Southwest Power Pool

Southwest Power Pool
MODEL DEVELOPMENT WORKING GROUP
May 21-22, 2014
Crowne Plaza Kansas City Downtown
Kansas City, Missouri

• M I N U T E S •

Agenda Item 1 - Administrative

The meeting was called to order at 1:02 p.m. The following Model Development Working Group (MDWG) members were in attendance:

Joe Fultz, Chair – Grand River Dam Authority
Nate Morris, Vice Chair – Empire District Electric
Scott Rainbolt – American Electric Power
Nathan McNeil – Midwest Energy
Reené Miranda – Southwestern Public Service
Brian Wilson – Kansas City Power & Light
Mike Clifton – Oklahoma Gas & Electric
Derek Brown – Westar Energy
Scott Schichtl – Arkansas Electric Cooperative
Jason Shook – GDS Associates
John Boshears - City Utilities of Springfield

SPP Staff in attendance included Anthony Cook (Secretary), John Mills, Chris Haley, Mitch Jackson, Scott Jordan, and Shannon Mickens.

The following guests were also in attendance:
Jason Hofer – (Proxy for Dustin Betz) Public Power District
Jason Bentz – American Electric Power
Dona Parks – Grand River Dam Authority
Martin Green – Grand River Dam Authority
Mark Reinart – Golden Spread Electric Cooperative
Gimod Olapurayil – ITC Great Plains
Liam Stringham – Sunflower Electric Power Corporation
Peter Howard – Kansas City Power & Light
Alex Mucha – Oklahoma Municipal Power Authority
Alan Burbach – Lincoln Electric System
Jerry Bradshaw - City Utilities of Springfield
Aravind Chellappa – Southwestern Public Service
Steve Hardebeck– Oklahoma Gas & Electric
Kyle Drees – Westar Energy
James Remley – Westar Energy
Mo Awad – Westar Energy
Daniel Benedict – Independence Power & Light
Holli Krizek – Western Area Power Administration

Meeting Minutes
The November 11, 2013 minutes were open for review. Nate Morris had a correction to the Meeting Minutes section. John Boshears motioned to approve the November 11, 2013 meeting minutes as amended; Brian Wilson seconded the motion. The motion passed unopposed. (**Attachment 1 - MDWG Minutes 20131111.doc)**

The April 16, 2014 minutes were open for review. The company name was added to an attending guess, Reené Miranda had submitted corrections to remove that Aravind was his proxy and wording for his question in the TPL-001-04-R1 section. Reené Miranda motioned to approve the April 16, 2014 meeting minutes as amended; Jason Shook seconded the motion. The motion passed unopposed.
(**Attachment 2 - MDWG Minutes 20140416.doc**)

Meeting Agenda
The agenda was reviewed by the group. Jason Shook motioned to approve the agenda as presented; Nathan McNeil seconded the motion. The motion passed unopposed.
(**Attachment 3 - MDWG Meeting Agenda 20140521-22.docx**)

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

Agenda Item 2 – Review of Past Action Items:
Anthony Cook reviewed the action items. There was discussion to make #42 more specific to individual standards. He stated that many of the items are on the agenda for discussion. (**Attachment 4 - SPP MDWG Action Items 20140521.xls**)

Agenda Item 3 – NERC Reliability Standards Updates:
Shannon Mickens introduced the SPP Reliability Standards department. He discussed what they do and how they can assistance the Working Groups with information dealing with the many NERC standards under development. Their objective is to make sure all SPP members are knowledgeable of changes to standards being proposed or implemented. He gave an overview of the standards that are currently under review. The yellow highlighted areas indicate the changes since the previous discussion of the standard.
(**Attachment 5 - NERC Activities Update - 052114.docx**),
(**Attachment 6 - First Posting-Unofficial Comment Form_0421_SPP comments_filed.docx**)

Agenda Item 4 – Modeling Contacts Updates:
Anthony Cook presented an updated list of Modeling Contacts. The members made additional changes. Nate Morris asked to add a column for company names. Joe Fultz asked to add whether the person is the powerflow, short circuit, and/or dynamic contact.
(**Attachment 7 - SPP_Modeling_Contacts_20140521.xls**)

AI: Add columns for company name and type of contact.

