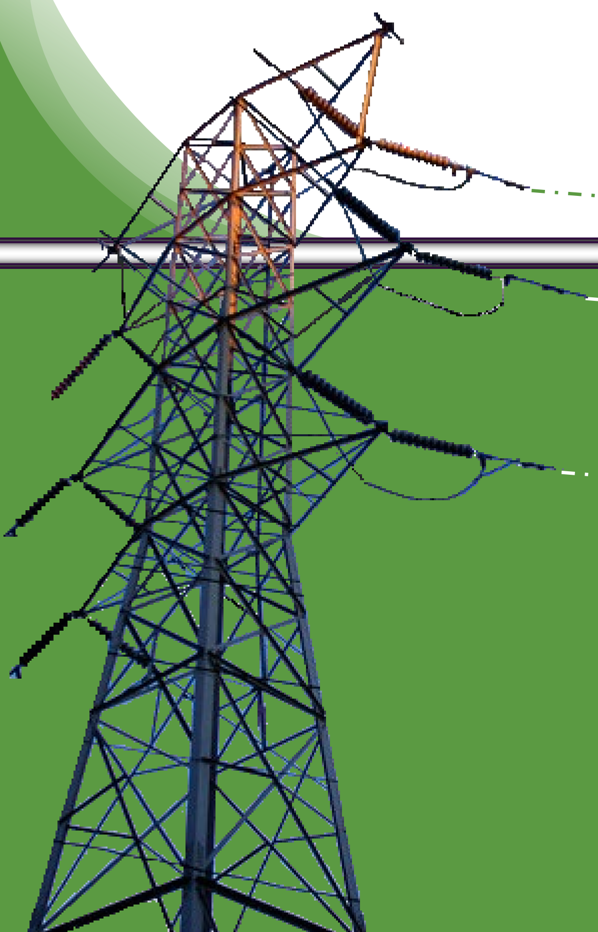
Eastern Interconnection
Reliability Assessment Group

Multiregional Modeling Working Group (MMWG)

Procedural Manual

Version 43



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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 Regional Data Coordinators and the MMWG Coordinator for the purpose of creating and maintaining the Power Flow Data Base (PFDB), power flow base case series, web System Dynamics Database (webSDDB), and dynamics simulation cases, which are to be used to evaluate the steady state conditions and dynamic performance of the systems of the Eastern Interconnection.

The MMWG Coordinator and most utilities in the Eastern Interconnection currently 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

NERC created compliance requirements for the electric industry regarding modeling and planning. It is not possible for an individual Planning Coordinator, power pool, or system to successfully construct an accurate system simulation model without input from other interconnected systems. The Eastern Interconnection Reliability Assessment Group (ERAG) plays 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. The credibility of the base case needed to perform these studies is important. Therefore, it is essential that the base cases be developed on a coordinated basis, following well-defined procedures. ERAG is in a unique position to achieve this goal. ERAG's continued leadership to coordinate activities in the creation and maintenance of large interconnected electric system models is important to the development of integrated power flow and dynamics base cases. The Multiregional Modeling Working Group (MMWG) was formed to develop an annual series of power flow and dynamics models for the benefit of the electric industry to act as the bases to perform reliability, interconnection, regional expansion, and market efficiency analyses. The MMWG model building process is the forum for participants to meet their NERC MOD-032 requirements while creating the modeling bases needed to meet other NERC compliance analyses (e.g. TPL-001, MOD-033, etc.).

The MMWG reports to the ERAG and is comprised of representatives from self-determined groupings of the Planning Coordinators (PC) in the Eastern Interconnection, referred to as Regional Data Coordinator(s) (currently MH, SaskPower, SERC-PC, MISO, SPP, NPCC-PC, PJM, FRCC), 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), Northeast Power Coordinating Council (NPCC), SERC Reliability Corporation (SERC), and Eastern Interconnection Planning Collaborative (EIPC). The MMWG appoints the Chair and Vice Chair 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 6.

A series of power flow and dynamic cases is created annually for selected years and seasons within the planning horizon. Each case reflects the latest available, at the time of data submittal, 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.

Pursuant to MOD-032, Requirement 4, each Planning Coordinator is obligated to provide models for its respective planning areas reflecting data provided to it pursuant to MOD-032 Requirement 2. The Regional Data Coordinators are responsible for submitting the power flow and dynamics data for the Planning Coordinator(s), which they represent, to the MMWG Coordinator. The MMWG Coordinator represents the contractor who receives the power flow and dynamics data and creates the selected cases as discussed above.

2. MMWG Scope

2.1. Scope of Activities

In carrying out the above purpose, the MMWG will:

A. Establish a schedule for all case development work.

B. Maintain a database (PFDB) of annually updated system power flow modeling data of the Eastern Interconnection.

C. 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 (see APPENDIX IX [Process Flowcharts]).

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

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

F. 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.

G. Maintain a Procedural Manual for use by the Regional Data Coordinators in submitting power flow and system dynamics modeling data, and for use by the MMWG Coordinator(s) in developing power flow and dynamics simulation models.

H. Work with the Regional Data Coordinators to ensure the timely submission of system data.

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

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

2.2. Representation

The MMWG membership shall be comprised of at least one representative with experience in power flow and dynamics modeling from each Regional Data Coordinator, a liaison from each Regional Entity, a NERC, FERC, and EIPC staff liaison and observers. However, each Regional Data Coordinator, regardless of the number of representatives, shall have only one vote. Designated and approved liaisons are non-voting representatives. Each Regional Data Coordinator may add alternate representatives who can attend and participate in MMWG meetings, but shall not vote except by proxy when the primary Regional Data Coordinator representative is absent.

Observers are individuals who can participate in MMWG meetings to listen, provide information when requested, and comment on issues. These observers can include additional staff from the Regional Data Coordinators or Regional Entities, and their participation is limited to a non-voting role

The MMWG Chair and Vice Chair are to be appointed from among the Regional Data Coordinators for a two-year term. Exceptions to the appointment of Chair may be necessary in order to maintain business continuity and should be evaluated on an as needed basis. The Vice Chair should be available to succeed to the Chair position.

2.3. 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(s) 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 PFDB, webSDDB and associated models is to be maintained and reported, at least annually, to the ERAG.

2.4. Reporting

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

3. Duties of the MMWG

3.1. Chair

The Chair role is rotated among the Regional Data Coordinators, following the officer rotation document and serves a two-year term. The term should begin at the spring meeting (year n) and end prior to the spring meeting (year n+2) pending the approval of the dynamics model build. The specific duties of the Chair 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, Procedural 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 Chair or designee may 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 Chair appropriately informed. However, in certain instances, the MMWG Coordinator may need specific assistance from the Chair in solving a particular problem. The Chair will assist by contacting individual Regional Data Coordinators.
G. Responsible for dispute resolution (see Section 'Model Issue Correction Process').
H. If a decision is needed immediately on a particular issue and there is no MMWG meeting/conference call imminent, the Chair will act on behalf of the MMWG.
I. Coordinate with the Secretary and Vice-Chair on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org.

3.2. Vice Chair

The Vice Chair role is rotated among the Regional Data Coordinators following the officer rotation document and serves a two year term. The term should begin at the spring meeting (year n) and end prior to the spring meeting (year n+2) pending the approval of the dynamics model build. The specific duties of the Vice Chair are:

A. Assist the Chair in the performance of the Chair's duties.
B. Serve on behalf of the Chair during the Chair's absence.
C. Monitor the schedule and send out reminders to Regional Data Coordinators in advance of upcoming data submittal due dates.
D. Serve as backup for Chair in dispute resolutions (see Section 'Model Issue Correction Process').
E. Coordinate with the secretary and Chair on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org.

3.3. Secretary

The Secretary role is rotated among the Regional Data Coordinators following the officer rotation document and serves a two year term. The term will begin and end at the spring meeting (year n) and end prior to the spring meeting (year n+2) pending the approval of the dynamics model build. The specific duties of the Secretary are:

A. Prepare the minutes of all MMWG meetings and conference calls.

B. Maintain the Procedural 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 Procedural Manual is sent to the group for each new version.

C. Send out materials before each meeting or provide to the Chair 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 Chair and Vice Chair on issues which are reported through the MMWG contact email address, contactmmwg@npcc.org.

3.4. Regional Data Coordinators

Each Regional Data Coordinator represents one or more of the Planning Coordinators that are responsible for submission of data pursuant to MOD-032. The Planning Coordinators determine the Regional Data Coordinator that will represent them. The principal function of the Regional Data Coordinator is to collect and submit the modeling data for the Planning Coordinator(s) which they represent, to the MMWG Coordinator. The Regional Data Coordinators and their respective modeling areas are listed in Appendix VI. The specific duties of the Regional Data Coordinator(s) are:

A. Vote on matters presented by the MMWG.

B. Collect and submit power flow and dynamic data, for the footprint which they represent, for each case in the series.

C. 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 represented PCs as outlined in Appendix VI.

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

E. 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.

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

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

H. Determine the cause of any problem associated with creating the cases and notify the Planning Coordinator so that the problem does not reoccur.

I. Work with the Planning Coordinator(s) which they represent to coordinate and ensure the timely submission of system data.

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

K. Coordinate with the MMWG Coordinator to incorporate modifications to the power flow data and the dynamics data.

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

M. Provide written notification to the MMWG Coordinator of all significant errors observed in any of the most recent PFDB, power flow cases, webSDDB, or dynamics simulation cases.
N. Provide a copy of the current MMWG Procedural Manual to their successor.
O. Help to maintain the MMWG roster.
P. Appoint an alternate representative to assure continuity in MMWG activities.
Q. Attend all regularly scheduled meetings of the MMWG. If unable to attend, the Chair should be notified and an alternate should attend.

