SERC Regional Criteria

Intra-Regional Long-Term Study Group Procedural Manual

SERC Reliability Corporation

Revision History

Revision	Date	Comments
1	February 28, 2008	This Rev 1 document is based on Revision 11 of the VSTE Procedural Manual and has been created for general manual updates and to convert the document to the SERC format to serve as the procedural manual for the Intra-Regional Long Term Study Group.
2	October 15, 2009 January 20, 2010	Minor revisions throughout the document to clarify compliance with FAC-012-1 and FAC-013-1; Foreword added to document; Section I.B, Section I.C, and Appendix D removed; Appendices A, C, E, F, and G updated; corrected revision history to reflect proper numbering. SERC Board Executive Committee approved as SERC Regional Criteria
3	March 16, 2011	Revisions to the document to clarify compliance with MOD-010-0. Foreword modified; Section II added – Key Procedures; Section III.B.2-8 added; Section IV.A-G updated; more detail for the DBU process; Section V.B updated; use of FTP site; Appendix A updated; Historical and Projected Work Schedule sheet - removal of the secretary position; Enclosures 1 – 7 updated.
4	March 13, 2013	Revised Enclosure 2 to add OMUA, BUBA, PLUM, OMLP, rename WESTMEMP to WMU, DENL to NLR, CONWAY to CWAY, remove DOE. Added information for adding new areas to the case. Updated Enclosure 5 and section IV.E with further model submission requirements. Updated chairperson duties in Section III.B. Reformatted various examples to better identify them as input code. Added a Review Requirements section for consistency to SERC Regional Criteria documents. Removed language referencing the retired FAC-012 and FAC-013-1.

Responsible SERC Groups

SERC Regional Studies Steering Committee (RSSC) and SERC Long-Term Study Group (LTSG)

Review and Re-Certification Requirements

This procedure will be reviewed every three years or as appropriate by the LTSG and RSSC for possible revision. The existing or revised document will then be re-certified and distributed to all members by the SERC Engineering Committee.

FOREWORD

The SERC Engineering Committee (EC) Intra-Regional Long-Term Study Group (LTSG) Procedural Manual was prepared by the LTSG under the direction of the SERC EC Regional Studies Steering Committee (RSSC). The purpose of this manual is two-fold; first, to document the processes and procedures for the annual SERC Data Bank Update and second, to document the processes, procedures, and study methodology used by the LTSG in executing intra-regional reliability studies.

This LTSG Procedural Manual details the method for submitting steady state data for modeling and simulation of the interconnected transmission system and a means to verify submission of data that conform to NERC Reliability Standards MOD-010 and MOD-011.

The LTSG Procedural Manual also details a method of performing intra-regional transfer capability analysis and a means to establish and communicate transfer capabilities.

Most regional member utilities employ Power Technologies Inc. (PTI) Power System Simulator for Engineering (PSS®E) and Managing and Utilizing System Transmission (PSS®MUST) software. Consequently, the various activities in the procedural manual incorporate PTI's procedures and nomenclature in describing these activities.

Inter-regional transfer capabilities are studied under the Eastern Interconnection Reliability Assessment Group (ERAG) Agreement in various study forums, including the SERC East-RFC Study and MRO-RFC-SERC West-SPP Studies. These inter-regional study efforts are guided by other procedures developed to address these activities, and the results of these studies are not reported by the LTSG.

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I. GENERAL INFORMATION

The LTSG Procedural Manual is prepared and maintained by the LTSG under the direction of the RSSC. The purpose of this manual is to serve as a reference for principle processes and procedures in a continuing effort to promote efficient coordination and implementation of activities of the LTSG.

The LTSG (formerly known as the VST Study Group) was formed in 1968 as a result of reliability agreements signed between CP&L and TVA, VACAR (CARVA) and Southern, and Southern and TVA. The purpose of the agreements was to further augment the reliability of each party's bulk power through coordination of the planning and operation of their generation and bulk power transmission facilities. It was decided that it would be more efficient and productive if the three groups worked together rather than separately in performing joint studies.

In the early 1970's, AEP joined the VST Study Group to form a VACAR-AEP-Southern-TVA (VAST) Study Group to conduct joint current-year operating studies separate from the future-year reliability studies of the VST Study Group.

In 1994, Oglethorpe Power Corporation signed a reliability agreement with TVA and joined the VST Study Group. In 1999, Entergy and Associated Electric Cooperative, Inc. signed appropriate reliability agreements to join the SERC organization and began full participation in what was known as the VSTE Study Group.

In October 2004, AEP joined PJM and in May 2005, Dominion (Virginia Power) joined PJM. In 2006, Ameren, East Kentucky Power Cooperative, Big Rivers Electric Corporation, City of Columbia, MO, Electric Energy, Inc., Illinois Municipal Electric Agency, and Southern Illinois Power Cooperative joined SERC. In 2007, City Water, Light & Power of Springfield, Illinois and LGEE also joined SERC. With the creation of the Electric Reliability Organization (ERO), SERC assumed the functions of the VSTE Study Group and the group was renamed Long-Term Study Group (LTSG).

SERC is now divided into five sub-regions: Central, Delta, Gateway, Southeastern, and VACAR.

SERC East includes the VACAR and Central sub-regions and SERC West includes the Southeastern, Gateway, and Delta sub-regions.

II. KEY PROCEDURES

A. ADMINISTRATIVE PROCEDURE FOR LTSG ROSTER CHANGES

Representatives and alternates are appointed by their companies or entities. They must be signatories to the SERC confidentiality agreement, and cannot be from the marketing side of the business. Liaison will also be maintained with the chairs of the Engineering Committee, RSSC and RSEC subcommittees as appropriate. Prior to changes to LTSG roster, the following criteria need to be met:

1. The sitting LTSG member (or your company's representative from a leadership committee) should notify the LTSG's SERC Support representative of an upcoming transition onto the LTSG. SERC Support (support@serc1.org) should be copied on this notification.
2. Each SERC member company has assigned a "Designated Employee" to assist in administering requirements of the SERC Confidentiality Agreement (also known as a "non-disclosure agreement"). If the Agreement has not been signed, contact your company's Designated Employee to complete the signatory process. Your signature verifies that you comply with the terms of the Agreement so that by virtue of your involvement with the LTSG, you may have access to confidential information in order to perform SERC functions. If required, SERC Support can assist in identifying your company's Designated Employee.
3. Your company's Designated Employee will ensure that SERC Support is provided your name on an updated employee list indicating that you have signed the SERC Confidentiality Agreement.
4. Each SERC member company has also identified a SERC Master Account Administrator (MAA) to provide local assistance in accessing information and data available through the SERC Portal/FTP site. As a new LTSG representative or alternate, contact your company's MAA to establish appropriate access for your role on the LTSG. If required, SERC Support can assist in identifying your company's MAA.

Roster changes shall be submitted and processed through the SERC office, attention sercsupport@serc1.org and the appropriate SERC support staff person. The SERC support staff will notify the committee chair, steering committee chair, company steering and Engineering Committee representatives of the requested changes.

The LTSG chair will notify the group that a member has been added or removed from the roster.

B. MEETINGS AND SCHEDULING

The LTSG typically meets on location twice a year: in May or June for the Data Bank Update and also at the annual summer SERC Regional Study Group meetings to review results from the future year reliability study and to better coordinate LTSG activities with those of the other associated groups. Other meetings are held on an as needed basis. All on location meetings and telephone conference calls are coordinated through the SERC office. Whenever possible, business is conducted via mail, telephone, or electronically. A guiding concern for the scheduling of data collection and the creation of power flow cases is the need to support data submission to the ERAG MMWG. The following items are included in the agenda:

1. The meeting is opened with a review of the SERC Confidentiality Policy and Antitrust Compliance Guidelines.

2. The chair shall present the minutes of the previous meeting to the LTSG and the LTSG shall approve them following discussion unless approved previously via e-mail.

3. SERC staff shall post approved minutes of meetings and telephone conference calls on the SERC portal.

4. The chair reports regarding correspondence or activities affecting the LTSG that have occurred between meetings.

5. The members provide updates on various activities affecting the LTSG.

6. MMWG representative provides an update on activities to the LTSG members.

7. Members shall discuss problems found in the data, database, models, or power flow cases for remedial actions and documentation.

8. RSSC and LTSG membership shall reserve the right to review and update the LTSG Procedural Manual as necessary. Information contained in the Appendices of the LTSG Procedural Manual is subject to changes in instructions. Changes to the LTSG Roster and Rotation Schedule do not require SERC RSSC approval.

9. The member Rotation Schedule is reviewed and modified as necessary.

10. SERC RSSC approval is required for current chair and vice chair assignment changes.

11. The next LTSG meeting is scheduled.

C. DATA REPORTING PROCESS FOR GOS, TOS, RPS AND TPS

The LTSG member representative will send out a data request to entities registered as GOs, TOs, RPs, and TPs every year in the January to April time frame. The data request is accompanied by the data the LTSG member representative has in his/her record for the devices for which the registered entities are responsible in the TP area which the LTSG member represents.

The GO, TO, RP or TP is responsible for verifying the static model data and making changes, as required. The GO, TO, RP or TP then submits the verified data to the LTSG member representative by the deadline specified in the data request. If there are no changes or additions, an e-mail notice to that effect is sufficient.

The GO, TO, RP and TP are accountable only for the data applicable to their registered function and must assure all data for Transmission System Modeling and Simulation submitted to the LTSG member representative is complete, correct and up-to-date.

If any GO, TO, RP or TP responsible for submitting static data to a LTSG member representative is not contacted by a LTSG member, the responsible entity should contact SERC office for assistance.

D. DEFINITIONS OF MMWG POWER FLOW CASES

The definitions of MMWG power flow cases are given in the MMWG Procedural Manual which can be found at the following link.

https://www.rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Pages/default.aspx

III. LONG-TERM STUDY GROUP ACTIVITIES

A. PURPOSE

The LTSG functions under the direction of the RSSC, which reports to the SERC Regional Studies Executive Committee (RSEC). The RSEC includes members from each system participating in LTSG activities. This committee has input to the study activities performed by the study group. More specific information regarding base case development, study work procedures, and study work assignments and schedules are provided in Section III, Section IV, and Appendices A and B, respectively.

The following is a general list of the current responsibilities and activities of the LTSG.

1. Conduct joint studies as assigned by the RSSC to evaluate the performance of bulk power supply facilities under both normal and contingency conditions for future years (i.e., planning horizon). These studies focus on the evaluation of sub-regional and company-to-company transfer capability and may include reliability studies to evaluate summer peak-operating conditions in future years and special studies as assigned by the RSSC.
2. Coordinate voltage levels and reactive interchange between systems.
3. Exchange information on forecasted loads, bulk power facility plans, and system conditions.
4. Publish reports of the joint studies to be used by planning personnel of the SERC Region and the regions.
5. Conduct an annual update of power-flow models to be used for operating and future year studies. These models are incorporated into the power-flow models of the interconnected regions of the North American Electric Reliability Corporation (NERC) updated annually by the ERAG Multi-regional Modeling Work Group (MMWG). Appendix A includes additional information regarding the ERAG MMWG.
6. Investigate improved study methods and procedures and coordinate study parameters with operations personnel for "realism." Provide recommendations to the RSSC on new study methods and procedures.

More specific information regarding base case development, study work procedures, and study work assignments and schedules are provided in Section III, Section IV, and Appendices A and B, respectively.

All LTSG study processes shall be performed in accordance with this procedural manual. As a result, all LTSG reliability study reports shall include the following statement: “The transfer capability values in this study were developed consistent with the Transfer Capability Methodology documented in the LTSG Procedural Manual.”

B. DUTIES OF THE LTSG

1. CHAIRPERSON

The RSSC will appoint one of the LTSG members to serve as the study group chairperson whose term will be rotated among the LTSG systems every two years with the term of office beginning on November 1 of the rotation year.

The chairperson's duties include the following:

a. Prepares schedule of work activities.

b. Ensures the schedules are met.

c. Attends RSSC meetings.

d. Serves as a communications link between the study group and the steering committee.

e. Provides the steering committee reports of current work.

f. Sets the agenda and has minutes prepared for all study group meetings. When approved, minutes are provided for study group and steering committee information.

g. Coordinates periodic updates of the current roster of all members and liaison representatives of the study group.

h. Maintains a current list of the rotated study responsibilities for the study group.

i. With approval from the RSSC, forwards LTSG study reports and appropriate supporting data to the SERC office for public use through adopted procedures for data release. The LTSG chair also forwards approved version of study reports to the LTSG, RSSC, and the SERC Reliability Coordinator Subcommittee (RCS).

j. Coordinates the periodic update of the LTSG Procedural Manual.

k. Sends notification to study group for roster changes.

l. Updates the SERC LTSG Data Bank Update Enclosures for that year’s activities.

m. Submits a “member data submittal confirmation letter” to the SERC office after the DBU to provide evidence for MOD-010 requirements and posts the confirmation letter to the ftp site.

n. Updates on an annual basis, Appendix A – Enclosure 4 based on the current year ERAG MMWG case modeling list.

o. Inform SERC RSSC of any requests related to obtaining transfer assessment methodology or results.

2. VICE CHAIRPERSON

The SERC RSSC chair shall appoint the vice chair from among the member representatives to a two-year term on a rotating basis.

The principal functions of the vice chair are to assist the chair in the performance of the chair's duties and to serve on behalf of the chair during the chair's absence. The vice chair is expected to succeed the chair at the end of the chair's term.

3. DATA BANK UPDATE (DBU) HOST

The DBU Host is rotated between Entergy, Southern and TVA annually. See Appendix A – Historical and Projected Rotation Schedule of Major Assignments.

The principal function of the DBU Host is to coordinate and compile each member's data to create the SERC LTSG power flow base cases. Details for the duties of the DBU are covered in Section IV.F. In addition, the DBU Host is responsible for coordinating the logistics of the meeting with the SERC offices.

4. POWER FLOW RUNNER

The power flow runner is rotated on an annual basis. See Appendix A – Historical and Projected Rotation Schedule of Major Assignments. The primary responsibility of the power flow runner is to perform the linear analysis using member data files and the PSS®MUST program.

5. REPORT WRITER

The report writer is rotated on an annual basis. See Appendix A – Historical and Projected Rotation Schedule of Major Assignments. The primary responsibility of the report writer is to compile member write-ups into the future year report and update the report as needed. See Appendix B - LTSG STUDY REPORT RECOMMENDED OUTLINE

6. SERC MMWG REPRESENTATIVE

The MMWG representative is rotated between Ameren, Dominion, Progress Energies Carolina's and DUKE members on a bi-annual basis. See Appendix A – Historical and Projected Rotation Schedule of Major Assignments.

The principal function of the SERC MMWG representative is to coordinate with other regional representatives the development of designated power flow and dynamics simulation base case models for use by ERAG members for reliability and transfer capability studies.

7. SERC LTSG MEMBERS

Member representatives are responsible for providing the power flow data used in constructing study models and study cases for SERC.

Member Representatives are responsible for making a data request annually to all GOs, TOs and other entities in the member company area based on the Data Coordination Workbook posted on the SERC Portal. In addition, the member representatives are responsible for updating the Data Coordination Worksheet in the Data Coordination Workbook annually, subject to availability of data.

Member representatives are responsible for performing data checks prior to submitting data in order to ensure that the cases assembled by the designated Data Coordinator will solve with a minimum of adjustment.

Details for the duties of the member representatives are covered in Section IV.F and Section V.A.

Finally, the member representatives are responsible for providing support as required for studies assigned to the LTSG by the SERC RSSC.

8. SERC OFFICE

The SERC office is responsible for compiling and updating the applicable registered entity company listing in the Data Coordination Workbook prior to the DBU meeting. In addition, SERC is responsible for notifying the LTSG members of company changes based on NERC registered entities.

C. QUALITY CONTROL

Recognizing the benefits obtained through joint studies and in order to be more effective in its work, the study group has the following recommendations:

1. It is preferred that each system be represented on the study group by experienced persons. When this is not practical, the system with the less experienced person should give that person the training and support necessary to be effective in the study group work. In addition, special considerations will be made regarding the rotation of the study work assignments (including study group chair) in order to accommodate the addition of new/inexperienced personnel to the study group.
2. Each system should give their representative on the study group the necessary commitment of time and support so their representative can be effective and supportive of study group efforts.
3. The RSSC should provide the LTSG chair with the final minutes of its meetings for distribution to LTSG members.

D. ANNUAL ACTIVITIES

The following is an overview of primary LTSG activities. A detailed account of the study group assignments and work schedules is provided in the Appendix A.

Each year, power-flow models representing the SERC Region systems are compiled as part of the LTSG Data Bank Update (DBU). These models serve as the primary starting point for both LTSG and SERC Near-Term Study Group (NTSG) study activities for the year. In addition, these models are submitted to the ERAG MMWG annual update to represent the SERC Region in power-flow cases developed through this organization.

The LTSG will conduct a study each year in the Near-Term Planning Horizon (Year 1-5) as selected by the RSSC, and any other future year studies deemed necessary by the RSSC. The study group may meet several times to fully coordinate and complete each study. At the request of the RSSC, the LTSG may meet with the steering committee to discuss issues related to activities of the study group.

E. DISCLAIMER

The representation of future system elements in the LTSG data models is not an agreement to construct these elements in the time period shown in the models or at a later date. The configuration of each system in the models only reflects the changes that the individual system is predicting will be necessary for maintaining reliable operation. The results of studies obtained through the use of the data models developed by the LTSG will be the sole responsibility of the receiving party.

IV. LTSG POWER FLOW MODEL DEVELOPMENT

A. INTRODUCTION

The LTSG Data Bank is a library of power-flow models for operating and future year studies. Generally, the library contains power-flow models to support the ERAG MMWG modeling effort for the year, additional seasonal models as required to support the NTSG OASIS effort, and other selected models that may be required and agreed to by the study group members. A sample case list, "Enclosure 4", is shown in Appendix A.

