Southwest Power Pool

Southwest Power Pool, Inc.
Model Development Working Group
Net Conference
June 12: 8:00 A.M. – 12:00 P.M.

• M I N U T E S •

Agenda Item 1 – Administrative

The meeting was called to order at 8:02 a.m. The following MDWG members were in attendance:

MDWG Members present:

MDWG Member	Proxy	Company	Present
Nate Morris		Empire District Electric Company	No
Derek Brown		Westar Energy	Yes
Jason Bentz		American Electric Power	Yes
Dustin Betz	Jason Hofer	Nebraska Public Power District	No
John Boshears		City Utilities of Springfield	Yes
Jerad Ethridge		Oklahoma Gas & Electric	Yes
Joe Fultz		Grand River Dam Authority	Yes
Wayne Haidle		Basin Electric Power Cooperative	Yes
Holli Krizek		Western Area Power Administration	Yes
Reené Miranda	Aravind Chellappa	Southwestern Public Service	No
Scott Schichtl		Arkansas Electric Cooperative Company	Yes
Jason Shook		GDS Associates	Yes
Brian Wilson		Kansas City Power & Light	Yes
Liam Stringham		Sunflower Electric Power Corporation	Yes
Anthony Cook		Southwest Power Pool, Inc	Yes

The following guests were also in attendance:

Alan Burbach – Lincoln Electric System
Aravind Chellappa – Southwestern Public Service
Edgardo Manansala – Midwest Energy
Ellis Lutz – Associated Electric Cooperative Inc.
Gimod Olapurayil – ITC Great Plains
Jeremy Severson – Basin Electric Power Cooperative
John Weber – Missouri River Energy
Mark Reinart – Golden Spread Electric Cooperative
Ryan Baysinger – Kansas City Power & Light
Jarrod Wolford – Northeast Texas Electric Cooperative
Andrew Berg – Minnkota Power Cooperative
Jason Hofer – Nebraska Public Power District

Jordan Lamb – East River Electric
Scott Rainbolt – American Electric Power
Michael Odom, Moses Rotich – Southwest Power Pool

Meeting Agenda

The group was asked if anyone had any issues or needed more time to review the posted materials. There were no concerns from anyone.

The agenda was also reviewed by the group.
(Attachment 1 - MDWG Meeting Agenda 20170612.docx)

Motion: Joe Fultz made the motion to approve the agenda. Scott Schichtl seconded it. The motion passed unanimously.

Previous Meeting Minutes

The group was asked if they had any comments to the May17-18, 2017 meeting minutes. There were no comments.
(Attachment 2 - MDWG Minutes May 17-18, 2017.docx)

Motion: Jason Shook made the motion to approve the May 17-18, 2017 meeting minutes. Scott Schichtl seconded it. The motion passed unanimously.

Agenda Item 2 – MDWG Procedure Manual Updates:

Michael Odom noted that he would be presenting on language changes in order to remove ambiguity in the existing MDWG manual language and also align the MDWG manual with the ITP Manual, which would reference the language for Phase Shifting Transformers and Load Forecasts in the MDWG manual. Michael presented the proposed load forecast language. He reminded the group that because the ITP manual references the MDWG manual, there is a need to update the MDWG manual. Load forecast language needed to be clarified in terms of what goes into the forecast (e.g., Distributed Energy Resources (DERs), controllable and non-controllable Demand Side Management (DSM), etc.) and also align the language with the requirements of the MMWG procedure manual. Joe Fultz requested that a 50/50 forecast curve graphic be included in the manual to help members visualize what an example forecast looks like. Aravind suggested that since 90/10 load forecasts are used in certain special studies, language needed to be added to acknowledge this scenario.

Action Item: SPP staff to add a 50/50 forecast curve graphic to the MDWG manual

During discussion of DERs, many in the group expressed concern about the complexity and granularity of DER modeling, since most modelers get their load forecast numbers from different groups within their own companies. Michael also noted that many Working Groups and companies in the industry are currently discussing DER modeling. He then mentioned that NERC has proposed some guidelines for DER modeling but this discussion will be had at a later date with the potential for a section dedicated to DER modeling being added to the MDWG manual.

Action Item: SPP Members to discuss DER modeling and inclusion in load forecasts internal to their companies

Action Item: SPP staff to add examples of controllable and non-controllable DERs

For the Phase Shifting Transformer (PST) language, Michael stated that it would be a good idea to have PST model guidelines in the MDWG manual so that the ITP manual can reference it similar to the load forecast language.

Michael then presented five options for renewable dispatch in the MDWG manual. He noted ideally there should be an alignment between the renewable dispatch methodologies in both the ITP and MDWG manuals but also recognized that assumptions in both model sets are different. Member opinions on the renewable dispatch varied, so the members were asked to review the language and provide feedback on the preferred option at a later date.
(Attachment 3 - SPP MDWG Model Development Procedure Manual (Public)_V10_RedLine.docx)

Motion: Joh Boshears made the motion to approve the load forecast and PST language updates. Brian Wilson seconded it. The motion passed unanimously.

Agenda Item 3 – Administrative Items:

Summary of Action Items

- **SPP staff to add a 50/50 forecast curve graphic to the manual**
- **SPP Members to discuss DER modeling and inclusion in load forecasts internal to their companies**
- **SPP staff to add examples of controllable and non-controllable DERs**

Future Meetings

- TBD

Adjourn Meeting

With no further business to discuss, Nate asked for a motion to adjourn.

Motion: Scott Schichtl made the motion to adjourn the meeting. Aravind Chellappa seconded it. The motion passed unanimously.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool, Inc.

