Southwest Power Pool

# Southwest Power Pool
# MODEL DEVELOPMENT WORKING GROUP
## August 14, 2014
## Conference Call
## 1:00 – 3:30 P.M.

**• M I N U T E S •**

**Agenda Item 1 - Administrative**

The meeting was called to order at 1:00 p.m. The following Model Development Working Group (MDWG) members were in attendance:

Joe Fultz, Chair – Grand River Dam Authority
John Boshears - City Utilities of Springfield
Derek Brown – Westar Energy
Mike Clifton – Oklahoma Gas & Electric
Nathan McNeil – Midwest Energy
Reené Miranda – Southwestern Public Service
Scott Rainbolt – American Electric Power
Jason Shook – GDS Associates

SPP Staff in attendance included Anthony Cook (Secretary), John Mills, Mitch Jackson, Zack Bearden and Scott Jordan.

The following guests were also in attendance:

Peter Howard – (Proxy for Brian Wilson) Kansas City Power & Light
Jason Bentz – American Electric Power
Jerry Bradshaw - City Utilities of Springfield
Josephine Daggett – Western Area Power Administration
Wayne Haidle – Basin Electric
William Hawkins – Western Farmers Electric Cooperative
Alex Mucha – Oklahoma Municipal Power Authority
Gayle Nansel – Western Area Power Administration
Garrick Nelson – Western Area Power Administration
Gimod Olapurayil – ITC Great Plains
John Payne – Kansas Electric Power Cooperative
John Porter – Southwestern Power Administration
Matthew Stoltz – Basin Electric
Liam Stringham – Sunflower Electric Power Corporation
Josh Verzal – Omaha Public Power District
John Weber – Missouri River Energy Services
Kevin Foflygen - City Utilities of Springfield
Dave Macey - City of Independence

*Meeting Minutes*
The July 1, 2014 minutes were open for review. Reené Miranda asked for specific improvements to be added to 2015 Series Model Timeliness Improvements section. The minutes will be postponed for review for the next meeting.

*Meeting Agenda*
The agenda was reviewed by the group. Derek Brown and Dustin Betz requested to add topics to agenda item 6. Jason Shook motioned to approve the agenda as amended; Derek Brown seconded the motion. The motion passed unopposed.
(**Attachment 1 - MDWG Meeting Agenda 20140814.docx**)

*Meeting Materials*
Anthony Cook asked if anyone had any issues or needed more time to review the posted material. There were no concerns from anyone.

**Agenda Item 2 – MDWG Modeling Practice Improvements:**

*Parallel Three Winding Transformer Ids*
Anthony Cook stated that it is his understanding that when Converting from PSS/e to ASPEN, there is an issue with parallel transformers having the same id. Nathan McNeil volunteered to see if this is an issue in ASPEN and Reené Miranda volunteered to check for CAPE.

**AI: Nathan McNeil and Reené Miranda work with Brandon Hentschel to see if there is an issue with parallel transformers utilizing same id.**

*Modeling Transactions*
Zack Bearden discussed changes made to the transactions sheet. He stated that these changes will help streamline transaction review in OASIS for the ITPNT model build. He added all firm transactions and additional columns. He asked the members to add any comments to their transactions that will help with the modeling accuracy. Anthony asked the members to only zero out the transaction if not going to be utilized in the MDWG models and not submit deletions. There were questions by the members on how the transactions are used in the model sets. Zack answered the questions and stated to give him a call or email if there are additional questions going forward.

*Modeling of Mothballed/Retired/Decommissioned Units*
Anthony discussed the previous proposal to model mothballed/retired units with the Pmax, Pmin, Qmax, and Qmin values as zero. Reené Miranda expressed concern of Operations calling upon units out for maintenance and that SPP hasn't allowed the outage of units for maintenance in the ITPNT models. Chris Haley stated that Ops should be using outage data that is scheduled in the CROW database. Anthony stated that for the ITPNT models, SPP doesn't like to model maintenance outages because any need that might show up due to the unit being out for maintenance would not be a valid project. There were a few proposals to change the unit id or bus code, but Anthony stated that these would involve a project to change the data and would create more work for the members and SPP staff. Derek Brown stated he likes the proposal and would like to see it in the procedure manual. Anthony stated that if the group would vote to approve the proposal he would add the language to the manual for the group to review

in the next meeting. Derek then motioned that for mothballed and future retired units, the Pmax, Pmin, Qmax, and Qmin values be modeled as zero. Decommissioned units should be removed from the models. Reené seconded the motion. With no further discussion, the group voted. The motion passed unopposed.

**AI: Anthony to add language of modeling mothballed, retired, and decommissioned units to the MDWG Procedure Manual for approval at the next meeting.**

*Pmin/Pmax accuracy to sync with dynamics data*
Scott Jordan described issues found in respect to generator Pmax and Pmin values between the powerflow models and data submitted for the dynamics models. He stated that he will email the members examples for the reference.

*Gross vs. Net Pmax, Aux Load*
Anthony just wanted to give a reminder for the members to be working toward gathering the data before the standard is effective.

**Agenda Item 3 – Model Development Procedure Manual:**

*General Updates*
Anthony presented the changes made to the manual. Anthony stated that many of the changes were suggestions made by the legal department. Several of the members asked for more time to review all of the changes being presented. Anthony asked if the group would vote to change the title, version, and member page as presented. Reené Miranda motioned to approve updating the title, version, and member page as presented. Jason Shook seconded the motion. The motion passed unopposed. (**Attachment 2 - SPP MDWG Model Development Procedure Manual (Public).doc**)

**AI: Anthony to make changes to manual and post updated manual.**

*BES Definition*
The group decided to discuss at future meetings for manual updates.

**Agenda Item 4 – Modeling Entity Expansion:**

Chris Haley discussed entities reporting for the capacity margin and matching the data with the models. He discussed moving toward a Load Serving Entity or Transmission Customer level of reporting for the models.

Nathan McNeil voiced concerns with entities that don't have PSS/e and don't understand transactions and that it could cause issues with data coordination and timeliness. He stated that the level of participation and accountability could be an issue.

Chris stated that the purpose would be to get more granular and not miss anyone in the footprint.

Reené Miranda and Derek Brown agreed with Nathan and also stated that they keep up with entities within their respective footprint and maintain the data. They stated that we need to focus on getting the models out on time for now.

Jason Shook added that mapping submitted data and educating all entities would be a big undertaking.

The group's opinion is to not pursue this method of reporting due to the potential impacts on accuracy, schedule and personnel.

The rest of the agenda items were tabled until the next meeting.

***Summary of Action Items:***

- **Nathan McNeil and Reené Miranda work with Brandon Hentschel to see if there is an issue with parallel transformers utilizing same id.**
- **Anthony to add language of modeling mothballed, retired, and decommissioned units to the MDWG Procedure Manual for approval at the next meeting.**
- **Anthony to make changes to manual and post updated manual.**

*Adjourn Meeting*

Jason Shook motioned to adjourn the meeting, everyone seconded the motion. The MDWG adjourned at 3:52 p.m.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool

**Southwest Power Pool, Inc.**

**MODEL DEVELOPMENT WORKING GROUP**

**August 14, 2014**

**Conference Call**

**1:00 P.M. – 3:30 P.M.**

**• A G E N D A •**

1. Administrative Items ........................................................................................ Joe Fultz (15 min)
    a. Call to Order
    b. Introductions
    c. Proxies
    d. Previous Meeting Minutes (Action Item)
        i. July 1, 2014 Conference Call
    e. Agenda Review (Action Item)
    f. Meeting Materials

2. MDWG Modeling Practice Improvements ........................................................... Staff (45 min)
    a. Parallel Three Winding Transformer Ids
        i. ASPEN Error
    b. Modeling Transactions
    c. Modeling of Mothballed/Retire/Decommissioned Units (Action Item)
        i. MOD Profiles Pmax/Qmax/Qmin = 0
        ii. Removal
    d. Pmin/Pmax accuracy to sync with dynamics data
    e. Gross vs. Net Pmax, Aux Load (Reminder)

3. Model Development Procedure Manual ........................................................................ All (30 min)
    a. General Updates
    b. BES Definition (Does it need referenced?)

4. Modeling Entity Expansion .................................................. Chris Haley and Anthony Cook (15 min)

5. MDWG Model Building Activities ........................................................................ Staff (25 min)
    a. 2014 Series
        i. Dynamic Update
    b. 2015 Series
        i. Schedule (Action Item)
            1. Short Circuit
            2. Dynamics

6. Other ........................................................................................................................... All (10 min)
    a. MOD Training
    b. TPL TF Updates
    c. TPL 007-1
    d. Addition of IS and others to 2015 Series

7. Summary of Action Items .......................................................................................... Anthony Cook (5 min)

8. Little Rock Meeting ................................................................................................................ Joe Fultz (5 min)
    a. MDWG: November 12
    b. Model Update Meeting 13 and 14

Southwest Power Pool, Inc.

# ~~POWER FLOW~~ MODEL DEVELOPMENT

# PROCEDURE MANUAL

MAINTAINED BY
SOUTHWEST POWER POOL
MODEL DEVELOPMENT WORKING GROUP

PUBLISHED: September 1985
VERSION ~~3~~4: ~~November 2009~~August 2014

# Version History

Original: September 1985

Version 2: August 2006

Version 3:  November 2009

**Version 4: August 2014**

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**TABLE OF CONTENTS**

**SECTION** **PAGE**

**<u>TABLE OF CONTENTS</u> (Continued)**

**<u>SECTION</u>** **<u>PAGE</u>**

**TABLE OF CONTENTS (Continued)**

**SECTION** **PAGE**

**TABLE OF CONTENTS (Continued)**

**SECTION** **PAGE**

## MODEL DEVELOPMENT WORKING GROUP

**Joe Fultz, Chairman**
Grand River and Dam Authority, OK (GRDA)

**Nate Morris, Vice Chairman**
Empire District Electric Company, MO (EMDE)

**Scott Rainbolt, ~~Chairman~~Member**
American Electric Power, OK (AEPW)

**~~Mo Awad~~Derek Brown, Member**
Westar Energy, KS (WERE)

**Dustin Betz, Member**
Nebraska Public Power District, NE (NPPD)

**John Boshears, Member**
City Utilities of Springfield, MO (SPRM)

**Mike Clifton, Member**
OG+E Electric Services, OK (OGE)

~~**Joe Fultz, Member**~~
~~Grand River and Dam Authority, OK (GRDA)~~

**Rene Miranda, Member**
Xcel Energy, Inc., TX (SWPS)

**Scott Schichtl, Member**
Arkansas Electric Cooperative Co, AR (AECC)

**Jason Shook, Member**
GDS Associates, GA (ETEC Representation)

**Brian Wilson, Member**
Kansas City Power & Light Company, MO (KCPL)
~~**Anthony Cook, Secretary**~~
~~Southwest Power Pool, Inc., AR (SPP)~~

**Nathan McNeil, Member**
Midwest Energy, Inc., KS (MIDW)

~~**Nate Morris, Member**~~
~~Empire District Electric Company, MO (EMDE)~~
**Anthony Cook, Secretary**
Southwest Power Pool, Inc., AR (SPP)

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# 1. GENERAL INFORMATION

## A. Purpose

This manual provides concise written guidelines and procedures for use by the system representatives in building and updating the Southwest Power Pool, Inc. (SPP)∗ Power Flow Models. Proper use of this document should aid in the coordination between systems, consistency in reporting of data, and realism of the model developed. As the responsibility of model development shifts from one person to another within the SPP systems, it is important that this document be used as the basis for instruction in order that the details are kept from deteriorating through word-of-mouth transfer.

## B. SPP Background

SPP was formed in the early summer of 1941 when 11 companies voluntarily joined together in order to serve a large industrial load and meet critical national defense needs during World War II. These 11 electric utilities joined together to form a major "Pool." This pooling of resources became known as the Southwest Power Pool. At the conclusion of World War II, the Executive Committee of SPP decided to retain the organization. This retention of SPP was due in part to the vast experience gained in power pooling and coordination.

In mid-1968, SPP became part of the North American Electric Reliability Council (NERC), one of nine regional reliability councils, and in late 1969, member systems signed a new Coordination Agreement, which reorganized SPP into a regional reliability organization as envisioned by a special task force of the Federal Power Commission (FPC) that studied the northeast blackout of 1965. Achieving reliability (adequacy and security) and economics of operations requires close coordination and communication between SPP Member Systems as well as with our neighboring councils of Southeastern Electric Reliability Council (SERC), Mid-Continent Area Power Pool (MAPP), Electric Reliability Council of Texas (ERCOT) and Western Electricity Coordinating Council (WECC).

