NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Conference Call Agenda
Disturbance Monitoring SDT — Project 2007-11

Thursday, September 9, 2009 | 10 a.m.–noon EST
Conference Number: 1.866.289.4175
Conference Code: 6762229123

1. **Administrative Items**
   a. Introductions — All
   b. NERC Antitrust Compliance Guidelines — Stephanie Monzon
   c. Conference Call Agenda and Objectives — Navin Bhatt

2. **Brief Status of DM Standard Development — Navin Bhatt and Stephanie Monzon**
   First Posting, Revisions to Standard, and Next Steps

3. **Review Plans for Data Collection — Chuck Jensen**
   The proposed NERC DMSDT contains requests for TO and GO data down to 4000 MVA short circuit level (this will include kV levels down to 69kV) and gens at 20 MVA nameplate single units and 75 MVA nameplate sums for generators at a given plants (these will have kV levels down to 69kV). Any comments on this level of data request and data coverage

4. **Additional FERC Staff Issues — Lead FERC Staff**

5. **Additional Standard Drafting Team Issues**

6. **Next Steps — Navin Bhatt**

7. **Action Items — Stephanie Monzon**

8. **Adjourn**

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Nominations for the SAR drafting team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30 day comment period March 22 – April 20, 2007.
3. Nominations for the standard drafting team (SDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.

Proposed Action Plan and Description of Current Draft:

The purpose of this standard is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances. This standard will replace PRC-002-1 and PRC-018-1.

The purpose of revising the above standards is to:

1. Ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties; the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development, and
    - Regional Reliability Standards Working Group (RRSWG – a NERC working group involved with regional standards development).

The standard drafting team (SDT) also considered the following additional issues that were not completely captured but were stated or referenced in the above materials.

1. Modify PRC-002-1 to remove RRO in the applicability and eliminate the reference to RRO in PRC-018-1.
2. Create continent wide requirements applicable to Transmission Owners and Generation Owners.
3. The new standard (PRC-002-2) is being proposed based on the requirements of the existing PRC-002-1 and PRC-018-1 standards and a recommendation for replacing both of these existing standards is being proposed. The requirements in PRC-018-1 are being incorporated into PRC-002-2 with the exception of the maintenance and testing requirements in PRC-018-1.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop and post reply comments to initial posting of standard	March 30 – April 20, 2009
2. Post for second 30-day comment period	June, 2009
3. Post for 30-day pre-ballot period.	September, 2009
4. Conduct initial ballot	December, 2009
5. Post response to comments on first ballot	January, 2010
6. Conduct recirculation ballot	February, 2010
7. Board adoption date.	To be determined.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

A. Introduction

1. Title: Disturbance Monitoring and Reporting Requirements

2. Number: PRC-002-2

3. Purpose: To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).

4. Applicability:

4.1. Transmission Owners with Bulk Electric System substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service)

4.2. Generator Owners connected to Bulk Electric System substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following

- Generating units having a single generating unit of 500 MVA or higher nameplate rating
- Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

5. Effective Date: NEED TO REVISIT

5.1.50% of locations/site fully (all the data requirements at the location as identified in RXX elements or all the elements required at the given location) monitored or 50% of the total required monitored elements within three years

5.2.100% of locations fully (all the elements required at the given location) monitored and all total monitored elements within six years

Requirements R1 through R11:

- The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:
  - Each Responsible Entity shall be at least 50% compliant on monitored equipment
- The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter four years after Board of Trustees adoption:
  - Each Responsible Entity shall be 100% compliant on monitored equipment.

Requirements R12 and R13

- First day of first calendar quarter eighteen months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Owner and Generator Owner shall record (or have a process in place to derive) the sequence of events data for changes in circuit breaker position (open/close) for each of the circuit breakers it owns at Transmission switching stations, transmission substations, generating stations, HVAC converter stations, HVDC converter stations that meet the following criteria:

Generator Owners connected to Bulk Electric System substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following

- Generating units having a single generating unit of 500 MVA or higher nameplate rating
- Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

R2. Each Generator Owner shall record (or have a process in place to derive) the sequence of events data for changes in circuit breaker position (open/close) for the equipment it owns and connected to Bulk Electric System substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following

Comment [A1]: 4/1/09 - Jim, Tracy, Felix and Dan will propose revised requirement language for R1 and R2
8/18/09 - The revised language addressed the issue that ownership will fall out by clearly identifying the locations and criteria

2.1. Generating units having a single generating unit of 20 MVA or higher nameplate rating

2.2. Generating plants with an aggregate plant total nameplate capacity of 75 MVA or higher

identified in Table 2-1:

Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data

Location	Equipment

Each generating plant having a single generating unit with a nameplate rating of 20MVA or higher, and connected to the BES at 10,000 MVA level and above	Each generator output circuit breaker, including low side breakers
Each generating plant with an aggregate plant total nameplate capacity of 75 MVA or higher, and connected to the BES at 10,000 MVA and above	Each generator output circuit breaker, including low side breakers
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher	Each circuit breaker 200 kV and above
Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	Each circuit breaker 200 kV and above

R3. Each Transmission Owner and Generator Owner shall record the time stamp (or have a process in place to derive the time stamp) to within one quarter of a 60 Hz cycle of input received for the change in circuit breaker position (open/close) for each of their respective circuit breakers specified in Requirements R1 and R2, respectively.

R4. Each Transmission Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 4-1:

- The three phase to neutral voltages on each monitored line or bus.

4.1. The three phase currents and the residual or neutral currents of each monitored line and transformer.

Comment [A2]: 3/31/09 - Based on industry comments the team decided to change this requirement from 4 ms to one quarter cycle. The industry suggested quarter cycle. The team debated making it 5ms; however, decided that either 4 or 5 would require technical justification as comments requested.