Agenda Item 5 – MDWG Member Survey Results

Anthony reviewed the MDWG Member Survey results with the group. He asked for clarification on the comments that were made.

- Member feedback was given that the MDWG should be more involved in the development of the different models that are being built by SPP. To encourage this, the MDWG should hold frequent conference calls and be readily available to give input during the model building process.
- Members requested that SPP Staff with stability understanding are available during the MDWG meetings to answer questions. Scott Jordan affirmed the upcoming dynamic workshop hosted by SPP and extended an invitation for all to attend.
- Members requested either assigning sections of the MDWG manual to members to update or form a task force in order to get the manual updated.
- Members requested truing up the wind farm topology between the powerflow and dynamic models which is a current action item.

(**Attachment 8 - 2013 org survey_analysis_MDWG.xlsx**)

Agenda Item 6 – MDWG Charter Updates:

Anthony Cook presented the MDWG Charter with edits provided by member feedback. The group was not prepared to discuss the updates made to the Charter. A few additional edits were added; however, the discussion was tabled. Anthony stated that he would resend the charter with updates to the group for members to provide additional comments.
(**Attachment 9 - MDWG_Charter_5-21-2014_DRAFT.docx**)

AI: Anthony to check on needing to name specific models being built in scope section.
AI: MDWG Members to provide comments on updating the Charter.

Agenda Item 7 – MDWG Model Building Updates:

2014 Series Dynamics
Scott Jordan reviewed changes made to the dynamic model building schedule due to the delay of the powerflow models. He also gave an update of the status of the model build.

2014 Powerflow and Short Circuit
Anthony recapped the delay of finalizing the models. He reviewed the reoccurring issues that were reported by the docucheck program.

Alan Burbach discussed the MRO model building process. He stated that for the first few passes, unsolved models are provided for members to check that topology is correct and that load, generation, and interchange are balanced. This reduced the scheduled time needed to build the models since solving models can take a considerable amount of effort if these are incorrect. Many of the members agreed that the first couple of passes could be issued without being solved.

The group discussed how many projects were added/modified each pass and how there are some entities that wait until the later passes and update their system all at once. Anthony expressed that this causes a considerable amount of time to be spent reviewing so many projects at one time. More attention needs to be made to the models at the beginning of the build and use the last few passes to make minor adjustments. Mo asked what the main reasons are for the unscheduled passes each year. Anthony stated that it goes back to the reoccurring issues presented in the docucheck output.

Anthony presented improvements that the SPP Modeling Staff created based on requests from members. These improvements would apply to all modeling data reporting entities. Nathan McNeil asked for an improvement to the report card because it doesn't capture the amount of work someone does at the beginning of the process and then makes minor changes at the end. It only shows that they made changes at the end of the process and maybe not throughout. He asked for some sort of scale that shows the amount of updates being submitted each pass. Dona Parks suggested having frequent conference calls during the build to check on the member's progress of submitting data. Nathan added to hold a call each pass and let Anthony discuss the issues that he is seeing. There was consensus to hold a call during each pass to help Anthony and the members discuss the building process.

Other thoughts are to require MOD training for new hires, start next series build immediately after finalizing previous series, SPP Staff to keep MOD updated, Staff not to accept corrections after deadline, build dynamic models in parallel with powerflow models.
(**Attachment 11 - DocuCode_2014Series_P1-FINAL_Compare-8MAY2014.xlsx**)
(**Attachment 12 - Member Accountability Process Improvement.docx**)

AI: Members to provide additional improvement suggestions to Anthony.

