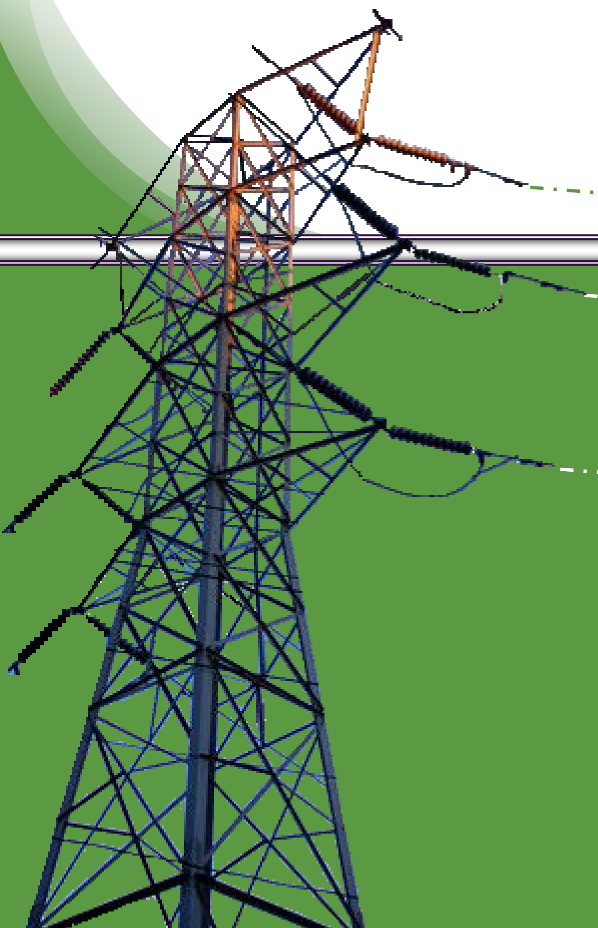
Eastern Interconnection
Reliability Assessment Group

Multiregional Modeling Working Group (MMWG)

Procedural Manual

Version 18



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Foreword

This manual, developed by the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG), provides the background and purpose of the Group, lists the guidelines and procedures adopted by the Group, and is intended to be a ready reference for each participant. This manual will be revised as needed to meet the needs of MMWG. The MMWG Procedural Manual is intended to minimize problems and delays in this time-critical effort. This manual is for use by the Data Coordinators and the MMWG Coordinator for the purpose of creating and maintaining the power flow base case series and creating and maintaining the web System Dynamics Database (webSDDB) and dynamics simulation cases, which are to be used to evaluate the dynamic performance of the systems of the Eastern Interconnection.

The MMWG Coordinator and most utilities in the Eastern Connection employ Siemens Power Technologies Inc. (PTI) Power System Simulator (PSS™E) software. Consequently, the various activities in the procedural manual incorporate PTI's procedures and nomenclature in describing these activities.

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1. Introduction

The MMWG is comprised of representatives from the Planning Coordinators (PC) in the Eastern Interconnection as well as liaison representatives of the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), ReliabilityFirst Corporation (RF), Midwest Reliability Organization (MRO), Florida Reliability Coordinating Council (FRCC), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC) and Southwest Power Pool Regional Entity (SPP RE). The group appoints the Chairman and Vice Chairman for two-year terms based on an established rotation among its members. The group is charged with the responsibility for developing and maintaining a series of power flow and dynamics base cases for the benefit of the electric industry. These cases may be obtained by following the Model Release Procedure in section 7.

A series of power flow cases is created annually for selected years and seasons within the planning horizon. Each case reflects the recently forecasted load at each node or bus on the interconnected system, the branches (lines and transformers) linking buses, the generating units available to supply the load, and the patterns of generation and interchange determined by economics and maintenance within the constraints of available capacity.

Increased demands on generating and transmission systems result in a need for a better understanding of system dynamic response. As a result of the interconnection between power systems, disturbances which occur on one system may affect the operation of interconnected systems. In order to properly simulate the behavior of the Eastern Interconnection it is necessary to develop and maintain representative dynamics simulation cases of the system using detailed data and to utilize widely available dynamic simulation software.

The Data Coordinators are responsible for submitting the dynamics data for the Data Submitting Entity which they represent along with any necessary alterations for the MMWG power flow cases which permit the dynamics data to be linked to the power flow cases. The MMWG Dynamics Coordinator represents the contractor who receives the dynamics data and power flow cases from which the webSDDB is updated and dynamics simulation cases are created. Dynamics cases are created annually.

2. Purpose of the MMWG

The purpose of MMWG is to coordinate, in a timely manner, the development of designated power flow and dynamics simulation base case models that realistically simulate steady state and dynamic bulk electric system behavior. To achieve this purpose, MMWG has established a set of common objectives and timetables for data submission. Generally, MMWG develops a series of operating and planning power flow and dynamics simulation models for industry use for reliability and transfer capability studies.

Of paramount importance in this effort is the detail in which the various systems are modeled. The detail included in each system model must be adequate for all interregional and intraregional study activities but not necessarily as detailed as required for internal studies. This means that each system model should include sufficient detail to ensure that power transfers or contingencies can be realistically simulated. Consideration of program limitations and other factors may inhibit each system from including a fully detailed representation at all voltage levels. However, any principal bulk electric facility that may be adversely affected by a contingency in another system should be included.

The series of base case models will be updated annually to assure that each model contains the best available data for the time period modeled. Anyone conducting a study may find it necessary to represent local system conditions and facilities in more detail, but substantial updating of other systems at the time of use should not be required. It is also expected that users will update the study area to incorporate changes in system plans which have occurred since the data for MMWG model was assembled.

In order to accurately simulate the performance of the interconnected electric systems, detailed rather than classical dynamics models are utilized. Standard PSS™E models shall be used, except as noted below, to make the database as widely useable as possible. Models are included of all equipment that significantly influences the performance of the bulk power system. The objective is to provide interregional dynamics databases and dynamics simulation cases that can be used to accurately evaluate the performance of the Eastern Interconnection.

3. MMWG Scope

3.1. Background

Many electric systems are experiencing increased loadings on portions of their transmission systems, which can, and sometimes do, lead to lightly damped, low frequency (0.2-0.8 Hz) inter-area oscillations. Such oscillations can severely restrict system operations by requiring the curtailment of electric power transfers. These oscillations can also lead to widespread system disturbances if cascading outages of transmission lines occur due to oscillatory power swings. It is also not uncommon for many generators throughout the interconnected systems to participate to some degree in these inter-area oscillations.

To properly capture the dynamic behavior of interconnected electric systems requires good dynamics modeling of all of the interconnected systems within state-of-the-art software capabilities. ERAG is playing a leading role in developing system representations for use in power flow and system stability studies because of the need for simulation models that cover a wide geographic area. It is not possible for an individual Planning Coordinator (in most cases), power pool, or system to successfully construct an accurate system dynamics simulation model without input from other interconnected systems. ERAG's continued leadership and coordination activities in the creation and maintenance of large interconnected electric system models are important to the development of an integrated webSDDB.

Many ERAG members are now faced with the need to accurately establish transmission limits--including those limits based on system stability considerations--in responding to requests from independent power producers and others for transmission services. The credibility of the databases needed to make such studies is important. Therefore, it will be essential that the stability models be developed on a coordinated basis, following well-defined procedures. ERAG is in a unique position to achieve this goal.

3.2. Scope of Activities

In carrying out the above purpose, the MMWG will:

A. Establish a schedule for all case development work.

B. Annually develop a series of solved power flow models of the Eastern Interconnection for use by industry.

C. Maintain a database (webSDDB) of annually updated system dynamics modeling data of the Eastern Interconnection.

D. Develop initialized dynamics simulation models of the Eastern Interconnection annually for at least two time periods — near term and approximately five years into the future. These dynamics models shall be based on selected models from the power flow model series.

E. Annually review the power flow base case and system dynamics simulation model requirements of the Eastern Interconnection and recommend power flow and system dynamics models to be developed.

F. Maintain a Procedural Manual for use by the Data Coordinators in submitting power flow and system dynamics modeling data, and for use by the MMWG Coordinators in developing power flow and dynamics simulation models.

G. Work with the Data Coordinators and the Data Submitting Entities to coordinate and ensure the timely submission of system data.

H. Keep abreast of the modeling requirements of the Regions and member systems and adopt or develop improved modeling and data handling techniques as required.

I. Evaluate alternative methods and software for developing the MMWG series of solved power flow models and the initialized system dynamics simulation models.

3.3. Representation

The MMWG membership shall be comprised of one power flow representative and one dynamics representative from each of the Data Submitting Entities and non-voting representatives as follows: one liaison representative each of the EI Regions, a coordinator from each of the organizations that provides model development services to MMWG, and a NERC and FERC staff liaison. Each Data Submitting Entity shall have one vote. One or more alternate representatives from each Data Submitting Entity may be added at their discretion.

The MMWG Chairman and Vice Chairman are to be appointed from among the Data Coordinators for a two-year term. The Vice Chairman will serve a two year term and should be available to succeed to the chairmanship.

3.4. Costs

A. The Regions of the Eastern Interconnection will be billed for all MMWG Coordinator(s) costs associated with the MMWG effort in accordance with the terms of ERAG Agreement. The ERAG will be responsible for the contract maintenance and payments for MMWG Coordinator authorized expenses.

B. The MMWG Coordinator(s) will bill each Region or ERAG group separately for manpower and computer costs for any special service, specifically requested by a Region or ERAG group.

C. A record of the direct costs involved with the development of the webSDDB and associated models is to be maintained and reported, at least annually, to the ERAG.

3.5. Reporting

The MMWG Chairman will report periodically to the ERAG on the current and projected MMWG budget.

4. Duties of the MMWG

4.1. Chairman

The chairman is selected from among the Data Coordinators, following the officer rotation document and serves a two-year term. The specific duties of the Chairman are:

A. Report to the ERAG at their regularly scheduled meetings on contract costs, proposed case lists, process changes and work progress.
B. Coordinate any proposed changes to the model development schedule, Procedure Manual and officer rotation schedule for approval and implementation by the group.
C. Monitor the case build progress and work to ensure that work and data submissions are completed on schedule.
D. The Chairman may also update various industry working groups and NERC committees on the activities of the MMWG.
E. Work with the MMWG Coordinator, as required, to solve problems which may arise in steady state and dynamics model development effort.
F. During the actual model development effort, problems sometimes arise in obtaining data and information on time or in processing the data and information that are submitted. The MMWG Coordinator normally handles most of these problems, keeping the Chairman appropriately informed. However, in certain instances, the MMWG Coordinator may need specific assistance from the Chairman in solving a particular problem. The Chairman will assist by contacting individual Data Coordinators.
G. If a decision is needed immediately on a particular issue and there is no MMWG meeting/conference call imminent, the Chairman will act on behalf of the MMWG.
H. Coordinate with the Secretary and Vice-Chairman on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org.

4.2. Vice Chairman

The vice chairman is selected from among the Data Coordinators following the officer rotation document and serves a two year term. The principal functions of the vice chairman are to assist the chairman in the performance of the chairman's duties. The vice chairman is expected to succeed the chairman at the end of the chairman's term. The specific duties of the vice chairman are:

A. Monitor the schedule and send out reminders to Data Coordinators in advance of upcoming data submittal due dates.
B. Serve on behalf of the chairman during the chairman’s absence.
C. Coordinate with the secretary and chairman on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org

4.3. Secretary

The Secretary is selected from among the Data Coordinators and appointed to a one year term. The term will begin and end at the start of each calendar year. The specific duties of the Secretary are:

A. Prepare the minutes of all MMWG meetings and conference calls.
B. Maintain the Procedure Manual, roster, schedule and officer rotation documents. Make changes to each document as needed during meeting/conference calls. Circulate latest version after meetings. A red line and clean version of the Procedure Manual is sent to the group for each new version.
C. Send out materials before each meeting or provide to the Chairman to send to the Group.
D. Act as presenter for all materials during scheduled meetings.

E. Arrange meetings and conference call/web conferences as needed. If the secretary does not have access to the required resources, they can coordinate resource needs with other members.

F. Coordinate with the Chairman and Vice Chairman on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org

4.4. Data Coordinators

The Data Coordinator is selected by Data Submitting Entity for which they will represent. The Data Submitting Entities are listed in Appendix VI. The principal function of the Data Coordinators is to supply the modeling data for the Data Submitting Entity, which they represent, to the MMWG Coordinator. The specific duties of the Data Coordinators are:

A. Collect and assemble data for the footprint which they represent for each case in the power flow series.

B. Coordinate interchange transaction schedules and tie lines for each case. (Note: Tie line listings should be in the format approved by the MMWG; see Appendix I.) Only the changes (changes, additions, deletions) to the tie lines from the prior year's list should be submitted to the MMWG Coordinator. The tie line entries should be clearly labeled. Tie lines are defined as facilities connecting two data submitting entities as outlined in Appendix VI.

C. Exchange coordinated listings of interchange transaction schedules and tie line data according to the approved schedule for each case.

D. Forward solved power flow cases, interchange transaction schedules, and tie line data to the MMWG Coordinator according to the procedures in this manual and in accordance with the approved schedule.

E. Provide the MMWG Coordinator with whatever assistance is needed to solve non-convergent base case models.

F. Review the converged MMWG cases to verify proper and complete representation according to the approved schedule.

G. Determine the cause of any problem associated with creating the cases and notify the data supplier so that the problem does not reoccur.

H. Work with the member companies which they represent to coordinate and ensure the timely submission of system data.

I. Provide assistance to the MMWG Coordinator in resolving any discrepancies between the power flow data and the webSDDB.

J. Coordinate with the MMWG Coordinator to incorporate modifications to the power flow data and the webSDDB.

K. Help to maintain the MMWG Procedural Manual for use by the Data Coordinators in submitting system dynamics data. Modify, update, and refine the procedures as needed.

L. Provide written notification to the MMWG Coordinator of all significant errors observed in any of the most recent webSDDB or dynamics simulation cases.

M. Provide a copy of the current MMWG Procedure manual to their successor.

N. Help to maintain the MMWG roster.

O. Appoint an alternate representative to assure continuity in MMWG activities.

P. Attend all regularly scheduled meetings of the MMWG. If unable to attend, the Chairman should be notified and an alternate should attend.

4.5. MMWG Coordinator(s)

The Power Flow Coordinator is responsible for creating the power flow base case series. Included among the specific duties of the Power Flow Coordinator are the following:

A. Help prepare time schedules for each MMWG function for approval by MMWG.
B. Request data from Data Coordinators and maintain the time schedule determined by the Group for each major MMWG effort.
C. Prepare and distribute progress reports to MMWG representatives at regular intervals during periods of significant MMWG activities and for each scheduled MMWG meeting.
D. Apprise the MMWG Chairman of the status of the MMWG effort and the actions of the various Data Coordinator areas.
E. Apprise the MMWG chairman of the status of coordinator activities performed for the MMWG.
F. Contact the appropriate Data Coordinator should any problems develop with data sets, such as not conforming to MMWG computational facility requirements and guidelines, or requiring special processing.
G. Maintain direct supervision over the Data Coordinators' review of the base models and take appropriate measures to expedite the successful completion of this task. Determine, with consultation if necessary, whether an additional calculation of a merged and solved case should be attempted if revisions would not affect the solution beyond a very local area.
H. Exercise direct supervision over any change made at the computational facility to any solved case.
I. Verify the data for the unique eighteen-character bus name and voltage for the following components: all generator buses, and all tie lines buses. Any discrepancies are to be returned to the Data Coordinators for correction.
J. Coordinate with the Data Coordinators and the Dynamics Coordinator to resolve any discrepancies between the power flow data and the webSDDB data.
K. Coordinate with the Data Coordinators to incorporate improvements in the power flow data.
L. Provide to the MMWG the final power flow cases, only after the MMWG has approved the finalization of the cases.
M. Allocate DC Line numbers, FACTS device numbers and Transformer Correction Table numbers to the requesting Data Coordinators.
N. Provide to the MMWG an annual final report that summarizes the efforts of the coordinator, including all modifications that were made to the MMWG power flow along with recommendations for improvements.
O. Assist the MMWG in the creation and revision of the MMWG Procedural Manual.

