-approved definition of the Bulk Electric System (BES) establishes detailed criteria that allows for the identification of BES Elements in a consistent manner on a continent-wide basis.

During the initial revision of the definition of the BES in Phase I of Project 2010-17, industry stakeholders expressed concerns related to the lack of technical justification associated with the existing parameters in the definition.

A1.2 Problem Statement: Transmission Facilities and Real and Reactive Resources:

The reliability of the interconnected transmission network is impacted by properly identified BES Elements. The ability to properly identify BES Elements is dependent on a BES definition that is based on factors directly associated with reliability. The NERC Board of Trustees-approved definition of the BES utilizes historical parameters from the current NERC Glossary of Terms definition of BES and the NERC Statement of Compliance Registry Criteria, neither of which is supported by technical justification.

The DBES SDT is seeking support from the NERC Technical Committees (Operating and Planning) for the development of technical justification to assist the SDT in developing potential revisions to the following parameters currently embedded in the NERC Board of Trustee approved definition of the BES:

- 100 kV bright line (core definition)
- Generation thresholds (Inclusions I2 and I4)
- MVA values associated with single-unit and multiple-unit facilities
- Reactive power sizing (MVA level) parameters (Inclusion I5)

It is anticipated that the technical justification will consider the criteria currently established within the definitions of Adequate Level of Reliability and Adverse Reliability Impact, to determine the appropriate values for the thresholds associated with the identification of Transmission Facilities and Real and Reactive Resources as BES Elements.
The SDT received the following suggestions of studies that could be utilized for these issues:

<u>100 kV Bright Line</u>

- Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion to determine 100 kV or 200 kV threshold, at pp. 11-18 (May 15, 2009)[23]
- Concept of considering Surge Impedance Loading (SIL) alongside the corresponding normal thermal ratings, whichever is less, for typical compensated/uncompensated and overhead/underground transmission lines at various kV levels. A single MVA bright line could then act to screen which subsystem Elements fall in or out of the BES definition.[24,25]

[23] http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspxID=21&Source=/Standards/Development
[24] IEEE Transactions on Power Apparatus and Systems, Vol.PAS-98, No.2 March/April 1979 pp 606-617, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," as well as its referenced articles.
[25] AECI related white paper prepared for the BES Definition SDT, as well as AECI's referenced Eastern Interconnection PSEE 2011 Winter Peak Branch-data, with per-unit SIL calculations, for further analysis, available from AECI upon request.

- NPCC study presented in the NPCC/NERC 9/21/09 filing in FERC Docket No. RC09-3-000

Generation Thresholds and Reactive Power sizing

- ISO-NE and NYISO planning and operating study process to demonstrate loss of largest source without Adverse Reliability Impact to the Bulk Electric System.
- Snohomish County PUD White Paper entitled "A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System" (April 2011) discusses a methodology for distinguishing BES from non-BES Elements based on their performance in the electric system.
- Project 2007-09 for proposed standard MOD-026 developed generation modeling thresholds.[26]
- Draft white paper for possible exclusion of generators from BES as submitted to the DBESSDT.

A1.3 Local Networks:

Local networks (LN) (Exclusion E3) provide local electrical distribution service and are not planned, designed, or operated to benefit or support the balance of the interconnected transmission network. Their purpose is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network. Their design and operation is such that at the point of connection with the interconnected transmission network, their effect on that network is similar to that of a radial facility, particularly in that flow always moves from the BES into the LN. As governed by the fundamentals of parallel electric circuits, any distribution of parallel flows into the LN from the BES is negligible, and, more importantly, is overcome by the Load served by the LN, thereby ensuring that the net actual power flow direction will always be into the LN at all interface points. An LN is not intended to enhance the operability of the interconnected transmission network; therefore, its separation from the BES will not diminish the reliability of the interconnected transmission network.

The NERC Board of Trustees-approved definition of the BES identifies the characteristics, based on the bright-line concept, which establishes specific criteria that must be met to allow an LN to be excluded from the BES. One such characteristic identifies the threshold associated with power flows and states:

> *Power flows only into the LN, and the LN does not transfer energy originating outside the LN for delivery through the LN.*

This requirement assumes that the condition (power flows only into the LN) will have to be met at each connection point of the LN. The SDT is seeking support from the NERC Technical Committees (Operating and Planning) for the development of technical justification to potentially revise the power flow provision (including duration and system conditions) identified in Exclusion E3 of the NERC Board of Trustees-approved definition of the BES.