2015 Series Model Selection
Anthony presented the 2015 series model selection if it were to stay as usual. Nathan McNeil discussed Requirement 2.1 of TPL-001-04. Anthony stated that the current model selection does comply with the NERC definition if year 1 is 2017. Nathan stated that the TPL Task Force (TPLTF) decided for the 2015 series, year 1 will be 2016. In doing this, there isn't a 5 year or 10 year model in the current selection. Anthony presented how the MDWG models align with the MMWG models. Nathan discussed the document that the TPLTF created specifically the options tables. The group discussed whether to add 2020 summer and 2025 summer to the presented model selection or shift the set and rebuild the 2020 and 2025 models and not build 2021 and 2026 models. Nathan McNeil motioned to shift the model selection and rebuild the 2020 and 2025 models for the 2015 series. Mike Clifton seconded the motion. The motion passed unopposed.
(**Attachment 13 - 2015 Series Model Selection.xlsx**)
(**Attachment 14 - Model Matchup Presentation.pptx**)
(**Attachment 15 - NERC_TPL-001-04.pdf**)
(**Attachment 16 - Powerflow_and_Dynamics_Model_Options_TPL-001-4.docx**)

2015 Series Schedule

Anthony Cook presented a proposed schedule for the 2015 series MDWG model build. The group discussed that the chair of the TWG wants to see the model build end by December 31. The group discussed that this date wouldn't allow for the inclusion of the Board approved NTC projects to be added to the model set. There were several suggestions on how to improve the schedule. The group asked SPP Staff to prepare a couple of schedules and send them to the group to decide which one to adopt. (**Attachment 17 - MDWG 2015 Series Schedule_Draft.pdf**)

<u>Agenda Item 8 – MDWG Modeling Practice Improvements:</u>

Gross vs. Net Pmax, Aux Load
Anthony discussed the SPP Staff recommendations for modeling generator parameters document that had been sent out to the members before. He discussed that there is an action planned for the MDWG to decide in favor or against and then it will be presented to the TWG. Chris Haley stated that the process documentation has to be established by July 2015, and then everything is enforceable by July 2016 according to the new NERC MOD standards recently approved. The MDWG and SPP Staff made additional updates to the document. Derek Brown motioned to approve the document as revised with SPP Staff checking on the specificity of referencing MOD 25. Nate Morris seconded the motion. There was one vote against by Scott Rainbolt. He will supply a write-up prior to finalization of the minutes.

AI: SPP Staff and Members to look into the PSS\e issue of decimal places being added to generator values.

<u>Agenda Item 10 – TPL-001-4:</u>
Nathan McNeil discussed R1 and how outages of six months or longer are going to be reported. Emails have circulated to report those outages in the data submittal workbook that accompanies the model set being built. Scott Jordan stated that there have been some concerns of the market sensitivity of the information being in the workbook. Scott stated that whether it is in the workbook or not, the outages have to be represented in the models as of January 1, 2015. The 2014 series powerflow models might have to be altered to add these outages if not already modeled.

Nathan stated that we may have to change the process of building the short circuit models to comply with R2.3 of the standard. The MDWG and SPCWG will need to hold a joint meeting and the Short Circuit Task Force (SCTF) will possibly need to be revived for model improvements.

<u>Agenda Item 13 – Modeling Entity Expansion:</u>
Chris Haley asked the group for their opinion to move toward modeling based on Transmission Customer or Load Serving Entities. He asked for the members to send him an email with their suggestions on the subject. He stated that it was brought up to the MOPC and are currently collecting responses. The group asked for Chris to send an email request.

AI: Chris Haley to send members an email request for opinions.

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

<u>Agenda Item 16 – Summary of Action Item:</u>

- **Add columns for company name and type of contact to the modeling contact sheet.**
- **Anthony to check on needing to name specific models being built in scope section of the charter.**
- **MDWG Members to provide comments on updating the Charter.**
- **Members to provide additional improvement suggestions to Anthony for staying on schedule.**
- **SPP Staff and Members to look into the PSS\e issue of decimal places being added to generator values.**
- **Chris Haley to send members an email request for opinions.**

<u>Agenda Item 17 – Discussion of Future Meetings:</u>

Next Meetings Place and Date:

- Conference call in late June, 2014
- Face-to-Face in Little Rock on November 12, 2014
- Model Update Meeting on November 13-14, 2014

Adjourn Meeting

Reené Miranda motioned to adjourn the meeting, Nathan McNeil seconded the motion. With no further business to discuss, the MDWG adjourned at 12:26 p.m.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool

Southwest Power Pool
MODEL DEVELOPMENT WORKING GROUP
November 11, 2013
Southwest Power Pool Corporate Office
Little Rock, Arkansas
1:00 P.M. – 5:00 P.M.