3.5. MMWG Coordinator(s)

The MMWG Coordinator is responsible for creating the power flow and dynamic base case series and updating the PFDB and webSDDB annually. Included among the specific duties of the MMWG Coordinator are the following:

A. Help prepare time schedules for each MMWG function for approval by MMWG.
B. Request data from Regional Data Coordinators and maintain the time schedule for each major MMWG effort.
C. Prepare and distribute progress reports to the MMWG at regular intervals during periods of significant MMWG activities and for each scheduled MMWG meeting.
D. Apprise the MMWG Chair of the status of the MMWG effort and the actions of the various Regional Data Coordinators.
E. Contact the appropriate Regional Data Coordinator should any problems develop with data sets, such as not conforming to MMWG computational facility requirements and guidelines, or requiring special processing.
F. Maintain direct supervision over the Regional 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.
G. Exercise direct supervision over any change made at the computational facility to any solved case.
H. 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 Regional Data Coordinators for correction.
I. Coordinate with the Regional Data Coordinators to resolve any discrepancies between the power flow data and the dynamics data.
J. Coordinate with the appropriate Regional Data Coordinators to incorporate improvements in the power flow data and dynamics data.
K. Provide the MMWG approved final power flow cases to the MMWG.
L. Provide the MMWG approved final dynamics cases, access to the webSDDB, approved power flow cases, the converted power flow cases, and the corresponding PSS®E DYDA, CONEC, and CONET files in accordance with the guidelines specified in Section 8.5 of this document to the MMWG.
M. Allocate DC Line numbers, FACTS device numbers and Transformer Correction Table numbers to the requesting Regional Data Coordinators.
N. Provide to the MMWG an annual final report that summarizes the efforts of the MMWG Coordinator, including all modifications that were made to the MMWG power flow and dynamics data along with recommendations for improvements.
O. Assist the MMWG in the creation and revision of the MMWG Procedural Manual.

3.6. Staff Liaisons

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

4. Deliverables

4.1. Regional Data Coordinators

The Regional 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®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 or 15Series_18SUM and on_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®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®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 Regional Data Coordinator in IDEV format.

G. A comma delimited file listing all online generation which includes the columns below:
   1. Bus Number,
   2. Generator ID, and
   3. Frequency Response (S = Squelched, N = Not Responsive, F = Fully Responsive).

4.2. 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, and
   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), and
   5. Any IPLAN or PYTHON programs necessary to set up the dynamics case.

C. Complete SDDB and User Manual.

D. Final reports.

5. Key Procedures

5.1. 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 Regional 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, and study cases to be assembled the following year. Refer to the Case Selection Process in Appendix X.
B. The detailed data submittal and case finalization schedule for the current year effort is reviewed and revised as appropriate.
C. The MMWG Procedural Manual, group roster, schedule and officer rotation are reviewed as necessary.
D. Advancement in PSS/E version for the following year's series cases (e.g. discussion starts in 2018 for 2019 Series).
E. Status of model build contract procurement.
F. Review of number of user written models in each Regional Data Coordinator's system.
G. 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 Coordinator presents 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. Discussions on finalization of yearly model build contract.
E. Any other policy matter is discussed as appropriate.

5.2. Auxiliary Data

A. **Master Tie Line Database**

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

1. Only tie lines between represented PCs 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 Regional Data Coordinators.
4. The Regional 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 MMWG Coordinator will maintain only one Master Tie Line Database per series.
9. The Regional Data Coordinators should only submit tie line changes (additions, deletions, and changes) from the prior year's Master Tie Line Database to the MMWG Coordinator. Each entry of the tie line data should be clearly labeled.
10. Data for the Master Tie Lines should be submitted in the PFDB in the 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. Prior to the creation of each trial in the series, all transactions and interchange schedules shall conform to the template and be agreed to by the relevant Regional Data Coordinators in order to be included. Interchange coordination must be performed to ensure generation resources are allocated to the appropriate modeling area and therefore, generation in each modeling area is accurately dispatched to meet the modeling area's assigned 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.

If the existing and future resources with a signed interconnection agreement within a local Balancing Authority (BA) area and firm transactions from neighboring BA areas are insufficient to serve customer load, the preferred modeling practice is to coordinate non-firm transactions between BA areas. If coordination of non-firm transactions is not achieved, future generation resources which do not have signed interconnection agreements may be modeled in the Long-Term horizon.

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 Distribution Provider'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 modeling area to modeling area transactions and all area total interchange schedules. The net interchange to each modeling area should be included in each Regional Data Coordinator's 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 modeling area.
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 PC would like to utilize a new transformer impedance correction table, their Regional Data Coordinator shall contact the MMWG Coordinator. The MMWG 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 MMWG Coordinator will assign the requesting Regional Data Coordinator a new transformer impedance correction table number. The official Impedance Correction Table will be maintained in the Procedural Manual (Appendix II).

D. **DC Circuit Names** – Assigned DC circuit names are shown in Appendix III. When a Regional Data Coordinator would like to use a new DC circuit name, they must contact the MMWG Coordinator. The MMWG Coordinator will consult the currently utilized DC circuit list and assign the requesting Regional Data Coordinator 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 Regional Data Coordinator 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).

G. **Exception Documentation –** List of all exceptions to the power flow data checks as outlined in Section 8.3 submitted to the MMWG Coordinator by the Regional Data Coordinators the creation of each trial in the series. After the creation of each trial in the series the MMWG Coordinator shall provide a full list of all exceptions previously submitted in prior trials.

5.3. PSS®E Version Acceptance Testing

A. The MMWG must not approve a new version of PSS®E 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 PSS®E version and the proposed new PSS®E version and verify that both versions produce identical results:
      a. Power flow solution using the solution requirements in 5.7E.
      b. ACCC solution using the five contingencies submitted by each Regional Data Coordinator from the most recent MMWG series.
      c. Other testing as deemed necessary by each Regional 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 PSS®E version.
   3. Compile source code using the proposed new PSS®E version.
   4. Using the proposed new PSS®E version, perform the dynamics testing required in Section 5.11 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 PSS®E version.

5.4. 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 7.2. It is the responsibility of each Regional Data Coordinator to ensure that the data is in the correct format.
   1. Each Regional Data Coordinator is to review zone and owner assignment of loads on respective buses.
   2. Each Regional Data Coordinator 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 MMWG Coordinator.
   3. Overloads or voltages that exceed the MMWG screening criteria shall be reviewed and commented on as to whether they are resulting from modeling errors. Corrections for modeling errors shall be made.
      a. Each Regional Data Coordinator shall be able to produce the results of the review upon request.

B. Each case submitted by each Regional Data Coordinator must solve via same method as the MMWG Coordinator is obligated to use as noted in Section 5.7 “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 MMWG Coordinator on or before the scheduled due date.

5.5. Receiving Power Flow Models

The MMWG Coordinator shall perform the following steps with every Regional Data Coordinator submission:

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 MMWG 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 Regional Data Coordinator for corrective action (see Section 7.4 for causes of non-convergence).

5.6. Power Flow Model Merging

Once all data has been received from the Regional Data Coordinators for a specific case, the MMWG Coordinator will merge the individual submittals into an 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, and ERCOT).

B. Regional Data Coordinators shall resolve all tie line discrepancies specified by the MMWG Coordinator per the approved schedule.

C. The Power Flow Database (PFDB) used by the MMWG Coordinator to merge the cases will utilize the Master Tie Line database for all tie lines between the separate areas modeled in the power flow case by the Regional Data Coordinators and their respective Planning Coordinators. The MMWG Coordinator will notify the responsible Regional Data Coordinators of any tie line insertion problems, typically due to duplicate or improperly named buses in the Regional Data Coordinator cases.

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

E. The MMWG Coordinator will check interchange in the merged case against the MMWG Scheduled Interchange Matrices. Any discrepancies will be reported to the responsible Regional 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 MMWG Coordinator will notify the Regional Data Coordinators for corrective action (see Section 7.4 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

5.7. Finalizing Power Flow Models

A. The Regional 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 have a total desired net interchange of zero.

D. A case shall satisfy all Power Flow Data Checks in Section 7.3 with exceptions properly documented when necessary before it can be finalized.

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

1. Solve in less than 20 iterations (preferably in less than 10 iterations).
2. A reasonable attempt to solve using the flat start option (can exceed iteration requirement above) and be documented in the MMWG Coordinator's final report.
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 Regional Data Coordinator. Each Regional Data Coordinator is to send all necessary information to conduct five AC N-1 contingencies (PSS®E format for .CON).

F. A case is considered final when the above criteria is met. Exceptions to the criteria may be allowed by a majority vote.

G. The MMWG Coordinator will post the final cases along with the interchange table, MTL and exception excel spreadsheet to a secure site for the Regional Data Coordinators to download.

NOTE: Where possible, the cases will be solved with the Full Newton Solution (FNSL) with the above conditions prior to finalization.

5.8. Dynamics Data Preparation and Submittal

A. Dynamics data should be prepared and submitted in accordance with Section 8 requirements and guidelines.

B. Unique bus names, base voltages, and unit id combinations submitted by Regional 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 Regional Data Coordinator must notify the MMWG Coordinator of that change.

C. Regional Data Coordinators shall initialize the furthest out case to ensure errors are identified and corrected and relay any identified issues to the MMWG Coordinator. Initial condition power flow solution must solve in one iteration. Ideally, "INITIAL CONDITIONS CHECK O.K." message should be received; however, suspect initial conditions may be ignored for known exceptions if the "No-fault" test is passed. Refer to Section 8.5 for the recommended initialization procedure.

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

E. The MMWG 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 Regional Data Coordinator prior to submission to the MMWG Coordinator.

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

H. Regional Data Coordinators have two options, described below for submitting dynamics data to the MMWG 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 Regional Data Coordinators.

5.9. webSDDB (webSystem Dynamics Database)

The webSDDB is used to maintain all dynamic data for each series and track all changes made. The MMWG 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 Regional Data Coordinators which are currently not supported.

C. The Regional Data Coordinators provide data to the webSDDB for their respective areas in accordance with the above Section 5.8: "Dynamics Data Preparation and Submittal".

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

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

F. The MMWG 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 8. The MMWG Coordinator documents the power flow/dynamics discrepancies and all modifications made to resolve them. Based on the discrepancy resolution process, the MMWG Coordinator updates the webSDDB and updates the MMWG power flow cases.

G. The MMWG 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 Regional Data Coordinator, and the power flow cases and the webSDDB updated as necessary.

5.10. Dynamics Simulation Case Initialization

The MMWG 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 Regional 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 Regional 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 Regional Data Coordinator. The Regional 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.

5.11. Finalizing Dynamic Models

The dynamics cases are declared final only after meeting the criteria in Section 8. The MMWG Coordinator shall provide the following items to the Regional Data Coordinators:

A. A copy of the PSS®E dialog which shows that the initial condition power flow solved in one iteration prior to determining machine initial conditions in accordance with Section 8.5, step 9.

B. Resolution, including accepting “as-is”, of any identified suspect conditions.

C. Results of Case Acceptance Criteria Tests (Section 8.6) for each case in the series.

D. Changes to the power flow case for the dynamic build should be sent, by the Dynamic Regional Data Coordinators, to the Power Flow Regional Data Coordinators to be incorporated, as appropriate, into the next year’s series of cases.

E. A case is considered final when the above criteria is met. Exceptions to the criteria may be allowed by a majority vote.

5.12. Frequency Response Case Processing

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. All of the dynamics cases in each series will have this methodology applied. 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 Planning Coordinator 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.