MODEL DEVELOPMENT WORKING GROUP

June 12, 2017

• A G E N D A •

8:00 a.m. – 12:00 p.m.

1. Administrative Items .... Nate Morris (15 min)
    a. Call to Order
    b. Introductions
    c. Proxies
    d. Agenda Review (***Action Item***)
        i. Meeting Materials
    e. Previous Meeting Minutes (Action Item)
        i. May 17-18, 2017
2. MDWG Procedure Manual Updates .... Michael Odom
3. Administrative Items .... Nate Morris
    a. Summary of Action Items
    b. Future Meeting
        i. June 14, 2017
        ii. June 15, 2017
    c. Adjourn

Southwest Power Pool, Inc.
Model Development Working Group
St. Louis, Missouri
May 17: 1:00 P.M. – 5:00 P.M.
May 18: 8:00 A.M. – 12:00 P.M.

• M I N U T E S •

Agenda Item 1 - Administrative

The following MDWG members were in attendance:

MDWG Members present:

MDWG Member	Proxy	Company	Present
Nate Morris		Empire District Electric Company	Yes
Derek Brown		Westar Energy	Yes
Jason Bentz		American Electric Power	Yes
Dustin Betz		Nebraska Public Power District	Yes
John Boshears		City Utilities of Springfield	No
Jerad Ethridge		Oklahoma Gas & Electric	Yes
Joe Fultz		Grand River Dam Authority	No
Wayne Haidle		Basin Electric Power Cooperative	No
Holli Krizek		Western Area Power Administration	Yes
Reené Miranda		Southwestern Public Service	No
Scott Schichtl		Arkansas Electric Cooperative Company	Yes
Jason Shook		GDS Associates	Yes
Brian Wilson		Kansas City Power & Light	Yes
Liam Stringham		Sunflower Electric Power Corporation	Yes
Anthony Cook		Southwest Power Pool, Inc.	Yes

The following guests were also in attendance:

Alan Burbach – Lincoln Electric System
Alex Mucha – Oklahoma Municipal Power Authority
Aravind Chellappa – Southwestern Public Service
Bruce Doll, Armin Sehic – Municipal Energy Agency of Nebraska
Corey Falgout – American Electric Power
Daniel Benedict – Independence Power & Light
Dona Parks – Grand River Dam Authority
Edgardo Manansala – Midwest Energy
Gimod Olapurayil – ITC Great Plains
Jeff Crites – Empire District Electric Company
Joe Williams – Western Farmers Electric Cooperative
John Weber – Missouri River Energy
Mark Reinart – Golden Spread Electric Cooperative
Ryan Baysinger – Kansas City Power & Light

Scott Mijin – Southwestern Power Administration
Chris Colson – Western Area Power Administration
Michael Odom, Mitch Jackson, Moe Shahriar, Moses Rotich, Theva Chanthaseny, and Zack Bearden – Southwest Power Pool

Proxies
Aravind Chellappa held Reené Miranda's proxy. Dona Parks held Joe Fultz's proxy.

Meeting Agenda
The agenda was reviewed by the group. Derek Brown asked to add an item under the 2018 Series Model Build for modeling Transformers in regards to TPL-007. Jerad Ethridge motioned to approve the agenda as modified. The motion was seconded by Scott Schichtl. The motion passed unopposed.
(Attachment 1 - MDWG Meeting Agenda 20170517-18.docx)

The group was asked if anyone had any issues or needed more time to review the posted materials. There were no concerns from anyone for this meeting.

Meeting Minutes
The April 11, 2017 minutes were open for review. Nate Morris asked if anyone remembered who made specific motions and who seconded the motions in the previous meeting. Derek Brown was able to provide names based on his notes. The minutes were modified to include the individual names for the motions. Jason Shook motioned to approve the minutes as modified. The motion was made and seconded by Scott Schichtl. The motion passed unopposed.
(Attachment 2 - MDWG Minutes April 11, 2017.docx)

Agenda Item 2 – 2. 2016 Organizational Effectiveness Survey Analysis:
Anthony presented the survey results and asked if anyone had any comments. Nate noted that some of the items that stood out to him were the meeting materials being posted late and that members are not prepared for meetings. He stated that the two go hand-in-hand. There were no other comments.

Agenda Item 3 – Charter Review:
Anthony provided the charter and mentioned that working groups are required to review their charter every year even if there are no changes to be made. After a few edits were made to the charter, it was decided that it would be better for the members to review the charter with their respective companies and provide updates to SPP at a later time. SPP will then compile the comments and the group will discuss them at a later meeting. Once the group makes all necessary updates, the charter will be provided to the TWG for review. Chris Colson suggested that the final charter be provided to the TPITF for feedback before taking it to the TWG for review.

****Action Item**: SPP Staff to send out request for Charter updates.**
****Action Item**: Members to submit Charter updates by May 31, 2017.**

Agenda Item 4 – 2017 Series Update:
Zack Bearden stated that the Pass 8 short circuit models are posted and is requesting the group to consider finalizing the model set in order for TPL studies to begin. Edgardo Manansala stressed the importance of correctly representing the external data such as wind farm

representation as a constant current source in the short circuit models. He also mentioned that in order to accomplish this, it would entail another set of models on top of the ones already being created. Joe Williams also mentioned that this is a problem with large solar farms as well. Chris Colson and Derek Brown expressed concern about transformer connection codes and the need to have them corrected in the models in order to prep for TPL-007 compliance; however, this would cause an extension in the model build. Anthony cautioned that staffing at both SPP and the Member companies can become a problem due to competing work projects. Chris added that this will be a substantial effort and suggested that revisions be made in the MDWDG manual to capture connection codes. Zack asked the group if it will be beneficial to include a contingency analysis to show fault currents during each pass of the model build. Many members said that this would not be a high priority during their review. Nate solicited for a motion to finalize the models. Derek Brown made a motion to approve the pass 8 short circuit models as final. Brian Wilson seconded the motion. Aravind asked if the remaining issues in the docucheck should be fixed before the models are voted as final. Zack replied that the majority of the issues have to do with non-members of SPP; however, there is one 500 kV transformer that is in the SPP footprint that should be corrected. Derek amended his motion to approve the Pass 8 models as final with the caveat that the 500 kV transformer be corrected. Brian Wilson seconded the amended motion. The motion passed unopposed.