It is anticipated that the technical justification will consist of interconnection-wide studies that target the surrounding BES Elements at the connection points of the subject LN. The studies would utilize the criteria currently established within the definitions of Adequate Level of Reliability and Adverse Reliability Impact to determine the appropriate values for the thresholds associated with the potential power flow out of the LN. The final analysis should indicate the amount of acceptable parallel flow through an LN where a loss of the LN or portions of the LN would not result in a reduction of the reliability of the surrounding interconnected transmission network.

[26] http://www.nerc.com/files/Project_2007-09_Generator_Verfication_PRC-024_and%20MOD-026.pdf

Appendix 1C: BES SDT Response to PC Report (Draft 2012 BES definition report)

From: Heidrich, Peter [mailto:pheidrich@frcc.com]
Sent: Friday, January 25, 2013 4:48 PM
To: Dave Nevius; jeff.mitchell@rfirst.org; Crisp, Ben; John Moura
Cc: Ordax, Vince; dbessdt@nerc.com
Subject: BES SDT Response to PC Report (2012 BES Definition Report)

Gentlemen,

Following the receipt of the preliminary report titled *2012 BES Definition Report* drafted by the NERC Planning Committee (PC) in response to the Project 2010-17 Definition of Bulk Electric System Standard Drafting Team's (BES SDT) request for a technical evaluation of the thresholds contained in the Phase 1 BES definition, a sub-team was established under the BES SDT to investigate potential alternative conclusions, based on the draft PC report and recommendations in regards to the generator thresholds (20 & 75 MVA) currently embedded in the BES definition.

The conclusions of the sub-team are documented in the attached report titled: *Generation Threshold Sub-Team Report, January 2013.* Prior to the final approval of the PC report, the BES SDT is requesting that the PC, and specifically the Reliability Assessment Subcommittee (RAS), evaluate the conclusions drawn by the sub-team for potential reconsideration of the recommendations associated with this issue. To facilitate an open and transparent discussion, the BES SDT is extending an invitation to the RAS to participate on a conference call to discuss these issues during their February meeting.

Pending a resolution, the BES SDT requests deferring the PC approval of the *2012 BES Definition Report* until the regularly scheduled March meeting of the full committee. This will allow any potential revisions drafted by the RAS to be incorporated into the final report and then fully vetted by the entire PC for delivery to the BES SDT in mid-March. The BES SDT acknowledges that this will result in a delay of delivery of the final report and the BES SDT accepts that delay.

Thank you,

Peter A. Heidrich
Chair, Bulk Electric System Definition SDT

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Note: The report, *Generation Threshold Sub-Team Report, January 2013*, is not publically posted at this time.

Appendix 2: Interconnection Study Guidelines

A2.1 Eastern Interconnection Study

In the Eastern Interconnection (EI), ERAG annually develops power flow models of the bulk transmission system and performs inter-regional transmission assessment studies on some of those models. The power flow models incorporate varying specificity in the different transmission voltage levels, but most (if not all) of the facilities at 100 kV and above are included.

Since its inception, ERAG has traditionally studied the transmission systems in MRO, RFC, SERC, and SPP at 100 kV and above, because those facilities are inherently necessary to operate the Bulk Electric System. The 100–200 kV facilities are necessary to the operation of the Bulk Electric System, because they are the substantial underlying portions (i.e., voltages under 230, 345, 500, and 765 kV) of the rest of the BES, they carry significant portions of bulk power transfers, and they provide a backup transfer path when higher voltage facilities (i.e., 230, 345, 500, and 765 kV) are out of service.

Without including the 100–200 kV facilities in the BES, the higher voltage (i.e. 230, 345, 500, and 765 kV) facilities would not be able to solely, reliably carry the needed power to load without experiencing overloads, low voltages, SOLs, and possibly IROLs, as seen in previous ERAG studies and reports.

A2.1.1 Generation

The 100–200 kV level of transmission facilities is important for the interconnection of generation. Nearly a third of the total generation in the Eastern Interconnection is connected to the 100–200 kV level.

Table A2-1: Total Generation in Eastern Interconnection[27]

Total Generation in EI	884,519 MW	% of Total
Above 200 kV	565,929	64.0%
100–200 kV	249,833	28.2%
69 kV	25,472	2.9%
Below 69 kV	43,285	4.9%

A2.1.2 Load

The 100–200 kV level of transmission facilities is critical for generation to be delivered to load. Nearly a quarter of the load in the Eastern Interconnection is connected to the 100–200 kV level.