The LTSG DBU is under the direction of the RSSC. Current participants in LTSG activities are:

- Alcoa Power Generating, Inc.
- Ameren
- Associated Electric Cooperative
- Big Rivers Electric Corp.
- City of Columbia, MO
- City of Springfield, IL – CWLP
- Dominion Virginia Power
- Duke Energy Carolinas
- LG&E and KU Services Company, Inc for LG&E & KU
- East Kentucky Power Cooperative
- Entergy
- Georgia Transmission Corp.
- Midwest ISO
- Municipal Electric Authority of Georgia
- PowerSouth Energy Cooperative
- Progress Energy Carolinas
- South Carolina Electric & Gas Co.
- South Carolina Public Service Authority
- Southeastern Power Administration
- Southern Company Services
- Southern Illinois Power Cooperative
- Southwest Power Pool, Inc. – SPP
- Tennessee Valley Authority

The DBU is performed each year utilizing the computer facilities of a host company. Under current practice, TVA, Southern Company Services, and Entergy rotate the hosting duties of the DBU each year. A final face-to-face meeting and update session will be scheduled taking into account, as near as practical, the ERAG MMWG deadlines. In exchange for hosting the DBU, this arrangement requires that VACAR or Ameren furnish personnel to serve as the SERC coordinator for ERAG MMWG activities (reference Appendix A).

The LTSG typically uses the version of the PTI PSS®E program that is used by the ERAG MMWG.

B. PURPOSE OF LTSG DATA BANK

To facilitate coordinated planning and operating assessments, ERAG administers the development of a library of power-flow base case models for the benefit of NERC members. This activity is handled by the ERAG MMWG and includes direct representation from each

ERAG region in the Eastern Interconnection (RFC, MRO, NPCC, SERC, FRCC, and SPP) as well as liaison representation from TRE, WECC, and the NERC office.

The SERC data required for base case models developed by the ERAG MMWG is updated and assembled each year at the LTSG DBU, see Appendix A – Enclosure 1. In addition to developing power-flow models for the ERAG MMWG, additional models are developed as directed by the RSSC. The steering committee considers which power-flow models will be needed for use by the various study groups in the following year to continue to meet the goals of the LTSG.

C. PROCEDURES - LTSG SYSTEM DATA

Each year, the system hosting the Data Bank provides detailed instructions to each DBU participant in January (See Appendix A). These instructions set forth the dates for the update, bus number spectrum to be used by each system, the format for the data, etc.

The starting point for each system's data is generally its latest available internal base case library. Revisions are made to these cases as needed to reflect appropriate system representations in ERAG MMWG models.

1. The list of each system's buses to be retained in the LTSG cases is made taking into consideration, particular areas to be studied in the various bulk power planning studies. Each system is allocated a limited number of buses for the LTSG cases. All bus numbers for areas in SERC should remain the same for all base cases developed, corresponding to the bus ranges shown in Appendix A - Enclosure 2. If a system uses several load areas for its internal studies, the areas may need to be combined to accommodate the assigned area numbers for the LTSG study. A member can request to have a separate area number in the LTSG cases by contacting the MMWG representative and the LTSG chair.

   All SERC bus names should have a voltage code in column 1 of the bus names.
   The adopted codes are shown in the following table.

Code	Voltage	Code	Voltage
9	765 kV	4	138 kV
8	500 kV	3	115 kV
7	345 kV	2	46 kV to 69 kV
6	230 kV	1	Below 46 kV
5	161 kV	none	100 kV

   In the ERAG MMWG cases, regional tie lines must have exactly the same bus names for each case included as part of that series of base cases. The ERAG MMWG cases are developed referencing bus names instead of bus numbers to assemble regional tie lines. For this reason, LTSG tie lines to other regions should have exactly the same bus names for each case and must match the ERAG MMWG tie line list exactly (reference Appendix A). Tie line data is maintained in the SERC Master Tie Line list. This reference file is reviewed and modified each year as part of the LTSG DBU process.

Bus numbers within SERC should remain the same in each power-flow case developed as a part of the annual DBU. Generator bus names should remain the same for all base cases. The buses of each LTSG system are renumbered to conform to the assigned bus spectrum for the LTSG DBU, as directed by the ERAG MMWG. For the 2007 model update, ERAG MMWG updated the bus range for each region.

2. Once the power-flow data of each LTSG system has been modified, data files are posted to the SERC portal. The company hosting the LTSG DBU then downloads the data files for compilation. Specific guides for transferring data are contained in Section V.B. The data should be formatted according to the instructions provided by the host company, see Appendix A – Enclosure 5. Each LTSG participant is expected to take appropriate steps to insure that data provided is correct, conforms to the guidelines outlined in Appendix A – Enclosure 8 and can be interpreted by the host company.

3. Cases will be solved using the fixed slope decoupled Newton-Raphson solution method (FDNS) with a tolerance of 1 MW or 1 MVAR. Pass 0 cases should solve within 15 iterations from raw data format using a FDNS mismatch of 1MW.

D. PROCEDURES - EXTERNAL EQUIVALENTS

The base cases developed by the LTSG use the previous year library of ERAG MMWG cases for regions outside of SERC. For all outside equivalents, a 3.0 per unit impedance cutoff should be used to eliminate high impedance equivalent lines in the reductions, and thus help to maintain acceptable solution convergence properties. This process provides the best available data for representing systems outside SERC at the time of the LTSG DBU.

E. LTSG DATA BANK GUIDELINES

The DBU participants meet at the host company to review the LTSG power-flow cases and to finalize the interchange schedule and tie line list.

The following items should be reviewed for each case in the process of fine-tuning the LTSG cases:

1. Each case should have the proper load level and interchange for each system. Reference should be made to the ERAG MMWG Procedural Manual for development of spring, summer, fall, winter, light load and shoulder base cases.
2. Correct impedance, ratings, and tie line ownership data should be entered for all tie lines. A master tie line list is maintained within SERC and is updated for inclusion in the DBU process.
3. There should be no overloaded lines in the SERC LTSG areas.
4. The voltages and the swing bus in each system should have reasonable values for each case. This is particularly important for the outside equivalents. One equivalent is used for several different years and there may be diversity interchanges involved in some of the years and not others that would affect the area swing bus. Adjustment of the generation dispatch in some areas may be required.
5. RAW data files will only be accepted for PASS 1 and PASS 2.

6. Idevs will be submitted for PASS 3 and later.
7. RAW data files that are submitted must come from a solved case.
8. The bus names on both ends of tie lines with areas outside of SERC and the metering points of the tie lines should agree with the ERAG MMWG tie line list.
9. The convergence summary for each power-flow case should be reviewed to see if any particular bus or buses are causing convergence problems and correction should be made if necessary.
10. Checks against the ERAG MMWG case development criteria/guidelines should be made on the cases using the results from the Docucheck Program.
11. When submitting changes to a tie line or an interchange transaction:
    1. Highlight the cells that have been changed.
    2. Highlight the entire row when adding a new tie line or interchange transaction.
    3. Strikethrough the entire row when removing a tie line or interchange transaction.
12. Before the update is completed, the interchange schedule and tie line list to be used by the ERAG MMWG should be finalized. The SERC ERAG MMWG Coordinator should be notified immediately after the update of any changes to the tie line list or interchange schedules. Final checks against the ERAG MMWG case development criteria/guidelines are to be incorporated as part of the LTSG DBU.

F. TYPICAL PROCESS FOR LTSG DATA BANK UPDATE

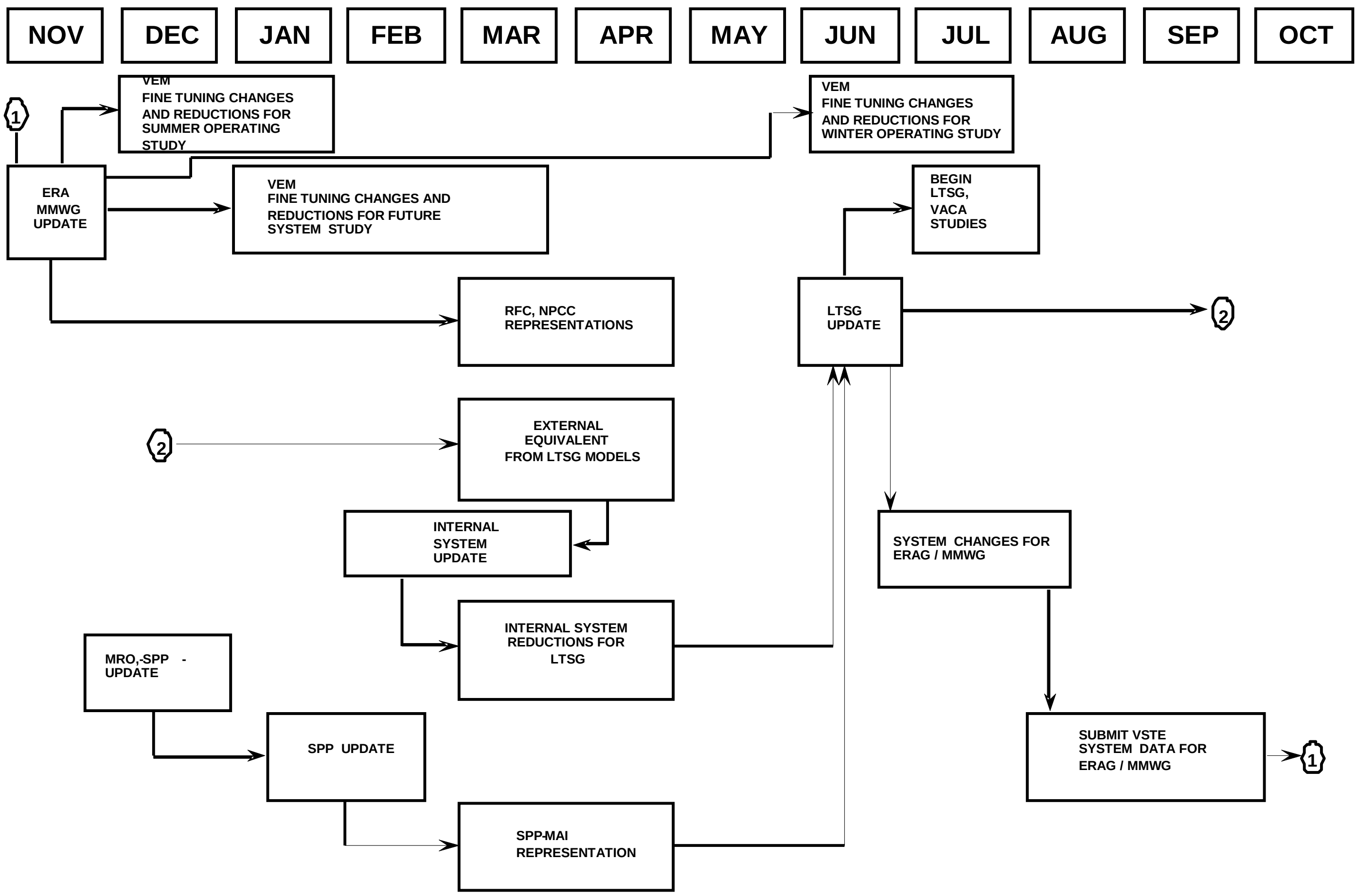
1. The Chair updates the 8 DBU Enclosures (Appendix A) as appropriate. The DBU host company updates Enclosure 5, creates that year's DBU folder, creates subfolders for member data and then posts the Enclosures on the SERC FTP site. Enclosure 6 contains the schedule for the DBU process.
2. The Chair of the LTSG initiates a kickoff teleconference with study group members.
3. The previous year's Master Tie Line list is posted to the SERC FTP site. The master tie line list is provided to each LTSG DBU participant to solicit any necessary changes. If modifications are required, each member shall coordinate the change with the company at the other end of the line. All changes to the master tie line list are incorporated by owner and cross mailed or posted to the SERC FTP site. Appendix A – Enclosure 3 defines company responsibilities for tie line coordination.
4. The previous year's Interchange Table template is posted to the SERC FTP site. Each LTSG member prepares an interchange table and posts it to the SERC FTP site. Members coordinate interchange schedules with parties involved in transactions with their system. Summer and winter peak season interchange data shall be provided for all study years outlined as part of the annual DBU, even if an LTSG case is not being developed for that year. After review, members post their interchange tables to the SERC FTP site.
5. All companies perform N-1 (DCCC) analysis on each case prior to submitting the pass 0 raw file inserts.
6. SERC posts the Data Coordination Workbook to the ftp website. Members fill out their respective Data Coordination Worksheet by listing entities that are a part of their data submission.
7. Each LTSG DBU participant prepares equivalent models of their respective system(s). The raw data files are posted to the SERC FTP site for each case without embedded tie line data. This step is completed at least three months prior to DBU.
8. At least one week after all equivalent models are posted, the host company will merge the models, create the Pass 1 cases, post the cases to the proper folder on the SERC FTP site and then will post Docucheck results.
9. LTSG DBU participants will review the Pass 1 cases, review the Docucheck results and submit IDEV files to make corrections. The host will incorporate the files and post a Pass 2 set of cases on the SERC FTP site along with new Docucheck results.
10. Members will review the Pass 2 cases and submit changes. If time allows, the host will incorporate the changes and post Pass 3 cases along with Docucheck results.
11. Participants gather at the host facility to complete the LTSG DBU.
12. Day 1 (afternoon): Members meet at the host company to integrate computer equipment into the host company configuration. Changes to the cases may be submitted for the host to incorporate that night for review on Day 2.
13. Day 2: LTSG members review all Pass 3 or 4 cases and Docucheck results complete with changes to date. It is expected that the most thorough review be performed on the first passes to minimize additional runs.
14. Day 3: LTSG members review changes incorporated on Day 2, review the Docucheck results and determine if additional changes are required.

15. Remaining days: Reviews continue until all changes have been incorporated satisfactorily.
16. Final changes are made to master tie line list and interchange table.
17. Final models completed by host within two weeks and are distributed to LTSG members along with final master tie line list and interchange table.
18. Following a two-week review period, final models will be posted to the SERC FTP site and made available for public use through adopted procedures for data release.
19. N-1 (DCCC runs) are to be performed on Summer and Future Year Study cases prior to beginning the Future Year Study.
20. The Chair of the LTSG submits a member data submittal confirmation letter to the SERC office. The SERC office sends the confirmation letter to members indicating that the DBU process was completed.
21. Members post updated Data Dictionaries for the final cases to the SERC FTP site.

Data submittal and/or participation in the Data Bank Update will meet compliance requirements specified in Standard MOD-010_R1 and MOD-010_R2.

G. BASE CASE DEVELOPMENT FLOW CHART

Figure 4. Base Case Formulation Flow Chart



V. LTSG TRANSFER CAPABILITY STUDY GUIDELINES

A. GENERAL WORK PROCEDURES

The analysis activities of the LTSG primarily focus on future-year reliability studies of the interconnected transmission system. Studies to be performed by the LTSG are identified and directed by the RSSC. The following is a summary of the LTSG study-work procedures for conducting transfer capability evaluations. Reliability margins (including TRM and CBM) are not considered in the evaluation of incremental transfer capability in LTSG Reliability Studies.

1. Establish base case parameters for peak-load conditions and cases with special conditions ("sensitivities"), if needed. The base case parameters listed below are developed and submitted by each LTSG member based on anticipated peak operating conditions for the member company.
   - Load Forecast and Profile
   - Generation Commitment and Dispatch
   - Projected Transmission Uses (including coordinated interchange)
   - Transmission System Topology
2. Develop study contingency and monitored branch lists (Con and Mon files).
3. Develop generation dispatches for each transfer to be simulated (Sub files).
4. Calculate linear transfer capabilities, NITC, FCITC, and FCTTC values, as appropriate using the PSS®MUST program. The LTSG will use the version of PSS®MUST that is currently in use by the Near Term Working Group (NTSG).
5. Determine the transfer capabilities to be verified by AC power flow.
6. If a voltage problem exists such that the FCITC is determined by a voltage condition, calculate the transfer capabilities based on the AC power flows.
7. Tabulate the base case conditions.
   - Major generation and transmission changes
   - Base case generation dispatch
   - Assumed capacity, load and reserves
   - Base case transcription diagrams
   - Interchange schedule
8. Facilitate common interpretation of study results
   - Meet to review transfer analysis results and documentation of base case conditions
   - Determine response of significant transmission facilities to line outages and/or transfers
   - Determine available Operating Procedures (if applicable)
   - Determine NITC, FCITC, and FCTTC values, as directed
9. Summarize study results and conclusions.
   - Outline system improvements
   - Summarize assumptions (base case and transfer analysis)
   - Identify impacts of external (non-LTSG) systems' base case conditions, as required
   - Identify changes in transfer capabilities from previous study, as directed
   - Operating procedures (if applicable)
   - Significant facilities

B. DATA TRANSFER PROCEDURES

1. Data submitted for base case development and the linear analysis activities should be posted to the SERC FTP Site.
2. Data for base cases will be submitted in PTI format and should be compatible with the current version of PSS®E adopted for use within LTSG. Data submitted for linear analyses are to be submitted in ASCII format (i.e., subsystem description data files, contingency files, and IDEV files).
3. All report data will be submitted in Microsoft WORD© format (i.e., all tables, discussions, system diagrams, etc.).

C. NAMING CONVENTION

Abbreviations

Company Identifiers:

AI	Associated Electric Cooperative Inc.
AM	Ameren
AP	American Electric Power
BR	Big Rivers Electric Cooperative
CE	Carolina Power and Light / East
CW	Carolina Power and Light / West
CL	City Water, Light & Power, Springfield, IL
CM	City of Columbia, MO
DK	Duke
EK	East Kentucky Power Cooperative
EE	Electric Energy, Inc.
EN	Entergy
DS	Delta Sub-region
GS	Gateway Sub-region
GT	Georgia Transmission Corporation
IM	Illinois Municipal Electric Agency
LG	LG&E and KU (formerly E.ON – U.S., LLC)
SC	South Carolina Public Service Authority
SG	South Carolina Electric and Gas
SE	Southeastern Sub-region
SO	Southern Company
SI	Southern Illinois Power Cooperative
TV	Tennessee Valley Authority
CS	Central Sub-region
DVP	Dominion Virginia Power
VC	VACAR Sub-region

Seasonal Load Identifiers:

S	Summer Peak Load
W	Winter Peak Load
Z	Spring Peak Load
F	Fall Peak Load
L	Light Load (Valley)
H	Shoulder

Table Identifiers:

CO	conclusions
MG	major generation changes
MT	major transmission changes
ID	import discussion
CF	critical facilities
VD	VACAR discussion
IT	FCITC tables
TT	FCTTC tables
OG	operating guide
GD	generation dispatch
DI	detailed interchange
IS	interchange schedule
TD	transcription diagram
OL	outage listing
CL	case listing

Base Case Naming Convention

Development:

When developing the base cases, the following naming convention should be used.