Some of the data models developed in SPP are used in the development of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) models. The ERAG MMWG was formerly under the NERC and is now under the ERAG Management Committee (MC). These models represent the

Multiregional electrical configuration of the entire eastern interconnected region, and are used primarily by the various regions to develop external equivalents.

### C. General Data Responsibilities

The SPP member transmission planners are responsible for the following categories of system modeling data:

1) Power Flow,
2) Short Circuit,
3) Dynamics

Power Flow models are developed for an annual series of SPP cases, including an annual series of ERAG MMWG cases. Specific models are prepared and modified for use in SPP designated studies as required by SPP Regional Tariff and Criteria.

The Dynamics Model is also updated annually with current generator unit information. Power Flow models are used in conjunction with stability data to run dynamic simulation.

System representatives should be responsive with good modeling techniques. SPP data models are used by individual systems for studying future needs in developing construction forecasts. Not planning a major expenditure by one year due to inaccurate data could be very expensive, since funding allocation for major construction projects requires more time resources. In addition, ATC, megawatt-mile and incremental losses are currently being calculated with these Power Flow models. With the large amount of interconnection within SPP, the impact of one system on another must be recognized and respected. Therefore, each system should prepare data consistent with its most recent official system forecasts in all data submitted to SPP including Energy Information Agency (EIA-411) Data. It is also important that the models represent the expected operation of the SPP system consistent with this manual and Criteria.

For the purpose of building planning models it is recognized that unplanned generation may be required to meet local load demands. Members submitting exploratory type generation to meet local load demands are required to submit Model On Demand (MOD) Projects with the appropriate Project Type (Reliability), Status (NERC Standard

∗ See Section 8 - ACRONYMS

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Compliance), and unit ID of Zx (where x is any second ID designation appropriate in PSS/E).

Entities in the SPP region that are not members of the SPP but required to submit data (i.e. IPPs, Municipalities) will submit data directly to the Transmission Owner or Balancing Authority in which their system resides. Upon review (i.e. data accuracy, quality) by the Transmission Owner or Balancing Authority the data will then be provided to the SPP during the annual MDWG model update process. The data submitted will be in the standard PTI format as specified in the MDWG Powerflow Development manual. All non-SPP members that are responsible for submitting this data should directly coordinate with the Transmission Owner or Balancing Authority on timing for sending data, as well as any special requirements in data formatting.

**D. Confidentiality and Proprietorship**

The representation of future system elements in SPP data models is not an agreement to construct these elements when shown in the models or at any time. The configuration of each model system only reflects the necessary changes that the individual model system needs for maintaining reliable operation. The results of studies obtained through use of the data models developed by SPP will be the sole responsibility of the receiving party. The recipient of SPP data models must assure confidentiality and proprietorship.

**E. Power Flow Development Manual Changes**

- Section 2.A.1 ---- Power Flow Model Development, Introduction
- Section 2.B.1 ---- Dynamic Model Development, Introduction
- Section 3.A.5 ---- Load Data
- Section 3.A.7 ---- Remote Generation Modeling Procedure
- Section 3.A.10 ---- Owner Data and Line Mileage Data (SAS-70 Control)
- Section 3.C.5.C ---- Wind generation modeling
- Section 4.C ---- MDWG Updates
- Section 6.C ---- SPP Members
- Section 9 ---- MDWG Contact List
- Section 10.B ---- Request an SPP Map / Model
- Section 11 ---- MDWG Model set

- Section 12 ---- MMWG Compliance Checks
- Section 13. MMWG Appendices for Reference
- Section 15 Compliance

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**2. SCHEDULE**

As with all schedules, the meeting of deadlines is most critical. All system representatives must familiarize themselves with the schedule well in advance of all deadlines. This will alleviate any problems with the timing of data submittal and data reviews. The schedule for model development will be sent with the first data request and posted with the starting models. An introduction to the power flow, dynamic, and short circuit model types is below.

### A. Power Flow Model Development

#### 1. Introduction

SPP planning model data is contained in the SPP database which is MOD and the Data Submittal Workbook. MOD data is divided into three parts a Base Case, Projects, and Profiles (Bus, Loads, Generation, Device Control, and Net Schedule Interchange). MOD also contains seasonal ratings for branches, two winding transformers, and three winding transformers, and short circuit model sequence data. The Data Submittal Workbook includes: Transactions, Generator Data, Owner Mapping, Load Mapping, Expanded Bus Names & Translation, Non-Scalable Load, Area Summary Report, and Regional Ties. The Data Submittal Workbook is posted on the SPP File Sharing site.

SPP MDWG Power Flow Models are published according to the schedule in Section 15 A.

#### 2. AC Contingency Analysis

SPP will perform AC Contingency Analysis of the current year Summer Peak model and the farthest out Summer Peak model after the final models are posted. Members' AC Contingency Mitigation Plans are due to SPP per the model building schedule. The purpose of this contingency analysis is to validate the models.

### B. Stability Model Development

#### 1. Introduction

The MDWG Stability Models include full MMWG cases and machine reduced cases. The initialized no-fault models can be solved with quarter-cycle and half-cycle time step steps. The MDWG Stability Model Update is used to support SPP reliability studies and ERAG MMWG Dynamic model requirements. It is important for all

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generating entities that interconnect to the SPP transmission to support the Regional Transmission Organization with current detailed dynamics data in the proper SPP model format. The current MDWG Stability Model Format is PSS/E dynamics DYRE and RAWD formats.

The Dynamics Model data includes:

a. Power Flow models
b. Dynamics model data in Siemens PTI PSS/E DYRE format
c. User written model source and object code (includes wind farms)
d. ERAG MMWG System Dynamics Database (SDDB)
e. SDDB data update worksheet

SPP MDWG Dynamic Models are published according to the schedule in Section 15 B.

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# 3. POWER FLOW MODEL DEVELOPMENT

## A. Data Preparation

The following section describes important items to be considered in the development of a Power Flow model. These guidelines must be followed in preparing the data for publishing new models or updating existing models. Each system must keep MOD data current or updated for the MDWG model builds. The transactions workbook will be updated for the MDWG models. The Data Submittal Workbooks will be updated annually. The MMWG Regional Tie data must be current for all models.

--- MOD data must be kept current for MDWG models
--- Data Submittal Workbooks updated annually for the MDWG B1 series models
--- MMWG Regional Tie Data must be current for MDWG models

Modifications to tie line data shall be made in MOD through a Project. Tie line modifications shall be coordinated with neighboring systems. Generator ratings must also be updated in the generator worksheet in the Data Submittal Workbook

All changes to the SPP Power Flow models are made through the Siemens PTI MOD, and PSS/E software.

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## Annual Models

| | Season | | | Season |
|---|---|---|---|---|
| 1 | Annual Spring Peak | | 9 | Annual + 1 Summer Peak |
| 2 | Annual Summer Shoulder | | 10 | Annual + 1 Fall Peak |
| 3 | Annual Summer Peak | | 11 | Annual + 1 Winter Peak |
| 4 | Annual Fall Peak | | 12 | Annual + 2 Summer Peak |
| 5 | Annual Winter Peak | | 13 | Annual + 2 Winter Peak |
| 6 | Annual + 1 April Minimum | | 14 | Annual + 6 Summer Peak |
| 7 | Annual + 1 Spring Peak | | 15 | Annual + 6 Winter Peak |
| 8 | Annual + 1 Summer Shoulder | | 16 | Annual + 10 Summer Peak |

The typical yearly models developed by the SPP MDWG, as identified within the NERC TPL reliability standards, encompass both near-term (years one through five) and longer-term (years six through ten) transmission planning models. The SPP models are defined in **Annual Models** table above with those transmission planning models representing the near-term planning horizon consisting of the MDWG models 1 through 13 and those representing the longer-term planning horizon consisting of the MDWG models 14 through 16. The longer-term models may be incremented as required by ERAG MMWG.

The annual series of models are developed by SPP staff with input from the Model Development Working Group and the Transmission Working Group.

The list of MDWG Power Flow models is in Section 11

Transactions modeled in all base cases should be limited to expected firm schedules and should not include other transfers such as emergency power or opportunistic economy energy even though they may be provided for in contractual agreements. Due to FERC's ruling of Roll-over rights, Long Term Firm Transactions should be considered in the models that extend into the future even if the transaction has a stop date. For a transaction to be considered firm, the transaction must be confirmed at both the source end and the sink end. Southwest Power Pool will do its best to confirm delivery of transactions outside of the Pool boundaries.

Firm transmission load includes capacity dependant interruptible loads with buy through provisions. In other words load that may be interrupted if the source runs out of capacity should still be modeled if the load has a choice and opportunity to purchase power from another source. This firm transmission load should be modeled in all cases. The load modeling entity is responsible for scheduling the power from a source and updating the transaction worksheet.

The ERAG MMWG Procedure Manual (May 07, 2009) states: “The power flow model will be based on a load forecast which assumes a statistical probability of one occurrence in two years (50/50).”

Loads should be derived using the 50/50 probability forecast as a minimum.

Various seasonal models are presently developed by SPP systems. They are: a Summer Peak condition, a Winter Peak condition, a Spring Peak condition, and a Fall Peak condition. These four seasonal peak conditions are defined to represent the one-hour system peak and should **not** consider coincidence between member systems' load.

| | |
|---|---|
| Spring Peak: | April & May |
| Summer Peak: | June thru September |
| Fall Peak: | October & November |
| Winter Peak: | December thru March |

The definition of the **April minimum** load level pinpoints a condition such as a **Sunday morning in April, hour ending 5:00 a.m**. The intent is to represent a system's minimum annual load. This, of course, would occur at different times for each system.

The seasonal on-peak average model is prepared primarily to calculate incremental losses for the SPP Regional Tariff. The on-peak average model, or shoulder, is defined to be 85% of the total seasonal peak load level.

1. **Area Summary Report**

   The Area Summary Report is an important part of data preparation and should be the initial step of the update process. This report, though not part of the Power Flow input forms, is an important part of the data coordination process. As such, the report should be distributed to all appropriate systems at least one week before the initial update data is due at the SPP Office. The standard area abbreviations listed in Section 6-B should be used on the Area Summary Report and in the Power Flow input data of area interchange and transactions. The following sequence of steps is to be used in completing this report:

a. The system name and area number, along with the name and phone number of the person that prepared the report, should be entered at the top of the form in the appropriate location.

b. The area slack bus and bus number. The area slack bus is to adjust for individual system losses only. It is not necessary for the area slack bus to be used for area load control in actual operation. Generation dispatch should be made to prevent the area slack bus from going to negative power output or power output above the stated rating of the unit when accounting for area losses. It is best that the area slack bus <u>not</u> represent a base load unit. The estimated slack bus generation should also be entered (Item 7). There should be room left on the slack bus for generation movement up & down.

c. For consistency, it is important that each system continue using a particular area slack bus rather than choosing a different bus from year-to-year, unless a specific reason exists to justify such a change. There is a new row on the Area Summary Sheet to identify the slack bus. To aid in solution time of the cases, the area slack bus should be located on a relatively strong portion of the system.

d. The case year and season should be entered in the appropriate locations in chronological order.

e. The current system official load forecast should be entered as net load (Item 6).

f. The estimated losses should be entered (Item 5). The reference cases can be used as a starting point to estimate system losses.

g. Load equals net load minus estimated losses (Item 4).

h. Purchases and sales should be entered (Item 2). These values must be coordinated with the parties involved in the interchange transaction prior to data preparation. The algebraic sum of these transactions should be equal to the total area interchange.

i. Net power (Item 3) must equal net load (Item 6). Generation (Item 1) is equal to the net power plus interchange.

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**2. Tie Line Coordination**

Each SPP system will receive a tie-line data comparison summary for the initial base case and after the final models are published. The member **must** coordinate with its neighbors on the tie line representation in the models being developed.

This coordination should consist of:

--- Agreement on which bus is to be metered for area loss accounting,

--- The in-service and out-of-service dates, if applicable,

--- Tie line characteristics and ratings

--- System responsible for supplying the update data.

SPP Member Tie data is maintained in a MOD Project file. The majority owner of the tie is responsible for maintaining the tie's Power Flow, Sequence, and Ratings data.

SPP uses the MMWG Regional Tie line list as the first database for tie line information for NERC/SPP inter-region ties. There will be other lower voltage SPP ties which are not listed in the NERC list. They will be checked using the SPP tie line reports.

**3. Line and Transformer Data**

Additions to the system tend to move from year-to-year based on changing load growth forecasts and budget requirements. As a result, future lines and transformers may move through several future cases. Line and Transformer Data is contained in MOD Projects and phases. The Project Type, Status, and Phase Effective Date determine if the data will be included in a particular model. The line and transformer data formats are found in Section 5.