5.13. Model Issue Correction Process

A. Issues received from the process outlined in Section 6.5 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 Regional Data Coordinator.

C. The Regional 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 Regional Data Coordinator.

E. The Regional 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 should be reviewed by the Regional Data Coordinator and corrections incorporated if necessary.

I. If there is a dispute regarding the resolution of an issue, the MMWG will work with affected parties to help understand modeling issues and identify their root cause. However, the MMWG expects the primary responsibility for driving resolution of issues to be on the affected parties. If the disputing parties fail to come to a resolution, the nature of the dispute shall be documented in the release notes. The actual language will be developed by the MMWG Chair with input from the disputing parties. Note: If the MMWG Chair is a member of the disputing parties, the Vice Chair will be responsible for the release notes documentation.

5.14. 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.

5.15. Non-Submittal of Data

In the event that a Planning Coordinator fails to submit their data to their respective Regional Data Coordinator per the approved schedule:

A. The MMWG Chair will contact the Regional Data Coordinator for that Planning Coordinator 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.

6. Model Release Procedure

6.1. 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 Regional Data Coordinators should handle distribution of models to the respective Planning Coordinator (PC) which they represent.

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

C. All others can request access through the FERC 715 process.

Models can be accessed through the appropriate Planning Coordinator by its members and affiliates per the PC's respective model release procedures.

6.2. MMWG Dynamic Simulation Case Access

FLECS source code can only be released to PSS®E licensees. To remove the burden of verifying licensure, only the compiled object files are available to those not affiliated with NERC Regions or Regional Data Coordinators through the SPOC.

6.3. 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 5.12.

7. Power Flow Modeling Requirements and Guidelines

7.1. Model Definition

Each cycle, MMWG shall establish cases utilizing the Case Selection Process described in Appendix X. 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
Winter Peak	**1/15/(yyyy+1)**
Spring Min Load	**4/15**
Spring Light Load	**4/15**
Spring Peak	**4/15**
Summer Shoulder Peak	**7/15**
Summer Peak	**7/15**
Fall Peak	**10/15**

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.

Spring Minimum Load (yyyySML) — is defined as the lowest "net" load level typically seen or expected to be seen by an area's transmission system under the spring timeframe, excluding data associated with significant outages caused by unexpected events such as but not limited to: acts of nature (e.g. hurricanes or wildfires), pandemics or terrorism. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before April 15th. Depending on an area's typical load profile, this may occur during weekend overnight or early morning hours, or during weekend midday hours with mild weather and high distribution-connected resource (DER) production. Where multiple times of day produce fairly similar load levels, the condition that produces the most severe high voltage conditions should be chosen. Load power factor should represent typical minimum load conditions, and inter-area transfers should be relatively light. Planned spring maintenance of generation and transmission should be reflected in this case. Spring or appropriate ratings should be used. Interchange should be based on what is allowable up to what is available under firm transmission service. Non-firm transactions that historically occur may be used when agreed upon between PC's. Due to these non-firm transactions, this model may not be appropriate for use in determination of AFC/ATC/or transfer capability.

Spring Daytime Minimum Load (yyyySDM) — is defined as the lowest "net" load level typically seen or expected to be seen by an area's transmission system under the daytime spring timeframe, excluding data associated with significant outages caused by unexpected events such as but not limited to: acts of nature (e.g. hurricanes or wildfires), pandemics, or terrorism. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before April 15th. This case should reflect weekend midday hours with mild weather, and high Inverter-Based Resource (IBR) and Distributed Energy Resource (DER) production. Where multiple times of day produce fairly similar load levels, the condition that produces both high voltages and low inertia conditions should be chosen. All IBRs including DERs, utility scale PVs, and wind should be modeled and dispatched at expected levels. Load power factor should represent typical minimum load conditions, and inter-area transfers should be relatively light. Planned spring maintenance of generation and transmission should be reflected in this case. Spring or appropriate ratings should be used. Interchange should be based on what is allowable up to what is available under firm transmission service. Non-firm transactions that historically occur may be used when agreed upon between PC's. Due to these non-firm transactions, this model may not be appropriate for use in determination of AFC, ATC, or transfer capability. As the dispatch for this case is being developed, consideration should be given to how pumped storage and grid-forming inverters are modeled to represent this low-inertia case.

Spring Light Load (yyyySLL) — is defined as a typical early morning load level, approximately 40% to 60% of summer peak load conditions. Topological modeling changes shall be incorporated into the model if they are to go into effect on or before April 15th. Depending on an area's typical load profile, this may occur when high distribution-connected resource (DER) and transmission connected renewable production occurs. 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. Spring or appropriate ratings should be used. Planned spring maintenance of generation and transmission should be reflected in this case. Interchange should be based on what is allowable up to what is available under firm transmission service. Non-firm transactions that historically occur may be used when agreed upon between PC's. Due to these non-firm transactions, this model may not be appropriate for use in determination of AFC/ATC/or transfer capability.

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.

Summer Shoulder Peak Load (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.

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.

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.

7.2. 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, semicolon.

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 (RATE A/RATE 1 and RATE B/RATE 2, respectively); use of the third rating field (RATE C/RATE 3) is optional[1]. 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.
6. **Branch and Transformer Names** –The branch and transformer names should not contain the following characters: comma, single and double quote, asterisk, semicolon. Beginning with PSSE 34, the branch and transformer names should begin with the area number or area name. Subsequent identifiers should be unique with no duplicates. Leaving this field blank is acceptable. Tie line coordination on naming convention would be required. Recommend prefix of AREA1:AREA2:. Failure to follow this recommended format may result in PSSE automatically changing this name to avoid duplicates.

   Lines with fake or placeholder ratings should use a rating of "9999" (four 9's), and not less (e.g., "999") since that may be an actual rating for some branches.

D. **Generators**

1 PSS®E Version 33 and prior utilizes Rate A, B, and C and PSS®E version 34 and higher utilizes Rate 1, 2, 3…12. Rate A, B, C will transition to Rate 1, 2, 3.

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 the Planning Coordinator. 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 Over Excitation Limiters (OEL), Stator Current Limit (SCL) and Under Excitation 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 and Solar Plants** - Include an equivalent representation consisting of all collector bus(es) and the main facility step-up transformer(s) from the collector bus(es) to the transmission network. Model the radial transmission line if significant length or if desired. Additionally, a single step-up transformer for each collector bus shall be included in the equivalent representation, with identical (same Type) wind/solar devices lumped together to represent the aggregate wind turbines or solar converters in each collection network. The equivalent model shall represent the as-built plant as reasonably as possible. Generator facilities comprised of more than a single inverter (battery, flywheel, etc.) and other similar technology should have similar equivalent model representation. Figure 1 and Figure 2 below are illustrations provided for use as guidance for the equivalent representations of such renewable resources; however, Figure 2 shall be the representation in the planning models.

7. Any future changes or updates to equipment (wind turbines or solar inverters) or electrical topology shall include an updated equivalent representation to the Planning Coordinator.

Figure 1: Detailed Wind and Solar Farm Representation (Not to be used for planning models)

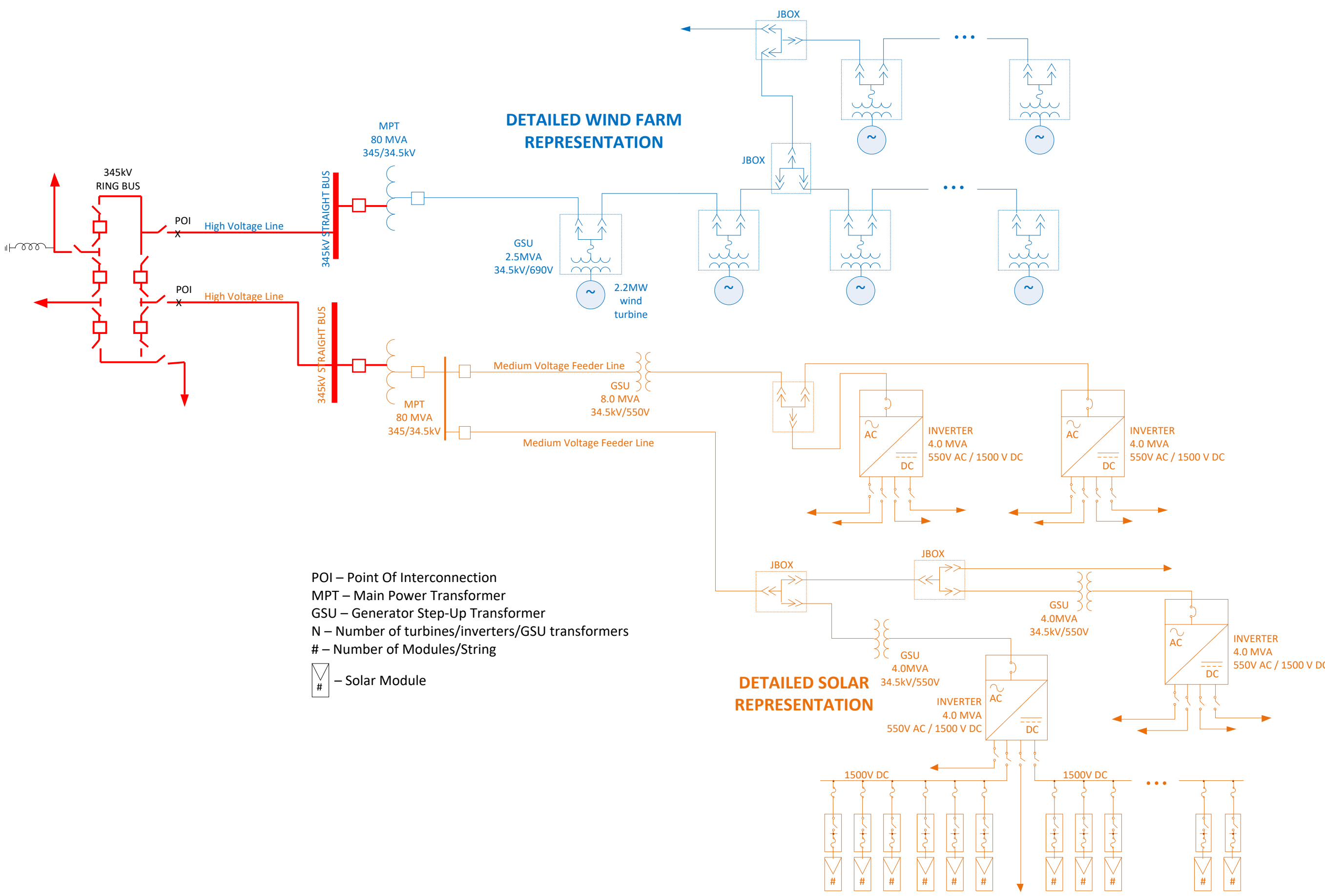
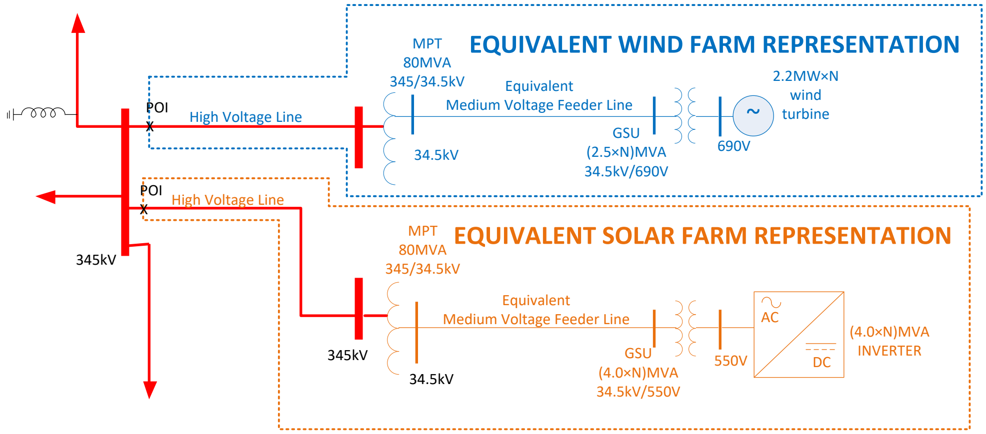