Comment [A3]:

Comment [A4]: 8/19 - this requirement should be revised since it refers to R1 and R2 which respectively apply to different entities.

Comment [A5]: 4/1/09 - Stopping point at the meeting

Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data

Location	Equipment

Each Substation containing any combination of three (3) or more elements consisting of transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above Each Substation connected at 200 kV or above through generating unit step up transformer(s) to a generating plant having a single generating unit of 500 MVA or higher nameplate rating Each Substation connected at 200 kV or above through generating unit step up transformer(s) to an aggregate plant with a total nameplate capacity of 1500 MVA or higher	• Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal • Each transmission bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

R5. Each Generator Owner shall record (or have a process in place to derive) the following fault recording data for its equipment identified in Table 5-1:

5.1. The three phase to neutral voltages or phase to phase voltages on Generator Step-up Transformers (GSU(s)) from the high voltage side or low voltage side of the GSU, or from the generator bus.

5.2. The three phase currents of GSU(s) from the high voltage side or low voltage side of the GSU, or from the generator bus.

5.3. The neutral current of wye connected GSU(s) high voltage windings.

5.4. The three phase to neutral voltages on each monitored line or bus as follows:

- On ring buses, the voltages of bus sections connected to transmission lines.
- On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages.
- On straight buses, common bus voltages or the individual line voltages.

The three phase currents and the residual or neutral currents of each monitored line and transformer.

Table 5-1: Generator Owner's Requirement R5 for Fault Recording Data	
Location	**Equipment**
Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above	Each GSU with a high side of 200 kV and above
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	• Each transmission line operated at 200 kV or above that does not have fault data recorded d at its remote terminal • Each bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

R6. Each Transmission Owner and Generator Owner shall have fault recording data for its equipment identified in Requirements R4 and R5 that conforms to the following:

6.1. A single record or multiple records that include the following:

- A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles

  OR

- At least two cycles of the pre trigger event; the first three cycles of an event; and the final cycle of an event.

A minimum recording rate of 16 samples per cycle.

(Unless a Transmission Owner has Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4 recorded no further than two Substations away, then for each Substation having a total of seven or more transmission lines connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data:

At least one phase-to-neutral voltage at each voltage level of 200 kV and above.

Frequency (at least one at the required Substation).

At least one phase current (on the same phase and at the same voltage as the voltage monitored in R7.1) (for each line operated at 200 kV and above).

Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (for each line operated at 200 kV and above))

R7. Each Generator Owner shall record (or have a process in place to derive) the following dynamic disturbance recording data at each of its generating plants with an aggregate nameplate rating of 1500 MVA or higher for each GSU that has a transformer high side connected at 200 kV or above:

7.1. At least one phase-to-neutral voltage or one phase-to-phase voltage at either the GSU's high side or low side voltage level, or the generator bus voltage.

7.2. Frequency (at least one at the required Substation)

7.3. At least one phase current (on the same phase and at the same voltage as the voltage monitored in R8.1) or two phase currents for phase-to-phase voltages for each GSU.

7.4. Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (per each monitored element) for each GSU.

R8. Each Transmission Owner and Generator Owner that has dynamic disturbance recording devices (to meet Requirement R7 or R8) shall manage its dynamic disturbance recording data in accordance with the following technical specifications:

8.1. Use the same phase for voltage and current recordings.

8.2. Collect at least 960 samples per second to calculate RMS electrical quantities.

8.3. Store calculated RMS values of electrical quantities at a rate of at least 6 times per second.

R9. Each Transmission Owner and Generator Owner that installs a dynamic disturbance recording device after January 1, 2011 to meet Requirements R7, R8 and R9 shall install a device that is capable of continuous recording.

R10. Each Transmission Owner and Generator Owner that has a dynamic disturbance recording device (to meet Requirements R7, R8 and R9) that does not have continuous recording capability shall set its device to trigger and record according to the following:

10.1. For rate-of-change of frequency.

10.2. For oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.

10.3. Set data record lengths at a minimum of three minutes.

R11. Each Transmission Owner and Generator Owner shall synchronize all of its sequence of event, fault recording, and dynamic disturbance recording functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) with the associated hour offset.

R12. Each Transmission Owner and Generator Owner shall have all recorded sequence of event, fault recording, and dynamic disturbance recording data available (locally or remotely) for 10 calendar days after a Disturbance.

R13. Each Transmission Owner and Generator Owner required to have disturbance monitoring equipment shall have a maintenance and testing program for those disturbance monitoring equipment that includes:

13.1. Maintenance and testing intervals and their basis.

13.2. Summary of maintenance and testing procedures.

C. Measures

M1. (To be added later)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

(To be added later.)

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

1.3.1 Each Transmission Owner and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.

1.3.2 Each Transmission Owner and Generator Owner shall each maintain, and report to the Regional Entity, Reliability Coordinator or NERC within 30 calendar days of a request, the following information for Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data:

- Location
- Make and model of equipment

- Type of data source (Sequence of Events, Fault Recording, or Dynamic Disturbance Recording).

- Monitored elements, such as transmission circuit, bus section, circuit breakers, etc.

1.4. Compliance Monitoring and Assessment Processes

(To be added later)

1.5. Additional Compliance Information

1.5.1 Each Transmission Owner and Generator Owner shall meet all of the following criteria when reporting Sequence of Event, Fault Recording , and Dynamic Disturbance Recording data to its Regional Entity, Reliability Coordinator, or NERC:

- All Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data shall be provided to the Regional Entity, Reliability Coordinator, or NERC within 30 calendar days of a request,

- All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111-1999 or successor) files may be used to process and evaluate the data,

- All known delays in interposing relays shall be reported along with the SOE data,

- All data files shall be named in conformance with IEEE C37.232-2007, or its successor, Recommended Practice for Naming Time Sequence Data Files.