The following steps should be considered when preparing line and transformer data:

a. The **device code** (Bus, Branch, Transformer) specifies what data is being added to the base case. The **action code** (Add, Modify, Delete) specifies the action to be taken with the Project data. Specifying the deletion of a bus will require a similar record to delete all associated or connected devices with the bus (lines, generators, loads, transformers, etc.) from the base case.

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b. The "from bus," "to bus", and circuit number identify the line or transformer. The order in which bus numbers are entered is important for tie lines to identify which bus is metered for loss accounting in some data formats. The "from bus" is assumed to be the metered end (unless the "to bus" is entered with a negative) and the "to bus" area will collect loss responsibility. For transformers, this order is also important in all formats because it specifies to which bus the Load Tap Changer (LTC) will attempt to maintain voltage and/or which bus is tapped. The code U in the branch data allows the user to select proper metered and tapped side by always entering the tapped side as the "from bus" or first bus number after the change code. The "from bus" is the metered end unless the "to bus" or second bus number is a negative number. Remember to include the circuit identifier.

c. The impedance data should be specified on a 100 MVA base. The smallest allowable reactance is 0.00011 P.U. on a 100 MVA base. Reactance values less than minimum will cause the Power Flow program to treat the line as a zero impedance line to reduce solution time.

d. Line charging data will be divided in the appropriate units depending on the specific format being utilized. Accuracy is needed to ensure a proper voltage profile in the model.

e. Each SPP member shall rate transmission circuits in accordance with the SPP Criteria (Section 12.2). This criteria calls for each member to compute, at a minimum, summer and winter seasonal ratings for each circuit element. Each Base Case (Network) and Project branch, two-winding and three-winding transformer must have a specified rate A (normal) and rate B (long-term emergency) for spring, summer, fall, and winter. The ratings data format is in the MOD Procedure Manual.

f. The transformer tap and tap limits shall be specified. The use of LTC transformers should be kept to a minimum to help reduce the case solution time. Using LTC transformers for local area voltage control where no such transformer exists should be avoided. Regulating transformers **should not** be located at a bus with a regulating generator or other voltage regulating device.

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g. Circuit mileage should be entered in the appropriate line length field of branch data. Ownership data for the line should also be entered in the appropriate fields of branch data. This mileage and ownership data will be used to validate and calculate Megawatt-mile for the SPP Regional Tariff. Circuit mileages should be coordinated on all jointly owned lines. Invalid line lengths result in inaccurate revenue allocations.

h. All NERC flowgates must be included in the data submitted by each region to the MMWG such that those flowgates are not equivalenced in the power flow models. 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. Enough detail should be added to model the flowgate accurately.

**4. Bus Data**

For all SPP Power Flow models, systems will model buses within their SPP allocated bus range (see Section 6-B). For the sake of consistency, the bus names and numbers should remain constant from case to case and year to year. All bus shunts will be modeled as switched shunt. The Switch Shunt may be locked. Any changes to bus names or numbers will be documented on the SPP Expanded bus name list. This will include renumbering buses as well as adding new or removing old buses from the models. When a change in bus voltage occurs, a new bus number will be given to the new higher voltage bus. This enables SPP to track when the old bus voltage changes. All interregional tie bus names should conform to the entries in the Master Tie Line Database as approved by the Regional MMWG Coordinators. 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. Unique generator bus names, base voltages, and unit id combinations should be consistent from case to case within a model series. The SPP Expanded bus name list can be used as a quick reference for new names. This will help ensure that the SPP bus names do not conflict with ERAG MMWG Standards.

The following steps describe options and data for most bus data formats:

a. The device code and the change code determine describes what action(s) are taken with the data supplied (addition, deletion, modification, etc…).

**<u>NOTE</u>: When a bus is deleted or removed from service, all associated network devices (lines, transformers, loads, generators, ect.) must also be deleted or removed from the power flow model within the Project.**

b. As previously mentioned, the bus names and numbers should remain constant unless there is a particular reason for changing them. This will aid the consistency of the models developed. Bus names may be up to 12 characters with the first character, preferably, alphabetic rather than numeric. The name should be left justified. The eighth character field of the bus name <u>should</u> be the SPP voltage code described as follows:

| | | |
|---|---|---|
| 1 - Below 69 kV | 4 - 138 kV | 7 - 345 kV |
| 2 - 69 kV | 5 - 161 kV | 8 - 500 kV |
| 3 - 115 kV | 6 - 230 kV | 9 - 765 kV or above |

The ninth through twelfth character fields of the bus name are reserved for the base kV designation (<u>right</u> justified). As associated with the voltage code, the generally used kV values are: 69.0, 115, 138, 161, 230, 345, 500 and 765.

c. For generator regulated buses, a desired voltage magnitude will be given with reactive power limits also specified. Generator buses should be modeled with operating characteristics as close to actual as possible. Generator ratings should also be specified for each generation bus (whether on or off-line) as described in SPP Criteria Section 12.1. Generators should model the net output of the generating facility while taking auxiliary load into account. The net generator output is usually modeled with an explicit auxiliary load (fans, motors, etc.) at the generator bus and the generator PMAX & PGEN set to a gross output level – OR – the generator PMAX & PGEN is simply set to the net power output (i.e., gross output – motor load – fan load, etc.) with the auxiliary load already accounted for. The practice of using generator for voltage support only (i.e. no real power output), should be avoided unless a synchronous condenser or static var controller physically exists on that bus or nearby in the system. When a generator is modeled offline (status 0), the MW (PGEN) and MVAR (QGEN) fields should be zeroed. Regulating transformers **should not** be located at a bus with a controlling generator or regulating shunt device.

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d. Bus loads should be specified with the real and reactive values provided **as a pair** in all entries.

e. When scaling area load, it is important to consider the reactive power as well as real power. This is particularly true when referencing a case of a different season. Realistic reactive load representation has a major effect on the overall case voltages. Reactive requirements are different for the various season models.

f. Capacitors and reactors represented in the models should be consistent with actual seasonal operation. These devices should be used in future cases calling for local area voltage support, rather than falsely regulating a bus. Attention should be given to these installations in cases that are referencing a different season model. Tertiary reactors should be modeled on the low voltage bus of transformers if the tertiary is not modeled explicitly.

   Do not model existing or planned shunts on the Bus record. Shunts should be modeled in the Switched Shunt Record unless they are line shunts and trip when the line is opened. Bus shunt voltage bandwidth must be wide enough to prevent "hunting" of shunt value during power flow solution of base case or contingency analysis. The switched shunts can be modeled as fixed shunts with specified B initial value.

**5. Load Data**

Load data is maintained in models via an IDEV file which is applied to the model. Profiles, Loads can belong to an Area that is not the same as the Bus Area. Refer to Section 5-A-3 for load data formats. The default solution technique will solve the case with Tie Lines and Loads. The Tie Lines and Loads solution option assumes that the Loads Area generation serves the load.

The Non-Scalable Loads will be identified in the Non-Scalable Load worksheet of the Data Submittal Workbook. This allows model builders to modify models without changing the loads that are constant.

Loads that are owned by municipal utilities should be modeled with an identifier in front of the number (i.e. Rayburn County load one should have the ID “R1”). These loads should be maintained in the Load Mapping worksheet of the Data Submittal Workbook.

**6. Generator Data**

Check Generator MW and Mvar output to ensure the unit is within the PMAX, PMIN, QMAX, QMIN and Mbase limits and that the output of the generator accounts for auxiliary load. Generator MW should be set to “gross” level if auxiliary load is modeled explicitly – OR – “net” level if auxiliary loads are not modeled. Qmax and Qmin values in the models should be based on unit test data. Intermittent resources (e.g., wind and run-of-river hydro) should not normally be dispatched beyond their net capability as established by SPP Rating of Generating Equipment Criteria 12. Ensure accurate values of ZR and ZX. This data is not needed in normal power flow and equivalent construction work, but is required for switching studies, fault analysis and dynamic simulation. For dynamic simulation, **this complex impedance must be set equal to the sub unsaturated transient impedance for those generators modeled by sub transient level machine models**, and to transient impedance for those modeled by classical or transient level models. Machine Base (MBASE) and Zero Impedance (ZSOURCE) values for the Power Flow models must match stability data. The MDWG powerflow models will use the unsaturated subtransient impedance data for generators (X’’di). Future Generators that are in the models but are not budgeted for construction need to be identified in the Generator Data worksheet of the Data Submittal Workbook.

**Rules for building +10 year model:**

When building the +10 year model, a member may not have enough generation to supply their load. Therefore, members should follow these guidelines to compensate. The solutions are listed in order of preference.

a. Use existing IPP’s inside of a member’s footprint to supply the needed generation.
b. Create a transaction from a first tier control area that has generation available. Then add this transaction to the transaction workbook with an ID of ‘ z ‘ and not checked as firm.
c. Create a new generator in the most likely spot for adding a generator to the members system and label it as an exploratory project. The location of the generator should consider transmission constraints for the area. In other words,

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can the power be pushed into the system at that location?

**Note: The Generator Data worksheet data will be maintained to provide a convenient source of data for Member and SPP Staff use. Therefore accurate data in the Generation workbook is imperative. The official SPP generator data is in the MOD Base Case or Project.**

## 7. Remote Generation Modeling Procedure

a. **Purpose**

This procedure assures that members adhere to a uniform process when modeling remote generation in SPP.

b. **Modeling Process**

If a member acquires remote generation outside their Control Area (Power Flow model numbered area), the following modeling process should be followed:

(1) All buses should be assigned numbers that are in the host's control area bus number range.
(2) Area Number/Name should be the host's control area number.
(3) Zone Number/Name should be in the host's control area zone range.
(4) Generation Owner Number should be the owner's designated ID number and percentage ownership.
(5) The generation recipient should coordinate the output level and the inter-area transfer with the host control area.

c. **Transaction Update**

The transaction workbook should be updated to show a transaction from the control area where remote generation is located to the generation owner control area. If the remote generation is owned by multiple owners, then multiple transactions should be modeled.

## 8. Power Flow Data Check List

The Power Flow Data Check List should be used as an aid for ensuring good model data. As the data and preliminary runs are reviewed for each model, the items should be checked off. A copy of this form can be found in **Section 7**.

## 9. Facilities Transferred to SPP's Functional Control

The SPP FERC "Docket No. RT04-01-00 Volume 1", ***In the July 2 Order, the Commission: …(7) ordered that SPP file a list of all transmission facilities that will be transferred to its operational control and revise the Operational Authority White Paper ("OA White Paper") or Membership Agreement, or provide some other binding document, to reflect SPP's clear authority to***

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***exercise day-to-day control over the appropriate transmission facilities within its footprint…***

Attachment AI to the SPP Regional Tariff contains the criteria for inclusion of facilities that are considered "***Facilities Transferred to SPP's Functional Control***". Transmission facilities meeting the definition set forth in Attachment AI must be included in the SPP MDWG Power Flow Models.

## 10. Owner Data and Line Mileage Data (SAS-70 Control)

Per SAS-70 requirements (i.e. – Loss calculations) SPP Loss models must be updated every June and October with current Owner Data and Line Mileage data. To meet the SAS-70 requirement the SPP models must include owner data and line-mileage data. SPP Staff will obtain this data from the MOD Base Case and Projects; therefore; it is important that Members keep the data current in MOD.

## 11. Zone Range Assignments

a. MMWG Region

| Region | Bus Numbers | Area Number | Zone Number | Owner Numbers |
|---|---|---|---|---|
| Entire System | 100,000 to 899,999 | 100 to 899 | 100 to 1,899 | 100 to 1,199 |
| NPCC | 100,000 to 199,999 | 100 to 199 | 100 to 199 and 1,100 to 1,199 | 100 to 199 |
| RFC | 200,000 to 299,999 | 200 to 299 | 200 to 299 and 1,200 to 1,299 and 1,800 to 1,899 | 200 to 299 |
| SERC | 300,000 to 399,999 | 300 to 399 | 300 to 399 and 1,300 to 1,399 | 300 to 399 |
| FRCC | 400,000 to 499,999 | 400 to 499 | 400 to 499 and 1,400 to 1,499 | 400 to 499 |
| SPP | 500,000 to 599,999 | 500 to 599 | 500 to 599 and 1,500 to 1,599 | 500 to 599 and 800 to 899 |
| MRO | 600,000 to 699,999 | 600 to 699 | 600 to 699 and 1,600 to 1,699 | 600 to 699 |
| ERCOT (future) | 700,000 to 799,999 | 700 to 799 | 700 to 799 and 1,700 to 1,799 | 700 to 799 |

b. SPP Area

Refer to the most current SPP Area Zone Assignments.