****Action Item**: Include language in the MDWG manual about connection codes.**
****Action Item**: SPP Staff get with appropriate member of transformer for corrections.**

Moe Shahriar stated that a revised schedule for the dynamic models was previously sent out to the group for review and that the big difference is that it changed by two weeks from the original deadline. He asked the group to approve the revised schedule. Derek Brown stated that he had a proposal that would be discussed in item 7 that could revise the schedule even further. The motion was tabled until after item 7. After the item 7 discussion, Jason Shook motioned to approve the dynamics schedule as provided by Moe. Jared Ethridge seconded the motion. The motion passed unopposed.

Agenda Item 5 – Renewable Dispatching:

Aravind Chellappa discussed that the SPP Criteria is not realistic for solar farms and that most discussions on renewable resources focus on wind. He stated that there is also a sizeable amount of solar requests in the SPP GI queue, so there is a need for the MDWG to develop language to cover solar dispatch. He stated that wind typically blows in the morning and evening hours when solar is low and solar farms typically produce during the day when wind is low. Joe Williams suggested using irradiance data for the different peaks to determine dispatch values. Michael Odom briefly discussed the new renewable dispatch criteria that will be used in the base reliability models for the summer and winter peaks. Anthony stated that the current language in the MDWG procedure manual was close to the language for the new base reliability renewable resource dispatch methodology. Michael asked the group if they would be interested in using the same method in the MDWG models. Dustin Betz voiced concern stating NPPD’s peak doesn’t align with the SPP coincident peak. Dispatching renewables in the summer is not reliable and when the wind is not available, it causes adverse effects in the operations realm. Derek Brown also voiced concern that there needs to be a companywide policy by SPP on renewables so that they are aligned in all processes. The policy would work for SPP internal members but how about external entities. Nate asked if the group had a preference on the renewable dispatch methodology in the MDWG. Some asked that the MDWG manual taskforce work on language with SPP Staff.

****Action Item**: Update renewable dispatch methodology language in the MDWG procedure manual.**

Agenda Item 6 – 2018 Series Model Build:

Anthony Cook presented the model set as requested by all groups within engineering at SPP. This set is to cover the needs of the MDWG and ITP since the models will be built in parallel due to the new TPITF process. He stated that SPP Staff pulled this as an action item because additional review needs to be performed as to what the "normal" model set will be vs. the need for the transition year. The group requested that Staff put together a presentation showing what the next three years will look like.

****Action Item**: SPP Staff to present three year timeline of the new model build process.**

Anthony presented the schedule and asked the group review the dates and approve it. Derek Brown made suggestions as to shortening the schedule by ending it in November, but allowing updates to be submitted through February to correct any last minute issues. He also suggested moving the dynamics finalization date from September to August. Chris Colson stated that the powerflow should be trimmed even further. Anthony voiced concerns over shortening the schedule since the MDWG hasn't produced models on time for the last several years. Aravind also voiced concern over DPP schedules and TPL studies being performed at the same time in the November timeframe and staff issues that go along with that. Jerad Ethridge stated that the schedule looked ok to him, and that the members need to just adhere to the voted on schedule. There was discussion about moving the Model Update meeting to later in the model build. Mark Reinart suggested shortening Pass 1 since there isn't a lot of participation early in the model build. The group decided to table voting on the schedule pending further review.

****Action Item**: MDWG members to review the schedule and provide changes to Anthony and Nate by 5/30/2017.**

Agenda Item 7 – Dynamic Load Task Force Recommendation:

Derek Brown went over his presentation. Questions were asked to whether 10MW or 20MW should be the threshold. Derek and Chris stated that 10MW was proposed because of industry standard based on gathered data. Derek recommended that the DLTF CMLD changes be included in the 2017 dynamic models. Nate Morris took a straw poll to determine implementing the practice in the 2017 vs. 2018 series and 10MW vs. 20MW. No one was in favor of requiring this in the 2017 Series; however, stated that dynamic loads can be submitted in the 2017 Series if individuals want to. There were nine in favor of the 10 MW threshold and two for the 20MW. Derek made a motion to approve the DLTF language revision about CMLD modeling in the MDWG procedure manual in the 2018 Series dynamic model build. Holli Krizek seconded the motion. The motion passed unopposed.

****Action Item**: Update MDWG manual to include Dynamic Load modeling of 10MW.**
****Action Item**: Send out link to NATF Guidance Document on TPL-001-4.**

Agenda Item 8 – Model On Demand:

Moses Rotich briefly discussed some of the MOD v8.1.0.1 issues/bugs encountered during the 2017 series MDWG powerflow and short circuit builds. He mentioned that SPP staff was exploring the possibility of upgrading to MOD v9 in order to rectify some of the issues. Furthermore, he also mentioned that the MDWG would be updated once a decision to move to MOD v9 is finalized.