If creating a base case starting from the LTSG Data Bank, the case will have the following naming convention:

> **LTSGYYSP#.RAW** denotes that the starting point for the case is the latest **LTSG** Case, **YY** denotes year, **S** denotes season and the **#** denotes the pass number (i.e., 1st pass, 2nd pass, etc.).
> i.e., **LTSG99ZP2.RAW** would denote the case was constructed from the latest **LTSG** data bank for the **1999 spring** peak load case and was the case from the **2nd** pass.

If creating a base case starting from the ERAG MMWG Data Bank, the case will utilize the following naming criteria:

> **NYYSP#.RAW** where the **N** designates the case is being constructed from the latest ERAG MMWG Data Bank.

Finalized Cases:

After all changes have been made and the final base case to be utilized by the study group is completed, the base case naming criteria provides specific case identification. This naming convention includes information identifying whether the case is used for a **R**eliability Study, an **O**ASIS Study, or a **S**pecial Study and includes the **year**, **study season,** and **base coding suffix**. For example:

> **NTR99S00** would denote an NTSG Reliability Study for the 1999 Summer Peak Load Base Case.
>
> **NTS99W000** would denote an NTSG Special Study for the 1999 Winter Peak Load Base Case.

This will identify the type of study, season, and allow up to nine reduced load cases to be constructed if necessary utilizing 10, 11, etc. numbering criteria. (Note: LTSG Future year studies will utilize VF as the case prefix and both the LTSG and NTSG will utilize VS for special studies. The case heading will identify what type of study is being performed.)

The base case headings will state the **year**, **season**, **whether it is an LTSG base case**, **the case file name**, and **date finalized**. For example:

> Heading line #1: `1999 SUMMER PEAK LOAD`
> Heading line #2: `LTSG99S00.SAV: LTSG RELIABILITY BASE CASE FINALIZED 09-20-98`

Note: the base case line #2 should not be modified during a linear run.

Subsystem Description File Examples:

The file name shall specify the company submitting the participation factors (p.f.s) and the file extension shall specify the year and season. For example:

SO99S.SUB includes Southern Control Area p.f.s data for the 1999 summer peak season.

All subsystem labels will be in quotes, identify the company, the MW test level, whether it is for an export or import, and the opposing company. (If the transfer level is valid for all transfers at the specified test level, no opposing system needs to be identified in the subsystem label.) Each subsystem will be commented to clarify the subsystem description. For example:

```
'SO3000IMVC'     /* Southern Company 3000 MW Import p.f.s from VACAR
'SO3000IMTV'     /* Southern Company 3000 MW Import p.f.s from TVA
'SO3000EX'       /* Southern Company 3000 MW Export p.f.s for all 3000 MW exports
'AP3000IM'       /* AEP 3000 MW Import p.f.s for all 3000 MW imports
```

All subsystems will have an END statement between them with no blank spaces between. If the subsystem contains a PARTICIPATE block, it must have an END statement as well. Subsystems will be listed from lowest MW test level import to highest, followed by the lowest export test level to the highest. For example:

```
SUBSYSTEM 'CE700IMSG' /* CP&L-E 700 MW Import p.f.s for transfers from SCE&G
AREA 'number'
PARTICIPATE
   BUS bsid       MW/%  /* Unit Name
   .
   .
   END
END
SUBSYSTEM 'CE1000IMGT' /* CP&L-E 1000 MW Import p.f.s for transfers from GTC
AREA 'number'
PARTICIPATE
   BUS bsid       MW/%  /* Unit Name
   .
   .
   .
   END
END
.
.
.
SUBSYSTEM 'CW500IM' /* CP&L / West import participation factors from all areas
AREA 'number'
PARTICIPATE
   BUS bsid       MW/%  /* Unit Name
   .
   .
   END
END
```

VACAR subsystem description data files shall be submitted separately and identify the company submitting the p.f.s. For example:

VCVP30EX.99S for VP's portion of the VACAR 3000 MW export p.f.s for the 1999 summer

VCCE30IM.99S for CE's portion of the VACAR 3000 MW import p.f.s for the 1999 summer

D. BASE CASE DEVELOPMENT

1. The seasonal power-flow base case will be created using the current version of PSS®E adopted for use within LTSG.
2. Base case developers will issue the reference case for companies to review and update so that all companies will be sending data based on the same case. Base case developers will also send along the interchange schedule associated with the reference case.
3. Model parameters, including generation dispatch, transmission topology and system demand should meet the requirements set forth in the MMWG Procedural Manual.

   https://www.rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Pages/default.aspx
4. Long-term, firm transmission commitments should be included in the model, to the extent possible. Commitments to be modeled across an interchange (adjusting an interchange schedule) must be agreed upon by all applicable parties to that interchange. Therefore, partial path commitments may not always be able to be modeled. If an LTSG member is changing an interchange schedule with a non-LTSG control area, the LTSG member is responsible for submitting generation dispatch and interchange data for the non-LTSG company. The LTSG member must also notify all other LTSG members about this change so that other LTSG members who are changing interchange with the same non-LTSG control area can coordinate. These changes will be coordinated via e-mail and sent to the base case developer as one change for the non-LTSG area. All parties involved must agree to changes to the interchange schedule.
5. Any adjustments to represent loop flows or parallel path flows should be made according to the participating company's planning practices.
6. RAWD updates are acceptable to submit for the first trial. Changes to the second, third, and so-on trials shall be submitted as IDEVs to reduce the problem of massive changes without additional checks.
7. Tie line changes shall be submitted as separate RAWD files.
8. All base cases shall solve using the (FDNS) function with a 1.0 MW mismatch tolerance, within 15 iterations and utilizing a 0.0001 p.u. minimum threshold impedance value (THRSHZ). Automatic adjustments will only include Area Interchange Control and the default setting for the application of VAR Limitations to the case. (Note: it may be necessary to change these parameters to get the model to converge to an acceptable solution during the first few passes. However, the final case submitted to the work group will have the case converge using the above settings.)
9. It is the responsibility of each control area to ensure that switched shunts in their control area do not toggle on and off when trying to develop a base (or reduced load) case when using the above solution criteria.

E. LINEAR LOAD FLOW DATA SUBMITTAL

1. At a minimum, participating companies will submit valid single contingencies 100 kV and above for their systems. An outage facility list will be prepared for each study.
2. Operating procedures (discussed in section L below) used to mitigate limits in study results must be included in the contingency file to be studied. If an operating procedure utilizes a generation re-dispatch, load shedding scheme, or load shift, it shall be included in the contingency file.
3. Monitored areas include all SERC control areas and most control areas interconnected to SERC companies. Other areas may be included as needed for particular studies. The monitored kV range is typically 44-765 kV (this is to prevent GSUs from being included in the output). Additional power system elements not included in this default range may be monitored as needed through supplemental instructions added to the monitored data list specified for each study. A monitor facility list will be prepared for each study.
4. The general format required for the monitored file is:

```
MONITOR BRANCHES IN SUBSYSTEM 'VASTMON'
MONITOR TIES FROM AREA 330
MONITOR BRANCHES IN SUBSYSTEM 'AECI345&UP'
MONITOR BRANCHES IN SUBSYSTEM 'AECI100TO345'
MONITOR VOLTAGE RANGE SUBSYSTEM 'AECI345&UP'     0.92 1.10
MONITOR VOLTAGE RANGE SUBSYSTEM 'AECI100TO345'    0.90 1.05
```

5. Dispatch files should be checked to verify that the values add up to the transfer test level or 100% prior to submittal.
6. Export and import dispatch files will have two END statements.
7. The subsystem name shall be in single quotations.
8. Each company will submit all their import and export participation factors in a single file in ASCII format. The VACAR participation factors will be submitted as separate subsystem files from each company to be combined by the linear runner and inserted into the master subsystem description data file.
9. A master subsystem description data file shall be compiled by the linear runner that will include all participation subsystems and the monitored subsystem. This will allow for the use of a single subsystem file to be loaded into the PSS®MUST program. It shall use the following naming convention: LTSGF07S.SUB (for a master subsystem description file for the **LTSG F**uture-year 20**07 S**ummer Study).

An example of the file is:

```
SUBSYSTEM 'VASTMON'
JOIN
  AREAS 300 400
  AREA  201   /* AP
  AREA  205   /* AEP
  AREA  207   /* HE
  AREA  210   /* SIGE
  AREA  502   /* CELE
  AREA  503   /* LAFA
  AREA  504   /* LEPA
  AREA  515   /* SWPA
  AREA  520   /* CESW
  AREA  523   /* GRRD
  AREA  524   /* OGE
  AREA  540   /* MIPU
  AREA  541   /* KACP
  AREA  544   /* EMDE
  AREA  546   /* SPRM
  KVRANGE 46 765
END
END


SUBSYSTEM 'DK2000EX' /* Duke Scale generation for 2000 MW export
 AREA 342
   PARTICIPATE
      BUS  306460  824      / CLIFSID6
      BUS  306119  620      / 6BUCK
      BUS  306486  169      / ROWANS1
      BUS  306484  157      / ROWANC4
      BUS  306485  157      / ROWANC5
      BUS  306019  54        / BUCK 3
      BUS  306020  19        / BUCK 4
    END
 END


SUBSYSTEM 'DK1000EX' /* Duke Scale generation for 1000 MW export
 AREA 342
   PARTICIPATE
      BUS  306119  517       / 6BUCK
      BUS  306486  169       / ROWANS1
      BUS  306484  157       / ROWANC4
      BUS  306485  157       / ROWANC5
   END
 END


SUBSYSTEM 'DK800EXCW' /* Duke Scale generation for 800 MW export to CP&LW
 AREA 342
   PARTICIPATE
      BUS  306460  800        / CLIFSID6
   END
 END


SUBSYSTEM 'DK2000IMAM' /* DUKE 2000 MW IMPORT FROM AMEREN
 AREA 342
   PARTICIPATE
     BUS 306003  1160  /* CATAWBA #1
    BUS 306004   840  /* CATAWBA #2
```

```
  END
END

END
```

10. The Master Subsystem description file participation factors shall be in the following order: VC, CE, CW, DK, SC, SG, VP, YD, AP, SE, GT, SO, TS, BR, EO, EK, TV, DS, AI, EN, GS, AM, CM, EE, IM, and SI. Each area's unit import participation factors will be listed first followed by their export participation factors.

F. LINEAR LOAD FLOW RUNS

1. The LTSG will use the version of PSS®MUST that is currently in use by the Near Term Working Group (NTSG).: All linear load flow data will be exported to another workbook into a single EXCEL file using **LTSGRYYS#**.XLS as the file name (where: YY denotes year, S denotes season and # denotes the pass of linears). The worksheet title will reflect the transfer (i.e., AEP to VACAR). Heading information in the case does not need to be changed since MUST lists the subsystem file names used in its summary report.
2. In order to maintain correlated input and output data, and to prevent duplication of outputs, only the designated linear runner will issue linear analysis output to LTSG study group members. If additional sets of linears are required or if linears must be repeated to correct input data errors, the designated linear runner will perform these evaluations and distribute results to all study participants.
3. Rerun mailings will be sequentially numbered to help the LTSG know the order that they should insert the reruns in their output.
4. Use the .con file Python scanning routine to check for errors in the file.
5. PSS®MUST should be run from the GUI and the logfile checked for errors in the .con, .mon, and .sub files. Verify that the complete .con file has run by checking the script in the log file that states the number of lines read. Verify that the complete .sub file has been read by verifying that the last subsystem read is available as a valid source/sink.
6. The following linear parameters will be used (parameters are specified for PSS®E but are to be applied to PSS®MUST except where noted):

1:	2	MW Mismatch Tolerance (If using PSS®MUST this parameter may have to be lowered to 0.1 to allow the case to be read into the PSS®MUST program)
2:	1	Base Case Rating (1=Rate A)
3:	2	Contingency Case Rating (2=Rate B)
4:	100	Percent of Rating
5:	1	Line Flow Code (1=AC Base Case)
6:	0	Phase Shifter (Locked=0, Regulating in Base Cases)
7:	1	0=Ignore base case constraints in contingency case, 1=Include)
8:	0	List study system buses (0=No, 1=Yes)
9:	0	List opposing system buses (0=No, 1=Yes)
10:	0	List study system tie lines (0=No, 1=Yes)
11:	0	Add study system ties to monitored line list (0=No, 1=Yes)
12:	0	Output Code (0=Summary, 1=Yes)
13:	0	Interchange Limit Output Code (0=Incremental, 1=Total)
14:	20	Number of elements to include in flow tables
15:	####	Maximum import or export in summary table: 250 MW above test level for 0-500 MW test levels 500 MW above test level for 501-1500 MW test levels 1000 MW above test level for test levels >1500 MW (If using PSS®MUST this option will be in the “FCITC Violations Dialog” options)
16:	0.03	Summary table minimum distribution factor magnitude
17:	##	Summary Table Maximum Times for Reporting this same Event (15 when using Operating Procedures, 5 when no O.P.’s are included in the contingency file)
18:	1	Apply minimum distribution factor to solution reports (0=No, 1=Yes)
19:	0.0	Minimum contingency case pre-shift flow change

20:	0.0	Minimum contingency case distribution factor change
21:	0	Convert Ratings to Estimated MW Ratings (0=No, 1=Yes)
22:	1	Summary Table Contingency Descriptions (0=Labels, 1=Events, 2=Both)

PSS®MUST Specific parameters in "FCITC Violations Dialog" options:

1: Output format selection will use "TWO LINES REPORT" format. (The output will then provide Line Outage Distribution Factors (LODF) for each contingency and Power Transfer Distribution Factors (PTDF) for both monitored and contingency elements).

2: Select the option: "Add Subsystem Adjustments Detailed Report" using the above stated criteria for maximum transfer level.

G. LINEAR ANALYSIS OUTPUT ("DC" POWER FLOWS)

In order to conduct an evaluation of transfer capability, the LTSG uses a "DC" power-flow technique (linear analysis) to determine line-flow conditions for modeled transfers and/or simulated outages of transmission facilities. The following discussions outline required study procedures to conduct and document linear analysis of transfer capability.

H. TRANSFER LEVELS

Study participants determine transfers to be studied and transfer levels to be tested based on the following factors. First, the size of the two parties involved in the transfer should be taken into account. It would not be reasonable to represent a transfer of 3,000 MW between two systems whose respective generating capacity and peak demand did not exceed 3,000 MW. In the same way, it would not be beneficial to simulate a very small transfer between two very large systems. In the latter situation, little information would be gained by the knowledge that the two large systems could transfer a small amount of power with no problems.

Second, the amount of expected reserves for the exporting company will occasionally limit the magnitude of the transfer. In this case, it is occasionally acceptable to decrease load in the exporting company by a reasonable level in order to test a transfer level that will yield beneficial results. For exporting companies outside of SERC, increasing generation geographically "behind" the exporting company can help to supply the needed generation.

Lastly, it is important when doing comparative studies to maintain consistent transfer magnitudes between studies. This prevents a comparison of two unequal quantities. For example, consider the outcomes of two studies that have been done to determine trends in transfer capability from one time period to the next. In one study, a transfer is simulated at 3,000 MW and in another, the same transfer is simulated at 2,000 MW. Suppose that no limit to transfer is found for either time period. In the study results, the FCITC values for the transfer would be listed as 3,000+ and 2,000+ for the two time periods. These study results might mistakenly be interpreted to indicate that transfer capabilities are 1,000 MW more in one time period than in the next. The study results would not accurately represent the trend in transfer capability in this case.

I. DISPATCH METHODOLOGY

The dispatch methodology used for LTSG studies is based on an "emergency demand" scenario. In this scenario, an emergency situation is simulated in which generating facilities within one system are unexpectedly outaged, causing that system to import backup power from a neighboring system. The neighboring system increases their dispatch to a new level in order to meet the importing system's deficiency in addition to their own generation requirements. Therefore, when modeling a transfer, the exporting system picks up generation using an economic dispatch. The importing system, on the other hand, reduces generation at certain plants in order to represent the emergency transfer scenario. When reducing generation on or near the interface between two systems, care must be taken not to distort the results of the study (see NERC's *Transmission Transfer Capability* Document, Page 16).

As stated in the Transfer Levels section, if sufficient generation in an exporting system is not available for the full transfer test amount desired to test each interface, load reduction can be included as a means to meet the export amount. This load reduction should be limited as to not reduce the exporting system's total load beyond the lower limit of the shoulder load definition by SERC and ERAG MMWG guidelines. If load must be reduced to make generation available, the SCALE ALL LOAD specification within MUST will be used to accomplish the reduction. The study results should note whether load was reduced to achieve a satisfactory test level and whether the load reduction had a significant effect on the study results.

J. TRANSFER FACTOR CUTOFF

A facility is generally not reported as a valid limit if the response to transfers [Transfer Distribution Factor (TDF)] is below 2-3% (see NERC's *Transmission Transfer Capability* Document, Page 18.). Usually the facility with a low transfer response is identified as a limit because it is heavily loaded in the base case. The 3% transfer factor cutoff is a guideline, but it is the owner of the facility in question who decides if the facility is a valid limit. To be able to track those facilities with transfer facilities just below 3%, the minimum distribution factor for use in the summary report should be set at 2%.