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**B. Data Transmittal**

Transmitting data to the Southwest Power Pool can be accomplished as follows:

(1) **ELECTRONIC** --- www.TrueShare.com

(2) **E-MAIL** --- planningmodeling@spp.org

The preferred method of submittal is through the "SPP MDWG File Sharing Site" www.TrueShare.com. Include a file (excel, word, or equivalent) with description of data files submitted and which to which models they apply.

The transmitted data file should include the title of the first case and area name, followed by the changes to the first case, title of the second case and the area name, followed by the changes to the second case, etc. See Section 6-B for a sample file format. Case title lines should include the case title as in the following format examples: *04SP, *04FA, *04SH, *07SP (no spaces between characters).

**C. Initial Run Review**

After all systems prepare and submit data, an initial run is made which assembles all system data, checks for errors, and results in a solved case. The initial run shows all entered data and diagnostic messages. This data is shown first in the initial run printout. Each system should review the data changes and solved case, making corrections as needed in the subsequent runs.

**1. Area Interchange**

The area interchange report shows the area control bus, generation on the area control bus, and the net area interchange. The detail of area interchange among SPP systems is shown in the transaction data. The transaction workbook will include the NODE, Provider, and OASIS reservation number. The transaction workbook will use code DDD for transactions that do not have an OASIS reservation number. This data should be checked to ensure accuracy. Discrepancies in the transactions between reporting systems will be noted in the diagnostic messages.

**2. Tie Line Metering**

The tie line report shows the tie lines and inter-company power interchange for each system. The tie line metered end should be verified, and should reflect line loss

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responsibility as accurately as possible. Any changes should be coordinated with the neighboring company involved.

**3. Area Totals**

The system generation and load should be checked on the system area summary. This data should be near expected values. The detail of generation is shown in the generation summary. If load is not the expected value, individual bus loads listed in the power flow detail report should be examined. If loads were scaled from a reference case, the scaling factor should be checked. The load power factor should also be checked as power factors change seasonally. Check Power-factor of loads. The load supplying entities for the MDWG models will validate each load power-factor with the most current system snapshot that represents that models load level (summer peak, winter peak, light load).

**4. Network**

Basic to the accuracy of the Power Flow model is the accuracy of the network. The layout of the system representation should be checked. Purely conjectural facilities should not be included. Planned facilities which were modeled in previous Power Flow models and have since been delayed or cancelled should be removed entirely from the Power Flow model. These facilities cause solution problems for some power flow programs if left in the model with an off-line status. Planned projects, including reactive resources such as capacitor banks, are to be included in the models. These projects are to be added through MOD in accordance with the MOD Type/Status Matrix of the Web Based Power Flow Model Development Procedure Manual.

**5. Review of Output**

The power flow report should be checked for the flow on major transmission lines and selected bus voltages. This check can locate unusual results, which does not necessarily mean that data is in error, but rather indicates that additional checking of the model may be appropriate.

Three useful reports for locating problems include:

--- The voltage summary,

--- The overloaded branch summary, and

--- The generation summary.

a. **Voltage Summaries**

Low or high voltages may be caused by a number of factors. Shunt devices may be sized inappropriately. Capacitors should have a positive value and reactors should have a negative value. (Check the CAP/REAC column of the power flow report). The bandwidth (difference between VSWHI and VSWLO) of switched shunt devices should be wide enough that switching one block of admittance does not move the voltage at the bus completely through the bandwidth, thus causing solution problems at the bus. It is recommended that the minimum voltage bandwidth be 4% if only switched shunts are used to regulate voltage. Switched shunts should not regulate voltage at a generator bus, nor should they be connected to the network with a zero impedance tie.

Transformer tap settings may also affect voltages. The power flow report should be checked for tap settings. Particular attention to LTC-equipped transformers should be given to make sure the proper bus is regulated.
A tap setting of less than 1.000 on the tap bus results in an increase in voltage on the non-tap bus. A tap setting greater than 1.000 on the tap bus results in a decrease in voltage on the non-tap bus.

The inclusion of LTC regulation makes tap setting more important. With LTC-equipped transformers, fixed taps may also exist. The LTC tap range should be adjusted to compensate for the effects of fixed taps if necessary. The number of taps should not be greater than 50.

Transmission line or transformer impedance errors may also affect voltages if the errors are large. See Section 6-A. for guidelines of typical transmission line or transformer impedance data.

b. **Summary of Overloaded Branches**

This summary shows each overloaded circuit, the flow on the circuit, and the normal and emergency ratings. Overloading may be caused by an incorrect rating. Both normal and emergency ratings should be given. Emergency ratings must never be less than normal ratings, though the ratings may be equal. The impedance of a circuit element or of a parallel element may also cause overloading. See Section 6-A for guidelines of typical transmission line or transformer impedance data.

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c. **Generation Summary**

All buses with generation as well as all buses with voltage regulation are shown in this summary. Generators should not be modeled as unregulated buses.

The MW ratings, Mvar ratings, machine base (MBASE), and ZSOURCE **must** be supplied for **each** generator. Generator PMAX ratings should represent the net capability of each machine connected to the bus. Ratings should be adjusted seasonally in consideration of scheduled outages. The generation should be shown on the correct bus. Generation **must not** exceed the rating. Generator MBASE values should be equal to the nameplate MBASE rating of the unit. Each unit should be explicitly modeled and listed in the SPP Generation Workbook. The generator workbook will be updated to include both the saturated and unsaturated impedance for each machine. Fuel types, especially wind farms, should be indentified in the appropriate column.

The reactive output limits (MAX and MIN) should be realistic values as defined in SPP Criteria 12.1.6 (see Section V.A.4). For generators, a general rule of thumb sets MVAR limits as:

QT --- MAX = one-half of MW rating

QB --- MIN = negative one-third of MW rating

If the slack bus generation changes significantly from the input value, it indicates an error in the model data. Regulated buses are not limited to generators, but also include other equipment such as synchronous condensers and static var controllers. If the actual voltage does not match the desired voltage, a reactive limit will be reached. The desired voltage for each regulated bus should be checked seasonally.

Wind farm generation should be modeled at the machine voltage bus (i.e. 575 V) when applicable; this is primarily done for Generation Interconnection studies when determining the power factor of a wind farm at the point of interconnection. For the purpose of other planning studies, all machines should be aggregated on a single machine voltage bus. The rating of the resulting unit should be the total rating of the wind farm. The unit should be dispatched per SPP Criteria 12.1.5.3.

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## 4. PERIODIC MODEL UPDATES

After the annual update process is complete, it may become necessary to perform an update to the information contained in the model(s). Some of the reasons for updating the model(s) and the procedure for doing so are listed below.

### A. System Impact Studies/Expansion Options Studies (Long-Term)

SPP performs transmission planning studies and assessments for various eligible customers. These model sets are developed in accordance with the SPP Planning Modeling Process and include models used for the SPP Transmission Expansion Plan, Transmission Service Studies, and Generation Interconnection Studies, which all use the data submitted to MOD as a base for model development.

### B. MDWG Updates

At some point after the current models are extracted out of MOD some data will need to be updated to reflect pertinent changes to the system (i.e., lost or added transmission capability, lost or added generation, improved data, etc…) There are several ways of submitting changes to the power flow models.

Two of these methods are:

a. Using the power flow update procedure in Section 5 to update MOD.
b. Submitting a PTI, IDEV format file to perform the RDCH operation**. This method should only be used for profile changes. Each company should only submit one IDEV file per modeling pass. Under special circumstances topology changes can be submitted in a IDEV file as long as a MOD Project is submitted in MOD.**

**It is imperative that any information submitted to SPP be error free and complete to avoid delays in the implementation of the changes.**

The most current update to the models will always be posted on the SPP file sharing site.

## 5. PROGRAM OPERATION

The **SPP Power Flow** models are created, modified, and maintained utilizing the Power Technologies, Incorporated (PTI) Power System Simulator for Engineers (PSS/E) software package. The PSS/E program is installed on SPP computer facilities located in

Little Rock, Arkansas.

**A. PTI-PSS/E Data Format**

Power Flow data is input to the models from computer text data files structured in the formats described in the PSS/E Program Operation Manual Volume I, Chapter 4: Section 1.1. All data is read in "free format" with data fields separated by a **comma** (**not** blanks). Each type of data category is terminated by the specification of a zero in the first field of the record with the exception of the model identification data.

Data is **added** to the SPP Power Flow models as specified in these format structures for records where no corresponding component is found in the model. The **modification** of existing data in the model is accomplished using the same format structure, except that only the values that need modification are specified.

Data may also be deleted from the models. When a bus is specified for deletion, all associated data for that bus will be removed (e.g., branches, transformers, generators, and loads). **The user cannot delete a piece of equipment and then add it with new data. For example, to upgrade a bus from one voltage to another, the bus data must be modified.** Data currently in the model is used as the default value for data fields not specified in the format.

**1. Power Flow Solution**

The power flow solution will have “Area interchange control” with the “Tie Line and Loads” option selected to meet ERAG MMWG model building requirements.

a. The SPP transaction workbook must not include transactions for sales to loads in other control areas if the loads are specifically identified with source control area number. If the loads in an external control area are not identified with the source control area’s number, then a transaction is necessary to schedule to this load. See example below for more details for a load that Source Area XXX has the obligation to serve:

<u>No Transaction Needed</u>
Source Area: XXX
Sink Area: YYY
Sink Load: XXX

<u>Transaction Needed</u>
Source Area: XXX
Sink Area: YYY
Sink Load: YYY

b. Loads may be modeled on the foreign area bus as long as it is identified as belonging to the owning area.

c. SPP will identify remote SPP loads in the base cases, pass 1, pass 2, and pass 3 models.

**B. TRANSMITTED DATA FILE EXAMPLES (Refer to MOD Procedure Manual)**

## C. PTI-PSS/E SHORT CIRCUIT DATA FORMAT

The SPP Short Circuit data is included in MOD Base Case (Network) and Project data. Short circuit data that is missing in the MOD Base Case must be entered in MOD via a MOD Project with the Project Type of Network and Project Status of Update. Missing Project sequence data must be updated by applying a sequence file to the Project in MOD.

***Member submitted sequence via an IDEV file applied to a model will not be included in the next published model (Pass N or Final).*** The reason that sequence data is not carried over from one model set to the next model set is that sequence data is exported from MOD. Post MOD model processing IDEV files are not applied to the next model set; therefore, a MOD project which includes the sequence data must be submitted to MOD and accepted before it is included in the next MOD exported model.

## 6. SPP DATA

### A. Typical Transmission Line or Transformer Impedance

These tables are only for the checking of reasonableness of line and transformer data and should not be used in data preparation for existing facilities.

**TYPICAL TRANSMISSION LINE DATA**

**(100 MVA BASE)**

| kV | Amps | R/mile | X/mile | (Mvar/mile) Charging | MVA | X/R |
|---|---|---|---|---|---|---|
| 69 | 600 | 0.00540 | .0143 | 0.00030 | 71 | 2.6 |
| 115 | 1200 | 0.00064 | .0050 | 0.00084 | 240 | 7.8 |
| 138 | 1200 | 0.00045 | .0038 | 0.00120 | 286 | 8.4 |
| 161 | 2000 | 0.00020 | .0019 | 0.00220 | 558 | 9.5 |
| 230 | 2000 | 0.00010 | .0010 | 0.0040 | 796 | 10 |
| 345 | 2000 | 0.00004 | .00048 | 0.0091 | 1195 | 12 |
| 500 | 2000 | 0.00002 | .00026 | 0.0170 | 1732 | 13 |

A typical transmission transformer's impedance is approximately 8% on the OA rating base.

**For example:**

**On a 345 kV Line that is 70 miles long –**

**R is:** **70(0.00004) = 0.0028**

**X is:** **70(0.00048) = 0.0336**

**Charging is:** **70(0.0091) = 0.637**

### B. System Abbreviations & Area Number Assignments

System Abbreviations & Area Number Assignments can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

### C. SPP Members

The SPP Members are identified on the SPP Website. See the "Members" link under "About SPP" on www.SPP.org.