In addition, Moses also informed the group about contract negotiations with Siemens pertaining to MOD and MOD file builder. He stated staff would have more wiggle room to create separate accounts for different data submitters rather than grouping different companies under one umbrella. He also mentioned that consultants working for SPP member companies will have to sign a different agreement in order to access MOD and MOD file builder.

Agenda Item 9 – SPP Engineering Hub Status Update:
Mitch Jackson provided the current status of the Engineering Hub. He stated that the MDWG portion was about complete and that SPP Staff has been testing the functionalities. The next step is the Resource Adequacy Working Group workbook. SPP Staff will be reaching out to a few members to help with external testing. The Hub will not be ready for the 2018 Series model build; however, SPP Staff hopes to provide training toward the end of the model build.

With the meeting drawing to a close, Moses quickly told the group that staff will be sending out a new data coordination template for entities to fill out, noting if they'll be submitting data for themselves only or on behalf of other entities as well in the 2018 series MDWG model build. Chris Colson asked that an aggregated data coordination workbook from the 2017 series MDWG model build also be provided in order for members to identify any gaps that might exist in terms of entities submitting data.

****Action Item**: SPP staff to provide an aggregated data coordination workbook to the members.**

All other items were tabled for future meetings.

Agenda Item 14 – Administrative Items:
Summary of Action Items

- **SPP Staff send out request for Charter updates.**
- **Members to submit Charter updates by May 31, 2017.**
- **Include language in the MDWG manual about connection codes.**
- **SPP Staff get with appropriate member of transformer for corrections.**
- **Update renewable dispatch methodology language in the MDWG procedure manual.**
- **SPP Staff to present three year timeline of the new model build process.**
- **MDWG members to review the schedule and provide changes to Anthony and Nate by 5/30/2017.**
- **Update MDWG manual to include Dynamic Load modeling of 10MW.**
- **Send out link to NATF Guidance Document on TPL-001-4.**
- **SPP staff to provide an aggregated data coordination workbook to the members.**

Adjourn Meeting
With no further business to discuss, Nate asked for a motion to adjourn. Aravind Chellappa motioned to adjourn the meeting, Jerad Ethridge seconded the motion. The motion passed unopposed. The meeting was adjourned.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool, Inc.

MODEL DEVELOPMENT

PROCEDURE MANUAL

MAINTAINED BY
SOUTHWEST POWER POOL
MODEL DEVELOPMENT WORKING GROUP

PUBLISHED: September 1985
VERSION ~~9~~10: ~~November~~ June 201~~6~~7

Version History

Original: September 1985

Version 2: August 2006

Version 3: November 2009

Version 4: August 2014

Version 5: September 2014

Version 6: October 2014

Version 7: May 2015

Version 8: June 2015

Version 9: November 2016

Version 10: June 2017

MODEL DEVELOPMENT WORKING GROUP

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

Derek Brown, Vice Chairman
Westar Energy, KS (WERE)

Jason Bentz, Member
American Electric Power, OK (AEPW)

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

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

Jerad Ethridge, Member
Oklahoma Gas & Electric, OK (OKGE)

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

Wayne Haidle, Member
Basin Electric Power Cooperative, ND (BEPC)

Holli Krizek, Member
Western Area Power Administration, MT (WAPA)

Reené Miranda, Member
Xcel Energy, Inc., TX (SWPS)

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

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

Liam Stringham, Member
Sunflower Electric Power Corporation, KS (SUNC)

Brian Wilson, Member
Kansas City Power & Light Company, MO (KCPL)

Anthony Cook, Secretary
Southwest Power Pool, Inc., AR (SPP)

Disclaimer

Model Disclaimer

Copyright

1. GENERAL INFORMATION

A. Purpose

To provide model data requirements and reporting procedures for use by the Southwest Power Pool, Inc. (SPP) system representatives for the building and updating of the SPP steady-state, dynamics, and short circuit models. Proper use of this document should aid in the coordination between systems, consistency in reporting of data, and realism of the model developed.

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 Reporting Responsibilities

The SPP data reporting entities are responsible for the following categories of system modeling data:

1) Steady-State
2) Short Circuit
3) Dynamics

Steady-State 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.

Short Circuit models are developed annually using a subset of the Reliability Steady-State models. All base MDWG steady-state models will include sequence data (including applicable mutual line impedance data)for the SPP footprint. The following 3 versions of short circuit models will be built:

1. MDWG steady-state base model
2. MDWG steady-state with PSS®E Classical assumptions
3. Maximum Fault case

The Base MDWG Short Circuit models are built by performing the following steps:

- Extract the SPP RAW and SEQ data with ties from the final MDWG steady-state model
- Extract the first tier company's RAW and SEQ data without ties from the final SERC Short Circuit model built by the Short Circuit Database Working Group (SCDWG)
- Merge the two data sets together.

The Classical assumptions MDWG Short Circuit Models are built by performing the following step:

- Apply Classical assumptions to the Base MDWG Short Circuit model as described in the PSS®E Program Operation Manual

Maximum Fault cases are built by performing the following steps:

- Place in-service (Apply a status of '1') all SPP planned and available existing generation and transmission facilities to the Base MDWG Short Circuit model

- Apply Classical assumptions

The Dynamics Model is also updated annually with current generator unit information. Steady-State models are used in conjunction with dynamic 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 Steady-State 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 Compliance), and unit ID of Zx (where x is any second ID designation appropriate in PSS®E).

Entities in the SPP Planning Coordinator 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 case type update process. The data submitted will be in the standard PTI format as specified in the MDWG Model Development procedure 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.