The Dynamics Coordinator is responsible for updating the webSDDB and creating the approved dynamics simulation cases annually. Included among the specific duties of the Dynamics Coordinator are the following:

A. Help prepare time schedules for each webSDDB and dynamics simulation case update.
B. Request data from Data Coordinators and maintain the time schedule determined by the Group for each major MMWG effort.
C. Prepare and distribute progress reports to the Data Coordinators at regular intervals during periods of significant MMWG activities and for each scheduled MMWG meeting.
D. Apprise the MMWG Chairman of the status of the MMWG effort and the actions of the various Data Coordinators.

E. Apprise the MMWG chairman of the status of activities performed for the MMWG.
F. Contact the appropriate Data Coordinator should any problems develop with data sets, such as not conforming to MMWG computational facility requirements and guidelines or requiring special processing.
G. Exercise direct supervision over any change made at the computational facility to any solved model.
H. Coordinate with the Data Coordinators and the Power Flow Coordinator to resolve any discrepancies between the power flow data and the webSDDB data.
I. Coordinate with the Data Coordinators to incorporate improvements in the webSDDB.
J. After the MMWG has approved the dynamics cases for finalization, provide to the MMWG access to the webSDDB, the power flow cases, the converted power flow cases, and the corresponding PSS^{TM}E DYDA, CONEC, and CONET files in accordance with the guidelines specified in Section 9.5 of this document.
K. Provide to the MMWG an annual final report that summarizes the efforts of the contractor, including all modifications that were made to the MMWG power flow and dynamics data along with recommendations for the webSDDB improvements.
L. Assist the MMWG in the creation and revision of the MMWG Procedural Manual.

4.6. Staff Liaisons

The staff liaisons represent their organizations in the MMWG efforts, support, and coordinate with the MMWG. The MMWG may have liaisons from the following organizations: NERC, FERC, RF, SERC, FRCC, SPP, NPCC and MRO.

4.7. Alternates

A Data Submitting Entity may designate one or more alternates to the MMWG. Alternates should be included in mailing lists for distribution of MMWG correspondence and documents. Alternates may attend and participate in MMWG meetings but shall not vote except by proxy when the primary Data Coordinator is absent.

5. Deliverables

5.1. Data Coordinators

The Data Coordinators will provide the following to the MMWG Coordinator(s).

Power Flow Cases

A. Data as needed to create the MMWG power flow cases in RAWD or Saved Case format and shall be within an entire solved MMWG power flow model in the approved PSS^TM^E revision format

B. Tie line and interchange data in the specified format

C. IDEV or Python files for any data changes for the series cases shall have filenames beginning with the prefix "yySeries" (i.e. 15Series_16SUM_SPP_TrialX.idv, 15Series_ALL_SPP_TrialX.idv). Files submitted for the seasonal assessment case shall have filenames beginning with the prefix "SA" (i.e. SA_16SUM_SPP_TrialX). Where the 'X' in 'TrialX' denotes the trial of cases the update is to be applied to.

D. PSS^{TM}E formatted contingency file containing five N-1 contingencies valid for all cases in the model series.

E. Data Dictionary containing fields for: Bus Number, 12 character PSS^{TM}E Bus Name, Non--Abbreviated Bus Name, EIA Plant Code (U.S. only), Area Number, Area Name and Bus kV.

Dynamics Cases

A. Dynamics input data in DYRE format for models not supported in webSDDB

B. Changes to current dynamics models should be made directly to the webSDDB

C. FLECS code and documentation for user defined models

D. Load conversion CONL file sorted by area

E. List of netted generation buses

F. Two contingency events per Data Submitting Entity in IDEV format

G. For the designated frequency response cases (See Section 6.12), Data Coordinators shall provide a comma delimited file listing all online generation which includes the columns below:

1. Bus Number
2. Generator ID
3. Frequency Response (S = Squelched, N = Not Responsive, F = Fully Responsive)

5.2. MMWG Coordinator(s)

The MMWG Coordinator(s) will post the following to a secure site:

A. Power Flow Cases - Initialized steady state cases.

1. Power Flow SAV and RAWD case file
2. Master Tie Line list
3. Data Dictionary
4. Interchange Schedule
5. Associated Power Flow Checking files

B. Dynamics Cases - Dynamics case input data, output files and instructions including:

1. Dynamics input data in DYRE format
2. FLECS code for user defined models
3. Load conversion CONL file sorted by area
4. File containing netted generation (GNET)
5. Any IPLAN or PYTHON programs necessary to set up the dynamics case

C. Complete SDDB and User Manual
D. Final reports

6. Key Procedures

6.1. Meetings and Scheduling

Three meetings are held annually with additional dates scheduled as needed. The meetings are hosted per the rotation schedule and are typically held at the offices of one of the Data Coordinators. Below are typical agenda items for each meeting

Spring Meeting (April)
At the spring meeting, the following key items are usually included in the agenda:

A. List of steady state, dynamic, study and frequency response cases to be assembled the following year
B. The detailed data submittal and case finalization schedule for the current year effort is reviewed and revised as appropriate.
C. The MMWG Coordinator(s) presents a summary of the costs for the previous year's effort.
D. An initial cost estimate is made for the upcoming case development effort for use in the annual budget.
E. The MMWG Procedural Manual, group roster, schedule and officer rotation are reviewed as necessary
F. Any other policy matter is discussed as appropriate.

Summer Meeting (July)
At the summer meeting, the following key items are usually included in the agenda:

A. Review the progress on the current power flow series build
B. Procedures and issues for the upcoming dynamic case build
C. webSDDB upgrades
D. The MMWG Procedural Manual, group roster, schedule and officer rotation are reviewed as necessary
E. Any other policy matter is discussed as appropriate

Fall Meeting (October)
At the fall meeting, the following key items are usually included in the agenda:

A. The MMWG coordinators present the status of power flow and dynamics case development efforts concentrating on any problems.
B. The MMWG Procedural Manual, group roster, schedule and officer rotation are reviewed as necessary
C. Upgrades to the power flow checking program
D. Any other policy matter is discussed as appropriate.

6.2. Auxiliary Data

A. **Master Tie Line Database**

The Power Flow Coordinator maintains a Master Tie Line Database for use in the case creation process.

1. Only tie lines between data submitting entities are contained in the Master Tie Line Database.
2. Only the tie lines contained in the Master Tie Line Database will appear in the final power flow models.

3. All tie bus names and tie line data should conform to the entries in the Master Tie Line Database as approved by the Data Coordinators.
4. The Data Coordinator for the area in which a tie line bus is located shall specify the bus name nomenclature that is to appear in the Master Tie Line Database and in the final MMWG models.
5. A tie line will not be represented in a particular power flow base case model unless both parties involved have agreed to include it.
6. All tie line bus names and numbers should be standard and unique within each area in all models in a case series. Changes in tie line bus names and numbers from one series to the next must be kept to a minimum to reduce changes in computer support programs.
7. The in-service date is the date that the line will be operable. The out-of-service date that the line will be inoperable. The In-service and out-of-service dates will be expressed as mm/dd/yyyy.
8. The Power Flow Coordinator will maintain only one Master Tie Line Database per series.
9. The Data Coordinators should only submit tie line changes (additions, deletions, and changes) from the prior year's Master Tie Line Database to the Power Flow Coordinator. Each entry of the tie line data should be clearly labeled.
10. Data for the Master Tie Line Database should be submitted in the spreadsheet format determined by the MMWG. The data fields are specified in Appendix I.
11. Post case creation corrections to the tie line data shall only be made through the process above, and must include revisions to the Master Tie Line Database
12. Ties with an in-service/out-of-service date from 01/16/yyyy to 04/15/yyyy will be in-service/out-of-service in the spring model for the year yyyy.
13. Ties with an in-service/out-of-service date from 04/16/yyyy to 07/15/yyyy will be in-service/out-of-service in the summer model for the year yyyy.
14. Ties with an in-service/out-of-service date from 07/16/yyyy to 10/15/yyyy will be in-service/out-of-service in the fall model for the year yyyy.
15. Ties with an in-service/out-of-service date from 10/16/yyyy to 01/15/yyyy will be in-service/out-of-service in the winter model for the year yyyy.

B. **Interchange Schedule Matrices**

1. All transactions and interchange schedules conform to tables of interchange transaction schedules developed and agreed to by the Data Coordinators prior to the creation of the first case in the series. Interchange coordination must be performed to ensure generation resources are allocated to the appropriate Balancing Authority Areas (BAA) and therefore, generation in each BAA is accurately dispatched to meet the BAA's load plus losses. The interchange coordination should consider all transactions that have confirmed annual firm transmission service (for one year or longer, including consideration of rollover rights) along the entire path from source to sink and have a firm energy contract for the resource. The amount of interchange in any given year/season may not utilize the full capacity allowed under the transmission service or energy contract. The amount of interchange for a year/season should represent the expected and agreed upon firm capacity expected to serve load. For clarity and understanding, the table should include information identifying the source generation and the associated transmission service request numbers. It is important that the area where generation resources are expected to be sinking verify that the transfer is properly modeled to ensure the area's load will be served reliably. Omission of such firm transfers can create both transmission

system reliability concerns, as well as resource planning issues. Transmission system reliability concerns are created because the models, when used for evaluation of transmission service requests and planning studies, would not contain the flows associated with these firm transfers that are expected to occur in real time. Resource planning issues, such as double counting of resources and incorrect utilization or dispatch priority of generation, may also not be recognized.

Generation resources and transmission service are frequently not contracted for the entire ten years that the models are developed for. Coordination of interchange for these cases will require some judgment because all of the required elements (generation contract, source to sink transmission service) may not be available. Information provided by LSE's resource forecasts and plans, rollover/renewal of transmission service, and duration of energy contracts should be considered when interchange coordination, particularly in the out-year cases, is being performed.

2. The tables cover all cases in the MMWG power flow series. Complete interchange matrices should be submitted which include data submitting entity to data submitting entity transactions and all area total interchange schedules. The net interchange to each data submitting entity should be included in each data submitting entities table to allow identification of mis-coordination between them. The final model area interchange value for the cases is derived from the transaction workbook.
3. Seasonal transactions should be included, starting with the first year of the MMWG Base Case Series being developed.
4. Summer interchange schedules should reflect transactions expected to be in effect on July 15th.
5. Winter interchange schedules should reflect transactions expected to be in effect on January 15th.
6. Fall interchange schedules should reflect transactions expected to be in effect on October 15th
7. Spring interchange schedules should reflect transactions expected to be in effect on April 15th
8. Light Load interchange schedules should reflect transactions expected to be in effect on April 15th
9. The schedule shall show net scheduled interchange for each data submitting entity and for each area within that data submitting entity.
10. All interchanges must net to zero for all cases.
11. Any interchange schedule submitted that has an associated firm transmission service source to sink should be labeled with an X.
12. All areas should be identified with area names and numbers.
13. All net interchange schedules shall be integer values.

C. **Transformer Impedance Correction Table** – Assigned impedance correction table numbers are shown in Appendix II. When a Data Submitting Entity would like to utilize a new transformer impedance correction table, they shall contact the Power Flow Coordinator. The Power Flow Coordinator will consult the currently utilized transformer impedance correction table list and determine if any existing tables can be used for the new transformer impedance correction table. If no current transformer impedance correction table can be used, the Power Flow Coordinator will assign the requesting Data Submitting Entity a new transformer impedance correction table number. The official Impedance Correction Table will be maintained in the Procedure Manual (Appendix II).

D. **DC Circuit Names** – Assigned DC circuit names are shown in Appendix III. When a Data Submitting Entity would like to use a new DC circuit name, they must contact the Power Flow Coordinator. The Power Flow Coordinator will consult the currently utilized DC circuit list and assign the requesting Data Submitting Entity a new circuit for their exclusive utilization.

E. **Number Range Assignments**
Area, zone, owner, and bus number ranges assigned by the MMWG to each Regional Entity and Data Submitting Entity are shown in Appendix IV.

F. **System Codes for Power Flow Data**
All areas in the series of cases shall have proper area names and numbers for identification, consistent with the designations agreed to by the MMWG (see Appendix V).

6.3. PSSE Version Acceptance Testing

A. The MMWG must not approve a new version of PSSE until the following testing of the new version has been successfully performed:
   1. Using a power flow case (as chosen by the MMWG) from the most recent MMWG series, perform the following using the current PSSE version and the proposed new PSSE version and verify that both versions produce identical results:
      a. Power flow solution using the solution requirements in 6.7 D
      b. ACCC solution using the five contingencies submitted by each Data Submitting Entity from the most recent MMWG series.
      c. Other testing as deemed necessary by each Data Coordinator (e.g. test user-written auxiliary programs).
   2. Obtain updated source code for user-written dynamic models if needed for compatibility with the proposed new PSSE version.
   3. Compile source code using the proposed new PSSE version.
   4. Using the proposed new PSSE version, perform the dynamics testing required in section 6.11 and 9.3 C on a single dynamics case (as chosen by the MMWG) from the most recent MMWG series.
   5. Obtain confirmation from Siemens PTI that MOD, MOD File Builder, and MUST are all compatible with the proposed new PSSE version.

6.4. Power Flow Data Preparation and Submittal

A. All power flow data submitted should be in accordance with the Power Flow Modeling Guidelines contained in Section 8.2. It is the responsibility of each Data Coordinator to ensure that the data is in the correct format.
   1. Each Data Submitting Entity is to perform an N-1 screening of its bulk electric system for the purposes of identifying modeling errors before submitting their data to the Power Flow Coordinator.
   2. Overloads or voltages that exceed the Data Submitting Entities screening criteria should be reviewed and commented on as to whether they are resulting from modeling errors. Corrections for modeling errors should be made.
      a. Each Data Submitting Entity shall be able to produce the results of the review upon request.

B. Each case submitted by each Data Submitting Entity must solve via same method as the Power Flow Coordinator is obligated to use as noted in Section 6.6 "Finalizing Power Flow Models".

C. The version of software for each series of cases will be determined by the MMWG.

D. Cases shall be delivered to the Power Flow Coordinator on or before the scheduled due date.

6.5. Receiving Power Flow Models

The Power Flow Coordinator should perform the following steps with every received Data Submitting Entity base case model:

A. The dates of receipt are logged.

B. The data are read and saved in a file for conversion to the required format used by the Power Flow Coordinator for power flow data merging and calculation.

C. Area names, area numbers, zone number ranges, and bus number ranges are checked for compliance with those in Appendix IV.

D. Non-convergent cases are reported to the responsible Data Coordinator for corrective action. (See Section 8.4 for causes of non-convergence.)

6.6. Power Flow Model Merging

Once all data has been received from the Data Submitting Entities for a specific case, the Power Flow Coordinator will merge the individual submittals into a MMWG case.

A. One of TVA's Brown's Ferry generators, represented as on-line, will be the primary swing machine for each MMWG case. Other swing machines are included in all other non-synchronous areas (currently Hydro Quebec, northern Manitoba, WECC, ERCOT).

B. Data Coordinators shall resolve all tie line discrepancies specified by the Power Flow Coordinator within two weeks.

C. The Power Flow Database (PFDB) used by the Power Flow Coordinator to merge the cases will utilize the Master Tie Line database for all tie lines between Data Submitting Entities. The Power Flow Coordinator will notify the responsible Data Coordinators of any tie line insertion problems, typically due to duplicate or improperly named buses in the Data Submitting Entity cases.

D. The Power Flow Coordinator will check tie lines in the merged case against the MMWG Master Tie Line database. Any discrepancies will be reported to the responsible Data Coordinators.

E. The Power Flow Coordinator will check interchange in the merged case against the MMWG Scheduled Interchange Matrices. Any discrepancies will be reported to the responsible Data Coordinators. The sum of area interchange in the case must be zero. Also, the area interchange deviation tolerance for each area should be less than or equal to 5 MW.

F. If convergence of the merged case is not successful, the Power Flow Coordinator will notify the Data Coordinators for corrective action. (See Section 8.4 for possible causes of non-convergence.)