## 7. FORMS – Area Summary Report

SPP Southwest Power Pool

Area Name & Number: ______________________

Prepared By: ______________________

Telephone Number: ______________________

**POWER FLOW DATA AREA SUMMARY REPORT**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CASE | | | | | | | | | | | | | | | |
| 1. Generation | | | | | | | | | | | | | | | |
| Purchases (-)/Sales (+)<br>To/From Area Name | | | | | | | | | | | | | | | |
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| 2. Total Interchange | | | | | | | | | | | | | | | |
| 3. Net Power (1-2) | | | | | | | | | | | | | | | |
| 4. Load | | | | | | | | | | | | | | | |
| 5. Losses | | | | | | | | | | | | | | | |
| 6. Net Load (4+5) | | | | | | | | | | | | | | | |
| 7. Slack Bus Generation | | | | | | | | | | | | | | | |
| 8.Slack Bus Number & Name | | | | | | | | | | | | | | | |

***Note:***

## 7. FORMS – Power Flow Data Checklist

SPP Southwest Power Pool

Area Name & Number: ______
Prepared By: ______
Telephone Number: ______

**POWER FLOW DATA CHECKLIST**

| CASE | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS DATA | | | | | | | | | | | | | | | |
| Names - 12 characters | | | | | | | | | | | | | | | |
| Voltage Codes | | | | | | | | | | | | | | | |
| Power Factor | | | | | | | | | | | | | | | |
| Load - Real | | | | | | | | | | | | | | | |
| Reactive Load | | | | | | | | | | | | | | | |
| Voltage | | | | | | | | | | | | | | | |
| Fixed Shunts - Reactors | | | | | | | | | | | | | | | |
| Capacitors | | | | | | | | | | | | | | | |
| Dynamic Shunts - SVC's | | | | | | | | | | | | | | | |
| Synchronous Condensors | | | | | | | | | | | | | | | |
| Generation - Dispatch/Net | | | | | | | | | | | | | | | |
| Reactive Output | | | | | | | | | | | | | | | |
| Reactive Limits | | | | | | | | | | | | | | | |
| Regulated Voltages | | | | | | | | | | | | | | | |
| Generator Rating | | | | | | | | | | | | | | | |
| Slack Bus | | | | | | | | | | | | | | | |
| LINE DATA | | | | | | | | | | | | | | | |
| Ratings - Normal | | | | | | | | | | | | | | | |
| Emergency | | | | | | | | | | | | | | | |
| Impedance - Resistance | | | | | | | | | | | | | | | |
| Reactance | | | | | | | | | | | | | | | |
| Charging | | | | | | | | | | | | | | | |
| Flows | | | | | | | | | | | | | | | |
| Transformers - Taps | | | | | | | | | | | | | | | |
| Tap Ranges | | | | | | | | | | | | | | | |
| Regulated Bus | | | | | | | | | | | | | | | |
| OTHER DATA | | | | | | | | | | | | | | | |
| Net Area Interchange | | | | | | | | | | | | | | | |
| Area Transactions | | | | | | | | | | | | | | | |

***Note:***

## 8. ACRONYMS

ATC – Available Transfer Capability

CAP – Capacitor

EIA – Energy Information Act

ERAG – Eastern Interconnection Reliability Assessment Group

ERCOT – Electric Reliability Council of Texas

FPC – Federal Power Commission

IDEV – Input Device (PSS/E Dialog Input Device Selection Activity)

LTC – Load Tap Changing

MAPP – Mid-Continent Area Power Pool

MAIN – Mid-American Interpool Network

MBASE – Machine Base

MDWG – Model Development Working Group

MMWG – Multiregional Modeling Working Group

Mvar – Megavar

MW – Megawatt

NERC – North American Electric Reliability Corporation

PSS/E – Power System Simulator for Engineers

PTI – Power Technologies, Inc.

pu – Per-unit

RAWD – Raw Data

RDCH – Read Change (Command to read in and change data in PSS/E)

REAC – Reactor

SERC – Southeastern Electric Reliability Council

SPP – Southwest Power Pool, Inc.

STEP - SPP Transmission Expansion Plan

TWG – Transmission Working Group

WSCC – Western Systems Coordinating Council

ZSOURCE – Zero Impedance

*** NOTE** – A complete listing of other SPP acronyms can be found on the SPP website at www.spp.org. See the “Glossary and Acronyms” link under “Training”

## 9. MDWG Contact List

The MDWG Contact List can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

# 10. SPP Model Release Guidelines

## A. SPP Model Release Guidelines

### 1. Power Flow and Short Circuit Models

SPP Base Case Power Flow models and Short Circuit models are available to all SPP members. SPP and its members, by participating in SPP base case development, grant authority to the other participating members and SPP to release SPP Base Case Power Flow models or reduced network equivalents of those models to government agencies. The public may receive models through the FERC Critical Energy Infrastructure Information (CEII) formal request process. For more information on requesting Base Case Power Flow models, contact the SPP Model Contact.

Base case power flow models of external systems, which are beyond the electrical borders of SPP and released under FERC Form 715 to government agencies, shall be the SPP models or a reduced network equivalent of the SPP models. If equivalized, such external models must be disclaimed, as equivalent representations not intended for study of the transmission systems in those external areas.

### 2. System Dynamic Data Base and Dynamic Simulation Cases

SPP Stability Base Case Models are available to all SPP members. SPP and its members, by participating in MMWG dynamics database (SDDB) and dynamics simulation case development, grant authority to the other participating Regions, to receive and use the SDDB and dynamics simulation cases. Regional members may send dynamics simulation cases or dynamics data to third parties provided that the third party executes a written confidentiality/non-disclosure agreement. The MMWG Dynamics Database (SDDB) remains the property of and is for the sole use of the MMWG participating Regions of NERC and their members.

### 3. SPP Model contact:

Please send all general modeling questions and concerns to planningmodeling@spp.org.

### B. Request an SPP Map / Model

Questions? You may find it helpful to consult SPP Maps & Models FAQ.

If you are an SPP member, interconnection customer, transmission service customer (or their consultant) and would like to request an SPP Transmission Map or Model, please complete the appropriate forms below. (Requests for Joint & Interregional System Planning Models are addressed on this page.) If you are requesting access on behalf of an organization other than your employer, a Consultant Authorization Form must also be submitted on your behalf.

SPP Transmission Map Order Form
SPP Model Order Form
SPP Confidentiality Agreement
Consultant Authorization Form

All other requesters should file a Critical Energy Infrastructure Information (CEII) request with the Federal Energy Regulatory Commission (FERC). Detailed instructions on how to file a FERC CEII request are available at www.ferc.gov/help/filing-guide/ceii-request.asp. You may file your CEII request online at www.ferc.gov/legal/ceii-foia/ceii/eceii.asp.

If you have obtained FERC CEII approval and would like to request additional CEII, please submit the appropriate SPP Form(s) and SPP Confidentiality Agreement, **providing the requester's FERC CEII ID Number and attaching a copy of the FERC Authorization Letter (i.e., FERC Notice of Intent to Release)**.

Completed SPP Forms and the SPP Confidentiality Agreement should be e-mailed to SPP Customer Relations. The original, signed hardcopy of the SPP Confidentiality Agreement should be mailed to the attention of **Susan Polk, 415 North McKinley, Suite 140, Little Rock, Arkansas 72205**.

If you have questions or would like additional assistance, please contact SPP Customer Relations at (501) 614-3309.

*Last Updated April 20, 2009*

## 11. MDWG Model Set

The current MDWG Model Set can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

## 12. MMWG Compliance Checks

**ERAG MMWG Procedural Manual** May 7, 2009 - Appendix VI

The following data error screening checks will be used to check case quality:

- Interchange and tie line data not matching the raw data will not be accepted until either the interchange data or the raw data are corrected. *
- All CNTB errors shall be corrected. (Exceptions will be documented.)
- All instances of mode=1 switched shunts with VHI – VLO < .005 per unit shall be corrected.
- Any regulation by any regulating device of a bus more than one bus away, except where there is a three-winding transformer in which case no more than two buses away, shall be corrected.
- All instances of TCUL transformers with more than 50 tap steps shall be corrected.
- All instances of voltage controlling bandwidth less than twice the transformer tap step size shall be corrected.

* The effect of this check will be to delay acceptance of the applicable submittal until the problem is corrected.

## 13. MMWG Appendices for Reference

**Appendix II**
**Dynamics Data Submittal Requirements and Guidelines**

A. Power Flow Modeling Requirements

1) All power flow generators, including synchronous condensers and Static VAr Compensators (SVCs) modeled as generators, shall be identified by a bus name and unit id. All other dynamic devices, such as switched shunts, relays, and HVDC terminals, shall be identified by a bus name and base kV field. The bus name shall consist of eight characters and shall be unique within the Eastern Interconnection. Any changes to these identifiers shall be minimized.
2) 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.
3) 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.
4) In accordance with PTI PSS$^{TM}$E requirements, the Xsource value in the power flow generator data record shall be as follows:
    a) Xsource = $X''_d$ for detailed synchronous machine modeling
    b) Xsource = $X'_d$ for non-detailed synchronous machine modeling
    c) Xsource = should be equal to locked rotor impedance for an induction machine
    d) Xsource = 1.0 per unit or larger for all other devices
5) 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$^{TM}$E dynamic library 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.

B. Dynamic Modeling Requirements

1) 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. The PSS$^{TM}$E dynamic model types classified as detailed are GENROU, GENSAL, GENROE, GENSAE, and GENDCO.

The use of non-detailed synchronous generator or condenser modeling shall be permitted for units with nameplate ratings less than or equal to 50 MVA under the following circumstances:

a) Detailed data is not available because manufacturer no longer in business.

b) Detailed data is not available because unit is older than 1970.

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:

a) Unit is a phantom or undesignated unit in a future year MMWG case.

b) Unit is on standby or mothballed and not carrying load in MMWG cases.

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.

2) All synchronous generators and condensers modeled in detail per Requirement II.1 shall also include representations of the excitation system, turbine-governor, power system stabilizer, and reactive line drop compensating circuitry. The following exceptions apply:

    a) Excitation system representation shall be omitted if unit is operated under manual excitation control.

    b) 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.

    c) Power system stabilizer representation shall be omitted for units where such device is not installed or not in continuous operation.

    d) Representation of reactive line drop compensation shall be omitted where such device is not installed or not in continuous operation.

3) 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.

4) Standard PSS™E dynamic models shall be used for the representation of all generating units and other dynamic devices unless both of the following conditions apply:

    a) The specific performance features of the user-defined modeling are necessary for proper representation and simulation of inter-regional dynamics, and

    b) Standard PSS™E dynamic models cannot adequately approximate the specific performance features of the dynamic device being modeled.

5) 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.

Source code for User Models shall be submitted in the FLECS language of the current PSS$^{TM}$E revision, C, or FORTRAN. User models created in MATLAB/SIMULINK are not permitted because users of the SDDB cannot run them without purchase of additional software.

6) 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.)

7) 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.

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

9) Exceptions will be approved by MMWG on a case by case basis and the reason for each exception will be documented in the SDDB.

C. Dynamics Data Validation Requirements

1) All dynamics modeling data shall be screened according to the SDDB data screening checks.

   All data items not passing these screening tests shall be resolved with the generator or dynamic device owner and corrected.

2) All regional 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 III.H* of this manual (*yet to be written) may be applied for this purpose.

D. Guidelines

1) 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.).

2) 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 Regions should provide parameters for representing loads via the PTI PSS$^{TM}$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 interregional dynamic performance requires it.

**APPENDIX III**

**Procedures for Submission of Dynamics Data**

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

A. Dynamics Data Updates Using Excel Template

Regional dynamics data updates are incremental to the dynamics data in the previous year release of SDDB. Regional Coordinators should therefore verify that bus names and unit IDs in SDDB are consistent with those in the MMWG power flows to be made dynamics ready.

The table below describes the various types of updates and the required data and information that should be provided on the Excel template and in a separate DYRE file.

| Type of Update | Template Entries | Complete DYRE format record | Examples / Comments |
|---|---|---|---|
| Change one or more parameters of a dynamics model | Bus name, unit ID, model name, parameter name, new value | No | The voltage regulator gain is changed to the value determined by test. |
| Add a new model to an existing unit | No | Yes | A stabilizer is being added to a unit which did not have one. |
| Delete a model | Bus name, unit ID, model name | No | A stabilizer is removed. |
| Replace a model with another model of the same equipment group | Bus name, unit ID, model name for deleted model. | Yes for new model. | 1. A DC exciter is replaced by a static exciter.<br>2. A classical machine model is replaced by a detailed model. |
| Change bus name and/or unit ID for all models of an existing unit | Old and new names; old and new unit IDs | No | |
| Change bus number | No | No | Maintain the same name and unit ID and the model data will follow automatically. |
| Add dynamic models for a new generating unit | Bus name, unit ID, in service and out of service dates, MVA base, Zsource, RPM, unit type | Yes | Same requirements whether unit is at new or existing bus. |
| Remove a unit and all associated models | Bus name, unit ID | No | |

B. Complete Set of Dynamics Data

The regional dynamics data must be in the format of a PSS$^{TM}$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.