Table A2-2: Total Load in Eastern Interconnection[28]

Total Load in EI	645,556 MW	% of Total
Above 200 kV	53,302	32.8%
100–200 kV	147,076	22.8%
69 kV	111,909	17.3%
Below 69 kV	174,855	27.1%

[27] Data is from the ERAG 2012 Summer Peak case within the MMWG 2011 Series of power flow models.

[28] Data is from the 2012 Summer Peak case within the MMWG 2011 Series of power flow models. Generating plant auxiliary loads are included, if modeled.

A2.1.3 Transmission Line Mileage

The BES definition should include most of the transmission that is important to deliver generation to load. A majority of the total BES transmission line mileage is made up of 100–200 kV facilities. The total transmission miles that falls in the 100–200 kV range is 67% of the total miles. Mileage data for the tables below was taken from the 2011 NERC Long-Term Reliability Assessment data submittals.

Table A2-3: Transmission Circuit Line Mileage in Eastern Interconnection						
Area	**100-120 kV**	**121-150 kV**	**151-199 kV**	**Total**	**Area**	**100-199 kV %**
FRCC	2,251	2,277	0	4,528	FRCC	38%
MISO	7,606	19,071	5,778	32,456	MISO	66%
MRO	5,428	3,670	264	9,362	MRO	44%
NPCC[29]	19,439	3,527	138	23,104	NPCC	52%
PJM	4,911	23,120	395	28,426	PJM	54%
SERC	35,427	4,095	17,263	56,785	SERC	67%
SPP	9,082	8,729	4,801	22,612	SPP	69%

Table A2-4: Transmission Circuit Line Mileage in Eastern Interconnection					
Area	**200-299 kV**	**300-399 kV**	**400-599 kV**	**600 kV+**	**Total**
FRCC	6,095	0	1,350	0	7,445
MISO	3,022	13,117	340	0	16,479
MRO	9,801	2,041	257	0	12,099
NPCC[30]	11,759	8,145	1,600	160	21,664
PJM	9,148	9,417	3,816	2,206	24,587
SERC	18,383	1,577	7,473	0	27,433
SPP	3,572	6,559	114	0	10,245

A2.1.4 Transmission Assessment Study Results

Data for the tables below was taken from the ERAG summer seasonal studies listed in Tables A2-5 and A2-6. Many of the limited facilities for the studied transfers are on the 100–200 kV level, which indicates that the 100–200 kV facilities are inherent to the reliable operation of the BES.

Table A2-5: Limiting Elements in 2007 Study							
	Limiting Element					**Contingency**	
2007 Study	Total	100-199 kV	Percentage	200+ kV	Percentage	100-199 kV	200+ kV
MRSwS	18	17	94.4	1	5.6	4	13
SeR	8	4	50.0	4	50.0	4	6
RN	7	2	28.6	5	71.4	0	0
RFC	76	44	57.9	32	42.1	28	47

[29] Quebec Interconnection (QI) is excluded. The total of NPCC when adding QI is the following: 100–120 kV: 23,731; 121–150 kV: 3,527; 151–199 kV: 1,460; Total: 28,718; 100–199 kV %: 45%

[30] Quebec Interconnection (QI) is excluded. The total of NPCC when adding QI is the following: 200–299 kV: 13,733; 300–399 kV: 11,494; 400–599 kV: 2,357; 600 kV+: 7,257; Total: 34,842

Table A2-6: Limiting Elements in 2011 Study							
	Limiting Element					Contingency	
2011 Study	Total	100–199 kV	Percentage	200+ kV	Percentage	100–199 kV	200+ kV
MRSwS	19	14	73.7	5	26.3	9	13
SeR	6	3	50.0	5	50.0	4	3
RN	2	1	50.0	1	50.0	0	2
RFC	16	6	37.5	10	62.5	6	8

A2.2 Québec Interconnection

The Bulk Power System (BPS) in the Quebec Interconnection includes substations that have a 735 kV voltage level with their connected lines and transformers. These facilities do not directly serve end-use customers. They constitute the transmission system and provide interfaces for moving large amounts of power from remote northern generation to load centers in southern Québec (approximately 600 miles away). BPS assets have been identified through impact-based studies, using the NPCC A-10 methodology. The Régie de l'énergie of Québec provides the regulatory oversight within the Province of Québec, which includes the definition of the BPS and BES.