G. Successfully converged merged cases will be named in accordance with the following convention:

***Year* SERIES, ERAG/MMWG CEII Data**
Year Season* CASE, TRIAL *n

For Example:
2015 SERIES, ERAG/MMWG CEII Data
2016/17 WINTER PEAK CASE, TRIAL 1

6.7. Finalizing Power Flow Models

A. The Data Coordinators will review the series of cases and provide corrections for any modeling problems according to the previously determined schedule. This fine tuning phase is not intended as an opportunity for a complete revision of the case. Extensive revision should not be required at this time because basic case deficiencies or data errors should have been corrected before the case was submitted to the MMWG.

B. To make sure that no changes were made to the tie lines, the Master Tie Line database should again be read into the models.

C. A case shall satisfy all Power Flow Data Checks in Section 8.3 before it can be finalized.

D. A case shall solve using the Fixed Slope Decoupled Newton Solution (PSS™E activity FDNS) and Full Newton Solution (FNSL) with the following conditions before it can be finalized:

1. Solve in less than 20 iterations (preferably in less than 10 iterations)
2. Solve using the flat start option (can exceed iteration requirement above)
3. Employ a 1.0 MW/MVAR per bus mismatch tolerance
4. Enforce area interchange with the "Tie Lines and Loads" option.
5. Enable: (1) Tap changing transformers (2) Switched shunts (3) Phase shifters (4) DC transformer tap stepping
6. Enforce generator VAR limits in 1 iteration
7. Zero impedance cutoff setting of 0.0001 p.u.
8. Solve from a hot start under first contingency conditions provided by each Data Coordinator. Each Data Coordinator is to send all necessary information to conduct five AC N-1 contingencies (PSS™E format for .CON).

E. A case is considered final when all Data Coordinators approve it.

F. The Power Flow Coordinator will post the final cases along with the interchange table and MTL to a secure site for the Data Coordinators to download.

6.8. Dynamics Data Preparation and Submittal

A. Dynamics data should be prepared and submitted in accordance with Section 9 requirements and guidelines.

B. Unique bus names, base voltages, and unit id combinations submitted by Data Coordinators should be consistent from case to case within a model series. If a bus name, base kV or unit id combination is changed, the Data Coordinator must notify the dynamics coordinator of that change.

C. Data validation and checking using the procedures in Section 9.5 is recommended.

D. Dynamics data and linkages should be prepared for use with the annually updated release of the MMWG power flow cases.

E. The Dynamics Coordinator shall determine the media and format used to transmit models.

F. Dynamics data and linkages to the MMWG power flow cases are to be tested for accuracy by the Data Submitting Entity prior to submission to the Dynamics Coordinator.

G. Dynamics data and linkages to the MMWG power flow cases are to be delivered to the Dynamics Coordinator on or before the scheduled date.

H. Data Coordinators have two options, described below for submitting dynamics data to the Dynamics Coordinator.
   1. Models which are not compatible with webSDDB should be submitted in a PSS™E DYRE file. The data must be compatible and consistent with the MMWG power flows selected for the dynamics cases that are being developed. One file for all cases is preferable.
   2. Updates which are incremental to the dynamics data in the previous series of cases should be made directly to the webSDDB by the Data Coordinators.

6.9. webSDDB (webSystem Dynamics Database)

The webSDDB is used to maintain all dynamic data for each series and track all changes made. The Dynamics Coordinator performs the following steps:

A. Obtain and Update the designated MMWG power flow cases

B. Update the webSDDB with new models submitted by the Data Coordinators which are currently not supported.

C. The MMWG Data Coordinators provide data for the webSDDB for their respective areas in accordance with the above Section 6.8: "Dynamics Data Preparation and Submittal".

D. The Dynamics Coordinator updates the MMWG power flow cases with any power flow updates of dynamics-specific power flow data submitted by the Data Coordinators.

E. Dynamics data shall be collected for all machines with a gross nameplate rating greater than or equal to 20 MVA as well as all plants with an aggregate nameplate rating of 75 MVA or greater on the Eastern Interconnected System, irrespective of whether or not these machines are dispatched in a particular power flow case.

F. The Dynamics Coordinator correlates the MMWG power flow data with the dynamics models in the webSDDB. This correlation determines any missing dynamic models; identifies any models in the webSDDB for which there is no corresponding power flow data; and verifies correspondence of the webSDDB data with machines that are out-of-service in the MMWG power flow data. Dynamics data for machines that are out-of-service shall be included in the webSDDB. Any machine for which no dynamics data can be obtained shall be represented utilizing typical data or shall be netted out of the power flow in accordance with Section 9. The Dynamics Coordinator documents the power flow/dynamics discrepancies and all modifications made to resolve them. Based on the discrepancy resolution process, the Dynamics Coordinator updates the webSDDB and updates the MMWG power flow cases.

G. The Dynamics Coordinator reviews the MMWG power flow data and the dynamic models and parameters to identify questionable and bad data in either. Questionable or bad data shall be documented and resolved with the Data Coordinator, and the power flow cases and the webSDDB updated as necessary.

6.10. Dynamics Simulation Case Initialization

The Dynamics Coordinator in creating dynamics simulation cases performs the following steps:

A. Perform Initialization Based on DYRE, CONEC, CONET and RAWD Files

B. Read the updated power flow RAWD data into the PSS™E power flow program. Solve the AC power flow case. After the AC solution, convert the generators and load using the CONG and CONL activities. The appropriate percentages of constant impedance, constant current, and constant P/Q loads for the CONL conversion process are provided by the Data Coordinators. Using activities ORDR, FACT and TYSL, solve the converted power flow case. Save the converted case.

C. Obtain the DYRE file from the webSDDB. For each area in the MMWG power flow case, add the PTI "TOTA" model to the DYRE file. Also, add the "SYSANG" model and the "RELANG" model to express rotor angles relative to a weighted average angle. The outputs of these models will be used to assess the steady state stability of the dynamics simulation cases. The plots of these outputs will be required in the final report.

D. Using the PTI PSS™E dynamics simulation skeleton program, read in the solved converted power flow case. Perform activities FACT and TYSL.

E. Perform activity DYRE and read in the DYRE dynamics data file. Note and document any warning and error messages that are displayed. Run the IDEV to link parallel DC pole dynamics models (Chateauguay and Radisson-Sandy Pond). Create the CONEC and CONET files and compile command procedure before exiting the PSS™E dynamics simulation program. Resolve any problems indicated by the activity DYRE by coordinating with the appropriate Data Coordinator.

F. Add the user-written source codes to the respective CONEC and CONET files and execute the compile command procedure previously created. Create a snapshot to be used with the PSSDS executable. Execute CLOAD4 to link the files, thereby creating a PSSDS executable.

G. Using the user PSSDS executable created, read in the solved converted power flow case. Perform activities FACT and TYSL. Perform activity STRT. Note any states that are not initializing properly, i.e., any dynamic states whose derivatives are not zero, within the standard tolerance. Document and correct, as needed, these non-initializations of states. Repeat this procedure until all initialization problems have been corrected.

H. Once all the dynamic state initialization problems have been corrected, create a new snapshot, establish output channels, and using activity RUN, execute a no fault dynamics simulation for 20 seconds. Assess the steady-state stability of the dynamics simulation run by various relative machine angles, the outputs of the "TOTA" and "SYSANG". Adjust the integration time step and/or correct data until the dynamics simulation is judged to be flat.

I. To further verify the model integrity, it should be tested under contingency conditions at various locations (two per Data Submitting Entity). The Data Coordinators will provide corresponding switching information.

J. Finalize the webSDDB and Dynamics Simulation Cases corresponding to the power flow case based on all the updates.

6.11. Finalizing Dynamic Models

The dynamics cases are declared final only after meeting the criteria in section 9. The Dynamics Coordinator shall provide the following items to the Data Coordinators:

A. A copy of the PSS™E dialog which shows that the initial condition load flow solved in one iteration prior to determining machine initial conditions in accordance with section 9.5, step 9.

B. A list of suspect initial conditions that only involve the GAST2A and GASTWD governor models, and no other DSTATE errors.

C. A list of the remaining suspect initial conditions excluding GAST2A and GASTWD governor models, that have passed through peer review and have been given an exception. It is the Data Coordinators responsibility to resolve the suspect conditions. Exceptions can be granted for special conditions only after a peer review.

D. Results of Case Acceptance Criteria Tests (section 9.6) for each case in the series.

6.12. Frequency Response Case Creation Process

Dynamic simulations of the Eastern Interconnection have been found to be significantly optimistic in the representation of generator governor response. To address this issue, ERAG performed an analysis of the representation of overall frequency response in the Eastern Interconnection and found that:

- Effectively one-third of the connected capacity contributes to the primary control of frequency.
- A large fraction of the plant capacity that does contribute to primary control response in the short term does not sustain this response beyond the first few seconds of a frequency excursion.

MMWG developed a methodology to produce dynamics cases that more accurately simulate observed Eastern Interconnection frequency response. Two or more of the dynamics cases in each series, as determined at the spring meeting, will have this methodology applied and will be published as frequency response cases. They must pass the Dynamics Acceptance Criteria described in section 9.6. The first step is for each individual generating unit to be assigned one of three possible classifications of governor response:

1. Fully Responsive – The plant power output is fully sensitive to grid frequency in accordance with the primary control action of the governor, with other plant control elements supporting the action of the governor
2. Squelched – The power output is adjusted by the governor but the adjustment is overridden by the supervising action of a plant 'load controller' that returns plant output to a scheduled value within 10-20 seconds
3. Non-responsive – The power output changes minimally in the first few seconds after the disturbance

The methodology for classifying the response of individual units will be determined on a Data Submitting Entity basis. Where practical, it is recommended that recorded observations of frequency response of a particular unit be used to determine the classification of that unit.

The next step is to adjust the turbine-governor model components in the dynamics cases appropriately to simulate the behavior of squelched and non-responsive governors during time domain dynamic simulation. For a particular unit, the adjustments to be made are dependent on the specific turbine-governor model used:

A. All models except GGOV1
   1. Squelched - add an LCFB1 load controller model. Use the following data record if unit-specific data is not available:
      Bus # 'LCFB1' MACHID 0 1 0 1 0.01 1 0 0.03 1 /
   2. Non-Responsive - add an LCFB1 load controller model. Use the following data record if unit-specific data is not available:
      Bus # 'LCFB1' MACHID 0 1 0 1 0 1 1 0.2 1 /
   3. Fully Responsive - no change

B. GGOV1
   1. Squelched - adjust the power controller gain constant (Kimw) to represent squelching. Use 0.002 if a unit-specific value is not available. The following command performs this adjustment for Kimw = 0.002:

BAT_CHANGE_PLMOD_DATA Bus # 'MACHID' 7 GGOV1 24 0.002 0 0 ' '

2. Non-Responsive – bypass the governor model
3. Fully Responsive – no change

This adjustment is applied to each generator in the case. Note that units which are classified as "Fully Responsive" require no adjustment.

If no data exists for classifying the response of a unit, the following methodology can be applied to different fuel types for classifying the governor as responsive, squelched, or non-responsive:

1. Hydro - Responsive
2. Steam Turbine (Coal, Fuel Oil, etc.)
   a. Squelched (Based on Prime Mover Controller and Boiler Operation)
   b. Non-Responsive (Based on Prime Mover Controller and Boiler Operation)
3. Simple Combustion Turbines: Non-Responsive (due to nature of CTs and how they are operated to protect the turbines)
4. Combined Cycle
   a. CT - Non-Responsive (due to nature of CTs and how they are operated to protect the turbines)
   b. ST - Non-Responsive (Based on Boiler Operation)
5. Wind - Non-Responsive

6.13. Model Issue Correction Process

A. Issues received from the process outlined in section 7.5 will be monitored by the MMWG Chair, Vice-Chair, and Secretary.
B. The MMWG Chair, Vice-Chair, and Secretary will review all potential issues submitted by users and contact the appropriate Data Coordinator.
C. The Data Coordinator entity will work with the data owner to determine if a correction needs to be issued.
D. If a correction is needed, the data owner will submit the appropriate correction to the Data Coordinator.
E. The Data Coordinator will then provide the correction to the Chair, Vice-Chair, and Secretary.
F. The MMWG Chair, Vice-Chair, and Secretary will make sure the correction is posted to the secure site where the models are located and a summary report is sent to the ERAG. Notice will be sent to known users of the current cases.
G. A reply will be sent to the issue submitter on a resolution.
H. Before a series build begins, issues discovered from the previous year will be reviewed by the data submitting entity and incorporated if necessary.

6.14. Data Retention

The MMWG Coordinator(s) will store all MMWG series of cases for a full two years from the finalization date. ERAG should store all MMWG deliverables from the MMWG Coordinator(s) to the ERAG site for three years from the finalization date. Storage for longer periods can be made as requested and approved by the MMWG.

6.15. Non-Submittal of Data

In the event that a Data Submitting Entity fails to submit their data per the approved schedule:

A. The MMWG Chair will contact the Data Coordinator for that Data Submitting Entity to determine the reason for non-submittal and agreed to corrective action;

B. Any non-submittal of data will be communicated to the ERAG and the NERC liaison for further action.

7. Model Release Procedure

7.1. Introduction

The Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Power Flow Models contain data that has been deemed Critical Energy Infrastructure Information (CEII). Release of CEII data is restricted for the benefit of public safety and therefore ERAG MMWG will follow this "Model Release Procedure".

In general,

A. The MMWG Data Coordinators should handle distribution to the Planning Coordinator (PC), Transmission Provider (TP), and Transmission Owner's (TO's) of the Data Submitting Entity which they represent and those parties directly associated with their Data Submitting Entity (i.e. consultants who work directly for the Data Submitting Entity).

B. Regional confidentiality agreements are sufficient to cover the distribution within the regions

C. A Single Point of Contact (SPOC) will handle distribution to those not affiliated with a Region or Data Submitting Entity.

D. The SPOC will require completion of the included ID form and demonstration of FERC CEII approval (included in ID form) and Non-Disclosure Agreement (NDA) from all non-affiliated requestors. The entity must first request the current FERC-715 Part 2 filing data from FERC in order to obtain a FERC CEII number.

There is no model handling fee for MMWG model(s) released to the ERAG MMWG Data Coordinators or MMWG Agents (Non-ERAG MMWG members, NERC, Consultants, etc.) who perform direct services for MMWG and MMWG Regions.

Models can be accessed through the appropriate MMWG Data Coordinator by Data Submitting Entity members and those performing consultant services for the Data Submitting Entity per Data Submitting Entity procedures.

Otherwise, models can be obtained through the MMWG Single Point of Contact. A completed ID Form (**Section 7.3**) and MMWG Non-Disclosure Agreement (**Section 7.4**) must be filed with the MMWG Single Point of Contact before models are released.

Power flow models may also be accessed through FERC via the CEII link at:
http://www.ferc.gov/help/filing-guide/file-ceii.asp

In addition, the FERC CEII Contact link is:
http://www.ferc.gov/legal/ceii-foia/ceii.asp#skipnavsub

7.2. MMWG Dynamic Simulation Case Access

FLECS source code can only be released to PSS^{TM}E licensees. To remove the burden of verifying licensure, only the compiled object files are available to those not affiliated with NERC Regions or Data Submitting Entities through the SPOC.

7.3. ID Form

ID Form for Access to
Eastern Interconnection Reliability Assessment Group
Multiregional Modeling Working Group (MMWG)
Non-Public Information

Name:	
Organization:	
Email:	Phone:
Mailing Address:	
City, State Zip:	
FERC CEII identification:	
Data Requested: ____ 1. Power Flow Cases 2. Dynamic Cases 3. Authorization to received data from third party 4. Other	

Need for Information (intended use):

Reference: (This reference should be a person MMWG can contact to discuss your relation to the electric utility industry and your need for access to the requested information.)

Reference Person's Name:	
Organization:	
Email:	Phone:
Mailing Address:	
City, State Zip:	

Receipt of the ID Form and an executed Confidentiality Agreement must be received by MMWG prior to the MMWG Data Coordinator providing Recipient MMWG models and data. The SPOC is the ReliabilityFirst Corporation. Electronic or hard copies of these documents should be sent to the SPOC at:

ReliabilityFirst Corporation
Attn: John Idzior
3 Summit Park Drive
Suite 600
Cleveland, OH 44131
(216) 503-0615
john.idzior@rfirst.org

MMWG will provide email confirmation of receipt of your application within two business days and a status report of your request within one week, if applicable, to outline MMWG's actions in process to approve your request.