**APPENDIX IV**
**Deliverables**

A. Regional Coordinators

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

1. Power Flow Cases
   A. Data as needed to create the MMWG power flow cases in RAWD or Saved Case format, regional representation shall be within an entire solved MMWG power flow model in the proper PSS™E revision format
   B. Tieline and interchange data in the specified format
   C. IDEV files for any data changes
   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, 18 character PSS/E Bus Name, EIA Plant Code (U.S. only) and Non-Abbreviated Bus Name.
2. Dynamics Cases
   A. Dynamics input data in DYRE format for new models
   B. SDDB Excel worksheet for changes to the database
   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 region in IDEV format

B. MMWG Coordinator(s)

The MMWG Coordinator(s) will post the following to the ERAG Web Site.

1. Power Flow Cases
   Initialized steady state and regional contingency cases.
   A. Power Flow RAWD case file
   B. Conversion IDEV files
2. Dynamics Cases
   Dynamics case input data, output files and instructions including:
   A. Dynamics input data in DYRE format
   B. FLECS code for user defined models
   C. Load conversion CONL file sorted by area
   D. Any IPLAN or PYTHON programs necessary to set up the dynamics case
3. Complete dynamics database and User Manual
4. Final reports

## APPENDIX V

### Power Flow Modeling Guidelines

1. **Modeling Detail** – All transmission lines 115 kV and above and all transformers with a secondary voltage of 115 kV and above should be modeled explicitly. Significant looped transmission less than 115 kV should also be modeled.

2. **Nominal Bus Voltage** – All buses should have a non-zero nominal voltage. Nominal voltages of buses connected by lines, reactors, or series capacitors should be the same. The following nominal voltages are standard for AC transmission and sub-transmission in the United States and 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.

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

3. **Islanded Buses** – Islanded buses shall not be modeled in MMWG cases.

4. **Generator Modeling of Loads** – Fictitious generators should not be used to “load net” (by showing negative generation) a model of other nonnative load imbedded in power flow areas. It is recommended that a separate zone be used to model such loads to allow exclusion from system load calculations.

5. **Zero Impedance Branches** – Bus ties that are opened to represent switching during contingencies may be modeled in detail. Zero impedance branches are permitted to model bus ties using R=0.00000 + X=0.0001 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$^{TM}$E program. When connected between two voltage controlled (generator, switched shunt, or TCUL controlled), bus ties or other low impedance lines should be modeled using an impedance of R=0.0001 + X=0.002 and B=0.00000. This allows use of near-zero impedance attached to controlled buses that will be large enough to avoid significant solution problems.

6. **Impedance of Branches In Network Equivalents** – Where network representation has been equivalenced, a maximum cutoff impedance of 3.0 p.u. should be used.

7. **Negative Branch Reactances** – Except for series capacitors, negative branch reactances do not represent real devices. Their use in representing three winding transformers is obsolete. Negative branch reactances limit the selection of power flow solution techniques and should be avoided.

8. **Transformers** – Effective with Revision 28 of PSS$^{TM}$E, off-nominal turns ratios may not be specified for branches; a block of four or five data records must be entered for each transformer. The off-nominal turns ratio in per unit, or the actual winding voltage in kilovolts, and the phase shift in degrees shall be specified for each winding. The measured impedance (resistive and inductive) between each pair of windings shall be specified: data entry options permit these to be entered in (1) per unit on system (100 MVA) base, (2) per unit on winding MVA base, or (3) load loss in watts and impedance on winding MVA base and base voltage.

9. **Transformers Controlling Voltage or Reactive Power Flow** – The upper and lower limits of off-nominal turns ratio and the number of tap positions available are entered for winding 1 of transformers controlling voltage or reactive power flow. Default values of 1.1, 0.9 and 33 are representative of U.S. practice. The upper and lower voltage limits are entered for transformers controlling voltage and the difference, in per unit, should be at least twice the tap step size. The upper and lower MVAR limits are entered for transformers controlling reactive power flow and these limits should differ by at least 10 MVAR. Limits should accurately represent the actual operation of automatic control devices.
10. **Remote Regulation** – Regulation of a bus voltage more than one bus away (not counting hidden center point buses of three winding transformers) from the regulating device should be avoided. The sign of parameter CONT determines whether the off-nominal turns ratio is increased or decreased to increase voltage at the bus whose voltage is controlled by this transformer.
11. **Phase Angle Regulating Transformers** – For phase angle regulating (PAR) transformers, the active power flow into winding 1 is entered. The tolerance should be no less than 5 MW; i.e., a 10 MW dead band. The controlling band should be at least 10 degrees.
12. **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 regional and interregional studies. Three rating fields are provided for each branch and each transformer winding. Normal and emergency ratings should be entered in the first two fields (RATEA and RATEB, respectively); use of the third rating field (RATEC) is optional. Ratings should be omitted for model elements which are part of an electrical equivalent. The rating of a branch or transformer 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.
13. **Generator Step-Up Transformers** – Generator step-up transformers may be modeled explicitly as deemed necessary by either the transmission owner or the Regional Reliability Organization. Their modeling should be consistent with the associated dynamics modeling of the generator. Generator step-up transformers of cross-compound units should be modeled explicitly.
14. **Out-of-Service Generator Modeling** – Out-of-service generators should be modeled with a STATUS equal to zero.
15. **Generator MW Limits** – The generation capability limits specified for generators (PMIN and PMAX) should represent realistic seasonal unit output capability for the generator in that given base case. PMAX should always be greater than or equal to PMIN. Net maximum and minimum unit output capabilities should be used unless the generator terminal bus is explicitly modeled, the generator step up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.
16. **Generator MVAR Limits** – The MVAR limits specified for generators (QMIN and (QMAX) should represent realistic net unit output capability of the generator modeled. QMAX should always be greater than or equal to QMIN. Net maximum and minimum unit output capabilities should be given unless the generator terminal bus is explicitly modeled, the generator step up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.

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

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

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

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

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

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

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

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

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

**APPENDIX VII**

**Causes of Non-convergence and Problems in Merged Base Case Models**

A. Causes of Non-convergence

1. 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.)
2. Tie lines are missing because they were not picked up by model creation or tie lines are connected incorrectly.
3. 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.
4. A system's regulating (slack) bus is in a different system. This is probably due to an incorrect data entry in changing a model.
5. An isolated system (island) has been inadvertently created. Voltage phase divergence will be flagged immediately and the program will stop calculating after the first iteration.
6. Unrealistic tap changing transformer tap limits.
7. Radial system is very large.
8. Poor voltage regulation such as:
   a. Unequal voltage schedules at generating units connected by a low impedance line.
   b. Regulation of a radial line at both ends at unequal voltages.
      (Solution: Do not regulate a radial bus; hold MVAR output of a radial bus constant at the value obtained in last iteration.)
   c. Conflicting voltage regulation.
   d. Unreasonably small voltage range for switched shunts.
   e. Remote regulation of more than one bus away.
9. Over-equivalencing of outside Regions in regional base case models.
10. Not solvable from flat start.
11. Fictitious regulation of buses.
12. Extremely low voltage schedules.
13. Not following the approved MMWG sign convention for phase shifters (see page 3 of this **Appendix**) or not adhering to minimum MW tolerance for phase-shifting-under load transformers.
14. Zero or very low reactance branches. Minimum reactance = 0.0001 per unit.
15. Inconsistent representation of delta-wye transformers, typically by two companies interconnected at both voltage levels.

B. Problems

1. Duplicate bus names in an area(s).
2. The data will not permit power flow calculation, such as:
   a. Zero voltage regulation, resulting in division by zero. Notify Regional Coordinator.
   b. Interchange does not net to zero. Save the data but do not calculate until the Coordinator has given instructions for correcting the data.
   c. High R/X ratios in equivalent area causing non-convergence. Delete line or reduce ratio.
3. Missing tie lines. These tie lines may or may not be in the base case model. The program flags the tie lines as missing because of its tie line checking routine. A review of the data dump will verify the inclusion of a tie line if it is included and has been flagged as missing. Likewise, the validity of the error message will be verified by a review of the data dump.
4. Phase Shifting Transformers
   a. The first-named bus in the branch data is taken as the “From” bus and the second-named bus is taken as the “To” bus. The “From” bus is also taken as the tapped bus.
   b. If phase shift angle is specified in CDF as positive, $\square_A < \square_B$.
   c. Assuming $\square_A$ and $\square_B$ stay relatively constant for small changes, an increase in this positive phase shift angle will tend to change the voltage phase angle of Bus A in a lagging direction relative to that for Bus B. This causes an incremental increase in real power flow in the direction of B to C regardless of the direction of the initial real power flowing through the transformer.
   d. A desired positive real power flow into the phase shifting transformer at the "From" bus or tapped bus is specified with positive real power limits.
   e. The "Controlled Bus" specified should be the same as the tapped bus to be consistent and avoid confusion.

**Note:** The PTI PSS™E power flow program currently being used by AEP to process MMWG models requires the above convention. Therefore, it is desirable that all phase shifter models sent to AEP conform to this convention. If the data submitted does not conform to the above convention, AEP must be notified so that appropriate corrections can be made.

**APPENDIX VIII**

**Procedures for Initialization And No-Disturbance Checks Of Library DYNAMICS Cases**

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

1. Create a converged load flow case with as few limit violations and questionable data items as possible.
   A. Solve the case after each set of major changes [FNSL, FDNS, SOLV, or MSLV] and save it to minimize rework if a change has unintended consequences. If all of the following constraints are satisfied, convergence within tolerance, even from a flat start, should not take more than the default number of iterations. However, there is usually no reason to use a flat start if the case being updated was solved.
   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
      i. Machine MVA on the default base of 100. Although models will work if all load flow and dynamic model parameters are entered on this basis, limit checks will not work correctly.
      ii. Source impedance of 1.0 p.u. on machine MVA base. This value is substantially higher than normal for synchronous machines.
      iii. Source impedances equal to or less than zero. These will cause generator conversion to fail.
      iv. Real and/or reactive power limits of +9999 or –9999.
   C. Checks which report abnormal values
      i. Branch flows exceeding normal ratings. [RATE or OLTL and OLTR]
      ii. 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]
      iii. Overloaded generators. [GEOL]. Note that this activity checks machine output against the machine MVA base, MBASE, not against PMAX, PMIN, QMAX, and QMIN.
      iv. Branches with extreme impedances or tap ratios [BRCH]. Suggested options are:
         1. 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.
         2. 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.
         3. 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.
         4. Parallel transformers. Minor tap ratio differences may simply reflect field conditions, but differences exceeding one step should be checked to guard against inadvertent errors.
         5. High tap ratios.
         6. 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.
      i. 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.
      ii. 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.
      iii. Questionable voltage or flow controlling transformer parameters. [TPCH]
      iv. 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.

2. To confine the initialization to a subset of the original load flow, for instance the areas comprising one region, 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 <u>loads</u> (positive for flows out, negative for flows in). [BGEN]
3. Net generation with load at any buses where a generator(s) exists for which no dynamic models are available. [GNET].
4. Convert the generators in the load flow [CONG], solve, [ORDR, FACT, TYSL] and save converted case.[SAVE]
5. From the dynamics entry point, read in the dynamic model data file [DYRE] (Load flow case must also be in memory.)
   A. Specify CONEC, CONET, and COMPILE files.
   B. It is highly desirable to include a SYSANG model in the DYRE file, although this makes it mandatory to recompile even if no user models are included. This model provides six monitoring output channels, which can be used to scan a no-disturbance simulation for stability without attempting to select individual machines to monitor.
6. Concatenate FLECS code for user models onto CONEC or CONET files.
7. Compile.
8. Execute CLOAD4.
9. Restart from the dynamics entry point, this time using "user dynamics".
   A. Read converted load flow [CASE].
   B. Read in the dynamic data file [DYRE]
   C. Specify channels to record appropriate states and variables as simulation outputs [CHAN]. Include SYSANG variables if this model was included in the dynamics data file as suggested above.
   D. Check consistency of dynamic models [DYCH, option 1].
   E. Initialize dynamic simulation [STRT]. The output of this activity may have several important parts and it is desirable to keep a log file for reference while debugging.
      i. Warning messages for
         1. Generators in the load flow for which there is no active machine model.
         2. Models, usually of excitation systems or governors, initialized out of limits.
         3. The number of iterations required to initialize the initial-conditions power flow.
      ii. A tabulation of conditions at each online machine
         1. Terminal voltage
         2. Exciter output voltage
         3. Real and reactive power output
         4. Power factor
         5. Machine angle in degrees
         6. Direct and quadrature axis currents on machine base.
      iii. A diagnosis of initial conditions, either
         1. "Initial conditions check OK", or
         2. A listing of suspect initial conditions generally states whose time derivative is not "small" (relative to the value of the state). These may be caused by inconsistencies between the real and reactive power scheduled for a unit by the load flow (including automatic changes in reactive power to hold bus voltage at a target level) or by parameter errors.
      iv. For models flagged in steps i) through iii), consider using activity [DOCU] to identify parameters which may be causing problems. This activity will also give the automatically calculated values of exciter model parameters, which are derived if the corresponding parameters, as read in, are 0. Other warnings may indicate errors in the powerflow model.
   F. Modify model parameters or the load flow as appropriate and repeat steps up to this point until there are no warning messages nor suspect initial conditions.