Figure 2: Equivalent Wind and Solar Farm Representation (Required representation for planning models)



POI – Point Of Interconnection
MPT – Main Power Transformer
GSU – Generator Step-Up Transformer
N – Number of turbines/inverters/GSU transformers

8. **Swing Machine** (PSS®E **type 3 bus) -** Defined as the slack machine for the AC island**.**
9. **Area Slack Machine -** Defined as the individual area slack machine. There should be an adequate amount of available MWs on the area slack machine to account for variations in losses. Slack machines must not be dispatched at Pmax.
   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. Transformers controlling voltage should have a voltage bandwidth that is sufficiently large in relation to the tap step of the transformer. Voltage bandwidths that are too small (or tap steps that are erroneously too large) may result in the lack of existence of a power flow solution. The ratio of tap step (p.u.) to voltage bandwidth (p.u.) should be no less than 1.6; ratios below 1.0 are considered severe as they are extremely likely to prevent a power flow solution from being found.
6. **Phase Angle Regulating/Phase Shifting Transformers** – For phase angle regulating/phase shifting (PAR/PST) 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. Any shunt that would be switched for system control, either automatically or by supervisory control, should be modeled as switched. 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. An attempt should be made to model the voltage bandwidth that the supervisory control would utilize. 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 Regional Data Coordinator. 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 Regional Data Coordinator 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.[2]

2 TPL-001-4, R1.1.2

7.3. 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 MMWG 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 shall be documented unless listed as informational only.

Reference Appendix IX for Process Flowcharts.

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
RAW Read Warning	All Data	Warnings generated by PSS®E activity READ	Documented Exceptions Allowed	When reading in a case in RAW format, PSS®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	
Bus Number Out of Range	Buses	Bus number not in MMWG range	Bus numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	The MMWG defines a range of bus numbers for each Regional Data Coordinator in the interconnection. All buses must have a number in the range of the appropriate Regional Data Coordinator.
Owner Out of Range	Buses in Regional Data Coordinator	Bus number not in Regional Data Coordinator owner number range	Owner numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Regional Data Coordinator is defined by a range of bus numbers. Owner number ranges are assigned to the Regional Data Coordinator by the MMWG.
Zone Out of Range	Buses in Regional Data Coordinator	Zone number not in Regional Data Coordinator zone number range	Zone numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Regional Data Coordinator is defined by a range of bus numbers. Zone Number ranges are assigned to the Regional Data Coordinator by the MMWG.
Bus Voltage	Buses $\geq$ 100 kV;	VM > 1.1 p.u., VM < 0.9 p.u.	Documented buses normally operated at voltages higher or lower than their BASKV. Zones 1101 & 1102 in Area 103 operate at higher voltages and are checked for voltages greater than 260 kV for the 230 kV system and 132 kV for the 115 kV system.	
Gen Terminal Bus Voltage	All online Gen Terminal Buses	VM > 1.05 p.u., VM < 0.95 p.u.	Documented buses normally operated at voltages higher or lower than their BASKV.	

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
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	Buses; Generators	Bus with IDE of 2 and no generator at the bus	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
Generator Rsource / Xsource Ratio	Generators with PMAX > 0	$(R_{source} / X_{source}) > 1.0$	$X_{source} = 9999$, Documented Exceptions	
Gen Reactive Limit Power Factor	Generators with PMAX > 0 Mbase > 20 MVA	Power factor outside +0.80 (producing Vars) and -0.85 (consuming Vars)	Documented Exceptions	Generator reactive power limits (Qmax, Qmin) should have a reasonable power factor compared with maximum active power (Pmax)
Pos Seq TX Circulating Current	All Parallel XFMRs in case, T1, T, … Tn	For each pair of transformers, Tj and Tk, current cannot be in reverse directions. If Amps in Tj > 0, Amps in Tk cannot be < 0 and vice versa.	Documented Exceptions	
Poor Load Power Factor	Positive MW Loads > 2 MVA	(Pload / MVAload) < 0.5	Documented exceptions for eq and station service loads	
MBASE	Generators	MBASE = 100; MBASE ≤ PMAX	Winter Cases; Documented Exceptions	
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.

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
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, solar farms, and battery energy storage; Voltage controlling devices radially connected to the bus being controlled.	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 set points 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 in Control Mode 1	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	
Continuous Control Voltage Mode Band Mismatch	Switched Shunts	Control Mode 2, Vhi not equal to Vlow	No Exceptions	If condition not satisfied, the average of Vhi and Vlo will be selected as the target voltage.
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]	Document Exceptions	A small voltage band can cause unnecessary transformer tap toggling and extra power flow solution iterations[5].
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| or X/R ratio > 100 Transformers: R1-2 > |X1-2| or X/R ratio = 5 - 100	Document Exceptions Exception of R = 0 and R or X < 0	Fast-decoupled power flow solver is sensitive to the ratio R/X.

Name	Data Checked	Conditions Not Allowed	Exceptions Allowed	Comment
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.
Rating Errors	All transformers and branches	RATEB/RATE2 < RATEA/RATE1, RATEA/RATE1 = 0, RATEB/RATE2 = 0 RATEB/RATE2 >= 3 X RATEA/RATE1 (only for 69kV+)	Exception for branches with CKT = '99'/'EQ', zero impedance branches, and verified RATEB/RATE2 >= 3X RATEA/RATE1	The MMWG defines RATEA/RATE1 as Normal and RATEB/RATE2 as Emergency.
3 Winding Rating Errors	3-Winding Transformers[3]	RATEB/RATE2 < RATEA/RATE1, RATEA/RATE1 = 0, RATEB/RATE2 = 0 RATEB/RATE2 >= 3 X RATEA/RATE1 (only for 69kV+)	No Exceptions	The MMWG defines RATEA/RATE1 as Normal and RATEB/RATE2 as Emergency.
Branch Overloads	Branches ≥ 69kV[1]; Transformers ≥ 69kV[1, 3] All GSU's	Branch loading above 100% of RATEA/RATE1	Exceptions allowed for 10 year cases only. Valid and documented GSU exceptions allowed.	Overloads in the Near-Term with no plans to correct are not allowed. 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 PSS®E R, X & B values.	Branch ID must start with 'Z'	No Exceptions	
Gen at reactive power limit	Gen with status = 1 Bus type code = 2, 3 Qmax > Qmin Mbase > 20 MVA	Qgen at Qmax or Qgen at Qmin	Documented Exceptions allowed	Review
Load Owner Number Out of Range	Loads Owner Numbers in Planning Coordinator	Owner number not in Planning Coordinator owner number range	Owner numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Planning Coordinator is defined by a range of bus numbers. Owner Number ranges are assigned to the Planning Coordinator by the MMWG.
Generator Owner Number Out of Range	Generator Owner Numbers in Planning Coordinator	Owner number not in Planning Coordinator owner number range	Owner numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Planning Coordinator is defined by a range of bus numbers. Owner Number ranges are assigned to the Planning Coordinator by the MMWG.
Branch Owner Number Out of Range	Branch Owner Numbers in Planning Coordinator	Owner number not in Planning Coordinator owner number range	Owner numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Planning Coordinator is defined by a range of bus numbers. Owner Number ranges are assigned to the Planning Coordinator by the MMWG.
Load Zone Number Out of Range	Load Zone Numbers in Planning Coordinator	Load Zone number not in Planning Coordinator load zone number range	Load Zone numbers must follow table in Appendix IV. Documented and valid exceptions are allowed.	Planning Coordinator is defined by a range of bus numbers. Load Zone Number ranges are assigned to the Planning Coordinator by the MMWG.

[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.
[5]MMWG Coordinator is allowed to make reasonable data changes to accommodate PSS/E convergence solution. Any changes will be communicated to the Regional Data Coordinators.

7.4. 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 Regional Data Coordinator 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 Angle Regulating/Phase Shifting Transformers
   1. The controlled bus for phase shifting transformers should be designated as ‘0’. The ‘controlled bus’ field should only be non-zero for voltage-controlling transformers.
   2. An unduly narrow control band for the active power target flow should be avoided.

8. Dynamics Data Submittal Requirements and Guidelines

8.1. 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 short name is recommended to be not more than twelve characters. 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.

8.2. 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, GENQEC GENROE, GENSAE, GENDCO, and GENTPJU1. 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®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 8.2.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®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. Turbine governor models which represent dead band are recommended to be used. Starting with PSS®E v33.10 dead band modeling is part of the suite of available models.

H. Standard PSS®E dynamic models should be used for the representation of all generating units and other dynamic devices unless both of the conditions below apply. The use of models listed as unacceptable, in the ERAG Acceptable Model Working Group (AMWG) Dynamic Model List[3], should be avoided.
   1. The specific performance features of the user-defined modeling are necessary for proper representation and simulation of inter-Regional Data Coordinator dynamics, and
   2. Standard PSS®E dynamic models cannot adequately approximate the specific performance features of the dynamic device being modeled.

I. 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.

J. Source code, .dll file, and Object file(s) shall be provided for all User Models. Source code shall be submitted in the FLECS language of the current PSS®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.