A2.3 Electric Reliability Council of Texas (ERCOT)

In ERCOT Interconnection, the Steady State Working Group (SSWG) annually develops power flow models of the transmission system, and ERCOT staff, various ERCOT work groups, and market participants perform transmission assessment studies on these models. The power flow models incorporate almost all utility transmission facilities operated at 60 kV and above.

ERCOT is the smallest of the three interconnections in the United States[31] and operates wholly within Texas. As the independent organization (IO) under the Public Utility Regulatory Act (PURA), ERCOT is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, network reliability, and ensuring the reliability and adequacy of the regional electric network in accordance with ERCOT and NERC reliability criteria. ERCOT's relatively small size and unique market structure allows it to model almost all utility transmission facilities operated at 60 kV and above.

A2.3.1 Generation

The 100–200 kV level of transmission facilities is important for ERCOT since 44% of all generation is connected at 138 kV. Almost 99% of all the generation in ERCOT is connected at voltages above 100 kV.

Table A2-7: Total Generation in ERCOT[32]		
Total Generation in ERCOT	74,948 MW	% of Total
345 kV	41,053 MW	54.8%
138 kV	33,042 MW	44.1%
69 kV	853 MW	1.1%

A2.2.2 Load

The 100–200 kV level of transmission facilities is critical for the deliverability of generation to load. The amount of load in ERCOT connected at 138kV is 86%.

Table A2-8: Total Load in ERCOT[33]		
Total Load in ERCOT	73,387 MW	% of Total
345 kV	987 MW	1.3%
138 kV	63,097 MW	86.0%

[31] Considering Installed Capacity, the Québec Interconnection in Canada is smaller than ERCOT.
[32] Data is the level of dispatched generation from the SSWG 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

[33] Data is from the 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

69 kV	9,304 MW	12.7%

A2.3.3 Transmission Line Mileage

The total transmission line miles in ERCOT that falls in the 100–200 kV range is 58%, and over three quarters of the line miles operate at voltages above 100 kV. Over 22% of the physical transmission line miles in ERCOT operate at 69 kV.

However, ERCOT's 69 KV transmission lines are predominantly in rural areas and serve small electric loads and wind plants that are dispersed over a large geographic region. As shown in the tables above, the 69 kV system in ERCOT serves approximately 1% of the electric load and 13% of the generation in ERCOT. The loss of the small, lightly loaded 69 kV lines spread over a large geographic region in ERCOT do not pose a threat to the Bulk Electric System.

Table A2-9: Total Transmission Line Miles in ERCOT

Total Line Miles in ERCOT	Miles	% of Total
345 kV	9,498	18.8%
230 kV	13	0.1%
138 kV	29,349	58.3%
69 kV	11,460	22.8%

A2.3.5 Transmission Assessment Study Results

ERCOT Staff supervises and exercises comprehensive independent authority of the overall planning of transmission projects in the ERCOT Interconnection (transmission system) as outlined in PURA and Public Utility Commission of Texas (PUCT) Substantive Rules. ERCOT's authority with respect to local transmission projects is limited to supervising and coordinating the planning activities of Transmission and Distribution Service Providers. In performing its evaluation of different transmission projects, ERCOT takes into consideration the need for and cost-effectiveness of proposed transmission projects in meeting the ERCOT and NERC planning criteria. Therefore, ERCOT studies regularly identify constraints at 69 kV even though the facilities are not needed for the reliable operation of the BES.

A2.4 Western Interconnection

All facilities that have an impact on the BES should be included in the definition of the BES. The BES definition should be easy to understand and administer. BES classification should not be a moving target. For reliability, a more inclusive definition of the BES is desirable, rather than potentially omitting a facility that in a time of need may be necessary to support the BES.

For the purposes of this paper, WECC base cases have been utilized. The individual Transmission Planner's data submittals determined the level of detail in WECC base cases. The WECC Data Preparation Manual states that Transmission Planners should represent their systems in sufficient detail such that the impact of any disturbances, whether internal or external to their own systems, can be adequately evaluated. The level of detail represented by the Transmission Planners should be the same as that used by individual Transmission Planners in conducting their internal bulk transmission system studies or facility ratings studies.

WECC respects Transmission Planners' judgment and strongly considers it in the development of WECC base cases. Through an analysis of WECC base cases it can be seen that Transmission Planners in WECC model a majority of the load and generation connected to 100 kV and above. The inclusion of data in base cases indicates that this is the level of detail needed to model the BES for power flow and stability studies.