7.4. Non-Disclosure Agreement (NDA)

Eastern Interconnection Reliability Assessment Group
NON-DISCLOSURE AGREEMENT

Eastern Interconnection Reliability Assessment Group (ERAG) plans to make available certain information to your company (Recipient) related to Multiregional Modeling Working Group models and data. Prior to receiving this information, ERAG requires that Recipient execute this Non-Disclosure Agreement (Agreement).

For the purposes of this Agreement only, “employees” include third parties retained for professional advice (including, without limitation, attorneys, accountants, consultants, bankers and financial advisors) temporary administrative, clerical or programming support. “Need to know” means that the employee requires the Confidential Material in order to perform his or her responsibilities in connection with Recipient transacting business with ERAG or North American Electric Reliability Corporation Region Members.

By executing this Agreement, Recipient is affirming that all information designated by ERAG or its vendor(s) as “confidential”, “proprietary”, or other such designation as indicates protection of the material (Confidential Material), will be maintained in the strictest confidence and will not be disclosed to any person or entity other than its officers, directors and employees, consultants or its affiliates and their respective officers, directors, and employees who have a need to know, who have been advised of the confidentiality of the material, and who have agreed to be bound by the terms of this Agreement.

Recipient shall take necessary precautions to prevent disclosure of the Confidential Material to the public or any third party. Recipient agrees that the Confidential Material will not be copied or furnished to other parties. Recipient will safeguard the Confidential Material with the same degree of care to avoid unauthorized disclosure as Recipient uses to protect its own confidential and private information.

The obligation with respect to handling and using Confidential Material set forth in this Agreement is not applicable to information which:

1. Is in the public domain at the time of its disclosure to Recipient, or thereafter enters the public domain through no breach of this Agreement by Recipient;

2. Is known by Recipient at the time of disclosure by ERAG;

3. Is independently developed by Recipient or by a person or persons who have not had access to the Confidential Material received by Recipient from ERAG;

4. Is available to Recipient or others by inspection or analysis or related products available in the open market place;

5. Is made available by ERAG to anyone without similar restrictions by disclosing of such Confidential Material;

6. Is known to Recipient from a source other than ERAG;

7. Is approved for release by written authorization of a representative of ERAG;

Non-Disclosure Agreement (NDA) - continued

Eastern Interconnection Reliability Assessment Group
NON-DISCLOSURE AGREEMENT

8. Is required by law or regulation to be disclosed, but only to the extent and for the purposes of such required disclosure; or

9. Is disclosed in response to a valid order of a court or other governmental body of the United States or any of its political subdivisions, but only to the extent of and for the purposes of such order; provided, however, that Recipient will first notify ERAG of the order and permit ERAG to seek an appropriate protective order.

Confidential Material will be deemed the property of ERAG or its vendor(s). Recipient will, within ten (10) days of a written request by ERAG or its vendor(s), return all Confidential Material to ERAG or, if so directed, destroy all such Confidential Material. Recipient will also, within ten (10) days of a written request by ERAG or its vendor(s), certify in writing that it has satisfied the obligations of such a request.

No other obligation of any kind is assumed by or implied against any party except for those stated herein by the receipt of such Confidential Material, nor shall such receipt constitute a waiver of any rights any party may have with respect to similar material.

No manufacturing or software license under any patents or copyrights of any party is granted by this Agreement or by any disclosure of Confidential Material.

The parties agree that an impending or existing violation of any provision of this Agreement would cause ERAG or its vendor(s) irreparable injury for which there would be no adequate remedy at law, and that ERAG or its vendor(s) will be entitled to seek immediate injunctive relief prohibiting such violation without the posting of bond or other security, in addition to any other rights and remedies available.

No patent, copyright, trademark or other proprietary right is licensed, granted or otherwise transferred by this Agreement or any disclosure hereunder, except for the right to use such information in accordance with this Agreement. No warranties of any kind are given for the Confidential Material disclosed under this Agreement.

This Agreement may not be assigned by Recipient without the prior written consent of ERAG. Any assignment in violation of this provision will be void. This Agreement will be binding upon the parties and their respective successors and assigns.

If any provision of this Agreement is held invalid or unenforceable, such provision will be deemed deleted from this Agreement and replaced by a valid and enforceable provision which so far as possible achieves the parties intent in agreeing to this original provision. The remaining provisions of this Agreement will continue in full force and affect.

Each party warrants that it has the authority to enter into this Agreement and to lawfully make the disclosures contemplated hereunder.

Non-Disclosure Agreement (NDA) - continued

Eastern Interconnection Reliability Assessment Group
NON-DISCLOSURE AGREEMENT

ACKNOWLEDGED AND AGREED:

____
Company

By: ___________________________

Name: ________________________

Title: __________________________

Date: __________________________

7.5. Model Error Notification Process

If a potential issue is found, an email should be sent to contactmmwg@npcc.org describing the issue. Once the email is received, the MMWG will follow the process outlined in section 6.12.

8. Power Flow Modeling Requirements and Guidelines

8.1. Model Definition

Each MMWG case shall be of one of the types listed below. In no instance should loads be reduced for application of controllable demand-side management, curtailment of interruptible loads, or for emergency procedures such as voltage reductions and the anticipated effects of public appeals. The effects of uncontrolled demand-side management (peak shaving) should be reflected in the modeled load of summer and winter peak load cases. Renewable generation should be dispatched at seasonally expected values corresponding to the appropriate model. The power flow model will be based on a load forecast which assumes a statistical probability of one occurrence in two years (50/50).

	Topological changes modeled if in-service on or before
Summer Peak	**7/15**
Winter Peak	**1/15/(yyyy+1)**
Light Load	**4/15**
Shoulder Peak	**7/15**
Spring Peak	**4/15**
Fall Peak	**10/15**

Summer Peak Load (yyyySUM) — is defined as the summer peak demand expected to be served, reflecting load reductions for peak shaving. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before July 15th. Summer interchange schedules should reflect transactions expected to be in place on July 15th. Planned summer maintenance of generation and transmission should be reflected in the operating year case.

Winter Peak Load (yyyyWIN) — is defined as the winter peak demand expected to be served, reflecting load reductions for peak shaving. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before January 15th of the following year (yyyy + 1). Winter interchange schedules should reflect transactions expected to be in place on January 15th. Planned winter maintenance of generation and transmission should be reflected in the operating year case.

Light Load (yyyySLL) — is defined as a typical early morning load level, modeling at or near minimum load conditions. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before April 15th. 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 area during such load periods, not just including firm transactions.

Planned spring maintenance of generation and transmission should be reflected in this case. Summer or appropriate equipment ratings should be used.

Shoulder Peak Load (Summer) (yyyySSH) — is defined as 70% to 80% of summer peak load conditions. Dispatchable and pumped storage hydro units should be modeled consistent with the peak hour of a typical summer day with run-of-river hydro on-line. Generation dispatch and interchange schedules should be commensurate with the experience of the area during such load periods, not just including firm transactions. Summer or appropriate equipment ratings should be used.

Spring Peak Load (yyyySPR) — is defined as typical spring peak load conditions. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before April 15th. Pumped storage hydro units should be generally modeled on-line, but not necessarily at full generating capacity (generally not pumping). Dispatchable hydro units should generally be modeled on-line, but not necessarily at maximum generation, and run-of-river hydro should be modeled on-line. Generation dispatch and interchange schedules should be commensurate with the experience of the area during such load periods. Planned spring maintenance of generation and transmission should be reflected in this case. Summer or appropriate equipment ratings should be used.

Fall Peak Load (yyyyFAL) — is defined as typical fall peak load conditions. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before October 15th.Pumped storage hydro units should be generally modeled on-line, but not necessarily at full generating capacity (generally not pumping). Dispatchable hydro units should generally be modeled on-line, but not necessarily at maximum generation, and run-of-river hydro should be modeled on-line. Generation dispatch and interchange schedules should be commensurate with the experience of the area during such load periods. Planned fall maintenance of generation and transmission should be reflected in this case. Summer or appropriate equipment ratings should be used.

8.2. Guidelines

A. **Modeling Detail** – All transmission lines 100 kV and above and all transformers with a secondary voltage of 100 kV and above should be modeled explicitly. Significant looped transmission less than 100 kV should also be modeled.

B. **Bus Data**

1. **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 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 kV.
   a. Nominal voltages of generator terminal and distribution buses less than 25 kV are at the discretion of the reporting entity.
   b. If transformers having more than two windings are modeled with one or more equivalent center point buses and multiple branches, rather than as a 3-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.

2. **Islanded Buses** – Islanded buses shall not be modeled in MMWG cases.
3. **Bus Names** – The eighteen-character bus name and voltage should be unique for all buses 100 kV and above within an Area. The eighteen character bus name and voltage shall be unique for all generator buses and all MMWG tie line buses. The bus and equipment names shall not contain the following characters: comma, single and double quote, asterisk.

C. **Branch and Transformer Data**

1. **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=0.0001 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. All branches with the default impedance value of R=0.00000 + X=0.0001 and B=0.00000 will have an ID of 'Zx'. The 'x' character can be designated by the member as an additional identifier. The branch ID starting with Z shall be reserved for zero impedance branches only.
2. **Impedance of Branches In Network Equivalents** – Where network representation has been equivalenced, a maximum cutoff impedance of 3.0 p.u. should be used.
3. **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.
4. **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.
5. **Branch and Transformer Ratings** – Normal is defined as continuous ratings for system intact conditions and emergency is defined as limited duration ratings used until the system is returned to normal. Accurate normal and emergency seasonal ratings of facilities are necessary to permit proper assessment of facility loading in 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 winding 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. All tie Facility Rating methodology assumptions; including rating duration, should be coordinated between Facility owners.

D. **Generators**

1. **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.

2. **Generator Step-Up Transformers** – Generator step-up transformers may be modeled explicitly as deemed necessary by either the transmission owner or the Data Submitting Entity. 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.
3. **Out-of-Service Generator Modeling** – Out-of-service generators should be modeled with a STATUS equal to zero. For combined cycle units, the steam unit should be off-line if all combustion turbines are off-line.
4. **Generator MW Limits** – The generation capability limits specified for generators (PMIN and PMAX) should represent realistic continuous seasonal unit output capability for the generator in that given base case. PMAX should always be greater than or equal to PMIN. Gross maximum and minimum unit output capabilities should be used along with the unit auxiliary load modeled at the bus or buses from which it is supplied.
5. **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. Qmin and Qmax should be captured at Pmax based on the generator capability curve corresponding to OverExcitation Limiters (OEL), Stator Current Limit (SCL) and UnderExcitation Limiters (UEL) allowed by machine design, in addition to any effects from thermal limiters with generator cooling parameters on stator winding temperatures, rotor or field winding temperatures and/or H2 pressure for hydrogen cooled generators. These temperatures should reach a constant value (for testing purposes **-** no change larger than 2 degrees C or 1.8 degrees F within 5 minutes) at maximum capability. The capability of the generator should correspond to the season as most air-cooled machines are dependent on the ambient temperature with summer and winter capability rating variations. For more information, see *Power Flow Modeling Reference Document* on the NATF website.
6. **Wind Farms -** Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs.
7. **Swing Machine (**PSS^{TM}E **type 3 bus) -** Defined as the slack machine for the AC island**.**
8. **Area Slack Machine -** Defined as the individual area slack machine. There shall be an adequate amount of available MWs on the area slack machine to account for variations in losses.
    a. If a Control Area has generation with spinning reserve capability modeled on-line, the control area shall model one of the on-line generating units bus, within its boundaries, as its area slack bus.

E. **Regulation**

1. **Small Generators, Capacitors, and Static VAR Devices** – Small generators (e.g., 10 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.

2. **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.
    a. 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.
3. **Over and Under Voltage Regulation** – Regulation of voltage schedules exceeding 1.10 per unit, or below 0.90 per unit should be avoided.
4. **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.
5. **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 10 MVAR. Limits should accurately represent the actual operation of automatic control devices.
6. **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 5 MW; i.e., a 10 MW dead band. The controlling band should be at least 10 degrees.

F. **Reactive Devices**

1. **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.
2. **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.

G. **Flowgates** – All transmission elements comprising part of one or more flowgates should be included in the data submitted by each Data Submitting Entity. 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.

H. **Interchange**

1. **Interchange Tolerances** – In a solved case, the actual interchange for any area containing a Type 3 (swing) bus should be within 5 MW of the specified desired interchange value. (Note that PSS®E does not enforce the interchange deviation for areas containing Type 3 buses.)
2. **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.

I. **Areas, Zone and Owner Data**

1. Area numbers, zone numbers, owner numbers (if assigned), and bus number ranges must conform to those assigned to the Data Submitting Entity by the MMWG (see Appendix IV).
2. Ownership data, if used, should be consistent with the list in Appendix IV. If not used, the owner number should be set to the default value of 1, which is unassigned.

J. **DC Circuit Names** – DC circuit names should be consistent with those shown in Appendix III, Utilized DC Lines.

K. **Transformer Impedance Correction Table** – Impedance correction table numbers should be consistent with those shown in Appendix II, Utilized Impedance Correction Tables.

L. **Transmission Outages -** Known outage(s) of generation or transmission facility(ies) with a duration of at least six months shall be represented in the system models.[1]

1 TPL-001-4, R1.1.2

8.3. Power Flow Data Checks

The MMWG has established a set of Power Flow Data Checks, defined in the table below. The checks are implemented by the Power Flow Coordinator in a data checking program which is capable of identifying all errors according to the criteria given in this table. All finalized MMWG power flow models shall be free of all such errors. Only specific exceptions from the table below are allowed and should be documented.

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
RAW Read Warning	All Data	Warnings generated by PSS^{TM}E activity READ	Documented Exceptions Allowed	When reading in a case in RAW format, PSS^{TM}E performs certain checks to highlight suspect data that should be reviewed and corrected.
Duplicate Bus Names	Buses	Two or more buses in the same area with identical 12-char NAME and 4-char BASKV	No Exceptions	Dynamics data is referenced by bus names so they must be unique across each area.
Bus Number Out of Range	Buses	Bus number not in MMWG range	Bus numbers must follow table in Appendix IV.	The MMWG defines a range of bus numbers for each Data Submitting Entity in the interconnection. All buses must have a number in the range of the appropriate Data Submitting Entity.
Owner Out of Range	Buses in Data Submitting Entity	Bus number not in Data Submitting Entity owner number range	Owner numbers must follow table in Appendix IV.	Data Submitting Entity is defined by a range of bus numbers. Owner number ranges are assigned to the Data Submitting Entity by the MMWG.
Zone Out of Range	Buses in Data Submitting Entity	Zone number not in Data Submitting Entity zone number range	Zone numbers must follow table in Appendix IV.	Data Submitting Entity is defined by a range of bus numbers. Zone Number ranges are assigned to the Data Submitting Entities by the MMWG.
Bus Voltage	Buses	VM > 1.1 p.u., VM < 0.9 p.u.	Documented buses normally operated at voltages higher or lower than their BASKV	
Blank Voltage Fields	Buses	Blank BASKV field	No Exceptions	
Machines on Code 1 Buses	Buses; Generators	Generator at bus with IDE = 1	No Exceptions	
Code 2 Buses Without Machines	Buses; Generators	No generator at bus with IDE = 2	No Exceptions	
Unrealistic PMAX and PMIN	Generators Including off-line generators	PMAX < PMIN, PMAX > 2000, PMIN < -1000	No Exceptions	Identifies machines with unreasonable PMAX or PMIN
Unrealistic QMAX and QMIN	Generators Including off-line generators	QMAX < QMIN, QMAX > 1000, QMAX < -1000	No Exceptions	Identifies machines with unreasonable QMAX or QMIN
PGEN Outside Range	Generators with STAT = 1 & Bus IDE=2 or 3	PGEN > PMAX, PGEN < PMIN	No Exceptions	Identifies machines operating outside of their limits