K. 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.)

3 The AMWG Acceptable Model List is located on the ERAG Internet Site.

L. 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.

M. 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 and kV 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 and kV rating of the associated generator. An exception to this convention is noted in Section 8.7.D. 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.

N. All generators with power system stabilizer (PSS) should have an excitation system model

O. Second generation renewable models should be parameterized to site-specific conditions, namely as represented in the model check table and requirements mentioned below.
   1. Renewable plant models (REPC) should have a voltage control bus (or buses) and a monitored bus.
   2. Wind turbine pitch controllers should not have identical parameters to another installation.

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

8.3. 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.

Reference Appendix IX for Process Flowcharts.

Models Checked	Data Checked	Conditions Not Allowed	Good Condition	Exceptions Allowed
All Gen Models with time constants T''_{d0}, T'_{d0}, T''_{q0}, and T'_{q0}	T''_{d0}, T'_{d0}, T''_{q0}, T'_{q0}	$T''_{d0} > T'_{d0}$ and $T''_{q0} > T'_{q0}$	$T''_{d0} \le T'_{d0}$ and $T''_{q0} \le T'_{q0}$	No Exceptions
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 Model with S(1.0) and S(1.2)	S(1.0) & S(1.2)	0.03 > S(1.0) > 0.18 0.2 > S(1.2) > 0.85 S(1.2) not within 2 to 8 times S(1.0)	0.03 ≤ S(1.0) ≤ 0.18 0.2 ≤ S(1.2) ≤ 0.85 S(1.2) within 2 to 8 times S(1.0)	Verified and 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

Models Checked	Data Checked	Conditions Not Allowed	Good Condition	Exceptions Allowed
All Turbine Governor Models with lead/lag time constants X and Y	X & Y	$X \geq Y$	$X < Y$	No Exceptions
All Exciter Models with self-excitation parameter K_E	K_E	$K_E > 1$ $K_E \leq -2$	Exciter Models K_E = small negative number unless $K_E = 0$ or $K_E = 1$	Verified and Documented Exceptions
All non-classical Gen Model with speed 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 Note: For X'd = X"d, the error flag may be addressed by adding a small, incremental value to X'd, such as 0.01 pu.	X'd	X'd <= X"d	X'd > X"d	
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
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
WT3E electrical control for Type 3 Wind Generator for inconsistent wind speeds	ωPmin, ωP20, ωP40, ωP60, ωP100	ωPmin > ωP20 > ωP40 > ωP60 > ωP100	ωPmin < ωP20 < ωP40 < ωP60 < ωP100	No Exceptions
Renewable generator models (REGC) voltage limit points	lvpnt0 and lvpnt1	difference between the lvpnt0 and lvpnt1 settings < 0.1 p.u	difference between the lvpnt0 and lvpnt1 settings > 0.1 p.u	Verified and Documented Exceptions
Renewable generator models (REGC) LVPL characteristic voltage	zerox and brkpt	difference between the zerox and brkpt settings < 0.1 p.u	difference between the zerox and brkpt settings > 0.1 p.u	Verified and Documented Exceptions
Renewable generator models (REGC) Converter time constant (s)	Tg	Tg > 0.2 p.u.	Tg < 0.2 p.u.	Verified and Documented Exceptions
Renewable electrical models (REEC) maximum power limit	Pmax	Pmax setting > 1.0 p.u. of its dynamic MVA base	Pmax setting < 1.0 p.u. of its dynamic MVA base	Verified and Documented Exceptions

Models Checked	Data Checked	Conditions Not Allowed	Good Condition	Exceptions Allowed
Renewable electrical models (REEC) maximum value of the signal Qext or Vext	Qmax	Qmax setting > 1.0 p.u. of its dynamic MVA base	Qmax setting < 1.0 p.u. of its dynamic MVA base	Verified and Documented Exceptions. REECs should have a Qmax setting of less than 1.0 p.u. of its dynamic MVA base.
Renewable electrical models (REEC) minimum value of the signal Qext or Vext	Qmin	Qmin setting < -1.0 p.u. of its dynamic MVA base	Qmin setting > -1.0 p.u. of its dynamic MVA base	Verified and Documented Exceptions. REECs should have a Qmin setting of greater than -1.0 p.u. of its dynamic MVA base.
Renewable electrical models (REEC) Reactive current injection gain during over and under voltage conditions	Kqv	Default Kqv	Should have a non-default Kqv setting (Kqv > 0)	Verified and Documented Exceptions
Renewable electrical models (REEC) for Battery Energy Storage Systems should have a large Ts value	Ts	Ts < 30 seconds	Ts > 30 seconds	Verified and Documented 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 5.7 of this manual may be applied for this purpose.

C. Each Regional Data Coordinator 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.

8.4. 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 entities providing the data 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-Regional Data Coordinator dynamic performance requires it.

8.5. Dynamics Initialization and Checking Procedure

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

Step 1: Create a converged power 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 power 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 power flow, for instance the areas comprising one Regional Data Coordinator, 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 power 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] (Power 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 power 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 power 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 power 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 power flow model.

F. Modify model parameters or the power 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.

8.6. 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 between 50 and 60 seconds:

1. No generator MW change of 1 MW or more. Documented exceptions may be allowed.
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 0.001 p.u. or more, for generator busses or busses at or above 500kV, except in vicinity of exciters with dead band control

The 60 second disturbance simulations can be readily checked by saving a converted power flow at 50 seconds and at the end of the simulation and then comparing the two. The no-fault disturbance simulation can be checked by saving a converted power flow case 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 Regional Data Coordinator's represented area which have been supplied to the MMWG Regional Data Coordinator.

1. The outage of the biggest unit in the Regional Data Coordinator
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.

8.7. Additional Dynamics Information

A. WMOD

In PSS®E 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 PSS®E 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 PSS®E 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 Regional Data Coordinator or a Planning Coordinator.

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®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 PC	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
1	MISO	-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
2	SASK POWER	-70	1	-43	0.78	-32	0.85	0	0.5	32	0.85	43	0.78	70	1		
3	MH	-180	1	-150	0.5	0	0.5	150	0.5	180	1						
4	MISO	-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
5	MISO	-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
6	MISO	-35.1	1.5287	-26.7	1.3034	-18	1.1193	-9	1.0810	0	1	9	1.0810	18	1.1193	26.7	1.3034
7	MISO	-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
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
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
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
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
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
31	PJM	-15	2.076	0	1	15	2.076										
32	PJM	-15	1.62	0	1	15	1.62										
33	PJM	-5.7	2.061	0	1	5.7	2.061										
34	PJM	-10	1.782	0	1	10	1.782										
35	PJM	-30	1.65	0	1	30	1.65										
37	MISO	-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
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
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
50	SPP	-25	1	-12	0.25	0	0.001	12	0.25	25	1	0	0				

ERAG
Eastern Interconnection
Reliability Assessment Group

...to further augment the reliability of the bulk-power system...

Table Number	Data Submitting PC	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
51	NPCC	-25	2.4158	-18.75	2.0618	-12.5	1.7079	-6.25	1.3539	-1.56	1.0885	0	1	1.56	1.0885	6.25	1.3539
52	NPCC	-25	2.4038	-18.75	2.0529	-12.5	1.7019	-6.25	1.351	-1.56	1.0877	0	1	1.56	1.0877	6.25	1.351
53	NPCC	-25	2.424	-18.75	2.068	-12.5	1.712	-6.25	1.356	-1.56	1.089	0	1	1.56	1.089	6.25	1.356
54	NPCC	-25	2.3392	-18.75	2.0044	-12.5	1.6696	-6.25	1.3348	-1.56	1.0837	0	1	1.56	1.0837	6.25	1.3348
55	NPCC	-25	1.9532	-18.75	1.7149	-12.5	1.4766	-6.25	1.2383	-1.56	1.0596	0	1	1.56	1.0596	6.25	1.2383
56	NPCC	-25	2.4292	-18.75	2.0719	-12.5	1.7146	-6.25	1.3573	-1.56	1.0893	0	1	1.56	1.0893	6.25	1.3573
57	NPCC	-25	1.9625	-18.75	1.7218	-12.5	1.4812	-6.25	1.2406	-1.56	1.0602	0	1	1.56	1.0602	6.25	1.2406
58	NPCC	-25	1.2487	-18.75	1.1865	-12.5	1.1243	-6.25	1.0622	-1.56	1.0155	0	1	1.56	1.0155	6.25	1.0622
59	NPCC	-12	1.3774	-9	1.2831	-6	1.1887	-3	1.0944	-0.75	1.0236	0	1	0.75	1.0236	3	1.0944
60																	
61																	
62																	
63	NPCC	-30	1.9126	-22.5	1.6844	-15	1.4563	-7.5	1.2281	-1.88	1.057	0	1	1.88	1.057	7.5	1.2281
64	NPCC	-30	1.9092	-22.5	1.6819	-15	1.4546	-7.5	1.2273	-1.88	1.0568	0	1	1.88	1.0568	7.5	1.2273
65	NPCC	-25	2.0047	-18.75	1.7535	-12.5	1.5024	-6.25	1.2512	-1.56	1.0628	0	1	1.56	1.0628	6.25	1.2512
66	NPCC	-25	2.1297	-18.75	1.8473	-12.5	1.5649	-6.25	1.2824	-1.56	1.0706	0	1	1.56	1.0706	6.25	1.2824
67	NPCC	-37.8	2.1409	-28.35	1.8557	-18.9	1.5704	-9.45	1.2852	-2.36	1.0713	0	1	2.36	1.0713	9.45	1.2852
68	NPCC	-25	1.2457	-18.75	1.1843	-12.5	1.1229	-6.25	1.0614	-1.56	1.0154	0	1	1.56	1.0154	6.25	1.0614
69	NPCC	-25	1.9271	-18.75	1.6953	-12.5	1.4635	-6.25	1.2318	-1.56	1.0579	0	1	1.56	1.0579	6.25	1.2318
70	NPCC	-40	2.3448	-28.24	1.9492	-18.82	1.6328	-9.41	1.3164	-2.35	1.0791	0	1	2.35	1.0791	9.41	1.3164
71	NPCC	-40	2.2143	-28.24	1.8572	-18.82	1.5714	-9.41	1.2857	-2.35	1.0714	0	1	2.35	1.0714	9.41	1.2857
72	NPCC	-25	1.9599	-18.75	1.72	-12.5	1.48	-6.25	1.24	-1.56	1.06	0	1	1.56	1.06	6.25	1.24
73	NPCC	-25	1.9735	-18.75	1.7301	-12.5	1.4867	-6.25	1.2434	-1.56	1.0608	0	1	1.56	1.0608	6.25	1.2434
74	NPCC	-25	1.8582	-18.75	1.6436	-12.5	1.4291	-6.25	1.2145	-1.56	1.0536	0	1	1.56	1.0536	6.25	1.2145
75	NPCC	-25	2.2419	-18.75	1.9315	-12.5	1.621	-6.25	1.3105	-1.56	1.0776	0	1	1.56	1.0776	6.25	1.3105
76	PJM	-32.1	1.3967	0	1	8	1.223										
77	PJM	-32	1.568	-24.3	1.32	-16.3	1.124	-15	1.184	-8.2	1.078	0	1	8.2	1.077	15	1.187
78	SaskPower	-86	1	-77	0.929	-64.5	0.854	-50	0.805	-18.7	0.708	0	0.673	18.7	0.708	50	0.805
79	MH	-103	1	-84	0.696	-61.2	0.397	-38.2	0.17	-15.6	0.035	0	0.001	12	0.022	31.9	0.146
80	NYISO	-25	2.2267	-18.75	1.9201	-12.5	1.6134	-6.25	1.3067	-1.56	1.0767	0	1	1.56	1.0767	6.25	1.3067
81	NYISO	-40	1.4867	0	1	40	1.4867										
82	NYISO	0.9091	0.8003	0.9143	0.8092	0.9195	0.8188	0.9249	0.829	0.9302	0.8392	0.9357	0.85	0.9412	0.8615	0.9467	0.8736
83	NYISO	0.9091	0.751	0.9143	0.761	0.9195	0.7727	0.9249	0.786	0.9302	0.7985	0.9357	0.8127	0.9412	0.826	0.9467	0.841
88	SaskPower	-120.28	1	-117.14	0.9808	-113.96	0.9615	-110.74	0.9423	-107.46	0.923	- 104.14	0.9038	- 100.76	0.8845	-97.34	0.8653
		Tap or Angle	11 Factor	Tap or Angle	12 Factor	Tap or Angle	13 Factor	Tap or Angle	14 Factor	Tap or Angle	15 Factor	Tap or Angle	16 Factor	Tap or Angle	17 Factor	Tap or Angle	18 Factor
		-83.22	0.7883	-79.56	0.769	-75.88	0.7498	-72.16	0.735	-68.38	0.7113	-64.58	0.692	-60.74	0.6923	-56.86	0.6926