2. Violation Severity Levels (To be added later)

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL

E. Regional Variances

NERC Data Request — Facilitate Reliability Standard Development

PRC-002-2 — Disturbance Monitoring and Reporting Requirements Draft 2
Disturbance Monitoring Equipment (DME) Project 2007-11
http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

Industry Need

To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.

The project involves modifying two standards:

- PRC-002-1 Define Regional Disturbance Monitoring & Reporting Requirements: http://www.nerc.com/files/PRC-002-1.pdf
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting: http://www.nerc.com/files/PRC-018-1.pdf

The project involves replacing "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization, with continent-wide requirements that are applicable to other functional entities. As envisioned, each region will supplement PRC-002-3 with a regional standard that includes additional requirements. The project also involves bringing the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure.

Overview

The **Disturbance Monitoring and Reporting Standard Drafting Team (DM SDT)** is currently in the process of drafting a continent-wide standard that establishes requirements for the monitoring and recording of data essential to analyzing system electric grid events. A challenge with establishing continent-wide requirements is the regional variability of the electric grid. The exercise of identifying location thresholds for recording Sequence of Events, Dynamic Disturbance Recording, and Fault Recording data requires an analysis of data for several NERC regions that identifies appropriate thresholds. Once thresholds have been established and substantiated with supporting data, the standard requirements will be defined. The drafting team is soliciting data to perform a data analysis to substantiate continent-wide thresholds and to avoid creating unnecessary, costly technical requirements.

NERC Data Request Purpose

The NERC Disturbance Monitoring Standards Drafting Team (DMSDT) is requesting data from Generator Owners and Transmission Owners (in cooperation with their Transmission Operators as appropriate) to better determine the criteria for locations of disturbance monitoring equipment based on electric grid locations relative to lines, generation, short circuit MVA, voltage level, special equipment or special systems.

Timeframe

The data request period is 8 weeks from request release date, September 1, 2009. Due date October 30, 2009

Scheduled Webinar — Data Template and Data Collection FAQs:

Approximately 2 weeks after the initial data request release a NERC Webinar will be held on MM-DD-YY to discuss the data template and data collection FAQs.
Consult NERC Webinar https://nerc.webex.com/mw0305l/mywebex/default.do?siteurl=nerc

Targeted Locations

The data request is applicable to sites on the electric grid commonly referred to as:

1. Transmission Switching Stations
2. Transmission Substations
3. Generating Stations
4. High Voltage Direct current (HVDC) Converter stations

Data Collection Constraints

1. All buses with three phase short circuit MVA of 4000 MVA or larger should be included.
2. If the location buses and generators share the same ground grid, then these electric grid sites will appear on the data template as one individual row of an interconnected site.
3. If the location buses and generators do not share the same ground grid, then these electric grid sites will appear on the data template as multiple individual rows.
4. Optional: If an interconnected location has a bus with three phase short circuit MVA less than 4000 MVA, it may be reported as part of the interconnected buses for more complete connectivity topology.
5. All generators, regardless of the three phase short circuit MVA or ownership, with a nameplate rating of 20MVA or greater or an aggregate total of 75MVA or greater should be included.

NERC Requested Data

At each of the targeted locations requested data includes:

a. Line Count

1. Utilize Electric Grid Transmission One-Lines
2. Regardless of ownership, lines entering and leaving a location are typically crossing a perimeter and should be counted as they cross the location's perimeter.
3. Do include the number of tie lines to remote interconnect locations.
4. Do count radial lines. However, the radial lines will later be identified & excluded in the total lines and lines greater than 200kV data template calculations.
5. Do not count a line from a location to a generator step-up transformer for a generator and within the same ground grid. This line is associated with the generator connection ONLY.
6. Do not count lines connecting two different voltage level buses, interconnected with an autotransformer, and within the same ground grid. The lines used to interconnect the autotransformers are associated with the autotransformer connection ONLY.

b. Generators

Regardless of ownership or the three phase short circuit MVA:

1. Include any individual generator with a nameplate rating of 20MVA or larger
2. Include any location with an aggregate total of 75MVA (nameplate ratings summed) or larger
3. Two special columns are included for smaller generators connected at less than 100kV and greater than 60kV.
    i. one column for the number of units
    ii. with the second column for the individual sizes of the generating units.

c. Autotransformers — List the maximum MVA nameplate rating

d. Three Phase Short Circuit MVA

1. Utilize the most up-to-date Short circuit data for a NERC Operating Region.
2. Coordinate with Transmission Operators, Transmission Planners, Transmission Owners, System Protection, or Generator Owners where necessary to obtain current short circuit data.
3. Conditions for the short circuit program should include maximum generation with normal operating connectivity.
4. Provide data for all listed buses at a targeted location (row).

e. Special Equipment or Special Systems

The data template is simply asking Yes/No (Y/N), if any of this special equipment is connected as part of the interconnected buses for that row of the data template.

1. Static VAR Controller (SVC)
2. Flexible AC Transmission System (FACTS)
3. Dynamic Voltage Restorer (DVR)
4. Special Protection System (SPS)
5. Remedial Action Scheme (RAS)

Data Template — NERC Region Data Collection Examples

In the data template provided, complete system examples for EXE-CE (Chicago), ITC-METC (Michigan), and FRCC (Florida) regions were included to illustrate:

1. Site locations with interconnected lines, generators, and autotransformers that span voltages from 765kV to 100kV.
2. Three phase short circuit MVA for each targeted bus.
3. A data library sheet describes in detail the desired data for each column of the data template.