• M I N U T E S •

Agenda Item 1 - Administrative

The meeting was called to order at 1:04 p.m. The following Model Development Working Group (MDWG) members were in attendance:

Joe Fultz, Chair – Grand River Dam Authority
Nate Morris, Vice Chair – Empire District Electric
Scott Rainbolt – American Electric Power
Nathan McNeil – Midwest Energy
Reené Miranda – Southwestern Public Service
Brian Wilson – Kansas City Power & Light
Mike Clifton – Oklahoma Gas & Electric
Derek Brown – Westar Energy
Scott Schichtl – Arkansas Electric Cooperative
Dustin Betz - Public Power District
Jason Shook – GDS Associates

SPP Staff in attendance included Anthony Cook (Secretary), John Mills, Chris Haley, Mitch Jackson, Scott Jordan, and Billy Songer.

The following guests were also in attendance:
Jason Bentz – American Electric Power
Dona Parks – Grand River Dam Authority
Mark Reinart – Golden Spread Electric Cooperative
Gimod Olapurayil – ITC Great Plains
David Sargent – Southwestern Power Administration
John Shipman – Omaha Public Power District
Liam Stringham – Sunflower Electric Power Corporation
Peter Howard – Kansas City Power & Light
Jerad Ethridge – Oklahoma Gas & Electric
Alex Mucha – Oklahoma Municipal Power Authority
John Payne – Kansas Electric Power Cooperative
Peter Belkin – American Electric Power
Dave Macey – City of Independence
Perry Brown – American Electric Power

Meeting Agenda
The agenda was reviewed by the group. Scott Rainbolt asked to add a discussion topic for the Short Circuit models. The addition was made to Item 9. Scott Rainbolt motioned to approve the agenda with the edit; Derek Brown seconded the motion. The motion passed unopposed. (**Attachment 1 - MDWG Meeting Agenda 20131111.doc**)

Meeting Minutes
The July 26, 2013 and September 20, 2013 minutes were open for review. Nate Morris asked to reassign #71 to another SPP staff member under Review of Action Items. Mike Clifton motioned to approve the previous meeting minutes with edit; Brian Wilson seconded the motion. The motion passed unopposed. (**Attachment 2 - MDWG Minutes 20130726.doc, Attachment 3 - Finalization of Dynamic Cases Email Vote 20130920.doc**)

Review of Action Items
Anthony Cook reviewed the action items. He mentioned the items that had been completed were marked complete and would be removed for the next meeting. (**Attachment 4 - SPP MDWG Action Items 20131111.xls**)

<u>Agenda Item 2 – 2014 Series:</u>

Powerflow Update
Anthony Cook gave a status report of the 2014 Series MDWG powerflow model building effort. He stated that the 2013 Series MMWG models are not finalized due to issues trying to solve the models. He stated that the remaining MDWG models would be built using the latest trial of the MMWG models until they are finalized.

Dynamics Schedule
Scott Jordan discussed the proposed schedule for the 2014 Series build. Reené Miranda asked if items 94 and 95 could be made permanently into the powerflow models. Scott stated that these changes should be made in MOD by the members. He asked if the group thought that these two steps should be added into the powerflow schedule instead. Reené agreed that doing so would reduce time in the dynamics schedule. Scott will send out a request email to the MDWG members to review and make comments on the proposed schedule.
(**Attachment 5 - MDWG 2014 Series Schedule_Dynamics_REV1_10292013.pdf**)

Action Item: Scott to send email requesting members to review and comment on proposed dynamic schedule**.**

<u>Agenda Item 3 – Proposed NERC Standards:</u>

MOD B (MOD-032, MOD-033)
Reené Miranda discussed the current MOD B effort. He stated that this is the second posting and that the ballot window and comment period closes November 20. He covered the changes of the requirements and attachments of the proposed MOD 32 and 33 standards.