K. AC POWER FLOW VERIFICATION

As a part of transfer capability assessments, an AC power flow at the transfer test level will also be conducted with the first reported "hard limit" contingency in effect. Any operating procedure in effect to reach the "hard limit" should also be included. This screening is intended to determine if there may be a voltage constraint associated with this contingency below the reported thermal limit. This is not intended to be an inclusive AC verification of system voltages or a verification of the reported thermal constraint calculated from the linear power flow. Should this screening identify a voltage constraint, an additional study will be conducted (i.e., an AC power flow at the "hard limit" transfer level will be constructed to determine if the problem exists). Typically, only sub-regional transfers are tested. Other transfers may be tested at the request of a study group member. AC power flow results and reporting should include a check for thermal overloads and of voltages outside normal ranges, an interchange summary, and a case summary.

Study group members responsible for participating in sub-regional transfers will provide an IDEV file to the company that will be performing the AC verification runs. This IDEV file will re-dispatch the generation and update the area interchange in the participant's sub-region to match the generation participation provided in the subsystem files submitted for the PSS®MUST linears. Some areas may scale load (SCAL, AREA) for their participation in exports. A separate IDEV is generally required for each sub-regional transfer, which should also place into effect any operating guides that are required to reach the identified "hard limit". Once these changes are applied to the study case, the contingency that creates the "hard limit" is implemented. Upon reaching solution, the VCHK command is then used to identify any voltages that may be outside the normal range, typically those less than 0.95 p.u. and those greater than 1.05 p.u. The RATE command is also used to identify any branches that may be loaded greater than 100% of Rate B.

If study instructions specify testing for compliance with NERC Reliability Standards (TPL-001 through -004), each control area will submit the high and low voltage settings and voltage deviation limits (if applicable) for each kV level of their respective control area(s). Using the ACCC function in PSS®E, the power flow runner will perform a check for voltage violations and thermal overloads in the seasonal base case on all submitted contingencies. It is the responsibility of the individual group member submitting an operating guide for use in transfer analysis to ensure that no voltage violations occur due to the use of the operating guide since the ACCC function in PSS®E will not close or re-dispatch during contingency analysis. If there are any thermal and/or voltage constraints that violate NERC standards, they will be listed in the "Base Case Analysis" section of the report. Additional information on the violation (i.e., a list of any improvements to the area have been scheduled, post contingency operating guides, load level at risk, load shedding procedures, etc.) may be included in this section of the report. If there are no violations, a statement to the effect that the base case was checked and that no violations were found, should be included in report documentation.

Examples of the voltage check data:

```
MONITOR FILE DATA:
MONITOR BRANCHES IN SUBSYSTEM 'DUKE500&UP'
MONITOR VOLTAGE RANGE SUBSYSTEM 'DUKE500&UP'      1.00 1.10
MONITOR VOLTAGE DEVIATION SUBSYSTEM 'DUKE500&UP'    .05  .05
MONITOR VOLTAGE RANGE SUBSYSTEM 'DUKE230TO500'     .95 1.055
MONITOR VOLTAGE DEVIATION SUBSYSTEM 'DUKE230TO500'  .05  .05
MONITOR VOLTAGE RANGE SUBSYSTEM 'DUKE100TO230'    .95 1.07
MONITOR VOLTAGE DEVIATION SUBSYSTEM 'DUKE100TO230'  .06  .06
END
END
```

Subsystem File Data:

```
SUBSYSTEM 'DUKE500&UP'
JOIN
  KVRANGE 499 800
  AREA 342
END
END
SUBSYSTEM 'DUKE230TO500'
JOIN
  KVRANGE 229 498
  AREA  342
END
END
SUBSYSTEM 'DUKE100TO230'
JOIN
  KVRANGE 99 228
  AREA  342
END
END
```

An example IDEV to run ACCC (PSS/E Version 30 ONLY):

```
case
C:\LinearsV\HL Cases\LTSG11Supdated.sav
chng     /* set newton iteration limit
7

1
,,100


open
2 0 0
base_case.rate
rate zone
100
1
300 -399

dfax
dfaxlong.out
C:\LinearsV\HL Cases\LTSG11s.sub
C:\LinearsV\HL Cases\LTSG11s.mon

C:\LinearsV\HL Cases\LTSG11s.con

open
2 0 0
base_case.acc

bat_accc 3 1 1 0 1 1 0 0 'dfaxlong.out' 'accc_solution.acc' ' '

bat_pp_accc 2 3 0 0 1 0 0 0 0 9999 90 5.0 99999.0 0.02 3.0 30.0 'accc_solution.acc'
@END
```

L. OPERATING PROCEDURES

Specific study instruction may require the LTSG to identify specific operating procedures where necessary to improve transfer capabilities. When an operating procedure is identified, a verification case should be run with the operating procedure in effect to determine if additional limits to transfers are identified. The table of transfer capabilities should clearly show whether an operating procedure was in effect in order to obtain the noted transfer capability.

In order to comply with NERC guidelines for calculating transfer capabilities (refer *to Transmission Transfer Capability* Document in Appendix C), an automatic or normal operating procedure is characterized as an action that occurs automatically or can and will be implemented pre-contingency. Only operating procedures that meet the "Excluded Limitations" criteria can be implemented post-contingency. It is the responsibility of each LTSG member to determine that operating procedures identified will actually be implemented if conditions warrant. This determination is made by consulting with operations personnel of their respective system responsible for implementing the operating procedure(s). The validity of proposed operating procedures should be verified for each study period.

M. NITC, FCITC AND FCTTC VALUES

The Normal Incremental Transfer Capability (NITC) and First Contingency Incremental Transfer Capability (FCITC) identified through linear analysis techniques are not extrapolated beyond the test level. Extrapolation could result in the assumption that the generators used in the transfer dispatch may either exceed their rated capability or be dispatched to below zero generation. The calculated transfer capabilities shall respect all known System Operating Limits (SOLs).

If the transfer test level was 2,000 MW and the NITC or FCITC were calculated to be 2,175 MW, the reported results would be 2,000+. When the NITCs and FCITCs are equal to or exceed 1,000 MW, they are rounded down to the nearest 100 MW. When they are less than 1,000 MW, they are rounded down to the nearest 50 MW. For example, 1,575 MW would be rounded down to 1,500 MW (assuming the test level was at least 1,500 MW) and 875 MW would be rounded down to 850 MW. For transfers less than 200 MW round down to the nearest 10 MW.

Example MUST Output of FCITC Values
(NOTES: a Base Case FCITC violation is synonymous with NITC violations and the original MUST output has been edited for example purposes only)

21 Tran.DK2000EX CE2000IMDK 2000MW 16:19:34 08/29/2007

PSS(tm)MUST 8.3.1 -- Managing and Utilizing System Transmission -- WED, AUG 29 2007 16:19
2007 SERIES SERC LTSG POWER FLOW MODELS
2011 SUMMER
PEAK

Case.File C:\LinearsVI\LTSG11SupdatedVI.sav

Subsys.File C:\LinearsVI\LTSG11sVI.sub

Monit.File C:\LinearsVI\LTSG11SVI.mon

Contin.File C:\LinearsVI\LTSG11sVI.con

Exclud.File none

Study transfer. From DK2000EX To CE2000IMDK . Transfer level - 2000.0 MW

Violations report ordered by transfer capability. Total 12 violations

Guide	FCITC	N	FCITC	L: Limiting constraint C: Contingency description	Pre-Shift Flow	MW Rating	TDF	LODF	PTDF =	BaseCaseFlow = Init	Final
	550	1	593.5	L: 306106 8PARKWOD 500 306148 6PARKWOD 230 6	714.5	796.7	0.13854		0.08089	417.2	465.2
				C:DUKE0016 404							
				Open 306106 8PARKWOD 500 306148 6PARKWOD 230 5				0.73784	0.07813	403	449.3
	950	3	962.2	L: 306106 8PARKWOD 500 306148 6PARKWOD 230 5	707.9	840.0	0.13726		0.07813	403	478.1
				C:DUKE0016A 405							
				Open 306106 8PARKWOD 500 306148 6PARKWOD 230 6				0.73107	0.08089	417.2	495
	1500	4	1512.1	L: 306127 6ENO 230 306152 6PL GRDN 230 1	-329.6	-478.0	-0.09815		-0.06981	-183.4	-289
				C:DUKE0010 397							
				Open 306106 8PARKWOD 500 306107 8PL GRDN 500 1				0.17825	-0.15902	-820.1	-1060.6
	1500	5	1512.1	L: 306127 6ENO 230 306152 6PL GRDN 230 2	-329.6	-478.0	-0.09815		-0.06981	-183.4	-289
				C:DUKE0010 397							
				Open 306106 8PARKWOD 500 306107 8PL GRDN 500 1				0.17825	-0.15902	-820.1	-1060.6
	1700	7	1784.6	L: 306107 8PL GRDN 500 306177 8WOODLF 500 1	-1526	-1904.3	-0.21220		-0.17815	-1364.4	-1682.3
				C:DUKE0009 396							
				Open 304377 8RICHMON 500 306104 8NEWPORT 500 1				0.17520	-0.19429	-920.4	-1267.1
	1800	8	1806	L: 306107 8PL GRDN 500 306177 8WOODLF 500 1	-1521	-1904.3	-0.21220		-0.17815	-1364.4	-1686.1
				C:DUKE_OG14 774							

Open 306248 GT FALL1 100 306325 WATEREE 100 1	0.00000	0	-37.3	-37.3
Open 306248 GT FALL1 100 306325 WATEREE 100 2	-0.06096	0	-74.6	-74.6
Open 304377 8RICHMON 500 306104 8NEWPORT 500 1	0.17520	-0.19429	-920.4	-1271.3

Generation/Load adjustments in the [DK2000EX] sub-system. Type PartFactSpec.
Total change 2000.0 MW. (! Load Changes are shown with negative sign)

Bus#	BusName	KV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
306019	BUCK 3	13.8	342	1	54.00	0.0	19.0	73.0	19.0	0.0	54.0	73.0	54.0	
306020	BUCK 4	13.2	342	1	19.00	0.0	19.0	39.0	19.0	0.0	20.0	38.0	19.0	
306119	6BUCK	230	342	1	620.00	0.0	0.0	0.0	0.0	0.0	0.0	620.0	620.0	U
306460	CLIFSID6	27.0	342	1	824.00	0.0	0.0	0.0	0.0	0.0	0.0	824.0	824.0	U
306484	ROWANC4	18.0	342	1	157.00	0.0	0.0	0.0	0.0	0.0	0.0	157.0	157.0	U
306485	ROWANC5	18.0	342	1	157.00	0.0	0.0	0.0	0.0	0.0	0.0	157.0	157.0	U
306486	ROWANS1	18.0	342	1	169.00	0.0	0.0	0.0	0.0	0.0	0.0	169.0	169.0	U
	Total				2000.00	0.0	38.0	112.0	38.0	0.0	74.0			

Maximum transfers without violating limits with specified participation factors
Import= 0.0 MW. Export= 0.0 MW

Generation/Load adjustments in the [CE2000IMDK] sub-system. Type PartFactSpec.
Total change -2000.0 MW. (! Load Changes are shown with negative sign)

Bus#	BusName	KV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
304863	1BRUN #2	24.0	340	1	950.00	0.0	0.0	950.0	950.0	950.0	0.0	0.0	-950.0	
304869	1ROX #1	22.0	340	1	369.00	0.0	0.0	369.0	369.0	369.0	0.0	0.0	-369.0	
304872	1ROX #4	24.0	340	1	681.00	0.0	0.0	686.0	686.0	686.0	0.0	5.0	-681.0	
	Total				2000.00	0.0	0.0	2005.0	2005.0	2005.0	0.0			

Maximum transfers without violating limits with specified participation factors
Import= 2000.0 MW. Export= 0.0 MW

N. POSITIVE SIGNS IN REPORT TABLES FOR LODF AND TDF

As part of study-reporting efforts, each study participant is responsible for including LODF values in tables used to summarize calculated transfer capability. As part of performing computer simulations for these studies, the linear runner should provide sufficient data to permit each participant to tabulate LODF values. Particular attention is required if multiple sets of linears have been performed to insure appropriate values are correctly reported. LODF values may be generated using an abbreviated contingency and monitored file that lists only the contingency and monitored elements that will appear in the table. These values can be retrieved using the distribution factor reporting activity [OTDF] function of PSS®E. Specific data output formats using PSS®MUST also provide LODF values as a part of linear analysis results.

The LODF and TDF should be shown as positive values in the tables in the report. The signs of the LODF and TDF are dependent upon the order of the buses for both the monitored and outaged lines (i.e., Oconee-Norcross or Norcross-Oconee). The following table may be used to obtain positive signs for both the LODF and TDF. If the signs are:

TDF	LODF	Action
+	+	No action necessary
+	-	Reverse order of outaged line
-	+	Reverse order of monitored and outaged lines
-	-	Reverse order of monitored line

O. INCREMENTAL TRANSFER CAPABILITY TABLES

The "Interregional and Sub-regional" tables in the LTSG reliability studies are intended to provide a detailed summary of incremental transfer capability values for transfers between the VACAR, Southeastern, Central, Delta, and Gateway sub-regions of SERC. Additional tables of incremental transfer capability values are provided in these studies that detail two-party transfers between the individual companies. These values are obtained from the previously described linear power-flow analysis techniques. The following is a summary of the guidelines, as approved by the RSSC, for documenting incremental transfer, capability values in LTSG reliability study reports.

1. The first data column indicates the evaluated transfer and also provides the generation dispatch of the importing system for the modeled transfer. If the exporting company's load is reduced, the amount of load reduction should be noted here. The exporting system is economically dispatched. More detailed information concerning the generation dispatches is found in Exhibit A of the Supporting Data section of the report.
2. The second data column provides the NITC values (in ascending order) for each evaluated transfer. When practical, an NITC value is recorded for each limit that is encountered up to the transfer test value. Unless otherwise noted, the higher NITC values are determined independent of any Operating Procedures (if applicable to study) associated with the lower NITC values. For reporting purposes, the singular value that represents the maximum transfer capability (i.e., "identified limit") for the evaluated transfer is preceded by an asterisk symbol (*). Whenever there are no identified transfer limitations up to the tested level, only

the test level value is reported in the NITC column and a plus sign ("+") is placed to the right of the NITC value in the footnote indicator column.

3. The third data column provides identifiers that refer the user to footnotes related to the NITC values. The primary purpose of the footnote indicators is to identify the availability and utilization of operating procedures for the evaluated transfer. The absence of a footnote identifier indicates that an operating procedure is not available for that NITC limit and higher values of transfer capability cannot be obtained. The presence of the "(1)" footnote identifier indicates that an operating procedure (if applicable to study) is available for that respective NITC limit and implementation of that operating procedure will be required to obtain higher values of transfer capability. The presence of the "(2)" footnote identifier indicates that this NITC limit represents the maximum transfer capability that can be obtained with a previously implemented operating procedure.
4. For reporting purposes, the first occurrence of an absent or "(2)" footnote identifier indicates that the associated NITC value is the maximum transfer capability with all lines in-service for the evaluated transfer and the NITC value should be denoted by a preceding asterisk symbol (*).
5. The fourth data column provides the FCITC values (in ascending order) for each evaluated transfer. When practical, an FCITC value is recorded for each limit that is encountered up to the transfer test value. Unless otherwise noted, the higher FCITC values are determined independent of any operating procedures (if applicable to study) associated with the lower FCITC values. For reporting purposes, the singular value that represents the maximum transfer capability (i.e., "identified limit") for the evaluated transfer is preceded by an asterisk symbol (*). Whenever there are no identified transfer limitations up to the tested level, only the test level value is reported in the FCITC column and a plus sign ("+") is placed to the right of the FCITC value in the footnote indicator column.
6. The fifth data column provides identifiers that refer the user to footnotes related to the FCITC values. The primary purpose of the footnote indicators is to identify the availability and utilization of operating procedures (if applicable to study) for the evaluated transfer. The absence of a footnote identifier indicates that an operating procedure is not available for that FCITC limit and higher values of transfer capability cannot be obtained. The presence of the "(1)" footnote identifier indicates that an operating procedure is available for that respective FCITC limit and implementation of that operating procedure will be required to obtain higher values of transfer capability after the indicated contingency has occurred. The presence of the "(2)" footnote identifier indicates that this FCITC limit represents the maximum transfer capability that can be obtained after the indicated contingency has occurred with an available operating procedure. For reporting purposes, the first occurrence of an absent or "(2)" footnote identifier indicates that the associated FCITC value is the maximum single-contingency, transfer capability for the evaluated transfer and the FCITC value should be denoted by a preceding asterisk symbol (*).
7. The sixth data column identifies the limiting facility for each reported NITC or FCITC value. The same limiting facility is reported only a maximum of three times for each transfer. Only one limiting facility for parallel or series elements with identical line ratings are reported for the same outage facility.
8. The seventh data column identifies the MVA line rating for the respective limiting facility.
9. The eighth data column identifies the LODF for the respective limiting facility. This value is the response of the limiting facility to the indicated line outage.

10. The ninth data column identifies the TDF for the respective limiting facility. This value is the response of the limiting facility to the transfer after the line outage. NITC and FCITC limits are not reported for limiting facilities with a TDF value of less than 2%.
11. The tenth data column identifies the outaged facility for each reported FCITC value. Outaged facilities in parentheses indicate an operating procedure in effect.
12. The eleventh and final data column provides the operating procedure identifier associated with the transfer limitation and corresponds to the available operating procedure descriptions found in Table K and the footnote indicator in column 3 or 5.

VI. DISTRIBUTION OF PROCEDURAL MANUAL AND COMMENT RESOLUTION PROCESS

This document is publicly available on the SERC web site (www.serc1.org). If a recipient of this LTSG Procedural Manual external to the LTSG, RSSC, or RSEC provides documented technical comments on the Transfer Capability Methodology herein, the LTSG chair shall provide a documented response (after consultation and approval of the RSSC) to that recipient within 45 calendar days of receipt of those comments. The LTSG response shall indicate whether a change will be made to the methodology and, if no change will be made, the reason why. Any changes will be made per the SERC Standing Committee Documents Process.