NERC Data Request DMSDT Example 1, Figure 1

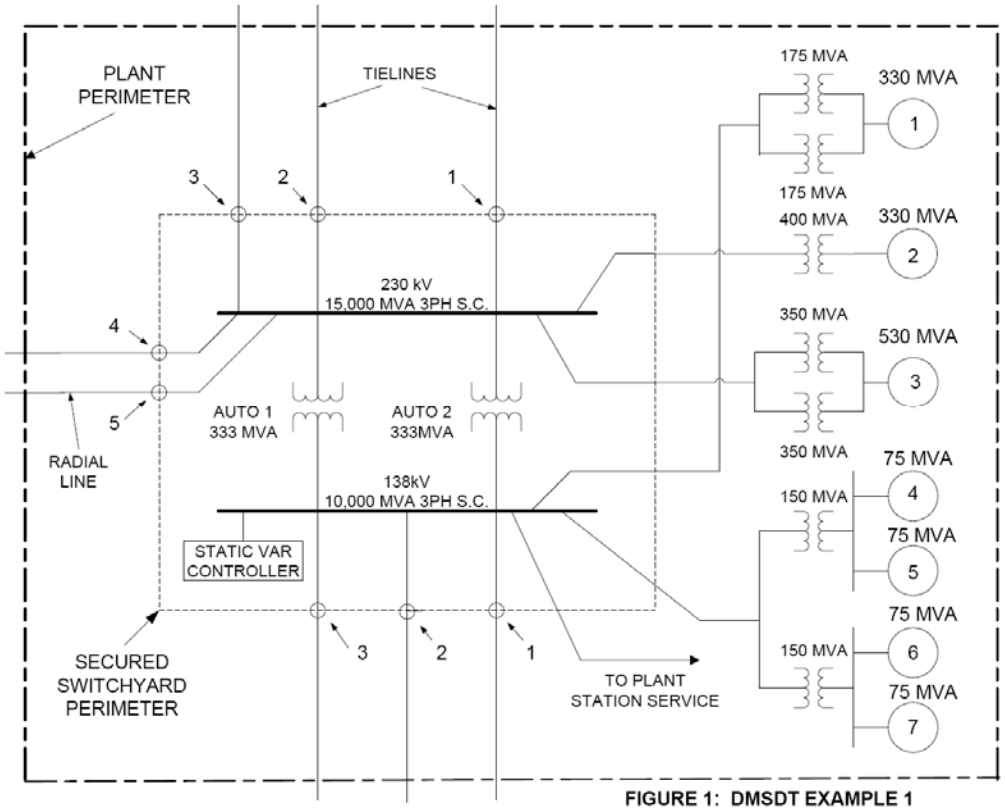

FIGURE 1: DMSDT EXAMPLE 1

a. Line Count

1. Transmission lines as they cross the substation or switchyard secured perimeter are counted, as illustrated by the circles shown at the perimeter.
2. In this example, there are five (5) 230kV lines that cross this perimeter and three (3) 138kV lines that cross the perimeter and need to be placed in the appropriate data template column.
3. One of the 230kV lines is radial.

b. Generators

1. Lines which cross the perimeter related to generator step up transformers, station service transformers and start-up transformer for generating plant equipment do not need to be counted in the line count.
2. Generating unit ratings are all nameplate MVA ratings.
3. The generating step up transformers are all shown with the highest MVA rating for the transformer; however, the data template does not request these individual GSU or station service transformer data.

4.List only the generating unit individual unit size data and then the summed aggregate size of all generating units.

c. Autotransformers

1. Lines associated with autotransformers, if they were to cross the secured switchyard perimeter, do not need to be counted, but will be assumed to be part of the autotransformer data.

2.Both autotransformers highest nameplate capacity rating is 333 MVA.

d. Three Phase Short Circuit MVA

1.The 230kV bus three phase short circuit is 15,000 MVA

2.The 138kV bus three phase short circuit level is 10,000 MVA.

3.Both values are listed on the same row.

e. Special Equipment or Special Systems

1. There is a Static VAR Controller (SVC) installed on the 138kV bus.
2. Two of the 230kV lines are tie lines to remote interconnect locations.

NERC Data Request DMSDT Example 1, Figure 1
Data Template Column Description & Corresponding Figure 1 Data

A summary of the data that would be collected for the data template all on one row is as follows:

Column A: Row #: 001
Column B: Substation Coded Name: North0004
Column C: Coded Owner Name: JEA
Column D: Coded App1 Name: Aspen0036
Column E: Coded App2 Name: MaxNSDE230, MaxNS138
Column F: Total # of Gen Units: 7
Column G: Total MVA of All Gen Units: 1490
Column H: through Column O: No Values are needed for Example 1
Column P: 200-299kV Total Lines: 5
Column Q: 200-299kV Individual Gens Sizes Connected: 530, 330
Column R: 200-299 Radial Lines: 1
Column S: 130-199kV Total Lines: 3
Column T: 130-199 Gen Sizes Connected: 330, 75, 75, 75, 75
Column U: 130-199 Radial Lines: 0
Column V: through Z: No Values are needed for Example 1
Column AA: Total Lines: Calculated Value = 7
Column AB: Lines > 200kV: Calculated Value = 4
Columns AC: through AF: No values are needed for Example 1
Column AG: Three phase symmetrical short circuit level at the (200-299) kV bus: 15,000
Column AH: No Value is needed for Example 1
Column AI: Three phase symmetrical short circuit level at the (130-199) kV bus: 10,000
Column AJ: through AO: No Values are needed for Example 1
Column AP: Maximum Short Circuit for All buses: 15,000
Column AQ: Bus Count: Calculated Value = 2
Columns AR: through AY: No Values are needed for Example 1
Column AZ: Total number of Autotransformers (200-299)/ (130-199) KV: 2
Column BA: Individual MVA sizes of the autotransformers in Col. AZ: 333, 333