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
Non-positive RMPCT	Generators	RMPCT ≤ 0	No Exceptions	RMPCT is the percent of the total Mvar required to hold the voltage at the bus controlled by the generator bus that are to be contributed by the generation at that bus. This value must be positive.
GTAP Out Of Range	Generators	GTAP > 1.1, GTAP < 0.9	Only Exceptions allowed: VSC Modeled as Generator	GTAP is the step up transformer off-nominal turns ratio.
Node Voltage Regulation	Switched Shunts; Generators; Transformers with COD1 = 1	Regulated bus more than one bus away from regulating bus	Three winding transformers modeled with star-point bus (unconverted); Zero impedance lines; Wind farms	Regulation of a distant bus can cause extra power flow solution iterations.
CNTB Errors	Switched Shunts; Generators; Transformers with COD1 = 1	Conflicting voltage objectives	Documented SMES units	This is performed using the activity CNTB which tabulates the voltage setpoints and desired voltage bands of voltage controlling equipment. It also performs certain checks on voltage controlling buses that are not themselves voltage controlled buses and includes those with suspect or conflicting voltage schedules or other errors.
Small Voltage Band Shunts	Switched Shunts	VSWHI – VSWLO < 0.0005	No Exceptions	A small voltage band can cause unnecessary switched shunt toggling and may prevent power flow convergence.
Missing Block 1 Steps	Switched Shunts	Missing Block 1 steps	No Exceptions	
Transformer MAX below MIN	2-Winding Transformers with COD1 ≠ 0	VMA1 ≤ VMI1, RMA1 ≤ RMI1	No Exceptions	
Transformer Default R	2-Winding Transformers with COD1 ≠ 0	RMA1 = 1.5 and RMA2 = 0.51	No Exceptions	Checks for PSS™E default values.
Transformer Default V	2-Winding Transformers with COD1 ≠ 0	VMA1 = 1.5 and VMA2 = 0.51	No Exceptions	Checks for PSS™E default values.
Small Voltage Band Transformer	All Transformers with COD1 = 1	VMA – VMI < 1.95 × Step Size[2]	No Exceptions	A small voltage band can cause unnecessary transformer tap toggling and extra power flow solution iterations.
Max or Min at 0	2-Winding Transformers with COD1 ≠ 0	RMA1 = 0, RMI1 = 0, VMA1 = 0, VMI1 = 0	No Exceptions	
High Resistance Branches	Branches ≥ 100kV[4]; 2-Winding Transformers ≥ 100kV[4]	Branches: R > |X| Transformers: R1-2 > |X1-2|	Document Exceptions	Fast-decoupled power flow solver is sensitive to the ratio R/X
Area Slack Machine	Online area slack machine	Areas without define area slack machine online	Only Exceptions allowed: net zero areas	All areas must have an online slack machine.

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
Rating Errors	All transformers and branches	RATEB < RATEA, RATEA = 0, RATEB = 0 RATEB >= 3 X RATE A (only for 69kV+)	Exception for branches with CKT = '99'/'EQ', zero impedance branches, and verified Rate B >= 3X Rate A	The MMWG defines RATEA as Normal and RATEB as Emergency.
3 Winding Rating Errors	3-Winding Transformers[3]	RATEB < RATEA, RATEA = 0, RATEB = 0 RATEB >= 3 X RATE A (only for 69kV+)	No Exceptions	The MMWG defines RATEA as Normal and RATEB as Emergency.
Branch Overloads	Branches ≥ 69kV[1]; Transformers ≥ 69kV[1, 3] All GSU's	Branch loading above 100% of RATEA or RATEB	Exceptions allowed for 10 year cases only	Ten-year cases often contain branches or transformers that will be upgraded but no plans exist. Transformers checked for loading in MVA, non-transformer branches in current.
Zero Impedance ID	Zero impedance branch ID with default PSSe R, X & B values.	Branch ID must start with 'Z'	No Exceptions	

[1] Refers to all two-winding transformers or branches connected to two buses with BASKV ≥ 69.
[2] The value of Step Size is calculated as:
If CW = 1: Step Size = [(RMA1 - RMI1) / WINDV2] / (NTP1 - 1)
If CW = 2: Step Size = {[(RMA1 / KV1) – (RMI1 / KV1)] / (WINDV2 / KV2)} / (NTAP - 1)
Where: KV1 and KV2 are bus base voltage (BASKV) specified in bus data section
[3] Refers to all three-winding transformers connected to two buses (of three) with BASKV ≥ 69.
[4] Refers to all two-winding transformers or branches connected to two buses with BASKV ≥ 100.

8.4. Troubleshooting/Causes of Non-convergence

A. A line whose impedance is very small as compared to that of a line connected in series with it. (Solution: If possible, add impedance of short and long series-connected lines and represent as one line.)
B. Tie lines or buses at the border of a control area are missing because they were not picked up by model creation or tie lines are connected incorrectly.
C. An impedance or susceptance value whose magnitude is extremely large. A decimal point may have been misplaced, or large cutoff impedance was specified during equivalencing.
D. A system's regulating (slack) bus is in a different system. This is probably due to an incorrect data entry in changing a model.
E. An isolated system (island) has been inadvertently created.
F. Radial system is very large.
G. Poor voltage regulation.
H. Over-equivalencing of outside areas in Data Submitting Entity base case models.
I. Extremely low voltage schedules.
J. Inconsistent representation of delta-wye transformers, typically by two companies interconnected at both voltage levels.
K. Phase Shifting Transformers
    1. The controlled bus for phase-shifting transformers should be designated as '0'. The 'controlled bus' field should only be zero for voltage-controlling transformers.

2. An unduly narrow control band for the active power target flow should be avoided.

9. Dynamics Data Submittal Requirements and Guidelines

9.1. Power Flow Modeling Requirements

A. All power flow generators, including synchronous condensers and Static VAr Compensators (SVCs) modeled as generators shall be identified by a bus name and unit ID. All other dynamic devices, such as switched shunts, relays, and HVDC terminals, shall be identified by a bus name and base kV field. The bus name shall consist of twelve characters and shall be unique within the Eastern Interconnection. Any changes to these identifiers shall be minimized.

B. Where the step-up transformer of a synchronous or induction generator or synchronous condenser is not represented as a transformer branch in the MMWG power flow cases, the step-up transformer shall be represented in the power flow generator data record. Where the step-up transformer of the generator or condenser is represented as a branch in the MMWG power flow cases, the step-up transformer impedance data fields in the power flow generator data record shall be zero and the tap ratio unity. The mode of step-up transformer representation, whether in the power flow or the generator data record, shall be consistent from case to case within a model series.

C. Where the step-up transformer of a generator, condenser, or other dynamic device is represented in the power flow generator data record, the resistance and reactance shall be given in per unit on the generator or dynamic device nameplate MVA. The tap ratio shall reflect the actual step-up transformer turns ratio considering the base kV of each winding and the base kV of the generator, condenser or dynamic device.

D. In accordance with PTI PSS™E requirements, the Xsource value in the power flow generator data record shall be as follows:
   1. Xsource = X''d for detailed synchronous machine modeling
   2. Xsource = X'd for non-detailed synchronous machine modeling
   3. Xsource = should be equal to locked rotor impedance for an induction machine
   4. Xsource = 1.0 per unit or larger for all other devices

E. Generally, SVCs should be represented in power flows as continuously variable switched shunts rather than as generators. In iterative power flow solutions, a generator which hits a VAR limit on solution iteration will lock at that value, but a switched shunt will move off the limit in a subsequent iteration if appropriate. PSS™E dynamic models compatible with either representation are available. If a user model representing particular SVC and control features is to be used and that model assumes generator representation, the SVC should be represented as a generator in the power flow.

9.2. Dynamic Modeling Requirements

A. All synchronous generator and synchronous condenser modeling and associated data shall be detailed except as permitted below. Detailed generator models consist of at least two direct axis circuits and one quadrature axis equivalent circuit. PSS™E dynamic model types classified as detailed are GENROU, GENSAL, GENROE, GENSAE, and GENDCO. The use of non-detailed synchronous generator or condenser modeling shall be permitted for units with nameplate ratings less than or equal to 50 MVA under the following circumstances:
   1. Detailed data is not available because manufacturer no longer in business.
   2. Detailed data is not available because unit is older than 1970.

B. The use of non-detailed synchronous generator or condenser modeling shall also be permitted for units of any nameplate rating under the following circumstances only:

1. Unit is a phantom or undesignated unit in a future year MMWG case.
2. Unit is on standby or mothballed and not carrying load in MMWG cases.

C. The non-detailed PSS^{TM}E model types are GENCLS and GENTRA. When complete detailed data are not available, and the above circumstances do not apply, typical detailed data shall be used to the extent necessary to provide complete detailed modeling.

D. All synchronous generators and condensers modeled in detail per Section 9.2.A shall also include representations of the excitation system, turbine-governor, power system stabilizer, and reactive line drop compensating circuitry. The following exceptions apply:
1. Excitation system representation shall be omitted if unit is operated under manual excitation control.
2. Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units in pumping mode and synchronous condensers.
3. Power system stabilizer representation shall be omitted for units where such device is not installed or not in continuous operation.
4. Representation of reactive line drop compensation shall be omitted where such device is not installed or not in continuous operation.

E. All other types of generating units and dynamic devices including induction generators, static VAR compensators (SVC), high-voltage direct current (HVDC) systems, and static compensators (STATCOM), shall be represented by the appropriate PSS^{TM}E dynamic models.

F. No wind turbine generators shall be modeled using the CIMTR1, CIMTR2, CIMTR3 or WT3G1 dynamic models. (WT3G1 does not accurately represent frequency response; WT3G2 should be used instead.)

G. Standard PSS^{TM}E dynamic models, listed in the NERC Library of Standardized Dynamic Models, shall be used for the representation of all generating units and other dynamic devices unless both of the following conditions apply:
1. The specific performance features of the user-defined modeling are necessary for proper representation and simulation of inter-Data Submitting Entity dynamics, and
2. Standard PSS^{TM}E dynamic models cannot adequately approximate the specific performance features of the dynamic device being modeled.

H. When user-defined modeling is used in the MMWG cases, written documentation shall be supplied explaining the dynamic device performance characteristics. The documentation for all MMWG user-defined models shall be posted on the MMWG Internet site as a separate document. Any benign warning messages that are generated by the model code at compilation time should also be documented.

I. Source code and Object file(s) shall be provided for all User Models. Source code shall be submitted in the FLECS language of the current PSS^{TM}E revision, C, or FORTRAN. User models created in MATLAB/SIMULINK are not permitted because users of the webSDDB cannot run them without purchase of additional software.

J. Netting of small generating units, synchronous condensers, or other dynamic devices with bus load shall be permitted only when the unit or device nameplate rating is less than or equal to 20 MVA. (Note: any unit or device which is already netted with bus load in the MMWG cases need not be represented by a dynamic model.)

K. Lumping of similar or identical generating units at the same plant shall be permitted only when the nameplate ratings of the units being lumped are less than or equal to 50 MVA. A lumped unit shall not exceed 300 MVA. Such lumping shall be consistent from case to case within a model series.

L. Where per unit data is required by a dynamic model, all such data shall be provided in per unit on the generator or device nameplate MVA rating as given in the power flow generator data record. This requirement also applies to excitation system and turbine-governor models, the per unit data of which shall be provided on the nameplate MVA of the associated generator. The maximum and minimum power of cross compound units should be provided on the nameplate MVA of one machine in accordance with PSS™E model IEEEG1 conventions.

M. Exceptions will be approved by MMWG on a case by case basis and the reason for each exception will be documented in the webSDDB.

9.3. Dynamics Data Checks

A. All dynamics modeling data shall be screened according to the dynamic data checks, defined in the table below. All data items not passing these screening tests shall be resolved with the generator or dynamic device owner and corrected.

Models Checked	**Data Checked**	**Conditions Not Allowed**	**Good Condition**	**Exceptions Allowed**
All Gen Model with inertia defined as H	H	H < 1.5 and H > 9.0	1.5 <= H <= 9.0	Verified and Documented Exceptions
All Gen Model with S(1.0)	S(1.0)	S(1.0) <0	S(1.0) > 0	No Exceptions
All Gen Model with S(1.2)	S(1.2)	S(1.2) <0	S(1.2) > 0	No Exceptions
All Gen Model with S(1.0) and S(1.2)	S(1.0)	S(1.0) > S(1.2)	S(1.0) <= S(1.2)	No Exceptions
All Gen Model with S(1.0) and S(1.2)	S(1.0) & S(1.2)	S(1.0) & S(1.2) > 1	S(1.0) & S(1.2) < 1	Documented Exceptions
All Gen/Exciter Model with S(E1)	S(E1)	S(E1) < 0	S(E1) >= 0	No Exceptions
All Gen/Exciter Model with S(E2)	S(E2)	S(E2) < 0	S(E2) >= 0	No Exceptions
All Gen/Exciter Model with S(E1) and S(E2)	S(E1)	S(E1) > S(E2) if E1 < E2	S(E1) <= S(E2) if E1<=E2	No Exceptions
All Gen/Exciter Model with S(E1) and S(E2)	S(E1)	S(E1) < S(E2) if E1 > E2	S(E1) > S(E2) if E1 > E2	No Exceptions
All non-classical Gen Model with spend coefficient damping D	D	D > 0	D = 0	No Exceptions
All Gov Models with development fractions $K_1 \ldots K_s$	$K_1 + K_2 + \ldots K_s$	$K_1 + K_2 + \ldots K_s$ /= 1.0	$K_1 + K_2 + \ldots K_s$ = 1.0	No Exceptions
All Gen Models with reactance/transient reactance defined as Xd and X'd in D axis	Xd	Xd <= X'd	Xd > X'd	No Exceptions
All Gen Models with transient reactance/sub-transient reactance defined as X'd and X"d in D axis	X'd	X'd <= X"d	X'd > X"d	For hydraulic unit (GENSAL), the condition (X'd=X"d) is exception
All Gen Models with sub-transient reactance/leakage reactance defined as X"d and XL in D axis	X"d	X"d <= XL	X"d > XL	No Exceptions
All Gen Models with reactance/transient reactance defined as Xq and X'q in Q axis	Xq	Xq <= X'q	Xq > X'q	No Exceptions
All Gen Models with transient reactance/sub-transient reactance defined as X'q and X"q in Q axis	X'q	X'q <= X"d (X"d=X"q)	X'q > X"d	No Exceptions
All Gen Models with reactance/transient reactance defined as X and X'	X	X <= X'	X > X'	No Exceptions
All Gen Models with transient reactance/sub-transient reactance defined as X' and X"	X'	X' <= X" if X"/=0 and T"/=0	X' > X" if X"/=0 and T"/=0	No Exceptions
All Gen Models with sub-transient reactance/leakage reactance defined as X" and XL	X"	X" <= XL if X"/=0 and T"/=0	X" > XL if X"/=0 and T"/=0	No Exceptions

Models Checked	Data Checked	Conditions Not Allowed	Good Condition	Exceptions Allowed
All Gen Models with transient reactance/leakage reactance defined as X' and XL	X'	X' <= XL if X"=0 or T'=0	X' > XL if X"=0 or T'=0	No Exceptions

B. All data submittals to the MMWG Coordinator shall have previously undergone satisfactory initialization and 20-second no-disturbance simulation checks for each dynamics case to be developed. The procedures outlined in Section 6.7 of this manual may be applied for this purpose.

C. Each Data Submitting Entity is to submit a contingency with well-known response so that the validity of the model can be tested and a suggested element to be switched (high voltage and high flow) to test the mathematical stability of the dynamics models.

9.4. Guidelines

A. Dynamics data submittals containing typical data should include documentation which identifies those models containing typical data. The CON conservation models, such as GENROA and GENSAA, which essentially copy dynamics data from one unit to another, may be useful for this purpose. When typical data is provided for existing devices, the additional documentation should give the equipment manufacturer, nameplate MVA and kV, and unit type (coal, nuclear, combustion turbine, hydro, etc.).

B. The voltage dependency of loads should be represented as a mixture of constant impedance, constant current, and constant power components (referred to as the ZIP model). The Data Submitting Entities should provide parameters for representing loads via the PTI PSS®E CONL activity. These parameters may be specified by area, zone, or bus. Other types of load modeling should be provided to MMWG when it becomes evident that accurate representation of inter-Data Submitting Entity dynamic performance requires it.

9.5. Dynamics Initialization and Checking Procedure

Note: PSS™E activities relevant to the following steps are shown in brackets.