Questions or comments on this document should be directed to SERC through support@serc1.org.

APPENDIX A – LTSG STUDY WORK

HISTORICAL AND PROJECTED
ROTATION SCHEDULE OF MAJOR ASSIGNMENTS
LTSG

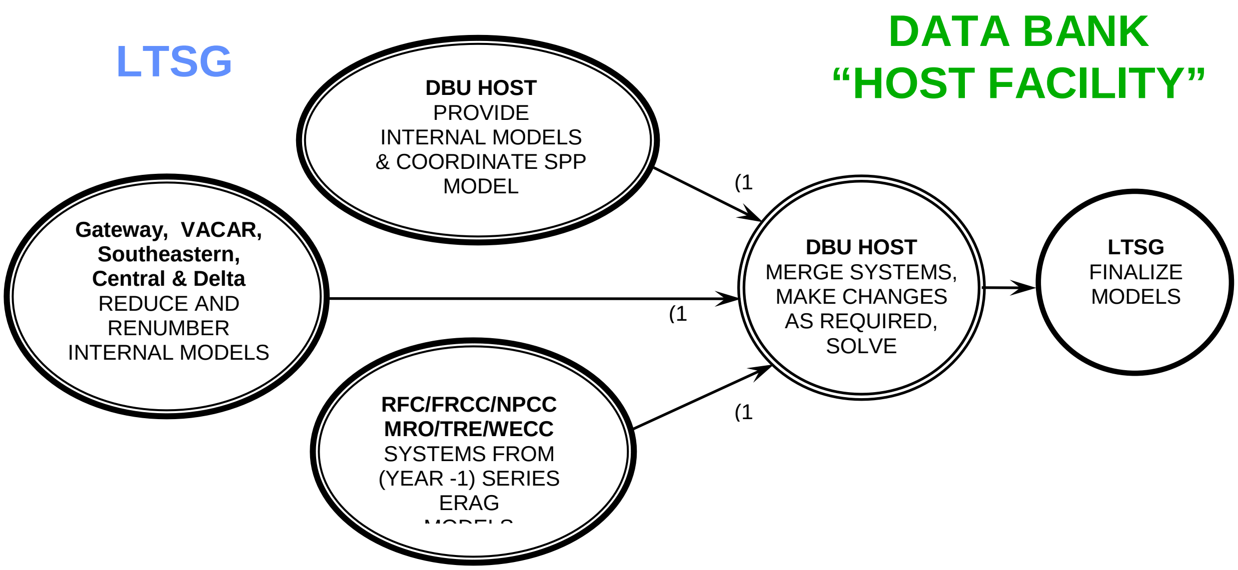
YEAR	CHAIR	VICE CHAIR	POWER FLOW	STUDY REPORT	VACAR DISCUSSION	DATA BANK UPDATE HOST	SERC MMWG
2002	Southeastern (SO)		Delta (EN)	VACAR (SG)	VP	TVA	VP
2003	Southeastern (SO)		VACAR (CP)	Southeastern (SO)	SCPSA	Southern	VP
2004	Delta (EN)		Central (TV)	Delta (EN)	SCE&G	Entergy	CP&L
2005	Delta (EN)		Southeastern (GT)	Central (TV)	CP&L	TVA	CP&L
2006	Central (TV)		Delta (AI)	VACAR (VP)	Duke	Southern	Duke
2007	Central (TV)		VACAR (DK)	Southeastern (GT)	VP	Entergy	Duke
2008	VACAR (VP)	Southeastern (GT)	Central (TV)	Delta (AI)	SCPSA	TVA	Ameren
2009	VACAR (VP)	Southeastern (GT)	Gateway (AM)	Central (TV)	SCE&G	Southern	Ameren
2010	Southeastern (GT)	Gateway (AM)	Southeastern (SO)	VACAR (SC)	CP&L	Entergy	VP
2011	Southeastern (GT)	Gateway (AM)	Delta (EN)	Gateway (AM)	Duke	TVA	VP
2012	Delta (EN)	Gateway (AM)	VACAR (VP)	Southeastern (SO)	SCPSA	Southern	CP&L
2013	Delta (EN)	Gateway (AM)	Central (TV)	Delta (EN)	SCEG	Entergy	CP&L
2014	Gateway (AM)	Central (TV)	Gateway(AM)	Central (TV)	VP	TVA	Duke
2015	Gateway (AM)	Central (TV)	Southeastern (GT)	VACAR (CP)	CP&L	Southern	Duke
2016	Central (TV)	VACAR (CP)	Delta (AI)	Gateway (AM)	Duke	Entergy	Ameren
2017	Central (TV)	VACAR (CP)	VACAR (DK)	Southeastern (GT)	VP	TVA	Ameren
2018	VACAR (CP)	Southeastern (SO)	Central (TV)	Delta (AI)	SCPSA	Southern	VP
2019	VACAR (CP)	Southeastern (SO)	Gateway (AM)	Central (TV)	SCE&G	Entergy	VP
2020	Southeastern (SO)	Delta (AI)	Southeastern (SO)	VACAR (SG)	CP&L	TVA	CP&L
2021	Southeastern (SO)	Delta (AI)	Delta (EN)	Gateway (AM)	Duke	Southern	CP&L

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 1

(YEAR) SERC LTSG DATA BANK UPDATE

DATA DEVELOPMENT FLOW DIAGRAM



Notes: (1) PSS®E Raw Data from solved power-flow cases via SERC

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 2: (YEAR) LTSG DATA BANK UPDATE BUS SPECTRUM

Area	Area Number	Zone Range	Bus Range	Owner No.	Number of Buses
AECI	330	300 - 309	300000 – 302999	300-302	3,000
LAGN	332	310 - 314	303000 – 303999	303	1,000
CP&L-E	340	315 - 324	304000 – 305999	304-305	2,000
CP&L-W	341	within CP&L-E's range	within CP&L-E's range		
DUKE	342	325 - 339	306000 – 309999	306-309	4,000
SCPSA	344	340 - 349	311000 – 312999	310-311	2,000
DVP	345	350 – 374	313000 – 315999	312-314	3,000
SOUTHERN	346	1385 - 1399	380000 – 389999	315-324	10,000
LGEE	363	375 - 384	324000 – 326999	325-327	3,000
OMUA	364	within LGEE's range	within LGEE's range		
SMEPA	349	within Southern's range	318000 - 318999	328	1,000
PS	350	within Southern's range	317000 – 317999	329	1,000
GTC		within Southern's range	within Southern's range		
MEAG		within Southern's range	within Southern's range		
ENTERGY	351	385 - 399	334000 – 338999	330-334	5,000
EES-EMI	326	within Entergy's range	within Entergy's range		
EES-EAI	327	within Entergy's range	within Entergy's range		
PLUM	328	within Entergy's range	within Entergy's range		
OMLP	329	within Entergy's range	within Entergy's range		
BCA	331	within Entergy's range	within Entergy's range		
WMU	334	within Entergy's range	within Entergy's range		
CWAY	335	within Entergy's range	within Entergy's range		
BUBA	336	within Entergy's range	within Entergy's range		
PUPP	337	within Entergy's range	within Entergy's range		
DERS	338	within Entergy's range	within Entergy's range		
NLR	339	within Entergy's range	within Entergy's range		
YADKIN	352	1300 - 1302	339000 – 339049	335	50
SEPA-HARTWEL	353	1303	339050 – 339099	336	50
SEPA-RBR	354	1304	339100 – 339149	337	50
SEPA-JST	355	1305	339150 – 339199	338	50
BREC	314	1310 - 1314	340000 – 340999	339	1,000
EKPC	320	1315 - 1324	341000 – 342999	340-341	2,000
CWLD	333	1325 - 1327	343000 – 343499	342	500
AMMO	356	1330 - 1344	344000 – 349999	343-348	6,000
AMIL	357	within Ameren's range	within Ameren's range		
SIPC	361	1345 - 1349	350000 – 350999	349	1,000
EEI	362	1350 - 1354	351000 – 351049	350	50

TVA	347	1355 - 1374	360000 – 369999	351-360	10,000
DOE	348	within TVA's range	within TVA's range		
SCEG	343	1375 - 1384	370000 – 371999	361-362	2,000
CWLP	360	1328-1329	343500-343999	363	500
TAP	366	1306 – 1308	375000 375099	365 – 366	100

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 3

(YEAR) LTSG DATA BANK UPDATE
TIE LINE RESPONSIBILITIES

VACAR *	VACAR – RFC VACAR – TVA VACAR – TAP VACAR – Internal Ties
SOUTHERN	SOUTHERN – TVA SOUTHERN – Entergy SOUTHERN – VACAR SOUTHERN – FRCC SOUTHERN – SMEPA SOUTHERN – AEC PS – SMEPA SMEPA – Entergy
TVA	TVA – AECI TVA – RFC TVA – AMIL TVA – BREC TVA – EEI TVA – Entergy TVA – EKPC TVA – LGEE TVA – SMEPA TVA – TAP
ENTERGY	Entergy – SPP Entergy – EES-EAI Entergy – EES-EMI Entergy – PLUM Entergy – OMLP Entergy – BUBA Entergy – NLR Entergy – DERS Entergy – PUPP Entergy – CWAY Entergy – WMU Entergy – AECI Entergy – LAGN Entergy – BCA, BCA – TVA LAGN – SPP

	LAGN – SOUTHERN
AECI	AECI – SPP AECI – MRO AECI – RFC
BREC	BREC – SIGE BREC – LGEE BREC – SIPC
EKPC	EKPC – RFC EKPC – DPL EKPC – LGEE
AMEREN	AMMO – AECI AMMO – EES AMMO – ALTW AMMO – AMIL AMMO – MEC AMMO – EEI AMMO – SWPA AMMO – MIPU AMMO – KACP AMIL – ALTW AMIL – AMMO AMIL – RFC AMIL – TVA AMIL – SIPC AMIL – CWLD AMIL – NI AMIL – MEC AMIL – CWLP AMIL – EEI AMIL – NIPS
LGEE	LGEE – RFC LGEE – OVEC LGEE – SIGE

* VACAR will divide this responsibility among the individual VACAR companies.

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 4

(YEAR) SERC LTSG DATA BANK UPDATE
MODELS TO BE DEVELOPED AND CORRESPONDING OUTSIDE SYSTEMS

Example of Table from the 2009 SERC LTSG DBU

FRCC, MRO, NPCC, RFC, TRE, WECC Systems (from ERAG MMWG 11/08) [1]	2009 LTSG UPDATE MODEL	Proposed 2009 MMWG Series Base Cases
2010 Spring Peak	2010 Spring Peak (*)	2010 Spring Peak
2009 Light Load	2010 Light Load (*)	2010 Light Load
2010 Summer Peak	2010 Summer Peak (*)	2010 Summer Peak
2010 Summer Peak	2010 Summer Shoulder Peak (*)	2010 Summer Shoulder Peak
2010 Fall Peak	2010 Fall Peak (*)	
2010/11 Winter Peak	2010 / 11 Winter Peak (*)	2010/11 Winter Peak
2010 Spring Peak	2011 Spring Peak (*)	2011 Spring Peak
2010 Summer Peak	2011 Summer Peak (*)	2011 Summer Peak
2010 Fall Peak	2011 Fall Peak (*)	2011 Fall Peak
2010/11 Winter Peak	2011 / 12 Winter Peak (*)	2011/12 Winter Peak
2014 Summer Peak	2013 Summer Peak	
2014/15 Winter Peak	2013 / 14 Winter Peak	
2014 Summer Peak	2015 Summer Peak (*)	2015 Summer Peak
2014/15 Winter Peak	2015 / 16 Winter Peak (*)	20015/16 Winter Peak
2014 Summer Peak	2016 Summer Peak	
2014/15 Winter Peak	2016 / 17 Winter Peak	
2019 Summer Peak	2020 Summer Peak (*)	2020 Summer Peak

[1] SPP model data obtained through SPP liaison representative to LTSG
*** Base case to be developed for the ERAG MMWG modeling effort**

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 5

(YEAR) SERC LTSG DATA BANK UPDATE DATA CRITERIA

The preference for receipt of data for LTSG Data Bank Update is as follows:

(1) Data characteristics Pass 0 Cases:

- PTI PSS®E Version (TBD each year by MMWG).3 raw data files.
- RAW data files will only be accepted for PASS 1 and PASS 2.
- Idevs will be submitted for PASS 3 and later.
- RAW data files that are submitted must come from a solved case.

(2) Local Computer Requirements/Media at Host company:

- Laptop wireless capability required.
- Attendees need administrator rights on their company laptops.
- Flash drive or CD ROM .
- Text idev files.
- Format for daily idev submittals to be defined by Host.
- Master tieline list and interchange table submittals via Excel spreadsheets.

(3) Internet:

- Host's e-mail coordination address: xxxxxxx@xxxxx.xxx
- SERC LTSG FTP site.
- Initial base case raw data files, interim and final zipped base case .sav files.
- Excel spreadsheets for MTL and interchange table.

(4) Final base cases in PSS®E raw data format along with master tieline list and interchange table will be uploaded to SERC LTSG FTP site

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 6: (YEAR) SERC LTSG DATA BANK UPDATE DRAFT SCHEDULE

Example of Schedule from the 2009 SERC LTSG DBU

February 5, 2009 (Monday)	• SOCO places all 8 enclosures for DBU09 kickoff teleconference on the SERC FTP site
February 10, 2009 (Tuesday)	• LTSG Chair (DVP) initiates DBU09 kickoff teleconference
February 13, 2009 (Friday)	• SOCO creates DBU09 folder and subfolders on SERC FTP site • SOCO posts final Master Tie Line list from DBU08 and Interchange Table Template on SERC FTP
March 6, 2009 (Friday)	• Study group members post the MTL corrections on SERC FTP site • Study group members post populated Interchange Table for all LTSG cases being developed on SERC FTP site. Members will coordinate interchange schedules with parties involved in transactions before submitting.
March 27, 2009 (Friday)	• SOCO posts updated Master Tie Line list and Interchange Table on SERC FTP site • **Study group members post zipped internal models and equivalents in .raw format <u>without</u> embedded tie line data for all cases in one zip file on SERC FTP site.** All companies perform N-1 (DCCC) analysis on each case prior to submitting the pass 0 raw file inserts.
April 17, 2009 (Friday)	• SOCO posts all zipped Pass 1 .sav cases (also in .raw format) for review on SERC FTP site along with Pass 1 Docuchecks
April 28, 2009 (Friday)	• Study group members post .idvs to adjust all Pass 1 cases along with updated MTL and Interchange Table on SERC FTP site
May 8, 2009 (Friday)	• SOCO posts all zipped Pass 2 .sav cases (also in .raw format), Pass 2 Docuchecks, updated MTL, and Interchange Table for review on SERC FTP site
May 19, 2009 (Friday)	• Study group members post .idvs to adjust all Pass 2 cases along with updated MTL and Interchange Table on SERC FTP site
May 28, 2009 (Monday)	• SOCO posts all zipped Pass 3 .sav cases (also in .raw format), Pass 3 Docuchecks, updated MTL, and Interchange Table to SERC FTP site
June 1-5, 2009 (Monday–Friday)	• Study group meets in Birmingham, AL to finalize all LTSG power-flow models, MTL, and Interchange Table. Study group also submits .mon, .con, and .sub files for DCCC N-1 scans.
June 12, 2009 (Friday)	• SOCO posts all finalized zipped .sav cases, zipped .raw cases, Docuchecks, MTL, and Interchange Table to SERC FTP site

July 10, 2009 (Monday)	• Study group members post updated Data Dictionaries for final 2009 series cases on SERC FTP site

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 7

(YEAR) SERC LTSG DATA BANK UPDATE ADDITIONAL ITEMS

(1) All bus numbers for areas in SERC should remain the same for all base cases developed, corresponding to the bus ranges shown on enclosure 2.

(2) All companies are required to perform N-1 (DCCC) analysis on each case prior to submitting the pass 0 raw file inserts.

(3) Bus names in SERC should have a voltage code in column 1. Generator bus names in SERC should remain the same for all base cases developed.

(4) The bus names and metering points of tie buses to areas outside of SERC should agree with the SERC tie line data list used for the ERAG MMWG update.

(5) There should be no overloaded lines in SERC in the base cases developed.

(6) Future Year Study season will be determined by the steering committee. N-1 (DCCC runs) is to be performed on 2009 Summer and Future Year Study cases prior to beginning the Future Year Study.

(7) Bus names/nominal voltage - in PSS®E: the 12-character bus name in the SERC system should have the leading voltage code.

(8) Final cases will be solved using the fixed slope decoupled Newton-Raphson solution method (FDNS) with a tolerance of 1 MW or 1 MVAR. The cases should solve within 15 iterations from raw data format using a FDNS mismatch of 1MW.

SAMPLE LTSG DATA BANK UPDATE INSTRUCTIONS

ENCLOSURE 8

POWER FLOW MODELING GUIDELINES

1. **Modeling Detail** - Lower voltage facilities, parallel transformers, two-line buses, remote bus regulation, variable phase angle regulators, switched shunts, HVDC facilities, and TCUL transformers should not be modeled unless their representation is significant to the proper evaluation of regional and interregional studies.
2. **Nominal Bus Voltage** - All buses must have a non-zero nominal voltage. The equivalent center point bus for three-winding transformer models should be distinguishable and non-zero. It is recommended that such buses should use the appropriate bus name with a 99 kV nominal bus voltage, which is distinctive and recognizable.
3. **Isolated Buses** - Isolated buses should not be modeled in ERAG cases.
4. **Generator Modeling of Loads** - Fake generators should not be used to "load net" (by showing negative generation) a model of other nonnative load imbedded in power-flow areas. It is recommended that a separate zone be used for modeling such loads to allow exclusion from system load calculations.
5. **Zero Impedance Branches** - Bus ties that would normally be modeled in detail should be represented with 0.0001 impedance, or the bus segments should be joined. Zero impedance branches are permitted to model bus ties using R=0.00000 + X=0.0001 and B=0.00000. This will differentiate between zero impedance lines, as designated by the zero impedance cut-off in the PSS®E program (THRSHZ). When attached between two voltage controlled buses (generator, switched shunt, or TCUL controlled), bus ties should be modeled using an impedance of R=0.0001 + X=0.0002 and B=0.00000. This allows use of near-zero impedance attached to controlled buses that will be large enough to avoid significant solution problems.
6. **Maximum Cutoff Impedance** - Where network representation has been equivalenced, a maximum cutoff impedance of 3.0 p.u. should be used.
7. **Tap Changing Transformers** - If tap changing under load (TCUL) transformers are modeled, the tap step size should be no smaller than 0.00625 p.u. and the controlling voltage band should be at least two times the tap step size.
8. **Phase Shifter Models** - Phase shifter sign conventions must be adhered to in all models. The MW tolerance for phase-shifting-under-load transformers should be no less than ± 5 MW; i.e., a 10 MW dead band.
9. **Large Negative Reactance** - Large negative reactance (< -3.0 p.u.) for branches do not represent real devices and are not allowed.