Columns BB: through BE: No Values are needed for Example 1
Column BF: Tie lines at these buses: Y, 2@230kV
Column BG: DC Converter Station: No value is needed for Example 1
Column BH: FACTS, SVC, DVR? Y, 1@138kV
Column BI: SPS, RAS? No value is needed for Example 1

DM Location Criteria

Use (MVA Short Circuit)

or

Substations, KV and Lines

By Chuck Jensen / JEA NERC DMSDT Mtg. 05/05/09

Original Purpose of Fault Data Collection

- Justify the use of >200kV for a technical paper (data to support team's decision to NERC & FERC)
- One idea - use the Top 100 Low Impedance busses (Short Circuit MVA) for a Region and determine what KV percentages were best represented from this analysis
- In the FRCC Region 10,000 MVA includes more than Top 100 busses, some 148 busses are included at 88 substations
- Short Circuit data based on the year ahead Summer Peak forecasted load flow for the region with selected generators and operating configurations to feed the forecasted summer peak loading
- FRCC Top 100 Low Impedance bus data process in place for over ten (10) years, signifies our regional high impact busses

MVA Short Circuit Advantages

- Voltage Level Independent, includes all voltage levels
- More likely to select busses which are more closely tied to generation
- More likely to select busses where delayed clearing can cause electric system cascading outages
- Selected busses directly correlate to the universal Power Transfer equation
  - Lower Impedance – increased power flows – more system impact
- Data is available from short circuit studies and is associated directly with the busses as modeled
- Could be used to better define the BES

WAPA UGP System					
	kV level	**Total**	**In top 100**	**> 15,000 MVA**	**> 10,000 MVA**
	525	5	5	1	1
	345	55	37	1	8
	230	139	33	0	4
	161	85	15	0	0
	115	343	10	0	0
	69 <= kV <= 100	277	0	0	0
	total	904	100	2	13
MVA Highest	29,914				
>15M at Bus	2				
>10M at Bus	13				
MVA at Bus 100	3,653				
Ratio MVA Hi / Bus 100 MVA	8.19				

WAPA RMR System					
	kV level	**Total**	**In top 100**	**> 15,000 MVA**	**> 10,000 MVA**
	525	3	3	2	3
	345	42	24	4	7
	230	171	54	0	1
	138	42	0	0	0
	115	404	19	0	0
	69 <= kV <= 100	284	0	0	0
	total	946	100	6	11
MVA Highest	21,723				
>15M at Bus	6				
>10M at Bus	11				
MVA at Bus 100	4,255				
Ratio MVA Hi / Bus 100 MVA	5.11				

WAPA DSW System					
	kV level	Total	In top 100	> 15,000 MVA	> 10,000 MVA
	525	46	37	29	32
	345	74	9	5	9
	230	211	54	21	54
	138	156	0	0	1
	115	204	0	0	0
	69 <= kV <= 100	570	0	0	0
CHECK:	total	1261	100	55	96
MVA Highest	49247				
>15M at Bus	55				
>10M at Bus	96				
MVA at Bus 100	11526				
Ratio MVA Hi / Bus 100 MVA	4.27				

FRCC Entire Region					
	kV level	**Total**	**In top 100**	**> 15,000 MVA**	**> 10,000 MVA**
	500	22	9	7	13
	230	442	88	34	129
	138 &115	937	3	0	6
	<100	1332	0	0	0
	Total	2733	100	41	148
MVA Highest	25,433				
>15M at Bus	41				
>10M at Bus	148				
MVA at Bus 100	10,793				
Ratio MVA Hi / Bus 100 MVA	2.36				

WAPA SNR System					
	kV level	**Total**	**In top 100**	**> 15,000 MVA**	**> 10,000 MVA**
	525	22	22	21	22
	345	na	na	na	na
	230	338	72	31	74
	115	962	6	0	6
	69 <= kV <= 100	291	0	0	0
	total	1613	100	52	102
MVA Highest	33,124				
>15M at Bus	52				
>10M at Bus	102				
MVA at Bus 100	10,352				
Ratio MVA Hi / Bus 100 MVA	3.20				

ITC - Michigan

kV level	Total	In top 100	> 15,000 MVA	> 10,000 MVA
345		48	26	48
200		6	1	6
100		3	0	3
Totals		57	27	57

MVA Highest	25,846
>15M at Bus	27
>10M at Bus	57
MVA at Bus 100	10,103
Ratio MVA Hi / Bus 100 MVA	2.56

PJM Summary for 10,000 MVA Busses

Nominal Voltage	Total Number of Buses	Buses with over 10,000 MVA Short Circuit Load	Percent of Total
765	50	43	86%
525	6	6	100%
500	118	105	89%
345	422	227	54%
335.6	10	7	70%
230	885	348	39%
209.5	2	0	0%
161	57	3	5%
144	1	0	0%
138	1820	55	3%
132	7	0	0%
115	725	2	0%
Total	4103	796	19%

New York System

kV level	Total	In top 100	> 15,000 MVA	> 10,000 MVA
765		2	0	2
500		9	9	9
345		49	38	49
230		17	10	17
138		23	4	23
Totals		100	61	100