Table Number	Data Submitting PC	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	22 Factor	Tap or Angle	23 Factor	Tap or Angle	24 Factor	Tap or Angle	25 Factor	Tap or Angle	26 Factor	Tap or Angle	27 Factor	Tap or Angle	28 Factor	Tap or Angle	29 Factor
		-41.02	0.6939	-37	0.6942	-32.94	0.6945	-28.88	0.6948	-24.78	0.6952	-20.68	0.6955	-16.56	0.6958	-12.42	0.6961
		Tap or Angle	33 Factor	Tap or Angle	34 Factor	Tap or Angle	35 Factor	Tap or Angle	36 Factor	Tap or Angle	37 Factor	Tap or Angle	38 Factor	Tap or Angle	39 Factor	Tap or Angle	40 Factor
		4.14	0.6967	8.28	0.6964	12.24	0.6961	16.56	0.6958	20.68	0.6955	24.78	0.6952	28.88	0.6948	32.94	0.6945
		Tap or Angle	44 Factor	Tap or Angle	45 Factor	Tap or Angle	46 Factor	Tap or Angle	47 Factor	Tap or Angle	48 Factor	Tap or Angle	49 Factor	Tap or Angle	50 Factor	Tap or Angle	51 Factor
		49	0.6933	52.94	0.693	56.86	0.6926	60.74	0.6923	64.58	0.692	68.38	0.7113	72.16	0.735	75.88	0.7498
		Tap or Angle	55 Factor	Tap or Angle	56 Factor	Tap or Angle	57 Factor	Tap or Angle	58 Factor	Tap or Angle	59 Factor	Tap or Angle	60 Factor	Tap or Angle	61 Factor	Tap or Angle	62 Factor
		90.36	0.8268	93.88	0.846	97.34	0.8653	100.76	0.8845	104.14	0.9038	107.46	0.923	110.74	0.9423	113.96	0.9615

APPENDIX III. **Utilized DC Lines**

DC Line Number	Regional Data Coordinator	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	NPCC_23_CHPE	Champlain Hudson Power Express (HVDC)
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	WELSH-HVDC	Welsh
46	SPP	SPP_46_RPCTY	Rapid City
47	SPP	SPP_47_STGL	Stegall
48	MH	MH_48_KW-RL	Keewatinoow - Riel

DC Line Number	Regional Data Coordinator	Name	Description
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	100-997	100-1902	100-1599
NPCC	100000-199999 700000-711099	100-199	100-199, 1100-1199	100-199
RF	200000-299999	200-299, 696	200-299, 1200-1299, 1800-1899	200-299
SERC	300000-312999 316500-318999 321000-339199 339400-340999 343000-395999 398000-399999 500000-503499	300-319 321-344 346-347 349-399 502-504	300-349, 375-399, 500-517, 806-899, 1300-1314, 1325-1399	300-311, 315-339, 342-368, 370-399, 502-504
SERC (*see PJM*)	339200-339399, 341000-342999, 313000-316499, 319000-320999	320 345	1315-1324 350-374	340-341 312-314
SERC *(see FRCC)*	396000-397999 400000-499999	348 400-499	800-805 400-499, 1400-1499	369 400-499
MRO	503500-599999, 600000-699999	500-501, 505-599, 600-695, 697-699, 997	518-599, 600-699, 1500-1599, 1600-1686, 1688, 1692, 1697-1699, 1900-1902	500-501, 505-599, 600-699, 800-849, 1500-1599
ERCOT	In MRO-SPP range	998	998	998
WECC	In MRO-SPP range	999	999	999

FRCC PC			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
348 400-499	396000-397999 400000-499999	369 400-499	800-805 400-499

Manitoba Hydro			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
667	667000-671999	667	1646-1653, 1900-1902

NPCC PCs			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
101	100000-124999	101	100-118, 141-144
102	125000-149999 700000 – 701999 705000-709099	141-155	145-177
103	150000-174999	103, 160, 161, 162, 163, 164, 168, 169	1101-1111

NPCC PCs (Continued)			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
104	176000-189999	104	1140-1179
105	190000-194999	105	1180-1199
106	195000-199999	156-166	186-199
107	175000-175999	107	1150
108	702000-704999 709100-711099	170-178	178-185

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	235000-238499	201, 255, 270-271	1201-1205
202	238500-241999	202, 221, 255, 270-271	1230-1249
	298900-298999	229	
205	242100-247999 269500-270599 288550-290999 291201-292700	204-205, 250-251, 270-271	1250-1259, 1290-1299
	288500-288549	229	
206	248000-248199	206, 250-251, 270-271	1206
209	253000-253499 291001-291099 291151-291200	209, 270-271	1209
	291100-291150	229	
212	249564-249603	212, 270-271	1220-1229
	249980-250234		
	251258-251715		
	251792-251848		
	251934-251993		
	252038-252999		
	299500-299999		
215	253900-254499	203, 215, 270-271	1215
222	270600 - 281599	222, 270-271	1270-1289
225	200000-200399	230, 234, 270-271	202-204, 1820-1833
226	200500-203999	226, 255, 270-271	205-213
227	204500-205999	227, 255, 270-271	214-222

PJM (Continued)			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
228	206200-207699	228, 231, 255, 270-271	223-231
229	207900-212899 276600-281599	270-271, 275-277	250-258
230	213400-216899	270-271, 279	259-267
231	216900-220399	232-233, 270-271, 281	250-258
232	220400-223899	270-271, 283-284	259-267
233	223900-226999	270-271, 286	268-271, 273-276
234	227400-230899	270-271, 289-290	277-285
235	230900-234199	270-271, 292-293	286-294
236	234200-234399	270-271, 295	295-297
237	234600-234799	270-271, 297	298-299
238	227000-227299	270-271, 287	272
320	339200-339399 341000-342999	270-271, 340-341	1315-1324
345	313000-316499 316500-316999 319000-320999 390000-390499	270-271, 312-314	350-374

SPP RTO			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
506	503500-503550	506	1586-1588
511	503900-504899	511	518-520
515	505300-506299	505, 515, 522, 528-529, 532, 537-538, 543, 555, 559, 583	521-523
520	506700-512199	507, 519-521, 582, 585-586, 597	524-553
523	512600-513599	508, 522-523, 528	554-562
524	514000-519999	510, 524, 836	563-574
525	520400-522399	525, 849	575-594
526	522700-528999	505, 510, 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 539000-539999	533-535, 550, 599, 836, 849	1522-1532 1541-1543
536	532600-538599	510, 532, 533, 535, 536, 550, 599, 836	1533-1540
541	540400-542399 542800-545799	533, 540-541, 552, 590	595-599 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, 646-649	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	652,654	1600-1615
	653000-653999	653	1612
	658000-658999	658	1624-1627
	655000-655999 659000-659999 663000-663999	655,659, 663 1500-1508	698-699, 1617, 1628-1633, 1676-1683
	656000-656999	656	1616
	660000-660999	660	1634
	662000-662999	662	
659	656000-656999	656	1616
	655000-655999 659000-659999 663000-663999	655,659,663,1500-1508	1617, 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, 367	300-309
340	304000-305999 321000-323999	304-305	315-324
341	304000-305999 321000-323999	304-305	315-324
342	306000-310999	306-309	325-339
343	370000-372999	361-362	1375-1384
344	311000-312999	310-311	340-349
346	317000-317999 380000-389999	329, 315-324	1385-1396
347	360000-369999	351-360, 365	1307, 1355-1374
352	339000-339049	335	1300-1302
353	339050-339099	336	1303
354	339100-339149	337	1304
355	339150-339199	338	1305
363	324000-326999	325-327	375-384
365	375008-375099	366	1308

MISO			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
207	248400-249199	207	1207
208	249500-252037 299000-299499	208, 250-253	1220-1229
210	253500-253899	210-211, 299	1210-1214
216	254500-254899	216	1216, 1800-1810
217	255100-255999	217, 247-249	1217, 1870-1889
218	256000-263999 281600-288499	218, 260-268	1218, 1260-1265
219	264500-269499 292701-294999	219, 242, 243, 244	1219, 1861-1864
295	691000-699999	691-699	1890-1899
296	691000-699999	691-699	1890-1899
314	340000-340974	339	1311-1314
315	340975-340999	368	1310
326	327000-338999	330-334	385-399
327	327000-338999	330-334	385-399
331	352000-352999	380	831-839
332	303000-303999	303	310-314
333	343000-343499	342	1325-1327
349	318000-318999	328	1397-1399
351	327000-338999	330-334	385-399
356	344000-346365 346567-349999	343-348	1330-1344
357	344000-346365 346567-349999	343-348	1330-1344
358	351050-351099	370	806
360	343500-343999	363	1328-1329
361	350000-350999	349	1345-1349
362	351000-351049	350	1350-1354
364	339975-339999	364	1306
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, 658
	657000-657999	657	1620-1623
627	627000-632999	627-629	661-675