ENCLOSURE 8 (Cont'd)

10. **Branch Ratings** - Normal and emergency seasonal ratings of facilities must be accurate. This is necessary to permit proper assessment of facility loading in regional and interregional studies. In all cases, the Emergency Rating (RATEB) should be greater than or equal to the Normal Rating (RATEA). Ratings need not be provided for model elements, which are part of an electrical equivalent.
11. **Small Generators and Static Var Devices** - Small generators (e.g., 10 MVA) and small static var devices cannot adequately regulate transmission bus voltage (69 kV and above) with their limited reactive capability. Modeling them as regulating only increases solution time. If a number of such machines or devices are located at a bus, they should be lumped into a sufficiently large equivalent to speed solution.
12. **Generator Step-Up Transformers** - Generator step-up transformers should not be modeled as branches unless their representation is deemed necessary for Regional or interregional studies. Their modeling should be consistent with the associated stability modeling of the generator.
13. **Out-of-Service Generator Modeling** - Out-of-service generators should be modeled with a STATUS = 0.
14. **Generator MW Limits** - The generation capability limits specified for generators (PMIN and PMAX) should represent realistic net plant output capability at the bus on which the generator is modeled. Also, PMAX should always be greater than or equal to PMIN.
15. **Generator MVAR Limits** - The var limits specified for generators (QMIN and QMAX) should represent realistic net plant output capability at the bus on which the generator is modeled. Also, QMAX should always be greater than or equal to QMIN.
16. **Remote Regulation** - Remote regulation of more than one bus away is not allowed.
17. **Conflicting Voltage Regulation** - Multiple regulating devices (generators, switched shunt devices, TCULs, etc.) controlling the bus voltage on a single bus must have their scheduled voltage and voltage control ranges coordinated.
18. **Over and Under Voltage Regulation** - It is recognized that there are times when voltage regulation above 1.05 per unit is warranted, such as regulating to 105% voltage on a 525 kV system modeled at a nominal 500 kV. However, regulation should neither be to target voltages in excess of 1.10 per unit, nor below 0.90 per unit. Such voltage extremes are not representative of the real world.

SERC DYNAMICS STUDY GROUP (DSG)

RECOMMENDATIONS FOR SERC LTSG

1. Allocate bus numbers and areas for Florida.
2. Bus numbers to stay consistent in all cases.
3. If possible, generator step-up transformers to be represented explicitly. Explicit generator step-up transformer representation required for Cross compound units.
4. When using implicit generator step-up transformer representation, Rtran and Xtran should be on machine MVA base. Gtap to be actual tap position.
5. If generators have dedicated step-up transformers, separate bus numbers are requested for each unit. If generators share step-up transformers, use one bus and designate units individually.
   a. We need to represent individual units so that we know how many units are dispatched and at what output. (Ok to Gnet less than 25 MW)
   b. Units not dispatched, should be included with status zero.
   c. Pmax and Qmax should not exceed MVA base.
6. Generator Mbase and Zsource should be on the generator base and match dynamics data.
7. Regulate bus voltage on correct side of generator step-up transformer.
8. If possible, generator bus numbers should be grouped together.

POLICY FOR LTSG PARTICIPATION IN ERAG MMWG

1. The VACAR Gateway sub-regions will supply the SERC coordinator for all ERAG MMWG work and provide necessary manpower to assure continuity of the work.
2. Southern Company Services, Entergy, or TVA will perform the Data Bank annual update on a rotating basis, with all costs borne by them.
3. The ERAG MMWG coordinator's work will consist of receiving updated powerflow data for future system base cases from the SERC participants and sending this to the ERAG MMWG Computational Facility (currently AEP) in the proper format. The coordinator will obtain agreement with other regional coordinators on interchange values and tie line data. The coordinator will spend time at the ERAG MMWG Computational Facility as necessary to complete base cases and will meet with other regional coordinators as necessary. He or she will submit SERC data for all summer peak cases according to the schedule determined by the regional coordinators (presently October 1 of each year). Similarly, the coordinator will submit SERC data for the winter operating base case according to the schedule determined by the regional coordinators (presently mid-March).
4. The computer cost for making the ERAG MMWG base cases will be paid by NERC and will be allocated to the regions using the NERC formula.
5. When other entities become active in LTSG work, this policy will be reviewed and revised as necessary.
6. Periodic review of this policy will be conducted and revisions made as needed.

APPENDIX B – LTSG STUDY REPORT RECOMMENDED OUTLINE

VSTE Steering Committee **August 1999**	
	<u>COMMENTS</u>
I. Executive Summary	The Executive Summary should focus on summarizing discussions on transmission limiting facilities. The limiting facilities can be provided in a list (by company) or on a map showing approximate locations. Discussions of transfer capability ranges and transfer capability bubble diagrams can also be useful.
II. Introduction and Study Procedures	Combine the two sections into one.
III. Study Results **A. Significant Facility Discussions**	The Significant Facility Discussions is a major section of the report that itemizes each significant facility including what generation, outages, and transfers affect it. The discussion should also include what approved operating procedures are available and part of current long-range plans to alleviate overloads (if applicable). For any facility that limits transfers, the company that owns the facility should decide whether to include the facility in the Significant Facility Discussions. As a guide, the following factors may be considered when determining if a limiting facility should be included: - if the facility is a hard limit to transfer, - the level at which it limits a transfer compared to the transfer test level, - the response of the facility to the transfer - the number of different transfers/companies impacted, - if a facility requires the use of an operating guide, along with an explanation of the operating guide and when it is to be applied, - if the outage of the facility results in the overload of numerous major transmission elements.
B. Individual Company Assessments	The Individual Company Assessments is also a major section that discusses each company's major transmission or operating condition changes, adequacy of transfer capability ranges (both imports and exports), and expected need for actions to alleviate overloads on significant facilities. This section can also include discussions of any sensitivity study results.
IV. Transfer Tables	This section includes each company's import capabilities and operating guides. No changes are needed to this section.
V. Parallel Transfer Results	This is a new section that provides PSS®MUST graphs showing the impact of cross-regional transfers on selected LTSG transfer

	capabilities (if applicable).
VI. Base Case Analysis **A. ACCC Results**	The ACCC results may be presented in tabular formats.
APPENDICES	
A. Major Generation and Transmission Facility Changes **B. Generation Dispatch Tables** **C. Detailed LTSG Interchanges** **D. Case Interchange Schedule** **E. Outaged Facilities** **F. Case Listing** **G. Abbreviations** **H. Transfer Capability Definitions Major Generation and**	Besides moving the Major Generation and Transmission Facility Changes to the Appendices, no changes are required.

APPENDIX C – TRANSFER CAPABILITY CONCEPTS

CALCULATION OF TRANSFER CAPABILITIES

Line Flows (MW)		
	Limiting Facility	Outaged Facility
Base Case	A	X
Base Case with Outaged Facility	B	
Transfer Case	C	Y
Transfer Case with Outaged Facility	D	

$$\text{LODF} = \frac{B-A}{X} \quad \text{or} \quad \frac{D-C}{Y} \quad \text{(p.u.)}$$

$$\text{PTDF} = \frac{C-A}{\text{Transfer Level}} \quad \text{(p.u.)}$$

$$\text{OTDF} = \frac{D-B}{\text{Transfer Level}} \quad \text{(p.u.)}$$

$$\text{NITC} = \frac{\text{Normal Rating of Limiting Facility - A}}{\text{PTDF}} \quad \text{(MW)}$$

$$\text{FCITC} = \frac{\text{Emergency Rating of Limiting Facility - B}}{\text{OTDF}} \quad \text{(MW)}$$

LODF: Line Outage Distribution Factor

PTDF: Transfer Distribution Factor with no outage

OTDF: Transfer Distribution Factor with outage

NITC: Normal Incremental Transfer Capability

FCITC: First Contingency Incremental Transfer Capability

TRANSFER CAPABILITY CONCEPTS GENERAL DISCUSSION

INTRODUCTION

The concept of "transfer capability" is useful as a measure of the strength of an interconnected power transmission network. Transfer capability definitions have been established by NERC.

While much attention has been given to the application of computers to transfer capability calculations, the need for informal engineering judgment in setting up the calculations has often been overlooked. The principles discussed in this report along with suggestions about making the calculations should be a useful reference for the use of the transfer capability concept.

An operator considers "transfer capability" to be the amount of power transfer that he or she can schedule without compromising system reliability, based on existing conditions. The system planner uses the transfer capability concept as an aid in his or her system design and appraisal. The methods and results used to appraise system strength are useful to an operator by the application of actual system conditions to bias calculated values. This discussion is concerned with the principles involved in the transfer capability concept along with the methods used in the calculations.

PURPOSE OF THE CALCULATION

It is important to carefully consider what transfer capability calculations are intended to accomplish before considering in detail how the calculations can best be made. The basic purpose is to measure the ability of the transmission network to transfer power from one area to another under the most limiting assumptions that are judged to be reasonable. Such a calculation can then be used as a consistent measure of the overall strength of the network that connects the two areas. A series of such calculations shows whether a system is being developed in a manner consistent with load growth. The various factors developed in the calculations can aid operators in actually scheduling transfers, and the studies can identify system weaknesses to planners.

It is emphasized that the exact conditions assumed in a transfer capability calculation probably never occur. What is important is that the conditions that are assumed stress the transmission network in a manner that is representative of the most limiting conditions that can reasonably be expected. This requires sound engineering judgment. Computer-generated conditions can help to screen test situations, but they are no substitute for an intelligent specification of system assumptions.

The most commonly used measure of transfer capability is the "first contingency incremental transfer capability" as defined by NERC. This is the capability to transfer power from one area to another with network loading such that the loss of any single significant facility will not result in any intolerable situation, such as overloaded circuits, unacceptable voltage levels, or loss of stability

Another important measure of transfer capability, as defined by NERC, is the "installed (normal) incremental transfer capability." This establishes the maximum power transfer that can be accomplished without any allowance for facility outages. Power transfer levels approaching this value are scheduled during extreme emergencies to avoid dropping load and sometimes, where a high-capacity line parallels a low-capacity line, transfers are routinely scheduled such that the loss of the high-capacity line would result in tripping the low-capacity line also.

Some systems calculate a transfer capability assuming that a key circuit is out of service for maintenance and making allowance for a second outage. The important point is that, in any case, the calculation being made must be consistent with the application of the results.

BASIC CALCULATION METHOD

There are two basic assumptions made in most methods of calculating transfer capability. One is that a circuit outage distribution factor is a constant; that is, the percent of the load carried by circuit "A" that is transferred to circuit "B" when circuit "A" is lost, is a constant, regardless of the initial loading of the network. A second (and more important) assumption is that a "transfer factor" is constant. This means that the load on a circuit varies linearly with power transfer between areas. Neither of these assumptions is exact, and a discussion of limitations on the use of these assumptions is included later in this report.

Figure 1 shows the basic method used in the normal calculation of thermal transfer capability. Point A is the base case flow in the most limiting circuit. Point B is the flow in the circuit for a test transfer. The point at which a straight line connecting points A and B crosses a horizontal line representing the continuous rating of the limiting circuit is the installed incremental transfer capability - with no allowance for circuit outages. Point C is the load on the limiting circuit with the most significant outage of another circuit. Point D is the load on the limiting circuit with the test transfer and the significant outage. A straight line connecting Points C and D crosses the horizontal line representing the short time rating of the limiting circuit at the first contingency incremental transfer capability.

Each of the four Points, A, B, C, and D, can be determined by test power-flow cases. Often, however, either Point C or Point D is calculated from other points, using the assumption that the effect of the outage on the flow in the limiting circuit is unaffected by transfer level (or that the outage distribution factor is constant). This is done to reduce the number of test cases needed.

The slope of lines A-B and C-D are the transfer factors. These assumed straight lines give the response of the load on the limiting circuit to the power transfer.

The two assumptions of constant outage distribution factors and constant transfer factors give excellent results for most conditions. There are situations, however, where the use of these assumptions causes significant errors, and these situations must be detected and avoided.

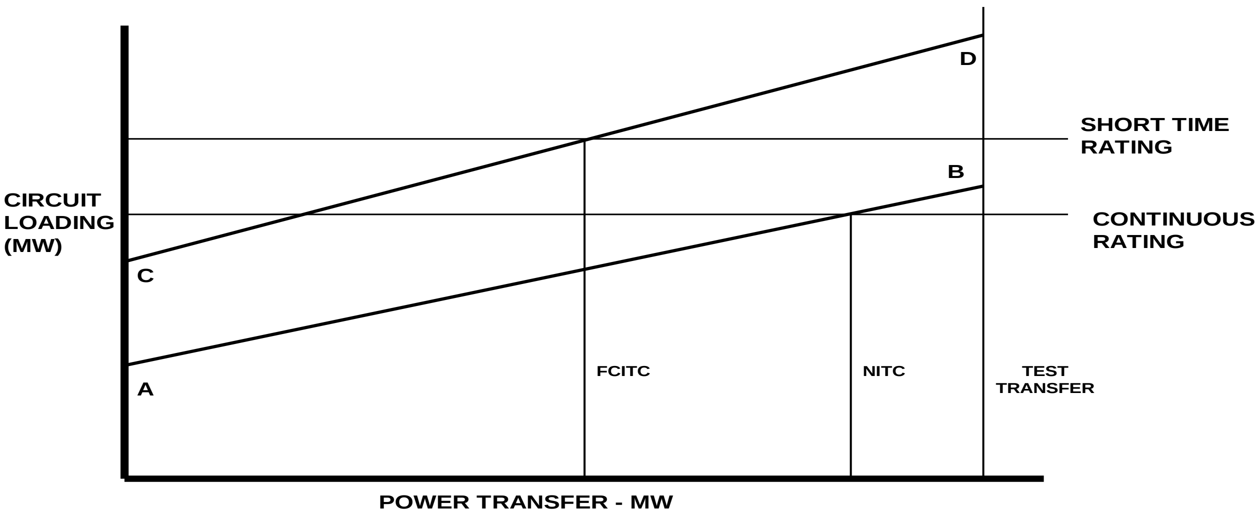
FUNDAMENTAL POWER FLOW EQUATION

To investigate limitations of the basic calculation method, it is necessary to consider the fundamental relationships between power flow in a circuit and other variables. Assuming a Pi equivalent of a line with the shunt capacitances lumped on the buses, the fundamental power flow relationship can be expressed as follows with all values in per unit:

$$P = \frac{N^2}{N^2+1}\frac{1}{X}[V_s V_r \sin\Theta] + \frac{1}{XN}[V_s^2 - V_s V_r \cos\Theta]$$

POWER TRANSFER DIAGRAM

Figure 1



Where: **P** is the power input to the circuit
X is the circuit reactance
$\mathbf{V}_s$ is the sending end voltage
$\mathbf{V}_r$ is the receiving end voltage
q is the angular difference between Vs and Vr
N is the X/R ratio of the circuit

For lines of high **X**/**R**, such as most transmission lines and particularly EHV lines, the second term can be neglected and a reasonable approximation is:

$$P = \frac{V_s V_r \sin \Theta}{X}$$

For relatively small values of q (up to 30° or so), Sin(q) is nearly proportional to q, and P is thus nearly proportional to q, with the other variables constant. For lines having a lower **X**/**R** ratio, the second term in the fundamental equation extends the close proportionality of P and q to somewhat higher values of q. But with increasing values of q, Sin(q) becomes no longer proportional to q; at q = 90° the slope of Sin(q) is zero. For values of q above 90°, the slope of Sin(q) is negative, which, of course, simply shows that the maximum power transfer through a line with no resistance occurs when q = 90°.

LINE OUTAGE DISTRIBUTION FACTOR (LODF)

The outage of a transmission circuit increases the impedance of the network. If the outage does not significantly affect voltage levels, implying adequate reactive supplies on the system, the approximate fundamental formula shows that to maintain a given power flow, then Sin q must increase in proportion to the increase in X. The angular changes distribute the power-flow changes throughout the network. As long as q is in the range where q and Sin(q) are proportional, the percent of the power carried by the lost circuit picked up by each remaining circuit will be essentially constant, regardless of the total power flow.

There may be conditions however, when the power being transferred is large, and there are local situations where a circuit outage results in depressed voltages, and the angles across particular circuits are greater than the range where q and Sin(q) are proportional. In such situations, the increase in power on a particular circuit will be a smaller percentage of the power flow on the circuit that was lost than at more moderate power transfer levels where voltages could be maintained and the angle across the circuit is smaller. These effects can be significant and even extreme as shown by the following table taken from an actual study.

TRANSFER - MW	LODF (%)
0	22.9
1000	20.6
1500	19.5
2000	18.0
3000	10.9

This study modeled a realistic situation as it was made for a pool-to-pool transfer on a 500 kV network where a 2,500 MW transfer had actually been scheduled within the previous year.