Agenda Item 4 – MDWG Pmax Presentation:

Anthony Cook referred to the presentation that was posted for the meeting. He started the discussion rehashing data presented in previous MDWG meetings. Scott Jordan continued with the MOD standards both current and proposed. Anthony added the recommendations of the RTO and RE.
(**Attachment 6 - MDWG Pmax Presentation 2013.pptx**)

John Payne asked what happens with the aux load if the unit is turned off. Anthony answered that the load would need to be made zero. Derek Brown stated that modeling the Pmax based off of a test performed on one day isn't fair if conditions are not just right for that season. Nathan McNeil asked for a size of the unit to be formally identified. Reené Miranda stated that all MOD standards are subject to the BES definition, meaning if the unit is not considered BES, than it would not fall under the requirement. Nate Morris expressed concerns keeping up with Aux load values and Pgen output. Scott Jordan discussed the use of automation programs for checks of Pgen levels versus Aux load values. Nate brought up Action Item #72 and asked Staff to work on this item. John Mills stated that Staff will formally identify units that will be subject to the standard and send to the group for approval.

Action Item: Staff to formally identify units that will be subject to the Pmax modeling standard and send to group for approval.

Agenda Item 5 – Wind Generation Dispatch

Criteria 12.1.5.3.g – Renewable Resource Accreditation
Nathan McNeil stated that Criteria 12.1.5.3.g does not allow for wind to be accurately represented in the off-peak models. He stated that the wind levels in the planning models are inconsistent with those in real time operations. He asked if all of the members are being consistent with the criteria. Scott Jordan mentioned that Chris Haley and himself are working on rewording Criteria 12.1. Nathan asked for a powerflow manual change to make the modeling of wind consistent by all members. He asked for Staff to discuss the Criteria and bring recommendations to the group for more discussion.

Agenda Item 6 – TPL-001-4:

Anthony Cook discussed the gap analysis that SPP Staff had created. He stated that the main change for modeling is the inclusion of known outages spanning six months or longer. He also stated the NERC definition of year 1 and that currently the standard is being met, but more discussion may be needed if a request is made to change which models are studied. He stated that the most current gap analysis can be obtained in the background material for the November 18, 2013, TWG meeting.

Agenda Item 7 – Member Ratings Email List:

Reené Miranda discussed that FAC-08 requires coordination of ratings for ties. He stated that SPS has created an email distribution list specifically for ratings coordination. He asked if other companies have a specific distribution list, and if so, could the Modeling Contacts list be updated.

Action Item: Post updated contacts list and notify members.

Agenda Item 8 – LSE Involvement:

Communication between SPP/TO/LSE, Topology Changes, Profile Data (Generation, Load)
Anthony Cook discussed having all Load Serving Entities (LSE) begin participating in the annual model build. He stated that it is not cost effective to purchase MOD licenses for every LSE and therefore would need to rely on TOs to help submit data. Anthony stated that there is a concern of the TO to be responsible for compliance of the LSE data being modeled correctly. Anthony stated that a template has been made to make it easy on the LSE and host TO to get profile data updated. The LSE can fill out the data fields and resubmit to SPP and/or the host TO. The host TO can use formulas in the template to create a raw file for submission to MOD. This will reduce the concerns of human error. Anthony will contact each TO to establish an agreement for LSE data submission.

Action Item: Contact individual TOs and establish agreement for LSE data submission.

Agenda Item 9 – Other:

Short Circuit Model Discussion
Scott Rainbolt brought up the short circuit model discussion at the System Protection and Controls Working Group (SPCWG) meeting last week. He stated that it was stated in the meeting that most members are keeping a more detailed system in house than what is in the MDWG cases. He stated that the SPCWG discussed creating a taskforce to handle short circuit model improvements.