MISO (Continued)			
Area Number	**Bus Range**	**Owner Numbers**	**Zone Numbers**
633	633000-634999	633	676-677
635	635000-639999	635, 639	678-685
661	661000-661999	661	1636-1640
663	659000-659999 655000-655999 663000-663999	655, 659, 663, 1500-1508	1628-1633, 1676-1683, 698-699
680	680000-682999	680-682	1666-1675
690	690000-690999	690	
694	691000-699999	691-699	1684-1687, 1692
696	691000-699999	691-699	1689-1691, 1693-1696
697	691000-699999	691-699	1697
698	691000-699999	691-699	1686, 1688, 1698
989	346366-346566	989	989

APPENDIX V. **Power Flow Modeling Areas Grouped by 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
238	SMECO	Southern Maryland Electric Cooperative
295	WEC	Wisconsin Electric Power Company (ATC)
296	MIUP	Michigan Upper Peninsula (ATC)

SERC – SERC Reliability Corporation

Area #	ID	System
314	BREC	Big Rivers Electric Corporation
315	HMPL	Henderson Municipal Power and Light
320	EKPC	East Kentucky Power Cooperative
326	EES-EMI	Entergy-Mississippi
327	EES-EAI	Entergy-Arkansas
330	AECI	Associated Electric Cooperative Inc.
331	LAGT	Eighteen Zero Three
332	LAGN	Louisiana Generating Company
333	CWLD	Columbia, MO Water and Light
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
345	DVP	Dominion Virginia Power
346	SOUTHERN	Southern Company
347	TVA	Tennessee Valley Authority
348	FPLNW	Florida Power & Light – Northwest (formerly Gulf Power (SERC))
349	SMEPA	South Mississippi Electric Power Association
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
358	SBMU	Sikeston Board of Municipal Utilities
360	CWLP	City of Springfield (IL) Water Light & Power
361	SIPC	Southern Illinois Power Cooperative
362	GLH	GridLiance Heartland
363	LGEE	Louisville Gas and Electric /Kentucky Utilities
364	OMUA	Owensboro Municipal Utilities
365	SMT	Brookfield/Smoky Mountain Hydropower LLC
401	FPL	Florida Power & Light
402	DEF	Duke Energy Florida
403	FKEC	Florida Keys Electric Cooperative
404	GVL	Gainesville Regional Utility
405	HST	City of Homestead
406	JEA	JEA
407	FMPA-E	Florida Municipal Electric Cooperative – East
408	FMPA-W	Florida Municipal Electric Cooperative – West
409	LWU	City of Lake Worth Utility
411	FMPP	Florida Municipal Power Pool
412	SEC	Seminole Electric Cooperative
415	TAL	City of Tallahassee
416	TECO	Tampa Electric Company
419	CFTOD	Central Florida Tourism Oversight District

427	OLEANDER	Oleander IPP at Brevard (FPL)
438	IPP-REL	Reliant at Indian River (FMPP)
502	CLEC	Central Louisiana Electric Company
503	LAFA	Lafayette Utilities
504	LEPA	Louisiana Energy and Power Authority

MRO – Midwest Reliability Organization

Area #	ID	System
506	MJMEUC	Missouri Joint Municipal Electric Utility Commission
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	EKC	Evergy Kansas Central
540	GMO	Greater Missouri Operations Company
541	EMMW	Evergy Metro and Missouri West
542	KACY	Board of Public Utilities
544	EMDE	Empire District Electric Company
545	INDN	City of Independence
546	SPRM	City Utilities of Springfield
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)
641	HAST	Hastings (NPPD)
642	GRIS	Grand Island (NPPD)
645	OPPD	Omaha Public Power District

MRO – Midwest Reliability Organization (Continued)

Area #	ID	System
650	LES	Lincoln Electric System, NE
652	WAPA	Western Area Power Administration
	CBPC	Corn Belt Power Cooperative
	NWPS	Northwestern Public Service
	MRES	Missouri River Energy Services
659	BEPC	Basin Electric Power Cooperative-SPP
661	MDU	Montana-Dakota Utilities Co.
663	BEPC-MISO	Basin Electric Power Cooperative -MISO
667	MHEB	Manitoba Hydro
672	SPC	Saskatchewan Power Corporation
680	DPC	Dairyland Power Cooperative
	WPPI	Wisconsin Public Power Inc.
690	MISO	Midcontinent Independent System Operator
694	ALTE	Alliant Energy East (ATC)
696	WPS	Wisconsin Public Service Corporation (ATC)
697	MGE	Madison Gas and Electric Company (ATC)
698	UPPC	Upper Peninsula Power Company (ATC)

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

APPENDIX VI. **Power Flow Modeling Areas Grouped by Regional Data Coordinator**

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
238	SMECO	Southern Maryland Electric Cooperative
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
315	HMPL	Henderson Municipal Power and Light
326	EES-EMI	Entergy-Mississippi
327	EES-EAI	Entergy-Arkansas
331	LAGT	Eighteen Zero Three
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
358	SBMU	Sikeston Board of Municipal Utilities
360	CWLP	City of Springfield (IL) Water Light & Power
361	SIPC	Southern Illinois Power Cooperative
362	GLH	GridLiance Heartland
364	OMUA	Owensboro Municipal Utilities
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.

MISO (Continued)

Area #	ID	System
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.
690	MISO	Midcontinent Independent System Operator
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)

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
352	YAD	APGI – Yadkin Division
353	SEHA	Hartwell – SEPA
354	SERU	Russell – SEPA
355	SETH	Thurmond – SEPA
363	LGEE	Louisville Gas and Electric /Kentucky Utilities
365	SMT	Brookfield/Smoky Mountain Hydropower LLC

SaskPower

Area #	ID	System
672	SPC	Saskatchewan Power Corporation

Manitoba Hydro

Area #	ID	System
667	MHEB	Manitoba Hydro

FRCC PC

Area #	ID	System
348	FPLNW	Florida Power & Light – Northwest (formerly Gulf Power (SERC))
401	FPL	Florida Power & Light
402	DEF	Duke Energy Florida
403	FKEC	Florida Keys Electric Cooperative404 GVL Gainesville
Regional Utility		
405	HST	City of Homestead
406	JEA	JEA
407	FMPA-E	Florida Municipal Power Agency – East
408	FMPA-W	Florida Municipal Power Agency – West
409	LWU	City of Lake Worth Utility
411	FMPP	Florida Municipal Power Pool
412	SEC	Seminole Electric Cooperative
415	TAL	City of Tallahassee
416	TECO	Tampa Electric Company
419	CFTOD	Central Florida Tourism Oversight District
427	OLEANDER	Oleander IPP at Brevard (FPL)
438	IPP-REL	Reliant at Indian River (FMPP)