Step 1: Create a converged load flow case with as few limit violations and questionable data items as possible.

A. Solve the case after each set of major changes [FNSL, FDNS, SOLV, or MSLV] and save it to minimize rework if a change has unintended consequences. If all of the following constraints are satisfied, convergence within tolerance should not take more than the default number of iterations.

B. Generator checks using a list of all data to spot unrealistic, typically default, generator data values. [LIST, option 5] There is no checking activity listing only machines having suspect values of the following

1. Machine MVA on the default base of 100. Although models will work if all load flow and dynamic model parameters are entered on this basis, limit checks will not work correctly.
2. Source impedance of 1.0 p.u. on machine MVA base. This value is substantially higher than normal for synchronous machines.
3. Source impedances equal to or less than zero. These will cause generator conversion to fail.
4. Real and/or reactive power limits of +9999 or –9999.

C. Checks which report abnormal values

1. Branch flows exceeding normal ratings. [RATE or OLTL and OLTR]
2. Bus voltages below 0.95 p.u. except in the case of generator terminal voltage buses connected to the transmission bus by a step-up transformer with a tap ratio significantly off nominal. [VCHK]
3. Overloaded generators. [GEOL]. Note that this activity checks machine output against the machine MVA base, MBASE, not against PMAX, PMIN, QMAX, and QMIN.
4. Branches with extreme impedances or tap ratios [BRCH]. Suggested options are:
   a. Small impedance. Note that very small impedances can be treated as zero impedance ties by selection of parameter THRSHZ and these will not be a problem.
   b. Negative reactance. These are typically found in Y representations of three winding transformers. Solution activity SOLV may not be used on cases containing such branches and MSLV may not be used if they are present at a Type 2 or 3 (generator) bus.
   c. Charging. Values exceeding the default upper check limit (5.0 p.u.) are normal on long EHV lines but others should be checked. Negative values are occasionally used for magnetizing impedance on transformers but this usage is not recognized in the PSS™E Program Operation Manual.
   d. Parallel transformers. Minor tap ratio differences may simply reflect field conditions, but differences exceeding one step should be checked to guard against inadvertent errors.
   e. High tap ratios.
   f. Low tap ratios.

D. Interactive checks: the user is asked to enter new value(s) for each exception, or hit "carriage return" for no change.
   1. Generators dispatched outside their real power limits [SCAL]. Scaling areas or zones should be used cautiously if generators having default PMAX (+9999) and PMIN (-9999) limits are present.
   2. Inconsistent targets at a bus whose voltage is controlled by two or more system elements: local generation, switched shunts, and voltage controlling transformers. [CNTB]. There is a tendency not to recognize different summer and winter operating strategies where appropriate.
   3. Questionable voltage or flow controlling transformer parameters. [TPCH]
   4. Buses in "islands" not containing a system swing bus. [TREE]. Note that there can be multiple islands each of which does contain a system swing bus, with DC links connecting them.

Step 2: To confine the initialization to a subset of the original load flow, for instance the areas comprising one Data Submitting Entity, proceed as follows.

A. Create a raw data file containing only the area(s) of interest. [RAWD, AREA]
B. Read in the raw data file just created. [READ]
C. If no system swing bus is in the area kept, change the type of a generator bus from 2 to 3 to make it the system swing bus. [CHNG]
D. Locate any islands created by the subsetting operation and either connect or drop them. [TREE].
E. Replace flows on tie lines severed by the subsetting operation with equivalent loads (positive for flows out, negative for flows in). [BGEN]

Step 3: Net generation with load at any buses where a generator(s) exists for which no dynamic models are available. [GNET].

Step 4: Convert the generators in the load flow [CONG], solve, [ORDR, FACT, TYSL] and save converted case.[SAVE]

Step 5: From the dynamics entry point, read in the dynamic model data file [DYRE] (Load flow case must also be in memory.)

- A. Specify CONEC, CONET, and COMPILE files.
- B. It is highly desirable to include a SYSANG model in the DYRE file, although this makes it mandatory to recompile even if no user models are included. This model provides six monitoring output channels, which can be used to scan a no-disturbance simulation for stability without attempting to select individual machines to monitor.

Step 6: Concatenate FLECS code for user models onto CONEC or CONET files.

Step 7: Compile.

Step 8: Execute CLOAD4.

Step 9: Restart from the dynamics entry point, this time using "user dynamics".

- A. Read converted load flow [CASE].
- B. Read in the dynamic data file [DYRE]
- C. Specify channels to record appropriate states and variables as simulation outputs [CHAN]. Include SYSANG variables if this model was included in the dynamics data file as suggested above.
- D. Check consistency of dynamic models [DYCH, option 1].
- E. Initialize dynamic simulation [STRT]. The output of this activity may have several important parts and it is desirable to keep a log file for reference while debugging.
  1. Warning messages for
     - a. Generators in the load flow for which there is no active machine model.
     - b. Models, usually of excitation systems or governors, initialized out of limits.
     - c. The number of iterations required to initialize the initial-conditions power flow.
  2. A tabulation of conditions at each online machine
     - a. Terminal voltage
     - b. Exciter output voltage
     - c. Real and reactive power output
     - d. Power factor
     - e. Machine angle in degrees
     - f. Direct and quadrature axis currents on machine base.
  3. A diagnosis of initial conditions, either
     - a. "Initial conditions check OK", or
     - b. A listing of suspect initial conditions generally states whose time derivative is not "small" (relative to the value of the state). These may be caused by inconsistencies between the real and reactive power scheduled for a unit by the load flow (including automatic changes in reactive power to hold bus voltage at a target level) or by parameter errors.
  4. For models flagged in steps i) through iii), consider using activity [DOCU] to identify parameters which may be causing problems. This activity will also give the automatically calculated values of exciter model parameters, which

are derived if the corresponding parameters, as read in, are 0. Other warnings may indicate errors in the powerflow model.

F. Modify model parameters or the load flow as appropriate and repeat steps up to this point until there are no warning messages nor suspect initial conditions.

Step 10: Record a snapshot [SNAP] of dynamic state values prior to application of any disturbance or simulation of any time period.

Step 11: Simulate undisturbed operation [RUN] for at least 20 seconds. Printing the convergence monitor [RUN,CM] can indicate where problems are, but considerably increases the amount of output.

Step 12: Stop simulation. Review output values in tabular and/or graphical form.

Step 13: Validate exciter model response to a step change in set point. [ESTR] and [ERUN]. Field voltage and terminal voltage will be output for each exciter model and may be reviewed in tabular or graphical form. Satisfactory response is indicated if the terminal voltage settles to the specified value within a few seconds, if the field voltage is reasonable, and the response is free of

A. Excessive overshoot
B. Sustained oscillations
C. High frequency noise (may be caused by using too long a simulation time step.)
D. Unexpected discontinuities in the output variables or their derivatives (except IEEE Type 4 “non-continuous” regulator models).

Step 14: Validate governor model response to a step change. [GSTR] and [GRUN]. Mechanical power and speed deviation will be output for each shaft where a governor model is present and may be reviewed in tabular or graphical form. Models of cross-compound unit governors specify two machines so four output variables are used. Steam or combustion turbine unit governors may require up to 20 seconds to attain equilibrium, and hydro units even longer, even if they are well tuned. Satisfactory response is indicated if speed deviation settles to approximately (- K) = (-1 / R), mechanical power to (1-1/K) times the specified value, and the response variables are free of excessive overshoot or sustained oscillations.

9.6. Dynamics Case Acceptance Criteria

A. 20 Second No-Fault Simulation

This test consists of a 20 second simulation with no disturbance applied. The test will be considered to be passed if the following criteria are met:

1. No generator MW change of 0.1 MW or more
2. No generation MVAR change of 0.1 MVAR or more
3. No line flow changes of 0.3 MW or more
4. No line flow changes of 0.3 MVAR or more
5. No voltage change of 0.0001 p.u. or more
6. For non-wind units, angle deviation should not be greater than 0.1
7. Check sensitivity of TYSL solution after case initialization to converter and inverter settings for reasonable number of iterations.

B. 60 Second Disturbance Simulation

This simulation consists of the application of a 3-phase fault for a few cycles at a key transmission bus, followed by removal of the fault without any lines being tripped. The simulation is run for 60 seconds to allow the dynamics to settle and will be considered to be passed if the following criteria are met:

1. No generator MW change of 1 MW or more

2. No generator MVAR change of 1 MVAR or more, except for exciters with dead band control (typically IEEE Type 4)
3. No voltage change of 0.0001 p.u. or more, except in vicinity of exciters with dead band control

The no-fault and 60 second disturbance simulations can be readily checked by saving a converted power flow at the end of the simulation and then comparing against the initial converted power flow case. For any case that violates these criteria, the individual component models that are in proximity to such large changes should be scrutinized carefully to determine their nature.

C. Dynamics Contingency Simulation

This test consists of the simulation of two contingencies for each Data Submitting Entity which have been supplied by the Data Coordinators.

1. The outage of the biggest unit in the Data Submitting Entity
2. A TPL Category P4, P5, or P6 contingency

An additional contingency simulating the August 4, 2007 Eastern Interconnection frequency excursion event will be used. This test will be considered to be passed if the simulation exhibits stable performance.

9.7. Additional Dynamics Information

A. WMOD

In PSSE revision 32 and later, the power flow generator parameter WMOD flag can be set to 0, 1, 2 or 3.

1. WMOD must be set to 1, 2 or 3 for a generator in the power flow case if any one of the generic dynamic wind models is to be used to represent the generator.
2. WMOD must be set to 0 for a generator in the power flow case if the generator is to be modeled using any other model, including CIMTR models or user-written wind turbine generator models.

B. Errors in PSSE 32.0.5 model library documentation for WT3G2 (included with subsequent V32 releases)

1. The WT3G2 model is incorrectly listed as WT3G2U
2. The DYRE format for this model is incorrectly listed in user model form:
   IBUS, ’USRMDL’, ID, ’WT3G2U’, 1, 1, 1, 13, 5, 1, ICON(M), CON(J) TO COM(J+12)
   The correct DYRE format is:
   IBUS, ’WT3G2’, ID, ICON(M), CON(J) TO CON(J+12) /
3. The block diagram incorrectly shows “PLLMIN” in two locations where “–PLLMAX” should be shown. PLLMIN is not defined in the list on CONs for this model.

C. WT3G1 vs. WT3G2 suitability for frequency response studies

The WT3G1 model has been found to be unsuitable for frequency studies due to observations that it provided unrealistic real power response to under-frequency conditions. Additional detail has been added into WT3G2 which make this model more suitable for performing frequency studies. This is the reason that WT3G1 is no longer allowed in the MMWG cases.

D. GGOV1 and GAST2A – TRATE issues

For most kinds of governors, the dynamic parameters are normalized on the machine MVA base; but for the governors GGOV1 and GAST2A, the per unit parameters are on the turbine MW base (Trate), which is typically smaller than the machine MVA base. It is suggested that turbine MW base (Trate) be used to check unit real power outputs instead of machine MVA base.

E. Network frequency dependence flag

In order to get the desired frequency response in simulations, the MMWG has enabled the ‘network frequency dependence’ option in the snapshots provided as part of the MMWG dynamics package. It is the responsibility of the end user to enable this option if they decide to build a dynamic case by generating their own snapshot using the DYRE files.

F. For PSSE version 33 USRMSC the MINS value must be a unique 8 digit number and be composed as follows. The first six digits will be the bus number at which the model is being applied. The last two digits will be a unique number to designate each particular model being used at the bus assigned by the Data Submitting Entity or data submitters.

APPENDIX I. Master Tie Line File Data Fields

Branch Data Fields

Submit Entity
In Service Date
Out Service Date
From Entity Name
From Area#
From Area Name
From Bus#
From Bus Name
From Bus kV
To Entity Name
To Area#
To Area Name
To Bus#
To Bus Name
To Bus kV
Metered End (F,T)= From/To
CKT
R
X
B
Summer Rating A
Summer Rating B
Summer Rating C
Winter Rating A
Winter Rating B
Winter Rating C
Spring Rating A
Spring Rating B
Spring Rating C
Fall Rating A
Fall Rating B
Fall Rating C
GI (pu)
BI (pu)
GJ (pu)
BJ (pu)
STATUS (0,1)
LEN (mi)
Owner 1
Fraction 1
Owner 2
Fraction 2
Owner 3
Fraction 3
Owner 4
Fraction 4

Two Winding Transformers

Submit By
In Service Date
Out Service Date
From Bus Entity Name
From Bus Area#
From Bus Area Name
From Bus Number
From Bus Name
From Bus kV
To Bus Entity Name
To Bus Area#
To Bus Area Name
To Bus Number
To Bus Name
To Bus kV
Tapped Side
CKT
CW
CZ
CM
MAG1
MAG2
Metered Side
NAME
STATUS (0,1)
Owner 1
Fraction 1
Owner 2
Fraction 2
Owner 3
Fraction 3
Owner 4
Fraction 4
R1-2
X1-2
SBase1-2
WindV1
NomV1
Ang1
Summer Rating A1
Summer Rating B1
Summer Rating C1
Winter Rating A1
Winter Rating B1
Winter Rating C1
Spring Rating A
Spring Rating B
Spring Rating C
Fall Rating A
Fall Rating B
Fall Rating C
COD1
Volt Control Bus Entity Name
Volt Control Bus Area Number
Volt Control Bus Area Name
Volt Control Bus Number (CONT1)
Volt Control Bus Name
Volt Control Bus kV
RMA1
RMI1
VMA1
VMI1
NTP1
TAB1
CR1
CX1
WindV2
NomV2

Three Winding Transformer Data Fields

In Service Date
Out Service Date
Winding 1 Entity Name
Winding 1 Area#
Winding 1 Area Name
Winding 1 Bus#
Winding 1 Bus Name
Winding 1 Bus kV
Winding 2 Entity Name
Winding 2 Area#
Winding 2 Area Name
Winding 2 Bus#
Winding 2 Bus Name
Winding 2 Bus kV
Winding 3 Entity Name
Winding 3 Area#
Winding 3 Area Name
Winding 3 Bus#
Winding 3 Bus Name
Winding 3 Bus kV
CKT
CW
CZ
CM
MAG1
MAG2
NMETR(1,2,3)
NAME
STATUS(0,1)
Owner 1
Fraction 1
Owner 2
Fraction 2
Owner 3
Fraction 3
Owner 4
Fraction 4
R1-2
X1-2
SBase1-2
R2-3
X2-3
SBASE2-3
R3-1
X3-1
SBASE3-1
VMSTAR
ANSTAR
WindV1
NomV1
Ang1
Summer Rating A1
Summer Rating B1
Summer Rating C1
Winter Rating A1
Winter Rating B1
Winter Rating C1
Spring Rating A1
Spring Rating B1
Spring Rating C1
Fall Rating A1
Fall Rating B1
Fall Rating C1
COD1
Control Bus 1 Entity
Control Bus 1 Area Number
Control Bus 1 Area Name
Control Bus #(CONT1)
Control Bus Name
Control Bus KV
RMA1
RMI1
VMA1
VMI1
NTP1
TAB1
CR1
CX1
WindV2
NomV2
Ang2
Summer Rating A2
Summer Rating B2
Summer Rating C2
Winter Rating A2
Winter Rating B2
Winter Rating C2
Spring Rating A2
Spring Rating B2
Spring Rating C1
Fall Rating A2
Fall Rating B2
Fall Rating C2
WindV3
NomV3
Ang3
Summer Rating A3
Summer Rating B3
Summer Rating C3
Winter Rating A3
Winter Rating B3
Winter Rating C3
Spring Rating A3
Spring Rating B3
Spring Rating C3
Fall Rating A3
Fall Rating B3
Fall Rating C3

Two Terminal DC Tie Data Fields

In Service Date
Out Service Date
I
MDC
RDC
SETVL
VSCHD
VCMOD (10)
RCOMP
DELTI
METER (RI)
DCVMIN
CCCITMX
CCCACC
IPR ENTITY NAME
IPR AREA#
IPR AREA NAME
IPR Bus#
IPR BUS NAME
IPR BUS kV
NBR
ALFMX
ALFMN
RCR
XCR
EBASR
TRR
TAPR
TMXR
TMNR
STPR
ICR ENTITY NAME
ICR AREA#
ICR AREA NAME
ICR BUS#
ICR BUS NAME
ICR BUS kV
IFR ENTITY NAME
IFR AREA#
IFR AREA NAME
IFR BUS#
IFR BUS NAME
IFR BUS KV
ITR ENTITY NAME
ITR AREA#
ITF AREA NAME
ITR BUS#
ITR BUS NAME
ITR BUS KV
IDR
XCAPR
IPI ENTITY NAME
IPI AREA#
IPI AREA NAME
IPI Bus#
IPI BUS NAME
IPI BUS kV
NBI
GAMMX
GAMMN
RCI
XCI
EBASI
TRI
TAPI
TMXI
TMNI
STPI
ICI ENTITY NAME
ICI AREA#
ICI AREA NAME
ICI BUS#
ICI BUS NAME
ICI BUS kV
IFI ENTITY NAME
IFI AREA#
IFI AREA NAME
IFI BUS#
IFI BUS NAME
IFI BUS KV
ITI ENTITY NAME
ITI AREA#
ITI AREA NAME
ITI BUS#
ITI BUS NAME
ITI BUS KV
IDI
XCAPI

Notes: (1) The data formats must be compatible with PSS^{TM}E input requirements.
(2) The in-service and out-of-service dates will be expressed as mm/dd/yyyy.