A2.4.1 Generation

In WECC, over 80% of the generation modeled in base cases is primarily connected through generator step-up transformers with high-side voltages of 100 kV and above. The table below shows that the largest portion of the generation modeled in WECC (40%) connects between 200 and 300 kV. Total generation in WECC maintains the currently filed 100 kV bright-line threshold without adjustment.

Table A2-10: Total Generation in WECC[34]		
Total Generation in WECC	**245,737 MVA**	**% of Total**
300 kV and Greater	61,274 MVA	24.93
200 to 300 kV	98,717 MVA	40.17
100 to 200 kV	42,553 MVA	17.32
50 to 100 kV	17,501 MVA	7.13
Less than 50 kV	25,692 MVA	10.45

A2.4.2 Load

The WECC base cases model load at various voltages. The table below shows that the vast majority of load is modeled below 200 kV, with a large portion modeled between 50 and 100 kV.

Table A2-11: Total Load in WECC[35]		
Total Load in WECC	**172,750 MW**	**% of Total**
300 kV and Greater	15 MW	0.01
200 to 300 kV	16,257 MW	9.41
100 to 200 kV	63,963 MW	37.03
50 to 100 kV	58,749 MW	34.00
Less than 50 kV	33,766 MW	19.55

A2.4.3 Transmission Line Mileage

The definition of the BES should include the transmission that is critical for delivering generation to load. Of the transmission line miles collected, over 40% of the total in WECC falls in the 100–200 kV range.

Table A2-111: Transmission Line Miles by Voltage Class[36]				
Line Voltage kV	**100- 199**	**200-299**	**300-399**	**400-599**
WECC (miles)	50,306	42,336	11,637	20,262

A2.4.4 Transmission Assessment Study Results

In WECC, path limits are primarily established through the WECC Rating Review Process. Path limits are set based upon transient and post-transient stability limits, as well as thermal limits. A review of paths that went through this process indicates that, although most paths are limited by 345 kV and 500 kV Elements, instances exist where the transfer capability limits are determined by facilities between 100 kV and 200 kV.

[34] Note: Data is the generation available in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.

[35] Data is the load forecasted in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.

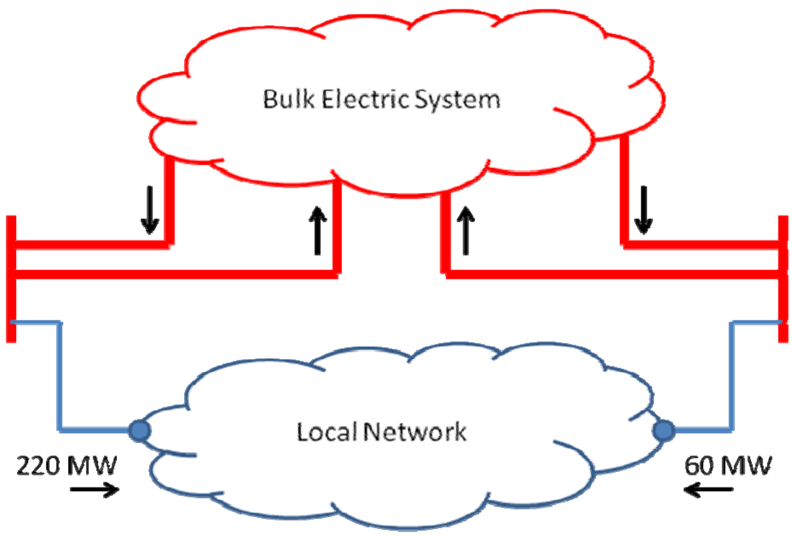
[36] Data is from the 2011 Long Term Reliability Data Collection. No data collected for transmission facilities below 100 kV

Appendix 3: Operational Considerations to Support Load Limit on Local Networks

The SAMS proposes to set a 300 MW maximum limit for the amount of load that may be served by a proposed local network (LN). This limit is proposed to ensure that LNs do not affect the reliable operation of the BES.