10. Record a snapshot [SNAP] of dynamic state values prior to application of any disturbance or simulation of any time period.
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.
12. Stop simulation. Review output values in tabular and/or graphical form.
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).
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.

**APPENDIX IX**
**Master TIE Line File DATA Fields**
**Branch Data Fields**

In Service Date,
Out Service Date,
From Region Name,
From Area#,
From Area Name,
From Bus#,
From Bus Name,
From Bus kV,
To Region Name,
To Area#,
To Area Name,
To Bus#,
To Bus Name,
To Bus kV,
Metered End (F,T),
CKT,
R,
X,
B,
Summer Rating A,
Summer Rating B,
Summer Rating C,
Winter Rating A,
Winter Rating B,
Winter 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

## MASTER TIE LINE FILE DATA FIELDS continued

### Two Winding Transformer Data Fields

In Service Date,
Out Service Date,
From Bus Region Name,
From Bus Area#,
From Bus Area Name,
From Bus Number,
From Bus Name,
From Bus kV,
To Bus Region 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,

## MASTER TIE LINE FILE DATA FIELDS
## continued

**Two Winding Transformer Data Fields - continued**

COD1,
Volt Control Bus Region 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

**MASTER TIE LINE FILE DATA FIELDS**
**continued**

## Three Winding Transformer Data Fields

In Service Date,
Out Service Date,
Winding 1 Region Name,
Winding 1 Area#,
Winding 1 Area Name,
Winding 1 Bus#,
Winding 1 Bus Name,
Winding 1 Bus kV,
Winding 2 Region Name,
Winding 2 Area#,
Winding 2 Area Name,
Winding 2 Bus#,
Winding 2 Bus Name,
Winding 2 Bus kV,
Winding 3 Region 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,

**MASTER TIE LINE FILE DATA FIELDS**
**continued**

### Three Winding Transformer Data Fields - continued

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,
COD1,
Control Bus 1 Region,
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,
COD2,
Control Bus 2 Region,
Control Bus 2 Area Number,
Control Bus 2 Area Name,
CONT2,
Control Bus 2 Name,
Control Bus 2 KV,
RMA2,

**MASTER TIE LINE FILE DATA FIELDS**
**continued**

### Three Winding Transformer Data Fields - continued

RMI2,
VMA2,
VMI2,
NTP2,
TAB2,
CR2,
CX2,
WindV3,
NomV3,
Ang3,
Summer Rating A3,
Summer Rating B3,
Summer Rating C3,
Winter Rating A3,
Winter Rating B3,
Winter Rating C3,
COD3,
Control Bus 3 Region,
Control Bus 3 Area Number,
Control Bus 3 Area Name,
CONT3,
Control Bus 3 Name,
Control Bus 3 KV,
RMA3,
RMI3,
VMA3,
VMI3,
NTP3,
TAB3,
CR3,
CX3

**MASTER TIE LINE FILE DATA FIELDS**
**continued**

### Two Terminal DC Tie Data Fields

In Service Date,
Out Service Date,
I,
MDC,
RDC,
SETVL,
VSCHD,
VCMOD (1,0),
RCOMP,
DELTI,
METER (R,I),
DCVMIN,
CCCITMX,
CCCACC,
IPR REGION 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 REGION NAME,
ICR AREA#,
ICR AREA NAME,
ICR BUS#,
ICR BUS NAME,
ICR BUS kV,
IFR REGION NAME,
IFR AREA#,
IFR AREA NAME,
IFR BUS#,
IFR BUS NAME,
IFR BUS KV,
ITR REGION NAME,
ITR AREA#,

## MASTER TIE LINE FILE DATA FIELDS (continued)

### Two Terminal DC Tie Data Fields

ITF AREA NAME,
ITR BUS#,
ITR BUS NAME,
ITR BUS KV,
IDR,
XCAPR,
IPI REGION 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 REGION NAME,
ICI AREA#,
ICI AREA NAME,
ICI BUS#,
ICI BUS NAME,
ICI BUS kV,
IFI REGION NAME,
IFI AREA#,
IFI AREA NAME,
IFI BUS#,
IFI BUS NAME,
IFI BUS KV,
ITI REGION NAME,
ITI AREA#,
ITI AREA NAME,
ITI BUS#,
ITI BUS NAME,
ITI BUS KV,
IDI,
XCAPI

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

**Appendix X**
**Number Range Assignments for**
**ERAG MMWG Power Flow Data**

| Region | Bus Numbers | Area Numbers | Zone Numbers | Owner Numbers |
|---|---|---|---|---|
| Entire System | 100,000 – 899,999 | 100 to 899 | 100 to 1,899 | 100 to 1,199 |
| NPCC | 100,000 to 199,999 | 100 to 199 | 100 to 199 and 1,100 to 1,199 | 100 to 199 |
| RFC | 200,000 to 299,999 | 200 to 299 | 200 to 299 and 1,200 to 1,299 and 1,800 to 1,899 | 200 to 299 |
| SERC | 300,000 to 399,999 | 300 to 399 | 300 to 399 and 1,300 to 1,399 | 300 to 399 |
| FRCC | 400,000 – 499,999 | 400 to 499 | 400 to 499 and 1,400 to 1,499 | 400 to 499 |
| SPP | 50,000 to 599,999 | 500 to 599 | 500 to 599 and 1,500 to 1,599 | 500 to 599 and 800 to 899 |
| MRO | 600,000 to 699,999 | 600 to 699 | 600 to 699 and 1,600 to 1,699 | 600 to 699 |
| ERCOT (future) | 700,000 to 799,999 | 700 to 799 | 700 to 799 and 1,700 to 1,799 | 700 to 799 |

[1] Area or zone number 1 is sometimes used as a default when the number is omitted by mistake.
Its use to number an actual area should be avoided.

# Appendix XI
# Utilized Impedance Correction Tables

| Table Number | Tap or Angle | 1 Factor | Tap or Angle | 2 Factor | Tap or Angle | 3 Factor | Tap or Angle | 4 Factor | Tap or Angle | 5 Factor | Tap or Angle | 6 Factor | Tap or Angle | 7 Factor | Tap or Angle | 8 Factor | Tap or Angle | 9 Factor | Tap or Angle | 10 Factor | Tap or Angle | 11 Factor |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | -60 | 1 | -36 | 0.358 | -24.4 | 0.192 | -12.4 | 0.054 | -8.3 | 0.024 | 0 | 0.01 | 8.3 | 0.024 | 12.4 | 0.054 | 24.4 | 0.192 | 36 | 0.358 | 60 | 1 |
| 2 | -70 | 1 | -43 | 0.78 | -32 | 0.85 | 0 | 0.5 | 32 | 0.85 | 43 | 0.78 | 70 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | -180 | 1 | -150 | 0.5 | 0 | 0.5 | 150 | 0.5 | 180 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | -152 | 1 | -121.5 | 0.625 | -85.4 | 0.372 | -42.2 | 0.217 | 0 | 0.157 | 42.2 | 0.217 | 85.4 | 0.372 | 121.5 | 0.625 | 152 | 1 | 0 | 0 | 0 | 0 |
| 8 | -40 | 1.848 | -30 | 1.468 | 0 | 1 | 30 | 1.538 | 40 | 1.83 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | -25 | 1.995 | 0 | 1 | 25 | 1.995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | -25 | 1.995 | 0 | 1 | 25 | 1.995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | -40 | 1.66 | -29.5 | 1.331 | -25.1 | 1.228 | -20.6 | 1.145 | 0 | 1 | 20.6 | 1.145 | 25.1 | 1.228 | 29.5 | 1.331 | 40.1 | 1.66 | 0 | 0 | 0 | 0 |
| 13 | -40 | 1.849 | -30 | 1.402 | -20 | 1.196 | -10 | 1.045 | 0 | 1 | 10 | 1.045 | 20 | 1.161 | 30 | 1.366 | 40 | 1.741 | 0 | 0 | 0 | 0 |
| 16 | -30 | 1.913 | 0 | 1 | 30 | 1.913 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | -47 | 6.34 | -41.7 | 5.44 | -33.3 | 4 | -27.5 | 3.06 | -18.5 | 2 | 0 | 1 | 18.5 | 1.76 | 27.5 | 3.278 | 33.3 | 3.643 | 41.7 | 5.25 | 47 | 1 |
| 18 | -40 | 2.31 | 0 | 1 | 40 | 2.31 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | -40 | 7.35 | -30 | 4.85 | -20 | 2.9 | -10 | 1.6 | 0 | 1 | 10 | 1.6 | 20 | 2.9 | 30 | 4.85 | 40 | 7.35 | 0 | 0 | 0 | 0 |
| 20 | 0.937 | 1.641 | 1 | 1 | 1.03 | 1.02 | 1.1 | 1.427 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | 0.889 | 0.575 | 1.04 | 1 | 1.2 | 2.89 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 0.8 | 1.563 | 0.85 | 1.384 | 0.9 | 1.235 | 0.95 | 1.108 | 1 | 1 | 1.05 | 0.907 | 1.1 | 0.826 | 1.15 | 0.756 | 1.2 | 0.694 | 1.25 | 0.64 | 1.3 | 1 |
| 23 | -10 | 1 | 5 | 0.655 | 20 | 1.449 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | -60 | 9.2 | -46.38 | 4.69 | -32.3 | 1.87 | -20 | 1 | 0 | 1 | 18 | 1 | 32.3 | 3 | 46.38 | 5.54 | 60 | 9.2 | 0 | 0 | 0 | 0 |
| 31 | -15 | 2.076 | 0 | 1 | 15 | 2.076 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 32 | -15 | 1.62 | 0 | 1 | 15 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | -5.7 | 2.061 | 0 | 1 | 5.7 | 2.061 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 34 | -10 | 1.782 | 0 | 1 | 10 | 1.782 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 35 | -30 | 1.65 | 0 | 1 | 30 | 1.65 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 37 | -15 | 2.076 | 0 | 1 | 15 | 2.076 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 40 | -40 | 1 | -35 | 0.75 | -25 | 0.6 | -12.5 | 0.55 | -7.5 | 0.52 | 0 | 0.5 | 7.5 | 0.52 | 12.5 | 0.55 | 25 | 0.6 | 35 | 0.75 | 40 | 1 |
| 42 | -42.5 | 1.784 | -32.6 | 1.497 | -22 | 1.26 | -11.1 | 1.07 | 0 | 1 | 11.1 | 1.05 | 22 | 1.193 | 32.6 | 1.443 | 42.5 | 1.782 | 0 | 0 | 0 | 0 |
| 44 | -52.9 | 1.9024 | -43.6 | 1.6768 | -33.7 | 1.4512 | -23.2 | 1.2256 | -12.3 | 1 | -1.2 | 1.1385 | 9.9 | 1.2769 | 20.9 | 1.4154 | 31.4 | 1.5539 | 0 | 0 | 0 | 0 |

**Appendix XII**
**Utilized DC Lines**

| DC Line Number | Region | Name | | DC Line Number | Region | Name |
|---|---|---|---|---|---|---|
| **1** | MRO | | | **26** | NPCC | |
| **2** | MRO | | | **27** | NPCC | |
| **3** | MRO | | | **28** | NPCC | |
| **4** | MRO | | | **29** | NPCC | |
| **5** | MRO | | | **30** | RFC | |
| **6** | MRO | | | **31** | RFC | |
| **7** | MRO | | | **32** | Unused | |
| **8** | MRO | | | **33** | Unused | |
| **9** | MRO | | | **34** | Unused | |
| **10** | MRO | | | **35** | Unused | |
| **11** | NPCC | | | **36** | NPCC | |
| **12** | NPCC | | | **37** | NPCC | |
| **13** | NPCC | | | **38** | NPCC | |
| **14** | NPCC | | | **39** | NPCC | |
| **15** | NPCC | | | **40** | Unused | |
| **16** | NPCC | | | **41** | SPP | |
| **17** | NPCC | | | **42** | SPP | |
| **18** | NPCC | | | **43** | SPP | |
| **19** | NPCC | | | **44** | SPP | |
| **20** | NPCC | | | **45** | SPP | |
| **21** | NPCC | | | **46** | MRO | |
| **22** | NPCC | | | **47** | MRO | |
| **23** | NPCC | | | **48** | MRO | |
| **24** | NPCC | | | **49** | MRO | |
| **25** | NPCC | | | **50** | Unused | |