This discussion suggests some means of avoiding problems with the application of outage distribution factors. The following procedures can considered:

1. Determine outage distribution factors from tests at the test transfer level (Point B and D in Figure 1).
2. Compare Vs and Vr in the case with the transfer and outage with base values, and note the magnitude moderate, the distribution factor can be used to calculate Point C in Figure 1.
3. If the conditions that are stated in Item 2 are not met, a test case should be run to establish Point C and the use of an outage distribution factor avoided.

TRANSFER FACTOR

An incremental change in power transfer scheduled through a transmission network causes a change in the loading of the circuits in the path of the transfer. As the network is static, the network impedance distributes the power increase in the network circuits, and the power increase on a particular circuit will be proportional to the transfer, provided certain conditions are met. Consider again the approximate fundamental formula. If a transfer results in low voltage at the terminals of a particular circuit, or if the angle across the circuit is large, the circuit will carry less than its proportional share of the power transfer. Furthermore, if the transfer is scheduled by first changing the output of one power station and then the output of a more remote power station, the change in power flow on a circuit will be the result of a combination of the two transfer schedules. The effect of the combination may not be linear.

It has been proposed that test transfers for transfer capability studies can be scheduled more consistently by increasing loads uniformly in one area and reducing them uniformly in the second area. This implies that generation can be considered distributed throughout an area in the same manner that loads are distributed. While this may be approximately true in some particular locations, it is not the general case, and in a critical situation, this assumption may not be realistic. A comparison of using load changes to schedule transfers with scheduling a realistic change in generation has shown that the load change procedure can result in large errors in the loading of significant circuits. Since the magnitude of the error is difficult to predict, the method of scheduling transfers by changing area loads should be used with caution.

Some suggestions on handling some of the difficulties resulting from non-constant transfer factors are as follows:

1. Make test transfers as close as possible to the actual transfer capability. (A simplified DC calculation which is often used to screen the system for significant facilities may be used as a guide).
2. Where test transfers show depressed voltages, extreme angles across lines, or a wide disbursement of power station outputs being changed, make another test transfer to closely bracket the actual transfer capability value.
3. Beware of extrapolation. Remember that a power station output cannot be extrapolated below zero, and that when generating units are taken off the line, they no longer provide reactive support.

OTHER ASSUMPTIONS

In making transfer capability calculations for thermal limitations, it is generally assumed that circuits can be thermally rated in MVA (rather than in amperes) and that the load on the circuit in MW can be compared with the circuit rating in MVA to establish transfer capability. While circuit loading can be converted to amperes, of course, reactive loads and voltage levels have proven difficult to determine accurately in studies, and experience has indicated that this refinement is not necessary. Although it seems somewhat inconsistent, it has been found that comparing the MW loading at the sending end of a circuit with the MVA rating of the circuit at rated voltage produces results that are comparable in accuracy to the rest of the transfer capability calculation. This is primarily because:

1. Reactive load is normally a small fraction of the power load at the sending end of a significant circuit.
2. Voltages are generally depressed much more at the receiving end of a significant circuit, and the sending end voltage must be reasonably good at any transfer level at which receiving end voltages are at all acceptable.

It is also generally assumed that thermal ratings of circuits can be predetermined on a rational basis and that the rating of a circuit is independent of the need for the power transfer. There is little consistency in rating circuits, however, even among members of a power pool. Its owner, taking into account the factors impacting that particular facility, must establish the rating of each facility. It must be recognized that thermal ratings of circuits are very weather sensitive and that different systems consider weather effects differently. It is important to realize that these differences exist, and care must be exercised in interpreting transfer capability results when comparisons must be made between values established by limiting facilities, which have been rated using different philosophies and different degrees of conservatism.

OTHER LIMITATIONS TO TRANSFER CAPABILITY

The discussions thus far have been related to the calculation of transfer capability as limited only by the thermal rating of facilities. Where lines of appreciable length are involved, however, voltage limits and/or stability considerations may establish lower limits to power transfers.

Voltage limits can be established simply by specifying that bus voltage cannot be reduced below a certain level. In using this approach, however, care must be exercised in interpolating (or extrapolating) voltage change as voltage levels do not vary linearly with power transfer. Also, as noted earlier, reactive loads and absolute values for voltage are difficult to accurately model in studies, particularly in longer-range studies.

A useful concept is to limit circuit loading (at least as a first approximation) to a multiple of surge impedance loading according to a curve developed in a general study. Circuits can be loaded greater than this curve under favorable conditions, particularly with good reactive support in the receiving area, but care should be exercised in exceeding these values. In any case, the general shape of the curve is valid for voltage-limited circuits, and appropriate modifications can be made for special circumstances. The use of the curve will allow rating circuits of different lengths and different voltages on a consistent basis down to lengths where thermal limitations prevail.

Stability effects are more difficult to predict. If there are questions of stability, there seems to be no substitute for making stability studies with the anticipated transfer in effect. It can be noted that transfers tend to depress voltages as they affect stability; sufficient reactive supply to support voltage levels will also help any stability problem.

CONCLUSION

The useful concept of transfer capability must be applied carefully to be meaningful. Calculations must be made properly, assumptions must be consistent, and results must be interpreted with care. Problems with the calculation of transfer capability values can be overcome by full consideration of the principles involved. This report should be a useful reference for transfer capability principle, and the suggestions it contains should be helpful in obtaining accurate results.

Transfer capability is a good network analysis concept. However, as with any other analysis tool, it must be used properly.

REFERENCES

(1) National Electric Reliability Council - Transfer Capability - A Reference Document - October 1980
(2) H. P. St. Clair - Practical Concepts in Capability and Performance of Transmission Lines - AIEE Transactions Paper 53-338
(3) Federal Power Commission - The 1970 National Power Survey - Page IV- 2-12

NOTES

This paper was originally written by Charles L. Rudasill of Virginia Power.

SURGE IMPEDANCE LOADING

The surge impedance of a transmission line is:

$$Z_o = \sqrt{(X_L)(X_C)}$$

Where X_L and X_C are the inductive and capacitive reactances respectively.
The surge impedance loading (SIL) is then:

$$SIL(3\Theta) = \frac{(kV_L)^2}{Z_o} MW$$

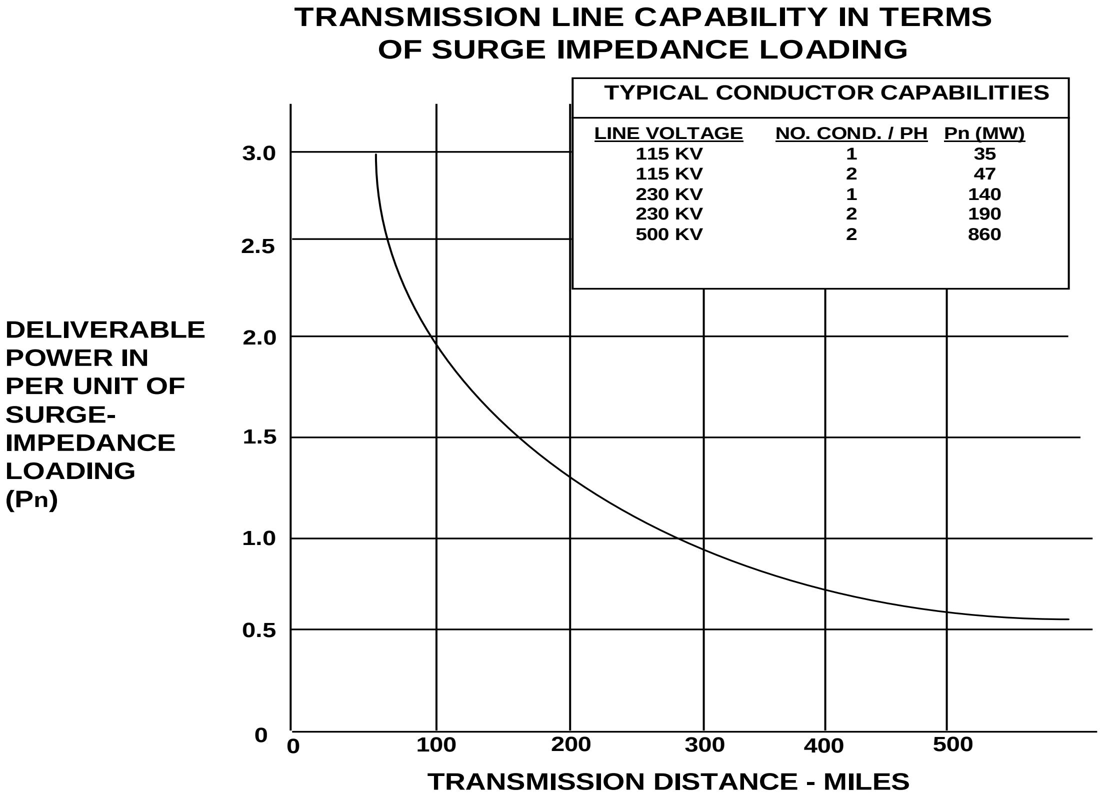
A transmission line loaded to its surge impedance loading has no net reactive power flow into or out of the line and will have approximately a flat voltage profile along its length. In other words, at SIL, a transmission line will have all the vars required by the series inductance of the line supplied by the shunt capacitance of the line so that no external var support is needed to maintain constant voltage everywhere along the line.

The surge impedance of a line is determined by the physical constants of the line such as conductor spacing and diameter, and the operating voltage. However, the surge impedance of a line may be varied by either series or shunt compensation so it agrees with the existing load on the line. This may be done with automatic control of the compensation so the voltage is held nearly constant along the line length.

A useful curve follows showing the approximate maximum loading of a transmission line expressed in terms of surge impedance loading. This curve can be used in the absence of more detailed analysis and is generally applicable for all transmission voltage levels. The curve is based on a relatively safe angle of 35 degrees as far as system stability is concerned between the sending and receiving end of the line. It should be noted from the curve that for lines less than 50 miles in length, the capability of the line is limited by its thermal rating rather than by SIL considerations.

REFERENCES

(1) Simpson Linke, "Surge-Impedance Loading and Power Transmission Capability Revisited", IEEE paper No. A77 249-6 presented at IEEE Winter Meeting, New York, N.Y., in 1977.
(2) Edward W. Kimbark, "A New Look at Shunt Compensation", IEEE paper No. 82 SM 415-8 presented at IEEE PES meeting, San Francisco, CA, 1982.
(3) EPRI, "Transmission Line Reference Book, 345 kV and Above", Second Edition, Revised 1987, pp 20-24, 124-125.


TRANSMISSION LINE CAPABILITY IN TERMS
OF SURGE IMPEDANCE LOADING
TYPICAL CONDUCTOR CAPABILITIES
LINE VOLTAGE NO. COND. / PH Pn (MW)
115 KV 1 35
115 KV 2 47
230 KV 1 140
230 KV 2 190
500 KV 2 860
DELIVERABLE POWER IN PER UNIT OF SURGE-IMPEDANCE LOADING (Pn)
3.0
2.5
2.0
1.5
1.0
0.5
0
0
100
200
300
400
500
TRANSMISSION DISTANCE - MILES

APPENDIX D – GLOSSARY OF TERMS

Capacity - The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Baseload Capacity - Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.

Peaking Capacity - Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

Net Capacity - The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, and less the capacity used to supply the demand of station service or auxiliary needs.

Intermediate Capacity - Capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.

Firm Capacity - Capacity that is as firm as the seller's native load unless modified by contract.

Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

Capacity Benefit Margin (CBM) - That amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements (see Available Transfer Capability).

Cascading - The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in an uncontrolled, widespread collapse of system power which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Contract Path - A specific contiguous electrical path from a Point-of-Receipt to a Point-of-Delivery for which transfer rights have been contracted.

Control Area/Balancing Authority - An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling its generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the Interconnection. A control area must be able to:

1. Directly control its generation to continuously balance its actual interchange and scheduled interchange, and;
2. Help the entire interconnection regulate and stabilize the interconnection's alternating current frequency.

Contingency - The sudden, unexpected failure or outage of a system component or element, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Probable Contingency - The loss of any single system component.

Credible, Less Probable Contingency - The loss of two or more system elements in a single substation, generating plant, or on a transmission right-of-way.

Severe Contingency - The loss of all elements in a single substation at one voltage level plus transformation or the entire substation, all generation at a plant, or all lines on a common transmission line right-of-way.

Distribution Factors - Measures of the electrical effect of power transfer on system facilities or an outage (removal from service) of a system facility or element on the remaining system facilities.

Line Outage Distribution Factor (LODF) - A measure of the redistribution of power on remaining system facilities caused by an outage of another system facility, expressed in percent (up to 100%) of the pre-contingency loading on the outaged facility.

Power Transfer Distribution Factor (PTDF) - A measure of the responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer. The PTDF applies only for the pre-contingency configuration of the systems under study.

Outage Transfer Distribution Factor (OTDF) - The electric power transfer distribution factor (PTDF) with a specific system facility removed from service (outaged). The OTDF applies only for the post-contingency configuration of the system under study.

Distribution (or Response) Factor Cutoff - The suggested minimum level or magnitude of the line outage distribution factor (LODF), the power transfer distribution factor (PTDF), or the facility outage transfer distribution factor (OTDF) considered significant and used in transfer capability calculations or other system analyses. LODFs, PTDFs, or OTDFs below 2-3% generally should not be considered in determining transfer capabilities. The suggested distribution factor cutoffs should not be universally applied without good engineering judgment. Any significant facility with a distribution factor below the cutoff should still be closely monitored in the analyses to ensure its limits are not exceeded and that system reliability will be maintained.

Disturbance - An unplanned event that produces an abnormal system condition.

Eastern Interconnection Reliability Assessment Group (ERAG) - An agreement signed by the six regional councils of the Eastern Interconnect to enhance reliability of the international bulk power system through reviews of generation and transmission expansion programs and forecasted system conditions within the boundaries of the Eastern Interconnection.

Incremental Heat Rate - The amount of additional heat that must be added to a thermal generating unit at a given loading to produce an additional unit of output. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh) of output.

Interchange - Operational term for power that flows from one control area to another. “Interchange” is synonymous with “transfer.”

Actual Interchange - Net metered power that flows from one control area to another.

Scheduled Interchange - Power scheduled to flow between control areas, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time.

Interchange Scheduling - The actions taken by scheduling entities to arrange transfer of power. The schedule consists of an agreement on the amount, start, and end times, ramp rate and degree of firmness.

Inadvertent Interchange - The difference between a control area's actual interchange and scheduled interchange.

Net Schedule - The algebraic sum of all scheduled transactions across a given transmission path or between control areas for a given period or instant in time.

Interconnection - When capitalized, this term means any one of the four major interconnected areas of NERC, which are comprised of one or more of the electric systems in the United States and Canada: the Eastern Interconnection, the Western Interconnection, the Quebec Interconnection, and the ERCOT Interconnection. When not capitalized, this term means the facilities that connect two electric systems or control areas.

Interface - The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

Island - A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Lambda - A term commonly given to the incremental cost that solves the economic dispatch calculation. It represents the cost of the next kilowatt-hour that could be produced from dispatchable units on the system.

Load Factor - A measure of the degree of uniformity of demand over a period of time, usually one year, and equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

Load Shedding - The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loop Flows - See Parallel Path Flows.

Margin - The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW).

Adequate Regulating Margin - The minimum online capacity that can be increased or decreased to allow the electric system to respond to all reasonable instantaneous demand changes to comply with the Control Performance Criteria.

Available Margin - The difference between Available Resources and Net Internal Demand, expressed as a percent of Available Resources. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippages.

Capacity Margin - The difference between net capacity resources and net internal demand expressed as a percent of net capacity resources.

Model Definition

Summer Peak Load - The summer peak demand expected to be served, reflecting load reductions for peak shaving. Summer interchange schedules should reflect transactions expected to be in place on July 15. Planned summer maintenance of generation and transmission should be reflected in the operating year case.

Winter Peak Load - The winter peak demand expected to be served, reflecting load reductions for peak shaving. Winter interchange schedules should reflect transactions expected to be in place on January 15. Planned winter maintenance of generation and transmission should be reflected in the operating year case.

Light Load - A load level in a typical early morning in April, modeling near-minimum load conditions. Pumped storage hydro units should either be modeled off-line or in the pumping mode, with appropriate pumping interchange schedules in place. Dispatchable hydro units should generally be modeled off-line, with run-of-river hydro on-line. Generation dispatch and interchange schedules should be commensurate with the experience of the regions during such load periods, not just including firm transactions. Planned spring maintenance of generation and transmission should be reflected in this case. Summer ratings should be used.

Shoulder Peak - Defined as 70%-80% of summer peak-load conditions. Pumped storage hydro units should be modeled online, but not at full generating capacity (generally not pumping). Dispatchable hydro units should generally be modeled online (probably not a maximum generation), with run-of-river hydro online. Generation dispatch and interchange schedules should be commensurate with the regions during such load periods, not just including firm transactions. Summer equipment ratings should be used.

Fall Peak Load - At typical October peak-load condition: Pumped storage hydro units should be generally modeled online, but not necessarily at full generating capacity (generally not pumping). Dispatchable hydro units should generally be modeled online, but not necessarily at maximum generation, and run-of-river hydro should be modeled online. Generation dispatch and interchange schedules should be commensurate with the experience of the regions during such load periods, not just including firm transactions. Planned fall maintenance of generation and transmission should be reflected in this case. Summer equipment ratings should be used.

Spring Peak Load - At typical April peak-load condition: Pumped storage hydro units should be generally modeled online, but not necessarily at full generating capacity (generally not pumping). Dispatchable hydro units should generally be modeled online, but not necessarily at maximum generation, and run-of-river hydro should be modeled online. Generation dispatch and interchange schedules should be commensurate with the experience of the regions during such load periods, not just including firm transactions. Planned spring maintenance of generation and transmission should be reflected in this case. Summer equipment ratings should be used.

Multiregional Modeling Working Group (MMWG) - An ERAG Group that includes direct representation from the eight NERC regions in the Eastern Interconnection, as well as a working group coordinator representing the supplier of computer services, a liaison representative of the NERC staff, and corresponding representative from the ERCOT and WSCC Regions. The MMWG is responsible for developing and maintaining a power-flow base case model library for the benefit of NERC members.