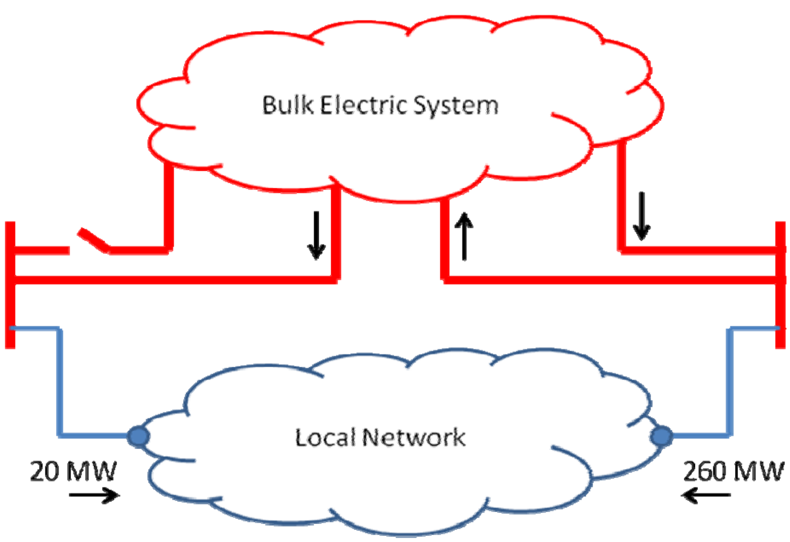
As represented in the figure below, under normal operating conditions, a two-terminal LN receives 220 MW on its western terminal and 60 MW on its eastern terminal (Figure A3-1).

Figure A3-1: Bulk Electric System Flow through Local Network



For a single BES contingency, the flow into the LN shifts from west to east by 200 MW, so that the LN now receives 20 MW on its western terminal and 260 MW on its eastern terminal (Figure A3-2).

Figure A3-2: Bulk Electric System Flow through Local Network

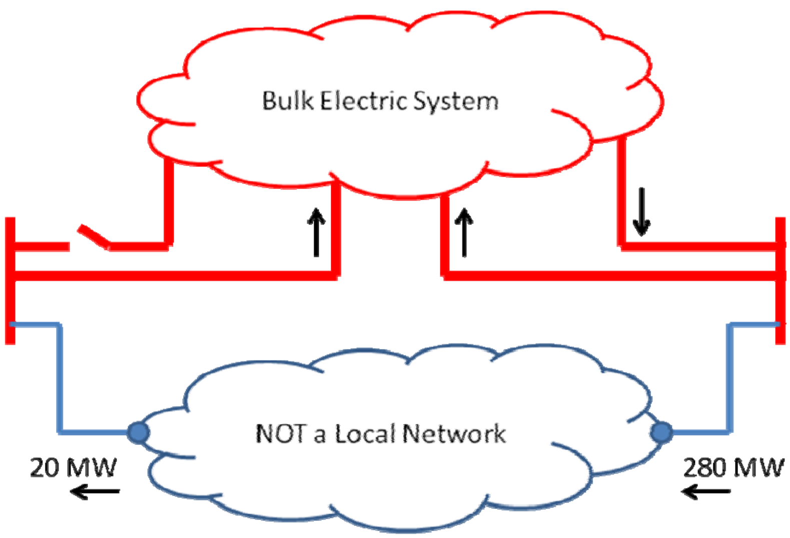


The 200 MW shift would be reflected in the BES and would be picked up by one of the BES transmission lines on the eastern side of the system; this change could represent a substantial increase in load for the affected line.

If a gross load limit were not placed on the size of the LN, then such a shift could be much larger, and the resulting impact to the BES could be significant. In a similar vein, consideration also may need to be given to limiting the size of a radial system (identified in Exclusion E1) since the total loss of load in the radial system could have a similarly significant impact to the BES depending on its location in the system.

Now consider the same system, but because of conditions within what was previously considered an LN (for example, non-BES generation dispatch and shifting load), the power now flows through the lower voltage system (Figure A3-3).

Figure A3-3: Bulk Electric System Flow through Local Network



In this case, the lower voltage system is not an LN since it is supporting flow through to the BES.

The 300 MW bright line is further supported by the following operational considerations:

1. Primary frequency response initially will be provided by the responding generating units in an interconnection. The industry-approved draft of the BAL-003-1 standard proposes that at least 1,700 MW of support will be provided within the smallest interconnection by primary frequency response controls.[37] This provides 5.7 times the resource margin needed to stabilize an interconnection for a 300 MW loss or gain in LN load. The interconnections recover from losses of generation in this MW range on a regular basis.