APPENDIX II. Utilized Impedance Correction Tables

Table Number	Data Submitting Entity	Tap or Angle	1 Factor	Tap or Angle	2 Factor	Tap or Angle	3 Factor	Tap or Angle	4 Factor	Tap or Angle	5 Factor	Tap or Angle	6 Factor	Tap or Angle	7 Factor	Tap or Angle	8 Factor	Tap or Angle	9 Factor	Tap or Angle	10 Factor	Tap or Angle	11 Factor
1	MRO	-60	1	-36	0.358	-24.4	0.192	-12.4	0.054	-8.3	0.024	0	0.01	8.3	0.024	12.4	0.054	24.4	0.192	36	0.358	60	1
2	MRO	-70	1	-43	0.78	-32	0.85	0	0.5	32	0.85	43	0.78	70	1								
3	MRO	-180	1	-150	0.5	0	0.5	150	0.5	180	1												
4	MRO	-152	1	-121.5	0.625	-85.4	0.372	-42.2	0.217	0	0.157	42.2	0.217	85.4	0.372	121.5	0.625	152	1				
5	RFC	-59.55	1.89	-45.4	1.48	-30.83	1.2	-14.87	1.06	0	1	15.51	1.08	30.75	1.32	45.15	1.57	60.04	1.9				
6	MRO	-35.1	1.5287	-26.8	1.3034	-18	1.1532	-9	1.0943	0	1	9	1.0943	18	1.1532	26.8	1.3034	35.1	1.5287				
7	RFC	-15	1.73	-12.5	1.48	-10	1.33	-7.4	1.2	-5	1.09	0	1	5	1.11	7.5	1.23	10	1.36	12.5	1.51	15	1.75
8	NPCC	-40	1.848	-30	1.468	0	1	30	1.538	40	1.83												
9	NPCC	-25	2.43	0	1	25	2.43																
10	NPCC	-25	1.995	0	1	25	1.995																
11	NPCC	0.941	0.5	1.04	1	1.15	2.45																
12	NPCC	-40	1.66	-29.5	1.331	-25.1	1.228	-20.6	1.145	0	1	20.6	1.145	25.1	1.228	29.5	1.331	40.1	1.66				
13	NPCC	-40	1.849	-30	1.402	-20	1.196	-10	1.045	0	1	10	1.045	20	1.161	30	1.366	40	1.741				
14	NPCC	-50	1.83	0	1	50	2																
15	NPCC	-25	1.978	0	1	25	1.978																
16	NPCC	-30	1.913	0	1	30	1.913																
17	NPCC	-47	6.34	-41.7	5.44	-33.3	4	-27.5	3.06	-18.5	2	0	1	18.5	1.76	27.5	3.278	33.3	3.643	41.7	5.25	47	6.34
18	NPCC	-40	2.31	0	1	40	2.31																
19	NPCC	-25	1.4629	0	1	25	1.5039																
20	NPCC	0.937	1.641	1	1	1.03	1.02	1.1	1.427														
21	NPCC	0.889	0.575	1.04	1	1.2	2.89																
22	NPCC	0.8	1.5625	0.85	1.3841	0.9	1.2346	0.95	1.108	1	1	1.05	0.907	1.1	0.8264	1.15	0.7561	1.2	0.6944	1.25	0.64	1.3	0.5917
23	NPCC	-10	1	5	0.6554	20	1.449																
24	NPCC	-37.8	2.1407	-17	1.2612	0	1	17	1.2612	37.8	2.1407												
25	NPCC	-60	9.2	-46.38	4.69	-32.3	1.87	-20	1	0	1	18	1	32.3	3	46.38	5.54	60	9.2				
31	RFC	-15	2.076	0	1	15	2.076																
32	RFC	-15	1.62	0	1	15	1.62																
33	RFC	-5.7	2.061	0	1	5.7	2.061																
34	RFC	-10	1.782	0	1	10	1.782																
35	RFC	-30	1.65	0	1	30	1.65																
37	MRO	-30	1	-22.73	0.5828	-15.36	0.3011	-7.67	0.098	0	0.001	7.67	0.0964	15.36	0.291	22.73	0.5711	30	0.9899				
38	MRO	-180	1	0	1	180	1																
40	SPP	-40	1	-35	0.75	-25	0.6	-12.5	0.55	-7.5	0.52	0	0.5	7.5	0.52	12.5	0.55	25	0.6	35	0.75	40	1
44	SPP	-52.9	1.90241	-43.6	1.67681	-33.7	1.4512	-23.2	1.2256	-12.3	1	-1.2	1.13847	9.9	1.27693	20.9	1.4154	31.4	1.55387				

APPENDIX III. Utilized DC Lines

DC Line Number	Data Submitting Entity	Name	Description
1	MISO	MISO_1_CC-DK	Coal Creek – Dickinson 1
2	MISO	MISO_2_CC-DK	Coal Creek – Dickinson 2
3	MISO	MISO_3_SQBDC	Square Butte-Arrowhead
4	MISO	MISO_4_SQBDC	Square Butte-Arrowhead
5	MH	MH_05_RD-DC	Radisson-Dorsey
6	MH	MH_06_RD-DC	Radisson-Dorsey
7	MH	MH_07_HY-DY	Henday-Dorsey
8	MH	MH_08_HY-DY	Henday-Dorsey
9	SPP	SPP_09_MCDC	Miles City E-W
10	SPP	SPP_10_SIDDC	Sidney
11	NPCC	NPCC_11_CHAT	Châteauguay CC1 (TE exporting)
12	NPCC	NPCC_12_CHAT	Châteauguay CC2 (TE exporting)
13	NPCC	NPCC_13_HIGH	Highgate (TE exporting)
14	NPCC	NPCC_14_MAD	Madawaska (TE exporting)
15	NPCC	NPCC_15_EEL1	Eel River CC1 (TE exporting)
16	NPCC	NPCC_16_EEL2	Eel River CC2 (TE exporting)
17	NPCC	NPCC_17_NIC	MTDC p1 (Radisson - Nicolet configuration)
18	NPCC	NPCC_18_NIC	MTDC p2 (Radisson - Nicolet configuration)
19	NPCC	NPCC_19_PH2	MTDC p1 (Radisson - Sandy Pond configuration)
20	NPCC	NPCC_20_PH2	MTDC p2 (Radisson - Sandy Pond configuration)
21	NPCC	NPCC_21_CHAT	Châteauguay CC1 (TE importing)
22	NPCC	NPCC_22_CHAT	Châteauguay CC2 (TE importing)
23	NPCC		Future
24	NPCC	NPCC_24_MAD	Madawaska (TE importing)
25	NPCC	NPCC_25_EEL1	Eel River CC1 (TE importing)
26	NPCC	NPCC_26_EEL2	Eel River CC2 (TE importing)
27	NPCC	NPCC_27_OUTA	Outaouais CC1 (TE exporting)
28	NPCC	NPCC_28_OUTA	Outaouais CC2 (TE exporting)
29	PJM/NPCC	PJM_29_NEP	Neptune (PJM/JCP&L exporting)
30	PJM		Future
31	PJM	PJM_31_Q	066 & Q206 Project
32	NPCC	NPCC_32_NPT	Northern Pass (Future Project)
33	NPCC	NPCC_33_NPT	Northern Pass (Future Project)
34	OPEN		
35	OPEN		
36	NPCC		Future
37	NPCC	NPCC_37_OUTA	Outaouais CC1 (TE importing)
38	NPCC	NPCC_38_OUTA	Outaouais CC2 (TE importing)
39	NPCC		Future
40	OPEN		
41	SPP	SPP_41_BLKWT	Blackwater
42	SPP	SPP_42_EDDY	Eddy County
43	SPP	SPP_43_LAMAR	Lamar
44	SPP	SPP_44_OKLUN	OKLAUNION
45	SPP	SPP_45_WELSH	Welsh
46	SPP	SPP_46_RPCTY	Rapid City
47	SPP	SPP_47_STGL	Stegall

DC Line Number	Data Submitting Entity	Name	Description
48	MH	MH_48_KW-RL	Keewatinoow - Riel
49	MH	MH_49_KW-RL	Keewatinoow - Riel
50	OPEN		

Note: The DC Line Number or Name may be used in the base case to designate DC lines

APPENDIX IV. Number Range Assignments

Region	Bus Numbers	Area Numbers	Zone Numbers	Owner Numbers
Entire System	100000-899999	100-899	100-1899	100-1199
NPCC	100000-199999	100-199	100-199, 1100-1199	100-199
RFC	200000-299999	200-299	200-299, 1200-1299, 1800-1899	200-299
SERC	300000-399999	300-399	300-399, 800-849, 1300-1399	300-399
FRCC	400000-499999	400-499	400-499, 1400-1499	400-499
SPP	500000-599999	500-599	500-599, 1500-1599	500-599, 800-849, 1500-1599
MRO	600000-699999	600-699, 997	600-699, 1600-1699	600-699
ERCOT	In SPP range	998	998	998
WECC	In MRO-SPP range	999	999	999

FRCC PC			
Area Number	Bus Range	Owner Numbers	Zone Numbers
400-499	400000-499999	400-499	400-499

Manitoba Hydro			
Area Number	Bus Range	Owner Numbers	Zone Numbers
667	667000-671999	667	1646-1653

NPCC PCs			
Area Number	Bus Range	Owner Numbers	Zone Numbers
101	100000-124999	101	100-118, 141-144
102	125000-149999	141-149	145-177
103	150000-174999	103, 160, 161, 162, 163, 164, 169	1101-1111
104	176000-189999	104	1140-1179
105	190000-194999	105	1180-1199
106	196000-199999	156-166	186-197
107	175000-175999	107	1150
108	195000-195999	168-178	178-185, 198-199

SaskPower			
Area Number	Bus Range	Owner Numbers	Zone Numbers
672	672000-675999	672	1654-1661

PJM			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
201	235000-237999	201, 255-258	1201-1205
202	238500-241999	202	1230-1249
205	242500-247999	204, 205	1250-1259, 1290-1299
	270000-270099	245, 246	1200
206	248000-248199	200, 206	1206, 1267-1269
209	253000-253299	209	1209
212	249564-249603	208, 250-253	1220-1229
	249980-250234		
	251258-251715		
	251792-251848		
	251934-251993		
	252038-252499		
215	253900-254299	203, 215	1215
222	270600-276599	220-240	1270-1289
225	200000-200399	269	202-204, 1820-1833
226	200500-203999	271	205-213
227	204500-205999	272	214-222
228	206200-207699	273	223-231
229	207900-212899	275, 276, 277	232-240
229	276600-281599	275, 276, 277	232-240
230	213400-216399	279	241-249
231	216900-219899	281	250-258
232	220400-223399	283, 284	259-267
233	223900-226899	286, 287	268-276
234	227400-230399	289, 290	277-285
235	230900-233899	292, 293	286-294
236	234200-234399	295	295-297
237	234600-234799	297	298-299
320	341000-342999	340-341	1315-1324
345	313000-315999	312-314	350-374

SPP RTO			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
511	503900-504899	511	518-520
515	505300-506299	515, 522, 528, 529, 532, 537, 538, 543, 555, 559, 583	521-523
520	506700-512199	507, 520. 582, 585, 586, 597	524-553
523	512600-513599	508, 522, 523, 528	554-562
524	514000-519999	524, 836	563-574
525	520400-522399	525, 849	575-594
526	522800-528799	526, 800, 801, 803-823	1500-1512
527	529200-529999	527	1513-1518
531	530400-530799	531, 533, 535, 599, 849	1519-1521
534	531200-532199	533, 534, 535, 550, 599, 836, 849	1522-1532
	539000-539999	539	1541-1543
536	532600-538599	532, 533, 535, 536, 550, 599, 836	1533-1540
540	540400-542399	540, 552, 590	595-599
541	542800-545799	533, 541, 552	1544-1555
542	546200-546799	542	1556-1558
544	547200-548199	544	1559-1571
545	548600-549099	545	1572-1582
546	549500-549999	546	1583-1585
640	640000-640999 643000-644999	640-643	686-690
641	641000-641999	641	687
642	642000-642999	642	688
645	645000-649999	645	691-695
650	650000-650999	650	696-697
652	652000-652999 654000-654999	652	1600-1615
	653000-653999	653	1612
	658000-658999	658	1624-1627
	655000-656999 659000-659999	655,656,659	1616, 1617, 1628-1633, 1676-1683, 698-699
	660000-660999	660	1634
		662	
659		655	1617
	655000-656999	656	1616
	659000-659999	659	1628-1633, 1676-1683, 698-699

SPP RTO (Continued)			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
997		652, 655,659	1602, 1603, 1628-1633, 1676-1683, 698-699
998	590000-599949		998
999	599950-599999		999

SERC PC's			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
330	300000-302999	300-302	300-309
340	304000-305999	304-305	315-324
341	304000-305999	304-305	315-324
342	306000-309999	306-309	325-339
343	370000-372999	361-362	1375-1384
344	311000-312999	310-311	340-349
346	380000-389999	315-324	1385-1399
347	360000-369999	351-360	1355-1374
350	317000-317999	329	1385-1399
352	339000-339049	335	1300-1302
353	339050-339099	336	1303
354	339100-339149	337	1304
355	339150-339199	338	1305
362	351000-351049	350	1350-1354
363	324000-326999	325-327	375-384
364	324000-326999	325-327	375-384
365	375008-375099	366	1308
366	375000-375007	365	1307

MISO			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
207	248400-249199	207	1207
208	249500-252037	208, 250-253	1220-1229
210	253500-253799	210-211, 299	1210-1214
216	254500-254899	216	1216, 1800-1810
217	255100-255499	217, 247-249	1217, 1870-1889
218	256000-263999	218, 260-268	1218, 1260-1265
219	264500-269499	219, 242, 243, 244	1219, 1861-1863
295	691000-699999	691-699	1890-1899
296	691000-699999	691-699	1890-1899
314	340000-340999	339	1310-1314
326	334000-338999	330-334	385-399
327	334000-338999	330-334	385-399
332	303000-303999	303	310-314
333	343000-343499	342	1325-1327
349	318000-318999	328	1397-1399
351	334000-338999	330-334	385-399
356	344000-349999	343-348	1330-1344
357	344000-349999	343-348	1330-1344
360	343500-343999	363	1328-1329
361	350000-350999	349	1345-1349
502	500000-501999	502	500-511
503	502400-502899	503	512-514
504	503300-503499	504	515-517
600	600000-607999	600-607	600-614
608	608000-609999	608	615-622
613	613000-614999	613	628-635
	625000-625999	625	656-657
615	615000-619999	615-617	636-647
620	620000-624999	620	648-655
	657000-657999	657	1620-1623
627	627000-632999	627	661-675
633	633000-634999	633	676-677
635	635000-639999	635	678-685
661	661000-661999	661	1636-1640
663	659000-659999 655000-655999 663000-663999	655, 659, 663	1628-1633, 1676-1683, 698-699