In an effort to determine who is collecting/submitting data for whom, all NERC registered entities within the SPP PC footprint (MOD-032-1: applicable to BA, GO, LSE, RP, TO, TP, and TSP) shall fill out the data coordination workbook to notify SPP if data is being submitted directly to SPP or through some other entity(ies) on behalf of your company. Likewise, SPP shall be notified if your company is submitting data on behalf of another entity(ies).

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.

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 as well as posted on the SPP corporate website, www.spp.org.

A. Steady-State and Short Circuit Model Development

1. Introduction

The MDWG Steady-State and Short Circuit data is contained in the SPP database Models On Demand (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 Steady-State and Short Circuit Models are published according to the approved schedule.

2. AC Contingency Analysis

SPP will perform AC Contingency Analysis on all models contained in the steady-state case type set. The purpose of this contingency analysis is to validate the models. Member updates for errors found due to contingency analysis are to be submitted during the next member data submission period per the latest MDWG model building schedule.

B. Dynamic Model Development

1. Introduction

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

The Dynamics Model data includes:

a. Steady-State 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.

3. MODEL DEVELOPMENT

A. Data Preparation

The following section describes important items that must be followed in the development of a steady-state model in preparing the data for publishing new models or updating existing models.

1. The data listed in Attachment 1 of the NERC Standard MOD-032-1 located on the NERC website.
2. MOD data should be kept current for each pass during the MDWG model build.
3. The Data Submittal Workbook tabs should be kept current for each pass during the MDWG model build including the items below.
   a. Transactions and tie line modifications shall be coordinated with neighboring systems
   b. Known outage(s) of Generation or Transmission Facility(ies) with a duration of at least six months
   c. Lines and Transformers operated as normally open shall be reported in the Normally Open Lines tab of the Data Submittal Workbook.

Steady-State and Short Circuit Data Format

PSS®E and MOD Users

The transmission modeling software approved by the SPP membership for performing planning and reliability studies is the Power Technologies Incorporated, Power System Simulator for Engineering (PSS®E) software. Data submitted for the building of the base SPP MDWG case types (models) needs to be in a format consistent with that used in PSS®E. The data shall be submitted via the SPP Models On Demand (MOD) Web Portal. Data submitted should be compatible with the MOD and PSS®E versions currently specified by SPP.

Non-PSS®E and Non-MOD Users

For those non-PSS®E users, load and generation profile data may be submitted via the Profile Submission form provided by SPP. SPP will aid with the submission of all other steady-state data in the correct PSS®E and MOD data formats. Any version changes will be discussed in the annual training provided by SPP.

Dynamic Data Format

PSS®E Users

Dynamics data needs to be submitted in the form of a flat text file or dyre file compatible with Siemens PTI PSS®E dyr file software. Dyre file submittals can be of changes to individual components from the existing dyre entries or of entire new representation of machines. Dynamic ready models are developed using the PSS®E software program. The data should be submitted via TrueShare or email. Data submitted must be compatible with the PSS®E version currently specified by SPP.

Non-PSS®E Users

Dynamics data needs to be submitted in the form of a flat text file or dyre file compatible with Siemens PTI PSS®E software. Siemens PTI PSS®E Software contains dyre file models for most conventional machines, exciters, governors, SVCs, HVDC ties, wind resources, and solar resources. SPP Modeling staff will work with the responsible entity or its designee to translate operational test data into the appropriate dyre file format compatible with the PSS®E version currently specified by SPP.

The members are expected to contact the SPP Modeling Staff if there are any additional questions regarding the data format.

Responsible Entities

Data owners are responsible for providing the data necessary to model their assets to its Transmission Planner(s) and Planning Coordinator(s) as described in this document. Data owners and their respective data submission responsibilities are noted in the NERC standard MOD-032-1.

- Generator Owners (GO) and Resource Planners (RP) are responsible for submitting modeling data for their existing and future generating facilities respectively.
- Load Serving Entities (LSE) are responsible for submitting modeling data for their existing and future load corresponding to the case types developed.
- Transmission Owners (TO) are responsible for submitting modeling data for their existing and
  future transmission facilities.
- The Planning Coordinator or Transmission Planner can request other information necessary for modeling purposes from the BA, GO, LSE, TO, or TSP.

Typical 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 the **Annual Models** table above with those transmission planning models representing the near-term planning horizon consisting of the MDWG case types 1 through 13 and those representing the longer-term planning horizon consisting of the MDWG case types 14 through 16. The longer-term models may be incremented or additional models may be included as required to support 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 schedule for submission to data and list of MDWG models (case types) can be found on the SPP corporate website, www.spp.org.

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 dependent 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 steady-state model will be based on a load forecast which assumes a statistical probability of one occurrence in two years (50/50). Therefore, loads should be derived using the 50/50 probability forecast as a minimum.~~ Load forecasting methodologies vary throughout the electric industry. SPP depends on load forecasts from Data Submitters to apply to the planning models. These load forecast amounts are to be Non-Coincident to the SPP region, meaning that the hour that a Data Submitter's system experiences a peak demand for a particular season, might not be the same hour that SPP, as a region, experiences a peak demand. In order to bring consistency and equivalency to the load forecast data submitted to SPP, load forecast data shall be based on a 50/50 forecast.

A 50/50 load forecast relates to a forecasted load amount having an equal probability of being either higher or lower than the amount forecasted. The forecasted load value is at the 50th percentile of a normal distribution curve and is typically discussed in terms of exceedance such that there is a 50% probability that the load forecast will be exceeded due to abnormal weather.

Commented [AC1]: Insert a distribution curve for a visual.