MVA Highest	34,131
>15M at Bus	61
>10M at Bus	100
MVA at Bus 100	10,072
Ratio MVA Hi / Bus 100 MVA	3.39

New England System

kV level	Total	In top 100	> 15,000 MVA	> 10,000 MVA
345		77	33	77
100		40	0	40
Totals		117	33	117

MVA Highest	29,392
>15M at Bus	33
>10M at Bus	117
MVA at Bus 100	10,011
Ratio MVA Hi / Bus 100 MVA	2.94

ERCOT System Summary					
	kV level	**Total**	**In top 100**	**> 15,000 MVA**	**> 10,000 MVA**
	345	406	100	223	318
	138	3389	0	11	294
	<100	3511	0	3	7
	total	7306	100	237	619
MVA Highest	53,875				
>15M at Bus	237				
>10M at Bus	619				
MVA at Bus 100	19,978				
Ratio MVA Hi / Bus 100 MVA	3.20				

>200kV Correlations by System

- UGP 100% Good
- RMR 100% Good
- DSW 99% Good
- FRCC 96% Good
- ITC-MICH 95% Good
- SNR 94% Okay
- PJM 93% Okay
- NY 77% ← Some concern here
- NE 66% ← Some more concern here
- ERCOT 51% ← Real Concern here

Looks like we are going to have to include >100kV !!!

How to include 100kV?

FRCC Region for >100kV

KV	Lines	Subs	Sub Type 500 /200 /100	Sub Type 200 /100	Sub Type 200	Sub Type 100	Chk	Lowest MVA	
>100kV	14 or more	3	3	0	0	0	3	7158	
>100kV	13 or more	4	3	1	0	0	4	9694	
>100kV	12 or more	7	3	4	0	0	7	10681	
>100kV	11 or more	16	5	11	0	0	16	2993	DDR
>100kV	10 or more	22	8	14	0	0	22	9341	
>100kV	9 or more	28	10	18	0	0	28	3997	
>100kV	8 or more	39	12	24	3	0	39	3624	
>100kV	7 or more	54	13	32	8	1	54	1754	DFR
>100kV	6 or more	76	14	49	11	2	76	3084	
>100kV	5 or more	109	14	65	22	8	109	1467	
>100kV	4 or more	159	14	82	40	23	159	1422	
>100kV	3 or more	209	16	92	61	40	209	2712	

MVA Calculations for DME - MVA Factors to Determine Busses Monitored

Name	Area or Region	MVA Highest	>15M at Bus	>10M at Bus	MVA at Bus 100	Ratio MVA Hi / Bus 100 MVA	DFR MVA Hi/MVAF	DDR MVA Hi/MVAF
ERCOT	Region	53,875	237	619	19,978	3.20	30786	43100
DSW	Area	49,247	55	96	11,526	4.27	28141	39398
NY	Area	34,131	61	100	10,072	3.39	19503	27305
SNR	Area	33,124	52	102	10,352	3.20	18928	26499
NE	Area	29,392	33	117	10,011	2.94	16795	23514
FRCC	Region	25,433	41	148	10,793	2.36	14533	20346
					MVA Factors (MVAF)		1.75	1.25
UGP	Area	29,914	2	13	3,653	8.19	17094	23931
ITC	Area	25,846	27	57	10,103	2.56	14769	20677
RMR	Area	21,723	6	11	4,255	5.11	12413	17378
							1.75	1.25

FRCC Region for >200kV

KV	Lines	Subs	Sub Type 500 /200 /100	Sub Type 200 /100	Sub Type 200	Sub Type 100	Chk	Lowest MVA	
>200kV	14 or more	1	1	0	0	0	1	19259	
>200kV	13 or more	1	1	0	0	0	1	19259	
>200kV	12 or more	2	2	0	0	0	2	19858	
>200kV	11 or more	4	4	0	0	0	4	16795	
>200kV	10 or more	7	7	0	0	0	7	15823	
>200kV	9 or more	11	9	2	0	0	11	9529	DDR
>200kV	8 or more	18	11	4	3	0	18	9940	
>200kV	7 or more	25	11	6	8	0	25	7139	
>200kV	6 or more	37	13	12	12	0	37	10018	
>200kV	5 or more	58	13	22	23	0	58	7122	DFR
>200kV	4 or more	84	13	30	41	0	84	4221	
>200kV	3 or more	117	15	42	60	0	117	2712	

Options for DMSDT on DFRs

- Align with NERC comments, other comments and other regional criteria to increase the number of lines to (5 or more lines with >200kV) for DFRs, accept this as this is more in alignment with the 10,000 MVA criteria
  - Exclusions:
    - radials (load only), these do not add to the line or element count
    - both ends of a line do not require monitoring
    - some 200kV elements
- Now for the >100kV criteria – DFR Options: (NERC comment to go down to 100kV)
  - Use >100kV, 9 or more lines, with same exclusions as above, but add < 100kV exclusion
  - Use MVA factor (MVAF) process using 1.25 for DDR and 1.75 for DFR based on a region's highest MVA, the TO & GO's area MVAF for DDR may be closer to 1.05 and DFR closer to 1.15

Options for DMSDT on DDRs

- Use the >200kV, 7 or more elements
- OR
- Use > 100kV, 11 or more lines for DDR or the MVA factor process:

  Additions:

  Add DDR requirements from RFC

  - Add HVDC & FACTS, WECC comments

  Exclusions:

  - radials (load only), these do not add to the line or element count, other elements like cap banks, etc.
  - other elements at 100kV & 200kV, like autotransformers between these voltage levels, do not add to line count

Questions?
Team Discussion

- TO, GO vs Regional for DDR, DFR (Two Views)
- Substations, lines, KV vs MVA factor methods
- Better define substation
- Better define substation & lines exclusions
- Better define bus, modeled bus for MVA SC, only one exclusion needed for busses <100kV
- Better define operating conditions to use when calculating MVA SC.