Net Capacity Resource - The total owned capacity, plus capacity available from independent power producers, plus the net of total capacity purchases and sales, less the sum of inoperable capacity, and less planned outages.

Net Dependable Capacity - The maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries.

North American Electric Reliability Corporation (NERC) - A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of eight Regional Reliability Councils whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these councils are from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The Regional Reliability Councils are: Electric Reliability Council of Texas, Inc. (ERCOT); Florida Reliability Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool, Inc. (SPP); Western Electricity Coordinating Council (WECC).

OASIS (Open-Access Same-Time Information System) - An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Operating Guides - Operating practices that a control area or systems functioning as part of a control area may wish to consider. The application of guides is optional and may vary among Control Areas to accommodate local conditions and individual system requirements.

Operating Procedures - A set of policies, practices, or system adjustments that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected systems. These actions or system adjustments may be implemented in anticipation of, or following a system contingency or system disturbance, and include, among others, opening or closing switches (or circuit breakers) to change the system configuration, the re-dispatch of generation, and the implementation of Direct Control Load Management or Interruptible Demand programs.

<u>Automatic Operating Procedures</u> - Operating procedures that require <u>no intervention</u> on the part of system operators for their operation. These require special protection systems (or remedial action schemes) or other operating systems installed on the systems that automatically alleviate system problems after a contingency has occurred.

<u>Normal (Pre-Contingency) Operating Procedures</u> - Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

<u>Post-Contingency Operating Procedures</u> - Operating procedures that are invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Parallel Path Flow - The flow of power on an electric system's transmission facilities resulting from scheduled power transfers between two other systems. It is the difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop Flows, Unscheduled Power Flows, and Circulating Power Flows.

Ratings - The operational limits of an electric system facility or element under a set of specified conditions.

<u>Normal Rating</u> - The rating as defined by the facility owner that specifies the level of loading (generally expressed in MVA or other appropriate units) that a system, facility, or element can support or withstand through the daily demand cycles without the loss of equipment life.

<u>Emergency Rating</u> - The rating as defined by the facility owner that specifies the level of loading (generally expressed in MVA or other appropriate units) that a system, facility, or element can support or withstand for a period of time sufficient for the adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of equipment life or safety limitations of the equipment involved. This rating is not a continuous rating.

<u>Continuous Rating</u> - The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in MVA or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life.

Thermal Rating - The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Real-Time Operations - The instantaneous operations of a power system as opposed to those operations that are simulated.

Region - One of the NERC Regional Reliability Councils or Affiliate.

Regional Reliability Council - One of eight Electric Reliability Councils that form NERC.

Reliability - The degree of performance of the elements of the bulk power system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system: Adequacy and Security.

Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reserve

Operating Reserve - That capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages, and local area protection.

Spinning Reserve - Unloaded generation, which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve - An amount of Spinning Reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve - An additional amount of Operating Reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this Operating Reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Non-spinning Reserve - That Operating Reserve not connected to the system but capable of serving demand within a specific time, or Interruptible Demand that can be removed from the system in a specified time. Interruptible Demand may be included in the Non-spinning Reserve provided that it can be removed from service within ten minutes.

Planning Reserve - The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Sub-region - A portion of a region. A sub-region may consist of one or more control areas.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Small-Signal Stability - The ability of the electric system to withstand small changes or disturbances without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance.

Voltage Stability - The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Stability Limit - The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

Tie Line - A circuit connecting two or more control areas or systems of an electric system.

Transfer Capability - The measure of the ability of interconnected electric systems to reliably move or transfer power (generally measured in megawatts) from one area to another area by way of all transmission lines (or paths) between those areas under specified system conditions. In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, sub-region or region, or a portion thereof.

Available Transfer Capability (ATC) - A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Non-recallable Available Transfer Capability (NATC) - Total Transfer Capability less the Transmission Reliability Margin, less non-recallable reserved transmission service (including the Capacity Benefit Margin).

Recallable Available Transmission Capability (RATC) - Total Transfer Capability less the Transmission Reliability Margin, less recallable transmission service, less non- recallable transmission service (including the Capacity Benefit Margin). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

First Contingency Incremental Transfer Capability (FCITC) - The amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, all facility loading are within normal ratings and all voltages are within normal limits.
2. The electric systems are capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element such as a transmission line, transformer, or generating unit.
3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency

operator-initiated system adjustments are implemented, all transmission facility loading are within emergency ratings and all voltages are within emergency limits.

Normal Incremental Transfer Capability (NITC) - The amount of power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-contingency loading reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

First Contingency Total Transfer Capability (FCTTC) - The total amount of power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Simultaneous Transfer Capability - The amount of power that can be reliably transferred between two or more areas of the interconnected electric systems as a function of one or more other electric power transfers concurrently in effect.

Non-Simultaneous Transfer Capability - The amount of power that can be reliably transferred between two areas of the interconnected electric systems when other concurrent normal base power transfers are held constant.

Economy Transfers - Power that is scheduled and reliably transferred between two areas or entities in the short term, or in the spot market, to take advantage of the disparity in the cost of electric power between the entities, thereby reducing operating costs and providing mutual benefits.

Emergency Transfers - Power that is scheduled and reliably transferred from an area with sufficient generating capacity margin to an area that has a temporary deficiency of generating capacity or other deficit system condition.

Scheduled Transfers - Power that is scheduled by or through control areas to be reliably transferred between buying and selling areas or entities.

Normal Base Power Transfers - Power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved. Other transfers, such as emergency or economy transfers are usually excluded.

Transmission Constraints - Limitations on a transmission line or element that may be reached during normal or contingency system operations.

Transmission Reliability Margin (TRM) - That amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions (see Available Transfer Capability).

Unit Commitment - The process of determining which generators should be operated each day to meet the daily demand of the system.

Voltage Collapse - An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Limits - The voltages within which the interconnected electric systems are to be operated.

Normal Voltage Limits - The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable on a sustained basis.

Emergency Voltage Limits - The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Wheeling - The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

APPENDIX E – ERAG MMWG POWER FLOW MODELING GUIDELINES

Excerpt from the ERAG MMWG Procedural Manual Version 3 (Dated: October 28, 2008)

1. **Modeling Detail** - All transmission lines 115 kV and above and all transformers with a secondary voltage of 115 kV and above should be modeled explicitly. Significant looped transmission less than 115 kV should also be modeled.
2. **Nominal Bus Voltage** - All buses should have a non-zero nominal voltage. Nominal voltages of buses connected by lines, reactors, or series capacitors should be the same. The following nominal voltages are standard for AC transmission and sub-transmission in the United States and/or Canada and should generally be used: 765, 500, 345, 230, 161, 138, 115, 69, 46, 34.5, and 26.7 kV. In addition, significant networks exist in Canada having the following nominal voltages: 735, 315, 220, 120, 118.05, 110, 72, and 63.5.

   Nominal voltages of generator terminal and distribution buses less than 25 kV are at the discretion of the reporting entity.

   If transformers having more than two windings are modeled with one or more equivalent center point buses and multiple branches, rather than as a three-winding transformer model, it is recommended that the nominal voltage of center point buses be designated as 999 kV. Because this voltage is above the standard range of nominal voltages, it can easily be excluded from the range of data to be printed in power-flow output.
3. **Isolated Buses** - Isolated buses should not be modeled in MMWG cases.
4. **Generator Modeling of Loads** - Fictitious generators should not be used to “load net” (by showing negative generation) a model of other nonnative load imbedded in power-flow areas. It is recommended that a separate zone be used to model such loads to allow exclusion from system load calculations.
5. **Zero Impedance Branches** - Bus ties that are opened to represent switching during contingencies may be modeled in detail. Zero impedance branches are permitted to model bus ties using R=0.00000 + X=0.00001 and B=0.00000. These values facilitate differentiating between bus ties and other low impedance lines, utilizing the zero impedance threshold THRSHZ in the PSS®E program. When connected between two voltage-controlled (generator, switched shunt, or TCUL controlled), bus ties or other low impedance lines should be modeled using an impedance of R=0.0001 + X=0.002 and B=0.00000. This allows use of near-zero impedance attached to controlled buses that will be large enough to avoid significant solution problems.
6. **Impedance of Branches In Network Equivalents** - Where network representation has been equivalenced, a maximum cutoff impedance of 3.0 p.u. should be used.
7. **Negative Branch Reactances** - Except for series capacitors, negative branch reactances do not represent real devices. Their use in representing three-winding transformers is obsolete. Negative branch reactances limit the selection of power-flow solution techniques and should be avoided. -
8. **Transformers** - Effective with Revision 28 of PSS™E, off-nominal turns ratios may not be specified for branches; a block of four or five data records must be entered for each transformer. The off-nominal turns ratio in per unit, or the actual winding voltage in kilovolts, and the phase shift in degrees shall be specified for each winding. The measured impedance (resistive and inductive) between each pair of windings shall be specified: data entry options permit these to be entered in (1) per unit on system (100 MVA) base, (2) per

unit on winding MVA base, or (3) load loss in watts and impedance on winding MVA base and base voltage.

9. **Transformers Controlling Voltage or Reactive Power Flow** - The upper and lower limits of off-nominal turns ratio and the number of tap positions available are entered for winding 1 of transformers controlling voltage or reactive power flow. Default values of 1.1, 0.9, and 33 are representative of U.S. practice. The upper and lower voltage limits are entered for transformers controlling voltage and the difference, in per unit, should be at least twice the tap step size. The upper and lower MVAR limits are entered for transformers controlling reactive power flow, and these limits should differ by at least ten MVAR. Limits should accurately represent the actual operation of automatic control devices.

10. **Remote Regulation** - Regulation of a bus voltage more than one bus away (not counting hidden center point buses of three-winding transformers) from the regulating device should be avoided. The sign of parameter CONT determines whether the off-nominal turns ratio is increased or decreased to increase voltage at the bus whose voltage is controlled by this transformer.

11. **Phase Angle Regulating Transformers** - For phase angle regulating (PAR) transformers, the active power flow into winding 1 is entered. The tolerance should be no less than five MW; i.e., a ten MW dead band. The controlling band should be at least ten degrees. .

12. **Branch and Transformer Ratings** - Accurate normal and emergency seasonal ratings of facilities are necessary to permit proper assessment of facility loading in regional and interregional studies. Three rating fields are provided for each branch and each transformer winding. Normal and emergency ratings should be entered in the first two fields (RATEA and RATEB, respectively); use of the third rating field (RATEC) is optional. Ratings should be omitted for model elements which are part of an electrical equivalent. The rating of a branch or transformer should not exceed the rating of the most limiting series element in the circuit, including terminal connections and associated equipment. The emergency rating should be greater than or equal to the normal rating.

13. **Generator Step-Up Transformers** - Generator step-up transformers may be modeled explicitly as deemed necessary by either the transmission owner or the Regional Reliability Organization. Their modeling should be consistent with the associated dynamics modeling of the generator. Generator step-up transformers of cross-compound units should be modeled explicitly.

14. **Out-of-Service Generator Modeling** - Out-of-service generators should be modeled with a STATUS equal to zero.

15. **Generator MW Limits** - The generation capability limits specified for generators (PMIN and PMAX) should represent realistic seasonal unit output capability for the generator in that given base case. PMAX should always be greater than or equal to PMIN. Net maximum and minimum unit output capabilities should be used unless the generator terminal bus is explicitly modeled, the generator step-up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.

16. **Generator MVAR Limits** - The MVAR limits specified for generators (QMIN and (QMAX) should represent realistic net unit output capability of the generator modeled. QMAX should always be greater than or equal to QMIN. Net maximum and minimum unit output capabilities should be given unless the generator terminal bus is explicitly modeled, the generator step-up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.

17. **Small Generators, Capacitors, and Static VAR Devices** - Small generators (e.g., ten MVA), small capacitors, and small SVCs have limited reactive capability and cannot effectively regulate transmission bus voltage. Modeling them as regulating increases solution time. Consideration should be given to modeling them as non-regulating by specifying equal values for QMIN and QMAX. If several similar machines or devices are located at a bus and there is a need to regulate with these units, they should be lumped into an equivalent- to-speed solution.

18. **Coordination of Regulating Devices** - Multiple regulating devices (generators, switched shunt devices, tap changers, etc.) controlling the bus voltage at a single bus, or multiple buses connected by Zero Impedance Lines as described above, should have their scheduled voltage and voltage control ranges coordinated.

    Also, regulated bus voltage schedules should be coordinated with the schedules of adjacent buses. Coordination is inadequate if solving the same model with and without enforcing machine regulating limits causes offsetting MVAR output changes greater than 500 MVAR at machines connected no more than two buses away.

19. **Over and Under Voltage Regulation** – Regulation of voltage schedules exceeding 1.10 per unit, or below 0.90 per unit should be avoided.

20. **Flowgates** - All transmission elements comprising part of one or more flowgates should be included in the data submitted by each region. A flowgate is a selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage stability, rotor angle stability, and contractual system constraints to power transfer.

21. **Fixed Shunts** - All fixed shunt elements at buses modeled in the power flow should be modeled explicitly (not as loads or included with load). The status should be set to zero if the shunt is not in service. Fixed shunt elements that are directly connected to a bus should be represented as bus shunts. Fixed shunt elements that are directly connected to and switch with a branch should be represented as line shunts.

22. **Switched Shunts** - Switched shunt elements at buses modeled in the power flow should be modeled explicitly. Continuous mode modeling using a switched shunt should not be used unless it represents actual equipment (e.g. SVC or induction regulator). The number and size of switched admittance blocks should represent field conditions. The bandwidth (difference between VSWHI and VSWLO) of switched shunt devices should be wide enough that switching one block of admittance does not move the voltage at the bus completely through the bandwidth, thus causing solution problems at the bus. It is recommended that the minimum voltage bandwidth be 4% if only switched shunts are used to regulate voltage. Switched shunts should not regulate voltage at a generator bus, nor should they be connected to the network with a zero impedance tie.

23. **Interchange Tolerances** - In a solved case, the actual interchange for any area containing a Type 3 (swing) bus should be within 25 MW of the specified desired interchange value. (Note that PSS™E does not enforce the interchange deviation for areas containing Type 3 buses.)

24. **Scheduled Interchange vs. Scheduled Tie line Flows** - Scheduled interchange between areas directly connected solely by ties with flows controlled to a specific schedule (PAR-controlled AC or DC) should be consistent with the PAR or DC scheduled flows.

APPENDIX F – ABBREVIATIONS

AEC	Alabama Electric Cooperative, Inc.
AEP	American Electric Power System
AM	Ameren
AMIL	Ameren Illinois (AmerenCILCO, AmerenCIPS and AmerenIP)
AMMO	Ameren Missouri (AmerenUE)
AP	Allegheny Power
BREC	Big Rivers Electric Corporation
CE	Commonwealth Edison
Central	Central subregion of SERC
CIN	Cinergy
CP&L	Carolina Power and Light Company (Progress Energy Carolina)
CP&LE	Carolina Power and Light Company - East
CPL&W	Carolina Power and Light Company - West
CWLD	City of Columbia, MO
CWLP	City Water, Light & Power – Springfield, IL
Delta	Delta subregion of SERC
DLCO	Duquesne Light Company
DOE	Department of Energy
DUKE	Duke Energy Carolinas
DVP	Dominion Virginia Power
EEI	Electric Energy Incorporated
EES	Entergy Electric System
EES-EAI	Entergy Arkansas
EES-EMI	Entergy Mississippi
EKPC	East Kentucky Power Cooperative
EES	Entergy Corporation
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
EST	Entergy-Southern-TVA
FRCC	Florida Reliability Coordinating Council
FCITC	First Contingency Incremental Transfer Capability
Gateway	Gateway subregion of SERC
GTC	Georgia Transmission Corporation
HE	Hoosier Energy Rural Electric Cooperative, Inc.
IMEA	Illinois Municipal Electric Agency
KU	Kentucky Utilities
LGE	Louisville Gas & Electric
LGEE	Louisville Gas & Electric and KU
LODF	Line Outage Distribution Factor
LTSG	SERC EC Intra-regional Long Term Study Group
MEAG	Municipal Electric Authority of Georgia
MISO	Midwest ISO
MMWG	Multiregional Modeling Working Group
MRO	Midwest Reliability Organization
NCEMPA	North Carolina Eastern Municipal Power Agency
NERC	North American Electric Reliability Corporation
NIPSCO	North Indiana Public Service Company
NITC	Normal Incremental Transfer Capability
NPCC	Northeast Power Coordinating Council

NP&L	Nantahala Power and Light Company
NTSG	SERC EC Intra-regional Near-Term Study Group
OPC	Oglethorpe Power Corporation
OTDF	Transfer Distribution Factor with Outage
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection (Pennsylvania, New Jersey, Maryland Interconnection)
PSS®E	Siemens PTI's Power System Simulator for Engineering software program
PSS®MUST	Siemens PTIs Managing and Utilizing System Transmission software
PTDF	Transfer Distribution Factor without outage
PTI	Power Technologies, Inc.
RFC	ReliabilityFirst Corporation
RRS	Reliability Review Subcommittee
RSEC	SERC Regional Studies Executive Committee
RSSC	SERC Regional Studies Steering Committee
SBA	Southern Balancing Authority
SCEC	South Central Electric Companies
SCE&G	South Carolina Electric & Gas Company
SCPSA	South Carolina Public Service Authority
SCS	Southern Company Services, Inc.
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Corporation
SIGE	Southern Indiana Gas and Electric Company
SIPC	Southern Illinois Power Cooperative
SMEPA	South Mississippi Electric Power Administration
Southern	Southern Company
Southeastern	Southern subregion of SERC
SPA	Southwest Power Administration
SPP	Southwest Power Pool
TAP	APGI-Tapoco Division
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolina's sub-region of SERC (formerly CARVA)
VAST	VACAR-AEP-Southern-TVA
VASTE	VACAR-AEP-Southern-TVA-Entergy
VP	Virginia Power (See also DVP)
VST	VACAR-Southern-TVA
VSTE	VACAR-Southern-TVA-Entergy