Some studies may require load forecasts other than a 50/50 load forecast and may be requested for such special studies. For example, a 90/10 load forecast has a 10% probability that the load forecast will be exceeded, which means the load forecast amount is higher than a 50/50 load forecast amount and would be considered atypical for general SPP transmission planning purposes.

There are various methods used to develop such forecasts and the forecasts are dependent upon many factors such as historical load values, temperature, humidity, economic forecasts, time of day, day of week, holidays, special events, and load uncertainty. Other factors, some of which are controllable, also impact the amount of forecasted load. Controllable Demand Side Management (DSM) and Distributed Energy Resources (DERs) are such factors.

Demand Side Management consists of activities or programs that an entity invokes to achieve a reduction in Demand. DSM consists of controllable and non-controllable systems. Load forecasts shall not be reduced for application of controllable DSM. There is control over whether or not the load will be shed by an operator or end-user and therefore cannot be guaranteed that the load will be reduced during peak hours. Load forecasts should be reduced for application of non-controllable DSM. This load has a high probability of being shed during peak hours without manual intervention. Distributed Energy Resources are power resources on the distribution system that can be aggregated together to provide power to meet Demand. For purposes of transmission planning, it is recommended that Distributed Energy Resources should not be applied to a Data Submitter's load forecast amount for incorporation into the SPP planning models.

Commented [AC2]: Add examples of each.

Summary of Data Submitter's load forecast data comprisal:

- Non-coincident to the SPP region
- 50/50 load forecast
- Load forecast amount includes non-controllable Demand Side Management
- Load forecast amount excludes controllable Demand Side Management
- Load forecast amount excludes Distributed Energy Resources (recommended)

Various seasonal models are presently developed by SPP systems. They include: 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** (light load) 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 70-85% of the total seasonal peak load level depending on the system and its locale.

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 steady-state 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 steady-state 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 not 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.

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 **<u>must</u>** 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 (Intra-SPP) is maintained in a MOD Project file. The majority owner of the tie is responsible for maintaining the tie’s steady-state, sequence, and ratings data.

SPP tie data with external entities (Inter-PC) is maintained in the MMWG PC tie line list. Entities must submit changes using the latest list, which will be posted with the latest case set. Changes are to be highlighted in order for SPP Staff to easily discern the submitted changes. The file name shall contain the company name of which is submitting the change. 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.

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 positive and zero sequence branch impedance data shall be provided on a 100 MVA base (per unit value). The smallest allowable reactance is 0.00011 P.U. on a 100 MVA base. Reactance values less than minimum will cause the steady-state program to treat the line as a zero impedance line to reduce solution time.

d. The positive sequence and zero sequence line charging data (conductance and susceptance) shall be provided on a 100 MVA base (per unit value) as applicable. A default value of zero will be assumed if no data is provided. 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 criterion 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. In general, regulating transformers **should not** be located at a bus with a regulating generator or other voltage regulating device; however, there may be exceptions based on current system topology and operating conditions.

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 steady-state 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 steady-state 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…).

NOTE: 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 steady-state 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 should 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 (right 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.. 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 shall model the gross output of the generating facility and explicitly model the station service auxiliary load. 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.

d. Bus loads should be specified with the real and reactive values provided **as a pair** in all entries. The load should be modeled to reflect the expected in-service/out-of-service status.

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, reactors, and SVCs 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 steady-state 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 MOD via a profile 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 per testing requirements in SPP Criteria 12.1. Generator MW shall be set to "gross" level with auxiliary load modeled explicitly. 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 12.1 for the summer and shoulder cases. Ensure accurate values of ZR and ZX. This data is not needed in normal steady-state 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 steady-state models must match dynamic data. The MDWG steady-state models will use the saturated 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.

When modeling mothballed and future retired units, the Pmax, Pmin, Qmax, and Qmin values should be modeled as zero. Decommissioned units should be removed from the models.

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, 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 (steady-state 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. Steady-State Data Check List

The steady-state 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 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 Steady-State 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.

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 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 steady-state 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 case types 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 steady-state 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 steady-state models and have since been delayed or cancelled should be removed entirely from the steady-state model. These facilities cause solution problems for some steady-state 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 Steady-State Model Development Procedure Manual.

5. Review of Output

The steady-state 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 steady-state 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 steady-state 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 minimum and maximum number of ULTC and NLTC taps should comply with common industry standard practices.

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.

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 tab of the Data Submittal 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 shall 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.

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 steady-state models.

Two of these methods are:

a. Using the steady-state 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 steady-state 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

Steady-State 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 steady-state 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. Steady-State Solution

The steady-state 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 (+) To/From Area Name															
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 – Steady-State Data Checklist

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. Steady-State and Short Circuit Models

SPP Base Case steady-state 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 steady-state models or reduced network equivalents of those models to government agencies. The public may receive models by filling out a SPP models order form and signing the appropriate SPP Confidentiality Agreement. For more information on requesting Base Case steady-state models, contact the SPP Model Contact.

Base case steady-state 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 Dynamic 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 SPP 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, 201 Worthen Drive, Little Rock, Arkansas 72223**.

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

Last Updated June 30, 2015

11. MDWG Case Type Set

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

12. Error Screening

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. **Dynamics Data Submittal Requirements and Guidelines**

A. Steady-State Modeling Requirements

1) All steady-state 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 steady-state cases, the step-up transformer shall be represented in the steady-state generator data record. Where the step-up transformer of the generator or condenser is represented as a branch in the steady-state cases, the step-up transformer impedance data fields in the steady-state generator data record shall be zero and the tap ratio unity. The mode of step-up transformer representation, whether in the steady-state 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 steady-state 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®E requirements, the Xsource value in the steady-state 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 steady-state as continuously variable switched shunts rather than as generators. In iterative steady-state solutions, a generator which hits a VAR limit on solution iteration will lock at that value, but a switched shunt will move off the limit in a subsequent iteration if appropriate. PSS®E dynamic 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 steady-state.