NERC Data Request - Facilitate Reliability Standard Development

PRC-002-2 – Disturbance Monitoring and Reporting Requirements Draft 2

Disturbance Monitoring Equipment (DME) Project 2007-11

http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

DMSDT Data Library for Substations, Generation, Lines, Short Circuit MVA, Special Equipment Data Collection

Column	Column Title	Description	Expected Values
A	Row #	Sequential row number	Integer
B	Substation Coded Name	TO, TOP, GO coded name rather than actual name, protected for confidentiality, TO, TOP, GO to keep Substation Coded Name to Actual Name for future reference.	Alphanumeric, text
C	Coded Owner Name	TO, TOP, GO coded owner name rather than actual name, protected for confidentiality, TO, TOP, GO to keep Coded Owner Name to Actual Name for future reference.	Alphanumeric, text
D	Coded App1 Name	TO, TOP, GO coded first application name. Optional field used by TO, GO or TOP for short circuit program name(s) or number(s).	Alphanumeric, text
E	Coded App2 Name	TO, TOP, GO coded second application name. Optional field used by TO, GO or TOP for maintenance management system or other application system name(s) or number(s) for this data row..	Alphanumeric, text
F	Total # of Gen Units	Total number of generating units on this row	Integer
G	Total MVA of All Gen Units	Total aggregate MVA of all generating units on this row	Integer
H	(600 - 799)kV or greater Lines	Number of (600 - 799)kV or greater lines entering or leaving the interconnected substation	Integer
I	(600 - 799)kV or greater Individual Gen Sizes	Individual generating unit sizes connected at the (600 - 799)kV or greater level, if more than one unit then use comma delimited format	Comma delimited text, i.e (600,600)
J	(400 - 599)kV Lines	Number of (400 - 599)kV lines entering or leaving the interconnected substation	Integer
K	(400 - 599)kV Individual Gen Sizes	Individual generating unit sizes connected at the (400 - 599)kV level, if more than one unit then use comma delimited format	Comma delimited text, i.e (600,600)
L	(400 - 599)kV Radial Lines	Number of (400 - 599)kV lines entering or leaving the interconnected substation that are radial, feeding load only.	Integer
M	(300 - 399)kV Lines	Number of (300 - 399)kV lines entering or leaving the interconnected substation	Integer
N	(300 - 399)kV Individual Gen Sizes	Individual generating unit sizes connected at the (300 - 399)kV level, if more than one unit then use comma delimited format	
O	(300 - 499) kV Radial Lines	Number of (300 - 399)kV lines entering or leaving the interconnected substation that are radial, feeding load only.	Integer
P	(200 - 299)kV Lines	Number of (200 - 299)kV lines entering or leaving the interconnected substation	Integer
Q	(200 - 299)kV Individual Gen Sizes	Individual generating unit sizes connected at the (200 - 299)kV level, if more than one unit then use comma delimited format	Comma delimited text, i.e (600,600)
R	(200 - 299)kV Radial Lines	Number of (200 - 299)kV lines entering or leaving the interconnected substation that are radial, feeding load only.	Integer
S	(130 - 199)kV Lines	Number of (130 - 199)kV lines entering or leaving the interconnected substation	Integer
T	(130 - 199)kV Individual Gen Sizes	Individual generating unit sizes connected at the (130 - 199)kV level, if more than one unit then use comma delimited format	Comma delimited text, i.e (600,600)
U	(130 - 199) kV Radial Lines	Number of (130 - 199)kV lines entering or leaving the interconnected substation that are radial, feeding load only.	Integer
V	(100 - 129)kV Lines	Number of (100 - 129)kV lines entering or leaving the interconnected substation	Integer

NERC Data Request - Facilitate Reliability Standard Development

PRC-002-2 – Disturbance Monitoring and Reporting Requirements Draft 2

Disturbance Monitoring Equipment (DME) Project 2007-11

http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

DMSDT Data Library for Substations, Generation, Lines, Short Circuit MVA, Special Equipment Data Collection