2. The requirements of the existing BAL-002-1 Disturbance Control Standard. Requirement R3 of the standard states, "[a]s a minimum, the Balancing Authority or Reserve Sharing Group (RSG) shall carry at least enough Contingency Reserve to cover the most severe single contingency." Requirement R4.2 states that recovery shall occur within 15 minutes of the start of a Reportable Disturbance.[38] Since the most severe single contingency in a Balancing Authority or RSG is typically a nuclear generating unit, the requirements of BAL-002-1 would provide from 2.5 to 3 times the resource margin needed to support a 300 MW LN.[39,40] This is supported by the fact that 89% of Balancing Authorities are part of an RSG. All RSGs were identified as carrying a minimum Contingency Reserve of 750 MW, which provides the resource margin stated above. Seven of the eight remaining Balancing Authorities that have

[37] NERC Website (2012, October 30). BAL-003-1 Attachment A. Retrieved from http://www.nerc.com/docs/standards/sar/Attachment_A_Frequency_Response_Standard_Supporting_Document_Clean_rev1.pdf

[38] A Reportable Disturbance is an event that causes an ACE change greater than or equal to 80% of the most severe single contingency of a Balancing Authority or RSG.

[39] The available resource margin was based on the average net electrical output of a nuclear generating unit, which was calculated to be 980 MW from the reactor data posted on the U.S. Nuclear Regulatory Commission Website (9/14/2012). List of Power Reactor Units. Retrieved from http://www.nrc.gov/reactors/operating/list-power-reactor-units.html.

[40] Resource margin was calculated by dividing the contingency reserve used to meet the most severe single contingency (980 MW-net) by the proposed LN limit of 300 MW. This margin differs from a planning reserve margin.

load and do not participate in an RSG carry over 300 MW of Contingency Reserves and would also be supported by surrounding entities as required by TOP-004-2, Requirement R6. The surrounding entities' AGC systems would also help balance real and reactive power needs. The eighth entity has 100 MW of load and a contingency reserve of at least 220 MW; no real and reactive power balancing issues are anticipated for this entity.

3. The ability of a Balancing Authority or Reserve Sharing Group to adjust real power resources to account for a 300 MW loss or gain in load. The 2012 estimated peak demands of Balancing Authorities average between 6,000 MW and 10,000 MW.[41,42] Therefore, a 300 MW LN represents approximately 3% to 5% of the average estimated peak demand of a Balancing Authority. Since the generating resources that supply the demand are able to adjust power output by ±2% per minute on AGC, a 300 MW loss or gain in LN load could be mitigated within the 15-minute recovery period allowed for a disturbance.[43,44]

Given the balancing capabilities identified in points 1 and 2 above and the fact that LNs are not intended for bulk power transfer, their disconnection from the BES should not affect reliability when limited to 300 MW.

Since LNs are not intended for bulk power transfer, their disconnection from the BES should not affect reliability when limited to 300 MW, given the balancing capabilities identified in points 1 and 2 above.

NOTE: The TPL transmission system planning standards require that projected customer demands and projected Firm (non-recallable reserved) Transmission Services are supplied at all demand levels (as applicable). The proposed standard TPL-001-2 further clarifies that system peak and off-peak load be modeled in the Near-Term Transmission Planning Horizon. Therefore, firm loads cannot be excluded from the planning process even if they are located within an LN.

[41] Based on whether the estimated peak demands (MW) of the largest ISOs/RTOs are included.
[42] Estimated peak demand (MW) data obtained from NERC Website (2012). 2012 CPS2 Blounds. Retrieved from http://www.nerc.com/docs/oc/rs/2012%20CPS2%20Bounds%20Report%20Final(Update20120821).pdf
[43] Kirby, Brendan & Hirst, Eric (1996, December 16). Generator response to intrahour load fluctuations. IEEE Transactions on Power Systems, 13(4), 1373-1378. Retrieved from http://www.consultkirby.com/files/PE627.pdf
[44] The paper referenced in footnote 7 states that hydro units can respond at 50% to 100% of their output per minute, combustion turbines at 10% to 20% of their output per minute, and coal powered units at 1% to 3% of their output per minute. The above information regarding thermal and hydro generating units is also supported by the following book: Kundur, P. (1994). Control of Active Power and Reactive Power, *Power system stability and control* (p. 618). New York, NY: McGraw-Hill, Inc.
An entity with 9,000 MW of generation is considered in this paper (the entity is within the average demand range of the Balancing Authorities considered herein).