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®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, static compensators (STATCOM), wind turbines, and photovoltaic systems shall be represented by the appropriate PSS®E dynamic models.

4) All demand data shall include a load model which represents the expected dynamic behavior of the loads. Absent detailed dynamic load models, the real portion (MW) of all demand data is converted to 100% constant current and the reactive portion (Mvar) of all demand data is converted to 100% constant admittance.

5) 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.

6) When user-defined modeling is used, written documentation shall be supplied explaining the dynamic device performance characteristics. The documentation for all user-defined models shall be provided as a separate document and must include the characteristics of the model, including block diagrams, values and names of all

model parameters, and a list of all state variables. 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®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.

7) 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.)

8) 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.

9) 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 steady-state generator data record. This requirement also applies to excitation system and turbine-governor models, the per unit data of which shall be provided on the nameplate MVA of the associated generator. The maximum and minimum power of cross compound units should be provided on the nameplate MVA of one machine in accordance with PSS®E model IEEEG1 conventions.

10) 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®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.

14. Procedures for Submission of Dynamics Data to the MMWG Coordinator
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 steady-state 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. 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®E DYRE file. The data must be compatible and consistent with the MMWG steady-state selected for the dynamics cases that are being developed. One file for all cases is preferable.

15. MMWG Deliverables

A. Regional Coordinators

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

1. Steady-State Cases
   - A. Data as needed to create the MMWG steady-state cases in RAWD or Saved Case format, regional representation shall be within an entire solved MMWG steady-state 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. Steady-State Cases

   Initialized steady state and regional contingency cases.
   - A. Steady-State 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

16. Steady-State Modeling Guidelines

1. **Modeling Detail** – Each bus should be assigned the appropriate area, owner, and zone. 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 bus voltages are expressed as a phase-to-phase 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 steady-state output.

3. **Islanded Buses** – Islanded buses shall not be modeled.
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 steady-state 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®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 steady-state solution techniques and should be avoided.
8. **Transformers** – Effective with Revision 28 of PSS®E, off-nominal turns ratios may not be specified for branches; a block of four or five data records must be entered for each transformer. The off-nominal turns ratio in per unit, or the actual winding voltage in kilovolts, and the phase shift in degrees shall be specified for each winding. The measured impedance (resistive and inductive) between each pair of windings shall be specified: data entry options permit these to be entered in (1) per unit on system (100 MVA) base, (2) per

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

9. **Transformers Controlling Voltage or Reactive Power Flow** – The upper and lower limits of off-nominal turns ratio and the number of tap positions available are entered for winding 1 of transformers controlling voltage or reactive power flow. Default values of 1.1, 0.9 and 33 are representative of U.S. practice. The upper and lower voltage limits are entered for transformers controlling voltage and the difference, in per unit, should be at least twice the tap step size. The upper and lower MVAR limits are entered for transformers controlling reactive power flow and these limits should differ by at least 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**~~**Phase Shifting Transformers** (PSTs) – Manufacturer tested capability and operational limits must be provided to SPP in order to allow corrective actions to be developed by SPP planning staff for transmission planning purposes.

    PSTs will be represented in the planning models as Two-winding transformers with both windings at the same nominal voltage level. ~~For phase angle regulating (PAR) transformers, t~~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. The following characteristics should be considered by the entity submitting PST modeling data for the planning models:

    a) Real-time operational auto or manual adjustment operation of the PST.
    b) Real-time operational average MW flow for a particular season (e.g. average hourly MW flow is +18MW [directional based] during the Summer Peak Season, June 1 – September 30) in order to represent what is typically flowing through the PST during a particular season. This applies to PSTs that are not modeled for auto adjustment, in order to appropriately model the phase shift angle and relative MW flow, but should also consider the capability of the transformer regardless of the type of operation.
    c) Real-time operational MW flow limits (e.g. ±20 MW).
    d) Real-time operational phase shift angle range (e.g. -52.9° to 31.4°).
    e) The applicable planning model impedance table should reflect the impedance correction adjustments as the phase shift angle moves through the various angle steps.
    ~~a)~~f) Applicable long-term firm transmission service levels for the PST.

~~11.~~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.

~~12.~~13. **Generator Step-Up Transformers** (GSU) – When modeled implicitly, the GSU Resistance, reactance and tap setting (all in per unit values) shall be provided along with the Generator data. Whenever modeled explicitly, a GSU shall be modeled similar to a power transformer and the GSU nominal winding voltages, impedance(s), tap ratios, minimum and maximum tap position limits, number of tap positions, regulated bus (as applicable), normal and emergency ratings and in-service status data shall be provided. GSUs 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.

~~13.~~14. **Out-of-Service Generator Modeling** – Out-of-service generators should be modeled with a STATUS equal to zero.

~~14.~~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.

~~15.~~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.

~~16.~~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.

~~17.~~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.

~~18.~~19. **Over and Under Voltage Regulation** – Regulation of voltage schedules exceeding 1.10 per unit, or below 0.90 per unit should be avoided.

~~19.~~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.

~~20.~~21. **Fixed Shunts** – All fixed shunt elements at buses modeled in the steady-state 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.

~~21.~~22. **Switched Shunts** – Switched shunt elements at buses modeled in the steady-state 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.