Column	Column Title	Description	Expected Values
W	(100 - 129)kV Individual Gen Sizes	Individual generating unit sizes connected at the (100 - 129)kV level, if more than one unit then use comma delimited format	Comma delimited text, i.e (600,600)
X	(100 - 129)kV Radial Lines	Number of (100 - 129)kV lines entering or leaving the interconnected substation that are radial, feeding load only.	Integer
Y	Generating Units connected within the less than (< 100kV to > 60kV) range	Individual generating unit sizes connected in the range of (< 100kV to > 60kV), if more than one unit then use comma delimited format	Comma delimited text, i.e (100,20,20, 20)
Z	Largest three phase MVA short circuit for Col. Y units.	Largest three phase short circuit MVA on the high side of the GSU(s) (highest kV winding for GSU). Individual generating unit sizes connected in the range of (< 100kV to > 60kV), for Column Y units.	Integer
AA	Total Lines	Summation of the number of lines entering or leaving the interconnected single voltage or multiple voltage substations, not including radial lines	Integer
AB	Lines > 200kV	Summation of the number of lines entering or leaving the interconnected single voltage or multiple voltage substations exceeding 200kV, not including radial lines	Integer
AC	(600 - 799)kV or greater Bus 3ph SC	Three phase symmetrical short circuit level at the (600 - 799)kV or greater bus	Integer
AD	(400 - 599)kV Bus 3ph SC	Three phase symmetrical short circuit level at the (400 - 599)kV bus	Integer
AE	(300 - 399)kV 3ph SC	Three phase symmetrical short circuit level at the (300 - 399)kV bus	Integer
AF	(300 - 399)kV 3ph SC (2)	Three phase symmetrical short circuit level at the second (300 - 399)kV bus, busses split due to high level of short circuit current	Integer
AG	(200 - 299)kV Bus 3ph SC	Three phase symmetrical short circuit level at the first (200 - 299)kV bus	Integer
AH	(200 - 299)kV Bus 3ph SC (2)	Three phase symmetrical short circuit level at the second (200 - 299)kV bus	Integer
AI	(130 - 199)kV Bus 3ph SC	Three phase symmetrical short circuit level at the (130 - 199)kV bus	Integer
AJ	(130 - 199)kV Bus 3ph SC (2)	Three phase symmetrical short circuit level at the second (130 - 199)kV bus, busses split due to high level of short circuit current	Integer
AK	(130 - 199)kV Bus 3ph SC (3)	Three phase symmetrical short circuit level at the third (130 - 199)kV bus, busses split due to high level of short circuit current	Integer
AL	(130 - 199)kV Bus 3ph SC (4)	Three phase symmetrical short circuit level at the fourth (130 - 199)kV bus, busses split due to high level of short circuit current	Integer
AM	(100 - 129)kV Bus 3ph SC	Three phase symmetrical short circuit level at the first (100 - 129)kV bus	Integer
AN	(100 - 129)kV Bus 3ph SC (2)	Three phase symmetrical short circuit level at the second (100 - 129)kV bus	Integer
AO	(100 - 129)kV Bus 3ph SC (3)	Three phase symmetrical short circuit level at the third (100 - 129)kV bus	Integer
AP	MAX SC	Three phase maximum symmetrical short circuit MVA of all the multiple KV busses listed from Col Y through Column AH	Integer
AQ	Bus Count	Count of the number of busses in Columns Y through AH	Integer

NERC Data Request - Facilitate Reliability Standard Development

PRC-002-2 – Disturbance Monitoring and Reporting Requirements Draft 2

Disturbance Monitoring Equipment (DME) Project 2007-11

http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

DMSDT Data Library for Substations, Generation, Lines, Short Circuit MVA, Special Equipment Data Collection

Column	Column Title	Description	Expected Values
AR	Total # of (600 - 799)/(300 - 499) kV Autotr.	Total number of (600 - 799)/(300 - 499) kV autotransformers for the interconnected substations	Integer
AS	MVA Sizes of (600 - 799)/(300 - 499) kv Autotr.	Individual MVA sizes of the (600 - 799)/(300 - 499) kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
AT	Total # of (500 - 599)/(200 - 299)kV kV Autotr.	Total number of (500 - 599)/(200 - 299)kV kV autotransformers for the interconnected substations	Integer
AU	MVA Sizes of (500 - 599)/(200 - 299)kV Autotr.	Individual MVA sizes of the (500 - 599)/(200 - 299)kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
AV	Total # of (300 - 399) / (200 - 299)kV kV Autotr.	Total number of (500 - 599)/(200 - 299)kV kV autotransformers for the interconnected substations	Integer
AW	MVA Sizes of (300 - 399) / (200 - 299)kV Autotr.	Individual MVA sizes of the (500 - 599)/(200 - 299)kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
AX	Total # of (300 - 499)/(100 - 199) kV Autotr	Total number of (300 - 499)/(100 - 199) kV autotransformers for the interconnected substations	Integer
AY	MVA Sizes of (300 - 499)/(100 - 199) kV Autotr.	Individual MVA sizes of the (300 - 499)/(100 - 199) kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
AZ	Total # of (200 - 299)kV/(130 - 199) KV Autotr.	Total number of (200 - 299)kV/(130 - 199) kV autotransformers for the interconnected substations	Integer
BA	MVA Sizes of (200 - 299)kV/(130 - 199) kV Autotr.	Individual MVA sizes of the (200 - 299)kV/(130 - 199) kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
BB	Total # of (200 - 299)kV /(100 - 129) KV Autotr.	Total number of (200 - 299)kV/(100 - 129) kV autotransformers for the interconnected substations	Integer
BC	MVA Sizes of (200 - 299)kV/(100 - 129) kV Autotr.	Individual MVA sizes of the (200 - 299)kV/(100 - 129) kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
BD	Total # of (130 - 199)kV /(100 - 129) KV Autotr.	Total number of (130 -199)kV/(100 - 129) kV autotransformers for the interconnected substations	Integer
BE	MVA Sizes of (130 - 199)kV/(100 - 129) kV Autotr.	Individual MVA sizes of the (130 - 199)kV/(100 - 129) kV autotransformers, if more than one, use comma delimited format	Comma delimited text, i.e (600,600)
BF	Tielines @ these busses (Y/N), quanity at KV level	Do busses on this row directly connect to tie lines to other entities? If Yes, specify the number at each kV level.	Y or N, 1@500kV, 2@230kV
BG	DC Converter Station @ these busses? (Y/N)	Do busses on this row directly connect to DC converter stations?	Y or N
BH	FACTS, SVC, DVR @ these busses? (Y/N), quanity at kV level	Do busses on this row directly connect to FACTS, SVC, or DVR?	Y or N, 1@230kV
BI	SPS, RAS @ these busses? (Y/N), quanity at kV level	Do busses on this row contain SPS or RAS? If Yes specify which kV level.	Y or N, 1@230kV