**APPENDIX XIII**
**System Codes for Use in ERAG MMWG Power Flow Data**

## 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 | TransEnergie |
| 105 | NB | New Brunswick Power |
| 106 | NS | Nova Scotia Power |
| 107 | CORNWALL | Cornwall |

## RFC – Reliability First Corporation

| Area # | ID | System |
|---|---|---|
| 201 | AP | Allegheny Power |
| 202 | FE | FirstEnergy |
| 205 | AEP | American Electric Power |
| 206 | OVEC | Ohio Valley Electric Corporation |
| 207 | HE | Hoosier Energy Rural Electric Cooperative, Inc. |
| 208 | DEM | Duke Energy Midwest |
| 209 | DAY | Dayton Power & Light Company |
| 210 | SIGE | Southern Indiana Gas & Electric Company |
| 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 |
| 220 | IPRV | Illinois Power- Riverside Plant |
| 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 | BG&E | Baltimore Gas & Electric Company |
| 233 | PEPCO | Potomac Electric Power Company |
| 234 | AE | Atlantic Electric |
| 235 | DP&L | Delmarva Power & Light Company |
| 236 | UGI | UGE Utilities, Inc. |
| 237 | RECO | Rockland Electric Company |
| 295 | WEC | Wisconsin Electric Power Company (ATC) |
| | ESE | Edison Sault Electric (American Transmission Company - ATC) |

## SERC – SERC Reliability Corporation

| Area # | ID | System |
|---|---|---|
| 314 | BREC | Big Rivers Electric Corporation |
| 320 | EKPC | East Kentucky Power Cooperative |
| 330 | AECI | Associated Electric Cooperative Inc. |
| 331 | BCA | Batesville |
| 332 | LAGN | Louisiana Generating Company |
| 333 | CWLD | Columbia, MO Water and Light |
| 334 | WESTMEMP | West Memphis |
| 335 | CONWAY | Conway |
| 336 | BUBA | Benton Utilities Balancing Authority |
| 337 | PUPP | Panda Union Power Partners |
| 338 | DERS | City of Ruston |
| 339 | DENL | City of North Little Rock |
| 340 | CPLE | Carolina Power & Light Company – East |
| 341 | CPLW | Carolina Power & Light Company – West |
| 342 | DUKE | Duke Energy Carolinas |
| 343 | SCEG | South Carolina Electric & Gas Company |
| 344 | SCPSA | South Carolina Public Service Authority |
| 345 | DVP | Dominion Virginia Power |
| 346 | SOUTHERN | Southern Company |
| 347 | TVA | Tennessee Valley Authority |
| 349 | SMEPA | South Mississippi Electric Power Association |
| 350 | AEC | Alabama Electric Cooperative |
| 351 | EES | Entergy Electric System |
| 352 | YAD | APGI – Yadkin Division |
| 353 | SEHA | Hartwell - SEPA |
| 354 | SERU | Russell - SEPA |
| 355 | SETH | Thurmond – SEPA |
| 356 | AMMO | Ameren Missouri |
| 357 | AMIL | Ameren Illinois |
| 360 | CWLP | City of Springfield (IL) Water Light & Power |
| 361 | SIPC | Southern Illinois Power Cooperative |
| 362 | EEI | Electric Energy Incorporated |
| 363 | LGEE | E.ON.US |

## FRCC Florida Reliability Coordination Council

| Area # | ID | System |
|---|---|---|
| 401 | FPL | Florida Power & Light |
| 402 | PEF | Progress Energy Florida |
| 403 | FTP | Fort Pierce Utility Authority |
| 404 | GVL | Gainesville Regional Utility |
| 405 | HST | City of Homestead |
| 406 | JEA | Jacksonville Electric Authority |
| 407 | KEY | City of Key West |
| 409 | LWU | City of Lake Worth Utility |
| 410 | NSB | Utilities Commission of New Smyrna Beach |
| 411 | FMPP | Florida Municipal Power Pool |
| 412 | SEC | Seminole Electric Cooperative |
| 414 | STK | City of Starke |
| 415 | TAL | City of Tallahassee |
| 416 | TECO | Tampa Electric Company |
| 417 | FMP | FMPA / City of Vero Beach |
| 418 | NUG | Non-Utility Generators |
| 419 | RCU | Reedy Creek Energy Services, INC. |
| 421 | TCEC | Treasure Coast Energy Center |
| 426 | OSC | Osceola at Holopaw (PEF) |
| 427 | OLEANDER | Oleander IPP at Brevard (FPL) |
| 428 | CALPINE | Calpine at Recker (TECO) |
| 431 | VAN | IPS Avon Park at Vandolah (PEF) |
| 433 | HPS | Hardee Power Station (TECO) |
| 436 | DESOTOGEN | Desoto Generation IPP at Whidden (FPL) |
| 438 | IPP-REL | Reliant at Indian River (FMPP) |

## SPP – Southwest Power Pool, Inc.

| Area # | ID | System |
|---|---|---|
| 502 | CELE | Central Louisiana Electric Company |
| 503 | LAFA | Lafayette Utilities |
| 504 | LEPA | Louisiana Energy and Power Authority |
| 505 | ALEX | City of Alexandria |
| 507 | RAYB | Rayburn Country Electric Cooperative |
| 508 | NTEC | North Texas Electric Cooperative |
| 509 | SRGT | Sam Rayburn G&T |
| 511 | AREC | Arkansas Electric Cooperative |
| 513 | CLWL | City of Clarksdale |
| 514 | MEAM | Municipal Energy Agency of Mississippi |
| 515 | SWPA | Southwestern Power Administration |
| 520 | AEPW | American Electric Power |
| 522 | KAMO | Kamo Electric Cooperative |
| 523 | GRDA | Grand River Dam Authority |
| 524 | OKGE | Oklahoma Gas and Electric Company |
| 525 | WFEC | Western Farmers Electric Cooperative |
| 526 | SPS | Southwestern Public Service |
| 527 | OMPA | Oklahoma Municipal Power Authority |
| 531 | MIDW | Midwest Energy |
| 534 | SUNC | Sunflower Electric Cooperative |
| 536 | WERE | Westar |
| 537 | SIKE | City of Sikeston, Missouri |
| 539 | WEPL | Westplains Energy |
| 540 | MIPU | Missouri Public Service Company |
| 541 | KAPL | Kansas City Power and Light Company |
| 542 | KACY | Board of Public Utilities |
| 544 | EMDE | Empire District Electric Company |
| 545 | INDN | City of Independence |
| 546 | SPRM | City Utilities of Springfield |

## MRO – Midwest Reliability Organization

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

## ERCOT & WECC

| Area # | ID | System |
|---|---|---|
| 700 | ERCOT | Electric Reliability Council of Texas, Inc. |
| 800 | WECC | Western Electricity Coordinating Council |

## 14. NERC Reliability Standards for Modeling, Data, and Analysis, MOD-010-0 through MOD-015-0

### Standard MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation

**Adopted by NERC Board of Trustees: February 8, 2005 1 of 2**
**Effective Date: April 1, 2005**

### A. Introduction

**1. Title: Steady-State Data for Modeling and Simulation of the Interconnected Transmission System**

**2. Number:** MOD-010-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

**4. Applicability:**

**4.1.** Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

**4.2.** Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

**4.3.** Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

**4.4.** Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

**5. Effective Date:** April 1, 2005

### B. Requirements

**R1.** The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

**R2.** The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

### C. Measures

**M1.** The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

### D. Compliance

**1.0** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2 M1). If no schedule exists, then on request (30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

**2.4. Level 4:** Steady-state data was not provided.

**E. Regional Differences**

**1.** None identified.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

## Standard MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

**Adopted by NERC Board of Trustees: February 8, 2005 1 of 3**
**Effective Date: April 1, 2005**

### A. Introduction

**1. Title: Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures.**

**2. Number:** MOD-011-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

**4. Applicability:**

**4.1.** Regional Reliability Organization

**5. Effective Date:** April 1, 2005

### B. Requirements

**R1.** The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:

**R1.1.** Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0 ), and location.

**R1.2.** Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.

**R1.3.** AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0 ) equipment status, and metering locations.

**R1.4.** DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

**R1.5.** Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.

**R1.6.** Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.

**R1.7.** Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.

**R2.** The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.

### C. Measures

**M1.** The Regional Reliability Organization shall have documentation of its Interconnection's steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Periodic review of data requirements and reporting procedures: at least every five years.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard MOD-011-0_R1.

**2.2. Level 2:** Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard MOD-011-0_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in Reliability Standard MOD-011-0_R1.

**E. Regional Differences**

**1.** None identified.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

**Standard MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation**

**Adopted by NERC Board of Trustees: February 8, 2005 1 of 2**
**Effective Date: April 1, 2005**

## A. Introduction

**1. Title: Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.**

**2. Number:** MOD-012-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

**4. Applicability:**

**4.1.** Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

**4.2.** Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

**4.3.** Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

**4.4.** Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

**5. Effective Date:** April 1, 2005

## B. Requirements

**R1.** The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R4.

**R2.** The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

## C. Measures

**M1.** The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

**2.2. Level 2:** Not Applicable.

**2.3. Level 3:** Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

**2.4. Level 4:** Dynamics data was not provided.

**E. Regional Differences**

**1.** None identified.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

**Standard MOD-013-0 — RRO Dynamics Data Requirements and Reporting Procedures**
**Adopted by NERC Board of Trustees: February 8, 2005 1 of 3**
**Effective Date: April 1, 2005**

**A. Introduction**

**1. Title: Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures**

**2. Number:** MOD-013-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

**4. Applicability:**

**4.1.** Regional Reliability Organization

**5. Effective Date:** April 1, 2005

**B. Requirements**

**R1.** The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements::

**R1.1.** Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

**R1.1.1.** Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

**R1.1.2.** The Interconnection-wide requirements shall specify unit size thresholds for permitting:

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

**R1.2.** Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

**R1.3.** Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

**R1.4.** Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R1.

**R2.** The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

**C. Measures**

**M1.** The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-013-0_R2.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Data requirements and reporting procedures: on request (5 business days).

Periodic review of data requirements and reporting procedures: at least every five years.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the four areas defined in Reliability Standard MOD-013-0_R1.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in two or more of the four areas defined in Reliability Standard MOD-013-0_R1.

**E. Regional Differences**

**1.** None.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

**Standard MOD-014-0 — Development of Interconnection-Specific Steady State System Models**
**Adopted by NERC Board of Trustees: February 8, 2005 1 of 2**
**Effective Date: April 1, 2005**

## A. Introduction

**1. Title: Development of Steady-State System Models**

**2. Number:** MOD-014-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

**4. Applicability:**

**4.1.** Regional Reliability Organization

**5. Effective Date:** April 1, 2005

## B. Requirements

**R1.** The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steadystate system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels.

**R2.** The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steadystate models to NERC in accordance with each Interconnection's schedule for submission.

## C. Measures

**M1.** Each Regional Reliability Organization shall have Interconnection-specific steady-state system models as specified in MOD-014-0_R1 and MOD-014-0_R2.

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Development of steady-state system models: annually, as determined by each Interconnection's schedule. Most recent steady-state system models: 30 calendar days.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** One of a Regional Reliability Organization's cases either was not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

**2.2. Level 2:** Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**2.3. Level 3:** Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**2.4. Level 4:** Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**E. Regional Differences**

**1.** None identified.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

**Standard MOD-015-0 — Development of Interconnection-Specific Dynamics System Models**
**Adopted by NERC Board of Trustees: February 8, 2005 1 of 2**
**Effective Date: April 1, 2005**

## A. Introduction

**1. Title: Development of Dynamics System Models**

**2. Number:** MOD-015-0

**3. Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

**4. Applicability:**

**4.1.** Regional Reliability Organization

**5. Effective Date:** April 1, 2005

## B. Requirements

**R1.** The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R1.

**R1.1.** The Regional Reliability Organization(s) shall develop Interconnection-specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.

**R2.** The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.

## C. Measures

**M1.** The Regional Reliability Organization shall have Interconnection-specific dynamics system models in accordance with Reliability Standard MOD-015-0_R1, MOD-015-0_R2 and MOD-015-0_R3.

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Development of dynamics system models: annually in accordance with each Interconnection's schedule.

Most recent dynamics system models: 30 calendar days.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** One of a Regional Reliability Organization's cases was either not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

**2.2. Level 2:** Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**2.3. Level 3:** Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**2.4. Level 4:** Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

**E. Regional Differences**

**1.** None.

**Version History**

**Version Date Action Change Tracking**

0 April 1, 2005 Effective Date New

## 15. Compliance

**A. MDWG Power flow model schedule**
**Note: The latest document can be found on SPP.org**

**B. MDWG Dynamic model schedule (Continued)**
**Note: The latest document can be found on SPP.org**

**C. Data Submittal Forms (This is a separate document)**

**D. MDWG Procedure for late or no data submittal (FUTURE)**