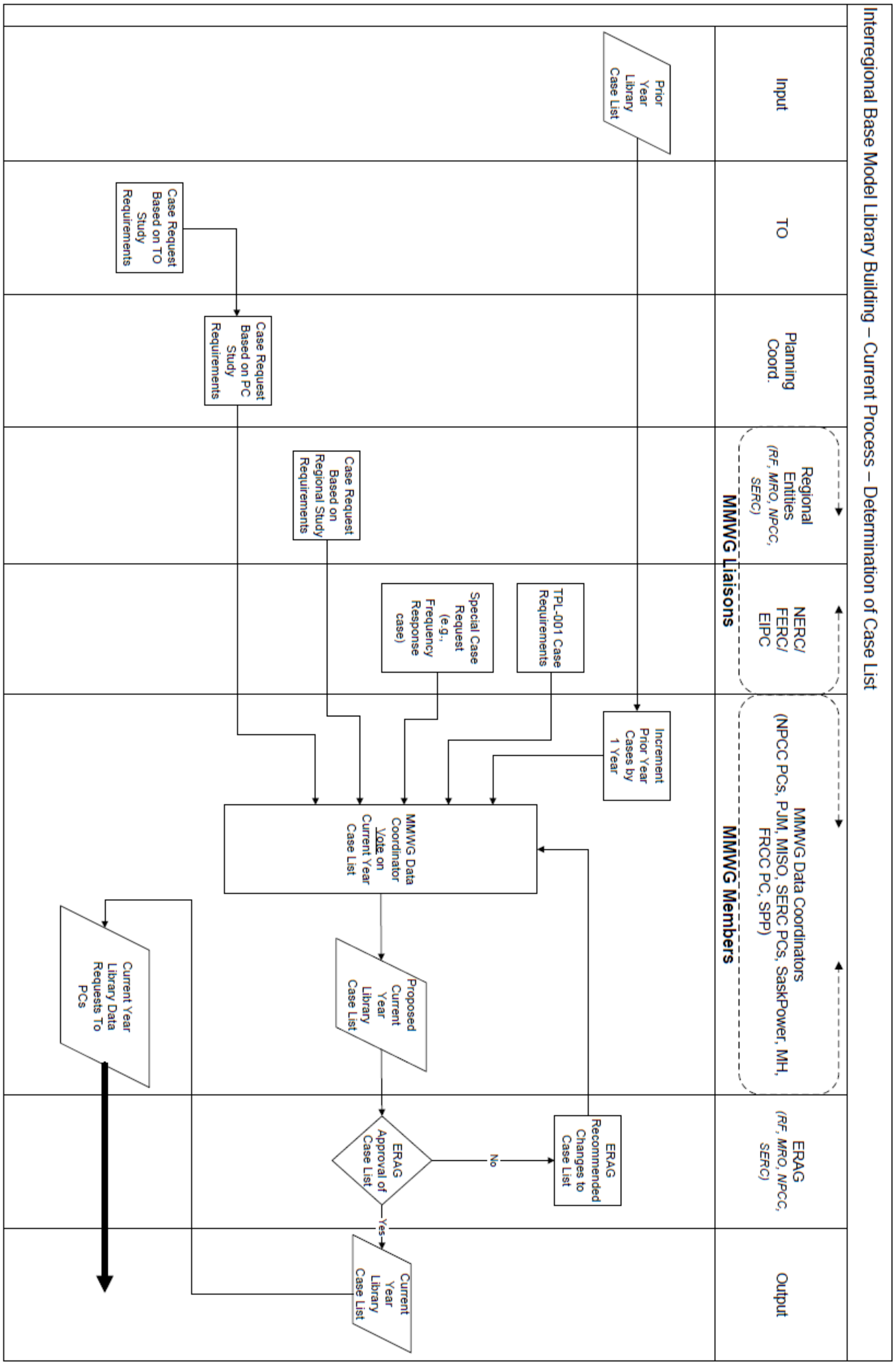
SPP RTO

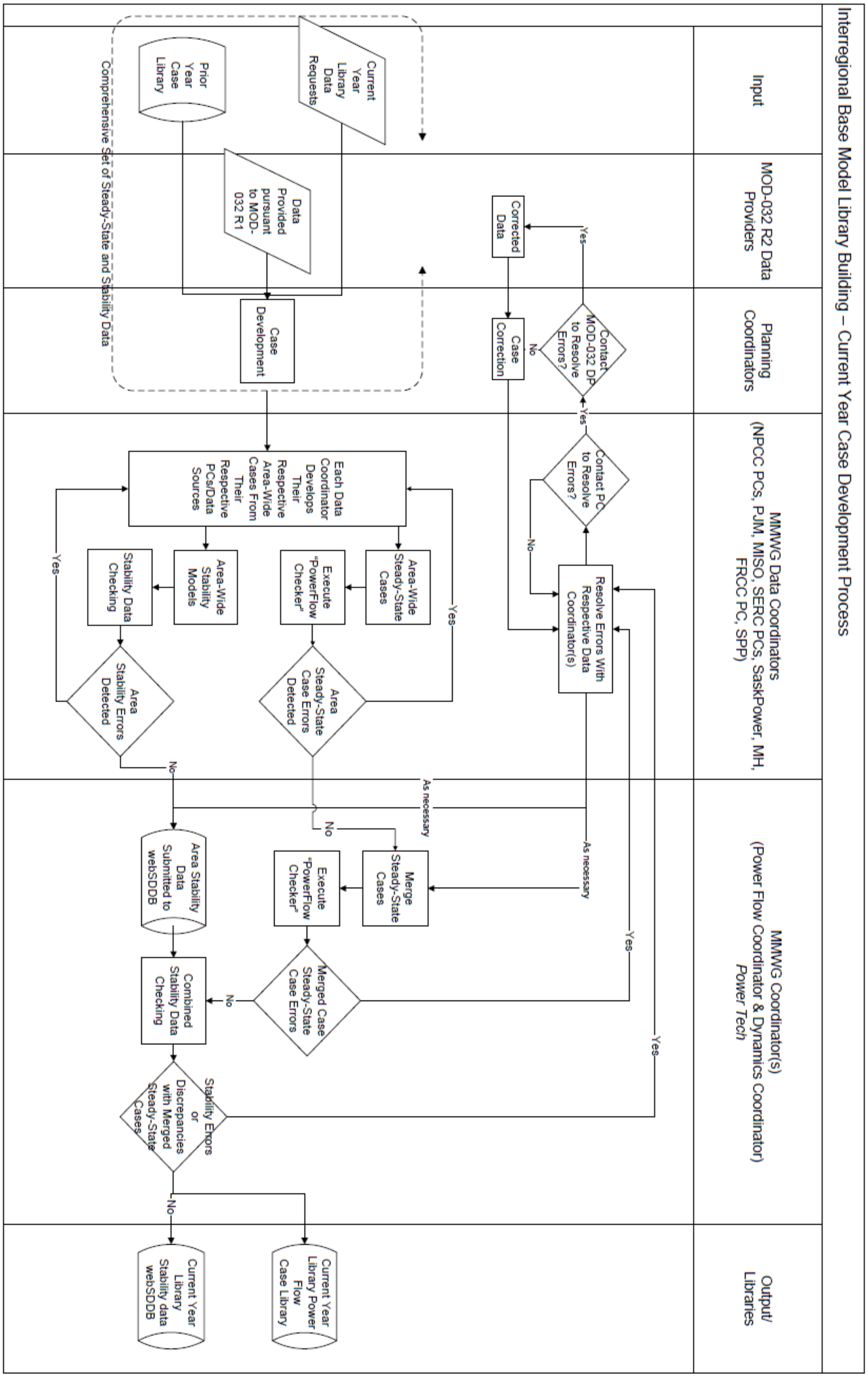
Area #	ID	System
506	MJMEUC	Missouri Joint Municipal Electric Utility Commission
511	AECC	Arkansas Electric Cooperative
515	SWPA	Southwestern Power Administration
520	AEPW	American Electric Power
523	GRDA	Grand River Dam Authority
524	OKGE	Oklahoma Gas and Electric Company
525	WFEC	Western Farmers Electric 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	EKC	Evergy Kansas Central
540	GMO	Greater Missouri Operations Company
541	EMMW	Evergy Metro and Missouri West542 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)
641	HAST	Hastings (NPPD)
642	GRIS	Grand Island (NPPD)
645	OPPD	Omaha Public Power District

SPP RTO (Continued)

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

APPENDIX VII. **Process Flowcharts**




Interregional Base Model Library Building – Current Year Case Development Process
Input
MOD-032 R2 Data Providers
Planning Coordinators
MMWG Data Coordinators (NPCC PCs, PJM, MISO, SERC PCs, SaskPower, MH, FRCC PC, SPP)
MMWG Coordinator(s) (Power Flow Coordinator & Dynamics Coordinator) Power Tech
Output/ Libraries
Current Year Library Data Requests
Prior Year Case Library
Data Provided pursuant to MOD-032 R1
Case Development
Comprehensive Set of Steady-State and Stability Data
Corrected Data
Contact MOD-032 DP to Resolve Errors?
Case Correction
Contact PC to Resolve Errors?
Each Data Coordinator Develops Their Respective Area-Wide Cases From Their Respective PCs/Data Sources
Resolve Errors With Respective Data Coordinator(s)
Area-Wide Steady-State Cases
Execute "PowerFlow Checker"
Area-Wide Stability Models
Stability Data Checking
Area Steady-State Case Errors Detected
Area Stability Errors Detected
Yes
No
As necessary
Merge Steady-State Cases
Execute "PowerFlow Checker"
Merged Case Steady-State Case Errors
Area Stability Data Submitted to webSDDB
Combined Stability Data Checking
Stability Errors or Discrepancies with Merged Steady-State Cases
Current Year Library Power Flow Case Library
Current Year Library Stability data webSDDB

APPENDIX VIII. **Case Selection Process**

Each cycle, Regional Data Coordinators vote on which cases will be included in the annual build. Requests to modify the case list should be submitted to MMWG leadership prior to the Spring Meeting. Delayed notification of a new/revised case will delay the implementation of the change.

Review Criteria

Each request for case modification from the previous cycle's list should consider the following:

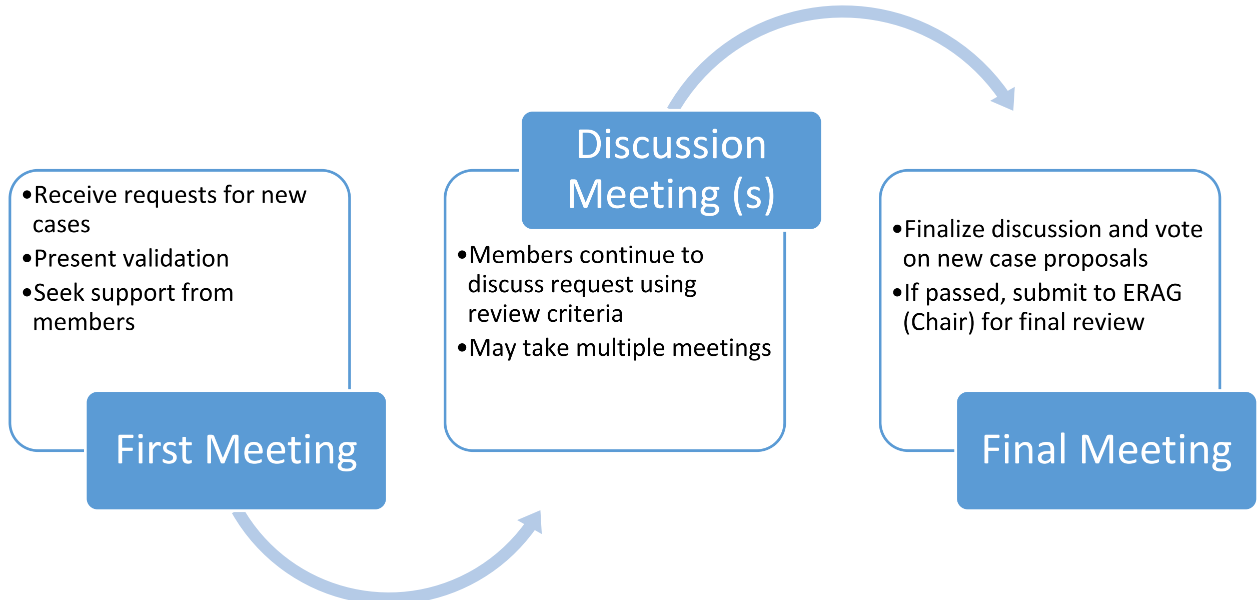
- Compliance with the latest version of TPL-001 Transmission System Planning Performance Requirements
- Compliance with the latest version of CIP-014 (R1)
- Represent satisfies an industry identified need for study – recurring need or one-time model
    - Does the intended study impact a large region of the interconnection?
- Regional Data Coordinator support for the alteration
- Will the number of models created be changed or will a model be discontinued to retain the current number?
    - Modifications to the contracted number of models must go through ERAG and be unanimously approved by both the Regional Data Coordinator and the MMWG Coordinator
- Implementation timeline – Regional Data Coordinators discuss needed time to modify data requests to its data submitters.

Cyclical Enhanced Review

At the start of each term for the MMWG Chair review the current case list to ensure the designated models are used and useful to the MMWG membership.

Discussion Timeframes and Case Confirmation

Any request for case modification should expect several meetings of discussion prior to voting on the new case. The complexity of the request will impact the number of discussion meetings needed prior to a change approval.



Example timing:

Spring Meeting
- Discuss any new/changed compliance requirements which would alter the case list for the next year's process (for example, discuss 2023 case list in 2022)
- Receive any proposals to alter the case list for the next year's process.

Summer Meeting
- Discussion on proposals to alter the case list
- Agree upon Case List for the next year's process (2023 case list in 2022)

Fall Meeting
- Vote to determine if case list alteration should be implemented
  - Earliest implementation would be for 18 months (2024 case list)