~~22.~~23. **Static Var Systems** – Static var elements should be modeled with accurate reactive power (leading/lagging) limits. An accurate voltage set point and equipment status, as well as any associated fixed/switched shunt equipment should also be modeled based on actual seasonal operation.

~~23.~~24. **HVDC** – All HVDC transmission facilities must be represented with a sufficiently detailed model to simulate its expected behavior.

~~24.~~25. **Interchange Tolerances** – In a solved case, the actual interchange for any area containing a Type 3 (swing) bus should be within 25 MW of the specified desired interchange value. (Note that PSS®E does not enforce the interchange deviation for areas containing Type 3 buses.)

~~25.~~26. **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.

17. 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 steady-state calculations, 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 steady-state 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.

18. 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 loads (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 steady-state.
      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 steady-state 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.

19. **Compliance**

A. MDWG [Model Development Procedure Manual]
Note: The latest document can be found on SPP.org

B. MDWG [Power flow, Short Circuit, and Dynamic model schedule and list]
Note: The latest document can be found on SPP.org

C. Data Submittal Forms (This is a separate document)
Note: The latest document is posted with every model set

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

APPENDIX I
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®E input requirements.
(2) The in-service and out-of-service dates will be expressed as mm/dd/yyyy.

Appendix II
Number Range Assignments for
ERAG MMWG Steady-State 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 III
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 IV
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 V
System Codes for Use in ERAG MMWG Steady-State 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

APPENDIX VI

MOD-032-1 – Attachment 1

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnectionwide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[1] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[2] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]

1 For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning
Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

2 For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. An LSE is responsible for providing this information, generally through coordination with the Transmission Owner.

3 Including synchronous condensers and pumped storage.

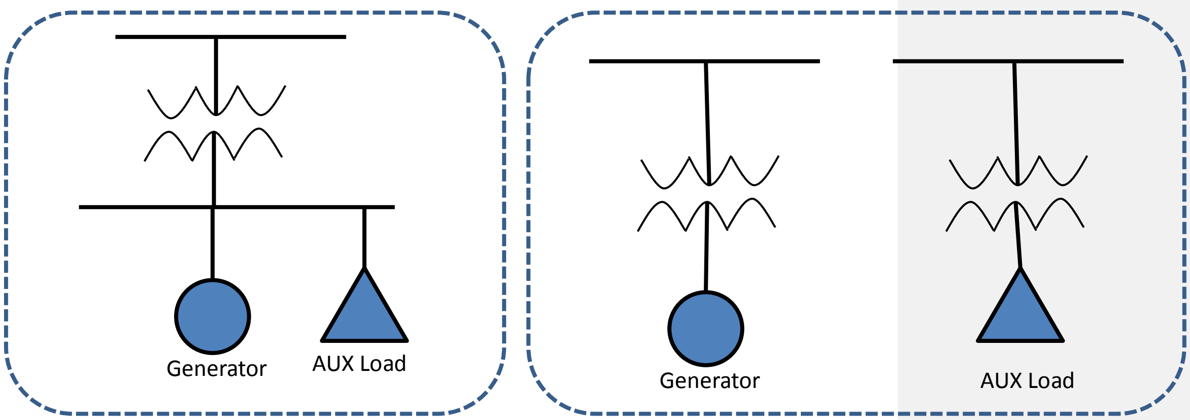
under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

APPENDIX VII

Modeling of Generator Parameters

1. **Applicable Facilities**
   The following Generators and SVCs connected to BES (100 kV and greater) or in accordance with the SPP OATT or Member OATT.
   i. All Individual units greater than 20 MVA (gross nameplate rating)
   ii. All Synchronous Condensers greater than 20 MVA (gross nameplate rating)
   iii. Generating plant/facilities greater than 75 MVA (gross aggregate nameplate rating)

2. **Modeling Process for Generator Parameters**
   a. The Generator parameter P_{MAX} shall be modeled as a gross seasonal maximum capability based on MOD-025-02 and SPP Criteria 12.1 testing and reporting procedures.
   b. AUX Load will be modeled explicitly on the appropriate bus.
   c. The Generator Parameters for P_{MIN}, AUX Load, Q_{MAX}, and Q_{MIN} shall be modeled in accordance with MOD-025-02 and SPP Criteria 12.1 testing and reporting procedures.



3. **Modeling of Renewable Resources P_{GEN}**
   a. P_{GEN} value should not exceed average historical values for the Winter, Spring, Light Load, and Fall Cases.
   b. P_{GEN} shall not exceed values based on the procedure outlined in SPP Criteria 12.1.5.3.g for the Summer and Summer Shoulder Cases

4. **Data Exemption Process**
   MDWG Members requested that there be a process by which the modeled generator maximum is different from the MOD-025-02/SPP Criteria testing. In accordance with Attachment 1, Section 5 of MOD-025-02 an exception process for generators that have undergone testing per MOD-025-02/SPP Criteria 12.1 for these differences is as follows:
   a. Member will fill out the “Exemption Form” and send it via e-mail to “Engineering Modeling” containing:

i. Generator Name
ii. Generator Bus Number
iii. Requested change(s) that deviate from the MOD-025-02/SPP Criteria testing.
iv. Justification of the change if it is greater than or less than 5% of the MOD-025-02/SPP Criteria testing.

SPP Modeling will process the Exemption and communicate back to the member requesting the exemption that it has been granted or if additional information is needed to process the exemption within 30 days of submission of the request.

****Effective date of sections 1&3 is in effect.**
****Effective date of section 2 is July 1, 2016.**
****Effective date of section 4 is July 1, 2016.**