MISO (Continued)			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
680	680000-682999	680-682	1666-1675
694	691000-699999	691-699	1684-1687
696	691000-699999	691-699	1689-1697
697	691000-699999	691-699	1697
698	691000-699999	691-699	1686, 1688, 1698

APPENDIX V. System Codes for Power Flow Data based on Regional Entity

NPCC – Northeast Power Coordination Council

Area #	ID	System
101	ISO-NE	ISO New England
102	NYISO	New York ISO
103	IESO	Independent Electric System Operator
104	TE	TransÉnergie
105	NB	New Brunswick Power
106	NS	Nova Scotia Power
107	CORNWALL	Cornwall
108	NF	Newfoundland

RF – ReliabilityFirst Corporation

Area #	ID	System
201	AP	Allegheny Power
202	ATSI	American Transmission Systems, Incorporated
205	AEP	American Electric Power
206	OVEC	Ohio Valley Electric Corporation
207	HE	Hoosier Energy Rural Electric Cooperative, Inc.
208	DEI	Duke Energy Indiana
209	DAY	Dayton Power & Light Company
210	SIGE	Southern Indiana Gas & Electric Company
212	DEO&K	Duke Energy Ohio & Kentucky
215	DLCO	Duquesne Light Company
216	IPL	Indianapolis Power & Light Company
217	NIPS	Northern Indiana Public Service Company
218	METC	Michigan Electric Transmission Co., LLC
219	ITCT	International Transmission Company
222	CE	Commonwealth Edison
225	PJM	PJM 500 kV System
226	PENELEC	Pennsylvania Electric Company
227	METED	Metropolitan Edison Company
228	JCP&L	Jersey Central Power & Light Company
229	PPL	PPL Electric Utilities
230	PECO	PECO Energy Company
231	PSE&G	Public Service Electric & Gas Company
232	BGE	Baltimore Gas & Electric Company
233	PEPCO	Potomac Electric Power Company
234	AE	Atlantic Electric
235	DP&L	Delmarva Power & Light Company
236	UGI	UGI Utilities, Inc.
237	RECO	Rockland Electric Company
295	WEC	Wisconsin Electric Power Company (ATC)
296	MIUP	Michigan Upper Peninsula (ATC)
	CLOV	Cloverland Electric Coop (ATC)

SERC – SERC Reliability Corporation

Area #	ID	System
314	BREC	Big Rivers Electric Corporation
320	EKPC	East Kentucky Power Cooperative
327	EES-EAI	Entergy-Arkansas
330	AECI	Associated Electric Cooperative Inc.
332	LAGN	Louisiana Generating Company
333	CWLD	Columbia, MO Water and Light
340	CPLE	Carolina Power & Light Company – East
341	CPLW	Carolina Power & Light Company – West
342	DUK	Duke Energy Carolinas
343	SCEG	South Carolina Electric & Gas Company
344	SCPSA	South Carolina Public Service Authority
345	DVP	Dominion Virginia Power
346	SOUTHERN	Southern Company
347	TVA	Tennessee Valley Authority
349	SMEPA	South Mississippi Electric Power Association
350	PS	Power South (Alabama Electric Cooperative)
351	EES	Entergy Electric System
352	YAD	APGI – Yadkin Division
353	SEHA	Hartwell - SEPA
354	SERU	Russell - SEPA
355	SETH	Thurmond – SEPA
356	AMMO	Ameren Missouri
357	AMIL	Ameren Illinois
360	CWLP	City of Springfield (IL) Water Light & Power
361	SIPC	Southern Illinois Power Cooperative
362	EEI	Electric Energy Incorporated
363	LGEE	Louisville Gas and Electric /Kentucky Utilities
364	OMUA	Owensboro Municipal Utilities
365	SMT	Brookfield/Smoky Mountain Hydropower LLC
366	TAP	APGI-Tapoco

FRCC Florida Reliability Coordination Council

Area #	ID	System
401	FPL	Florida Power & Light
402	PEF	Progress Energy Florida
403	FTP	Fort Pierce Utility Authority
404	GVL	Gainesville Regional Utility
405	HST	City of Homestead
406	JEA	Jacksonville Electric Authority
407	KEY	City of Key West
409	LWU	City of Lake Worth Utility
410	NSB	Utilities Commission of New Smyrna Beach
411	FMPP	Florida Municipal Power Pool
412	SEC	Seminole Electric Cooperative
415	TAL	City of Tallahassee
416	TECO	Tampa Electric Company
417	FMP	FMPA / City of Vero Beach
418	NUG	Non-Utility Generators
419	RCU	Reedy Creek Energy Services, INC.
421	TCEC	Treasure Coast Energy Center
426	OSC	Osceola at Holopaw (PEF)
427	OLEANDER	Oleander IPP at Brevard (FPL)
428	CALPINE	Calpine at Recker (TECO)
433	HPS	Hardee Power Station (TECO)
436	DESOTOGEN	Desoto Generation IPP at Whidden (FPL)
438	IPP-REL	Reliant at Indian River (FMPP)

SPP – Southwest Power Pool, Inc.

Area #	ID	System
502	CLEC	Central Louisiana Electric Company
503	LAFA	Lafayette Utilities
504	LEPA	Louisiana Energy and Power Authority
511	AECC	Arkansas Electric Cooperative
515	SWPA	Southwestern Power Administration
520	AEPW	American Electric Power
523	GRDA	Grand River Dam Authority
524	OKGE	Oklahoma Gas and Electric Company
525	WFEC	Western Farmers Electric Cooperative
526	SPS	Southwestern Public Service
527	OMPA	Oklahoma Municipal Power Authority
531	MIDW	Midwest Energy
534	SUNC	Sunflower Electric Cooperative
536	WERE	Westar
539	MKEC	Mid Kansas Electric Cooperative
540	GMO	Greater Missouri Operations Company
541	KCPL	Kansas City Power and Light Company
542	KACY	Board of Public Utilities
544	EMDE	Empire District Electric Company
545	INDN	City of Independence
546	SPRM	City Utilities of Springfield

MRO – Midwest Reliability Organization

Area #	ID	System
600	XEL	Xcel Energy North
	MUNI	Municipal data from Xcel Energy
	MMPA	MMPA Municipal data from Xcel Energy
	CMMPA	CMMPA Municipal data from Xcel Energy
608	MP	Minnesota Power & Light
613	SMMPA	Southern Minnesota Municipal Power Association
615	GRE	Great River Energy
620	OTP	Otter Tail Power Company
	MPC	Minnkota Power Cooperative, Inc.
627	ALTW	Alliant Energy West
633	MPW	Muscatine Power & Water
635	MEC	MidAmerican Energy
	RPGI	RPGI Municipal data from MEC
	IAMU	IAMU Municipal data from MEC
	MMEC	MEC Municipal data from MEC (AMES,CFU, etc.)
640	NPPD	Nebraska Public Power District
	MEAN	Municipal Energy Agency of Nebraska (NPPD)
	GRIS	Grand Island (NPPD)
645	OPPD	Omaha Public Power District
650	LES	Lincoln Electric System, NE
652	WAPA	Western Area Power Administration
	BEPC	Basin Electric Power Cooperative
	CBPC	Corn Belt Power Cooperative
	NWPS	Northwestern Public Service
	MRES	Missouri River Energy Services
661	MDU	Montana-Dakota Utilities Co.
667	MHEB	Manitoba Hydro
672	SPC	Saskatchewan Power Co.
680	DPC	Dairyland Power Cooperative
	WPPI	Wisconsin Public Power Inc.
694	ALTE	Alliant Energy East (ATC)
696	WPS	Wisconsin Public Service Corporation (ATC)
	CWP	Consolidated Water Power Company (ATC)
	MEWD	Marshfield Electric and Water Company (ATC)
	MPU	Manitowoc Public Utilities (ATC)
697	MGE	Madison Gas and Electric Company (ATC)
698	UPPC	Upper Peninsula Power Company (ATC)

ERCOT & WECC

Area #	ID	System
998	ERCOT	Electric Reliability Council of Texas, Inc.
999	WECC	Western Electricity Coordinating Council

APPENDIX VI. System Codes for Power Flow Data based on Data Submitting Entity

NPCC PC's

Area #	ID	System
101	ISO-NE	ISO New England
102	NYISO	New York ISO
103	IESO	Independent Electric System Operator
104	TE	TransÉnergie
105	NB	New Brunswick Power
106	NS	Nova Scotia Power
107	CORNWALL	Cornwall
108	NF	Newfoundland

PJM

Area #	ID	System
201	AP	Allegheny Power
202	ATSI	American Transmission Systems, Incorporated
205	AEP	American Electric Power
206	OVEC	Ohio Valley Electric Corporation
209	DAY	Dayton Power & Light Company
212	DEO&K	Duke Energy Ohio & Kentucky
215	DLCO	Duquesne Light Company
222	CE	Commonwealth Edison
225	PJM	PJM 500 kV System
226	PENELEC	Pennsylvania Electric Company
227	METED	Metropolitan Edison Company
228	JCP&L	Jersey Central Power & Light Company
229	PPL	PPL Electric Utilities
230	PECO	PECO Energy Company
231	PSE&G	Public Service Electric & Gas Company
232	BGE	Baltimore Gas & Electric Company
233	PEPCO	Potomac Electric Power Company
234	AE	Atlantic Electric
235	DP&L	Delmarva Power & Light Company
236	UGI	UGI Utilities, Inc.
237	RECO	Rockland Electric Company
320	EKPC	East Kentucky Power Cooperative
345	DVP	Dominion Virginia Power

MISO

Area #	ID	System
207	HE	Hoosier Energy Rural Electric Cooperative, Inc.
208	DEI	Duke Energy Indiana
210	SIGE	Southern Indiana Gas & Electric Company
216	IPL	Indianapolis Power & Light Company
217	NIPS	Northern Indiana Public Service Company
218	METC	Michigan Electric Transmission Co., LLC
219	ITCT	International Transmission Company
295	WEC	Wisconsin Electric Power Company (ATC)
296	MIUP	Michigan Upper Peninsula (ATC)
	CLOV	Cloverland Electric Coop (ATC)
314	BREC	Big Rivers Electric Corporation
326	EES-EMI	Entergy-Mississippi
327	EES-EAI	Entergy-Arkansas
332	LAGN	Louisiana Generating Company
333	CWLD	Columbia, MO Water and Light
349	SMEPA	South Mississippi Electric Power Association
351	EES	Entergy Electric System
356	AMMO	Ameren Missouri
357	AMIL	Ameren Illinois
360	CWLP	City of Springfield (IL) Water Light & Power
361	SIPC	Southern Illinois Power Cooperative
502	CLEC	Central Louisiana Electric Company
503	LAFA	Lafayette Utilities
504	LEPA	Louisiana Energy and Power Authority
600	XEL	Xcel Energy North
	MUNI	Municipal data from Xcel Energy
	MMPA	MMPA Municipal data from Xcel Energy
	CMMPA	CMMPA Municipal data from Xcel Energy
608	MP	Minnesota Power & Light
613	SMMPA	Southern Minnesota Municipal Power Association
615	GRE	Great River Energy
620	OTP	Otter Tail Power Company
	MPC	Minnkota Power Cooperative, Inc.
	MRES	Missouri River Energy Services
627	ALTW	Alliant Energy West
633	MPW	Muscatine Power & Water
635	MEC	MidAmerican Energy
	RPGI	RPGI Municipal data from MEC
	IAMU	IAMU Municipal data from MEC
	MMEC	MEC Municipal data from MEC (AMES,CFU, etc.)
661	MDU	Montana-Dakota Utilities Co.
659	BEPC-SPP	Basin Electric Power Cooperative-SPP
663	BEPC-MISO	Basin Electric Power Cooperative-MISO
680	DPC	Dairyland Power Cooperative
	WPPI	Wisconsin Public Power Inc.

694	ALTE	Alliant Energy East (ATC)

MISO (Continued)

Area #	ID	System
696	WPS	Wisconsin Public Service Corporation (ATC)
	CWP	Consolidated Water Power Company (ATC)
	MEWD	Marshfield Electric and Water Company (ATC)
	MPU	Manitowoc Public Utilities (ATC)
697	MGE	Madison Gas and Electric Company (ATC)
698	UPPC	Upper Peninsula Power Company (ATC)

SERC PC's

Area #	ID	System
330	AECI	Associated Electric Cooperative Inc.
340	CPLE	Duke Energy Progress (Carolina Power & Light Company – East)
341	CPLW	Duke Energy Progress (Carolina Power & Light Company – West)
342	DUK	Duke Energy Carolinas
343	SCEG	South Carolina Electric & Gas Company
344	SCPSA	South Carolina Public Service Authority
346	SOUTHERN	Southern Company
347	TVA	Tennessee Valley Authority
350	PS	Power South (Alabama Electric Cooperative)
352	YAD	APGI – Yadkin Division
353	SEHA	Hartwell - SEPA
354	SERU	Russell - SEPA
355	SETH	Thurmond – SEPA
362	EEI	Electric Energy Incorporated
363	LGEE	Louisville Gas and Electric /Kentucky Utilities
364	OMUA	Owensboro Municipal Utilities
365	SMT	Brookfield/Smoky Mountain Hydropower LLC
366	TAP	APGI-Tapoco

SaskPower

Area #	ID	System
672	SPC	Saskatchewan Power Corp.

Manitoba Hydro

Area #	ID	System
667	MHEB	Manitoba Hydro

ERCOT & WECC

Area #	ID	System
997	WBDC-WECC	WAPA Basin – Western Interconnection
998	ERCOT	Electric Reliability Council of Texas, Inc.
999	WECC	Western Electricity Coordinating Council

FRCC PC

Area #	ID	System
401	FPL	Florida Power & Light
402	PEF	Progress Energy Florida
403	FTP	Fort Pierce Utility Authority
404	GVL	Gainesville Regional Utility
405	HST	City of Homestead
406	JEA	Jacksonville Electric Authority
407	KEY	City of Key West
409	LWU	City of Lake Worth Utility
410	NSB	Utilities Commission of New Smyrna Beach
411	FMPP	Florida Municipal Power Pool
412	SEC	Seminole Electric Cooperative
415	TAL	City of Tallahassee
416	TECO	Tampa Electric Company
417	FMP	FMPA / City of Vero Beach
418	NUG	Non-Utility Generators
419	RCU	Reedy Creek Energy Services, INC.
421	TCEC	Treasure Coast Energy Center
426	OSC	Osceola at Holopaw (PEF)
427	OLEANDER	Oleander IPP at Brevard (FPL)
428	CALPINE	Calpine at Recker (TECO)
433	HPS	Hardee Power Station (TECO)
436	DESOTOGEN	Desoto Generation IPP at Whidden (FPL)
438	IPP-REL	Reliant at Indian River (FMPP)

SPP RTO

Area #	ID	System
511	AECC	Arkansas Electric Cooperative
515	SWPA	Southwestern Power Administration
520	AEPW	American Electric Power
523	GRDA	Grand River Dam Authority
524	OKGE	Oklahoma Gas and Electric Company
525	WFEC	Western Farmers Electric Cooperative
526	SPS	Southwestern Public Service
527	OMPA	Oklahoma Municipal Power Authority
531	MIDW	Midwest Energy
534	SUNC	Sunflower Electric Cooperative
	MKEC	Mid Kansas Electric Cooperative
536	WERE	Westar
540	GMO	Greater Missouri Operations Company
541	KCPL	Kansas City Power and Light Company
542	KACY	Board of Public Utilities
544	EMDE	Empire District Electric Company
545	INDN	City of Independence
546	SPRM	City Utilities of Springfield
640	NPPD	Nebraska Public Power District
	MEAN	Municipal Energy Agency of Nebraska (NPPD)
	GRIS	Grand Island (NPPD)
645	OPPD	Omaha Public Power District
650	LES	Lincoln Electric System, NE
652	WAPA	Western Area Power Administration
	BEPC	Basin Electric Power Cooperative
	HCPD	Heartland Consumers Power District
	CBPC	Corn Belt Power Cooperative
	NWPS	Northwestern Public Service
	MRES	Missouri River Energy Services
659	BEPC-SPP	Basin Electric Power Cooperative-SPP