Peter Belkin stated the needs for short circuit versus the needs for powerflow models pertaining to the modeling horizon. He stated the need for short circuit models to be built more often than planning models. Peter talked about the difference with PSS/e and Aspen, using a tool that is built to deal with short circuit, and having the models built by people who focus on short circuit.

Anthony discussed how the MDWG short circuit models are built creating both PSS/e and Aspen user models. John Mills suggested having a joint meeting with the SPCWG to discuss the concerns with the short circuit models.

Action Item: Anthony to get with Doug Bowman to set up a joint meeting with the SPCWG.

Agenda Item 10 - Closing Administrative Duties:

Review of Action Items:

1. Scott to send email requesting members to review and comment on proposed dynamic schedule.
2. Staff to formally identify units that will be subject to the Pmax modeling standard and send to group for approval.
3. Post updated contacts list and notify members.
4. Contact individual TOs and establish agreement for LSE data submission.
5. Anthony to get with Doug Bowman to set up a joint meeting with the SPCWG.

Next Meetings Place and Date:
TBD

Next Meeting Topics:
TBD

Adjourn Meeting

Scott Rainbolt motioned to adjourn the meeting, Reené Miranda seconded the motion. With no further business to discuss, the MDWG adjourned at 5:17 p.m.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool
MODEL DEVELOPMENT WORKING GROUP
April 16, 2014
Conference Call
1:00 P.M. – 3:00 P.M.

• M I N U T E S •

The meeting was called to order at 1:03 p.m. The following Model Development Working Group (MDWG) members were in attendance:

Joe Fultz, Chair – Grand River Dam Authority
Nate Morris, Vice Chair – Empire District Electric
Nathan McNeil – Midwest Energy
Scott Schichtl – Arkansas Electric Cooperative
Reené Miranda – Southwestern Public Service
Dustin Betz – Nebraska Public Power District
Derek Brown – Westar Energy
Mike Clifton – Oklahoma Gas & Electric
Brian Wilson – Kansas City Power & Light
John Boshears –City Utilities of Springfield
Jason Shook – GDS Associates

SPP Staff in attendance included Anthony Cook (Secretary), Brandon Hentschel, Mitch Jackson, Seth Mayfield, Zack Bearden, Scott Jordan, Daniel Harless, James Bailey, Austin Collier, and John Mills.

The following guests were also in attendance:
Jason Bentz – (Proxy for Scott Rainbolt) American Electric Power
Alan Burbach – Lincoln Electric System (LES)
Alex Mucha – Oklahoma Municipal Power Authority
Chandler Brown – Sunflower Electric Power Corporation
Dave Macey – City of Independence
Gimod Olapurayil – ITC Great Plains
Jerry Bradshaw – City Utilities of Springfield
John Mayhan – Omaha Public Power District (OPPD)
Jon Shipman – Omaha Public Power District (OPPD)
Liam Stringham – Sunflower Electric Power Corporation
Martin Green – Grand River Dam Authority
Noumvi Ghomsi – Public Service Commission of Missouri
Peter Howard - Kansas City Power & Light
Jeff Stewart – Lafayette Utilities
Aravind Chellappa –Southwestern Public Service

Meeting Agenda
There was not an agenda prepared for the meeting.

2014 Series Powerflow Model Status:

Anthony Cook asked the group if there were any issues that hadn't been addressed which would prevent the group from voting to finalize the powerflow models. Brian Wilson stated that he was fine with as long as the St. Joe to Cooper line is restored in the models as needed. Anthony stated that the issue had been corrected. He also stated that the additional corrections submitted by the members are local corrections and would not greatly affect the overall powerflow. Nate Morris asked if HPILS is in the latest posted models. Anthony stated that the members were directed to submit updated HPILS load, topology and generation per the letter from Noman Williams. Nate asked if the HPILS loads went through the AQ process. Anthony stated he was told that the HPILS study served as a "Super" AQ study and therefore individual loads did not necessarily go through the AQ process. With no other comments, Joe Fultz asked for a motion to finalize the models. Jason Shook motioned to finalize the 2014 Series MDWG Powerflow models with the submitted corrections added during the review period. Reené Miranda seconded the motion. The vote is 11 yes, 1 no. Nate Morris with Empire voted no. His explanation is below:

Mr. Chair & Secretary,

Here is the reasoning behind Empire's opposing vote on finalization of the 2014 MDWG model set:

Empire does not feel that the correct avenues were implemented for inclusion of the HPILS related loads, transmission projects, and generation. This type study should have been conducted separate of SPP's previously scheduled work so as not to disrupt the ongoing model development nor cause disruption of the results for load & project development. The manner in which this study was rushed through gave rise to more questions than answers provided and as a consequence members did not have adequate time to review the consistency of the models. The items that remain unanswered/ambiguous as to the integrity of the 2014 Model set are as follows:

1. SPP has yet to tabulate what additional transfers needed to force the models into solving
2. What & where were the additional loads added between February and the posting of Pass 8 models?
3. What transmission projects were placed in the models to serve the newly added/inserted loads?
4. Why were the loads added between Pass 6 and Pass 8 (vs. the previous 6 passes)? Members were not directed by TWG to include them so why were special permissions & additional passes granted so that these loads could be added? If these loads were consistent with the 50/50 projections, why were these not included in previous passes for the 2014 model build? In the discussion at the Feb TWG meeting, the MDWG was directed to notate and label the ALREADY present HPILS loads within the models, which stands contrary to the mention of the MDWG being directed to include all HPILS models and extending the number of passes on the 2014 model set.

5. The AQ process having been totally bypassed in this study raises questions as to how future loads/generation/transmission projects are to be included in future model builds. If any loads have not been vetted through the AQ process, how did these loads make it into the models, with assumed integration into the subsequent ITP models? There was mention that the HPILS was a "Super AQ" study. There is no such thing as a "Super AQ" study and therefore this is an invalid explanation.
6. What amount and where has generation been added to the models to help serve this unknown amount of additional load? Could these additional generators add or mask subsequent projects needed as a direct result of their inclusion within the models? In previous years, outer year models have been supplemented with fictitious generation in an attempt to cover load. That is understandable but it is unknown at this time how these required generators related to HPILS will/will not be integrated into subsequent models (i.e. – ITP models)
7. How will stability studies be treated with these new machines & unknown additional projects and how will the effects of said generators be viewed in the results? What ensuing evaluation will be made to determine the positive or negative impacts these generators will have on the models' dynamic responses? The members were simply informed that assumptions would be applied as in past dynamic simulations. Due to the fact that it has not been tabulated as to the amount of additional generation was added, this was too general of an explanation.

Due to the above ambiguities and the excessive unknowns that are present in the model set, Empire could not support finalizing the model set.

Regards,

Nate Morris, P.E.
Manager of Systems Planning & Protection

2014 Series Short Circuit Model Status:
Anthony stated that SPP has received little feedback on the posted Short Circuit models. He asked if the group was prepared to finalize those as well. With no comments, Joe asked for a motion. Scott Schichtl motioned to finalize the 2014 Series MDWG Short Circuit models. Reené Miranda seconded the motion. The vote is 11 yes, 0 no, 1 abstain. Nate Morris with Empire abstained.

TPL-001-04-R1:
Scott Jordan gave an overview of the requirements for the new NERC TPL-001-04 standard. He described adding five worksheets to the data submittal workbook to help with compliance needs for Requirements 1 & 7. He stated that SPP staff will add wording to the MDWG Procedural Manual and submit for approval from the group for the May MDWG Meeting. Scott asked the members to submit known outages so that he can get them into the 2014 Series Dynamics model set. Reené Miranda asked if a TO will be held accountable if a planned outage is shown in the models but is not able to take place as a result of the state of the transmission system when it is time to take the line out. Scott stated he would look into this.

(Attachment 1 - NERC_TPL-001-04_R1.pdf)
AI: SPP Staff to add wording to the MDWG Procedure Manual for TPL-001-04-R1.

AI: Scott Jordan will discuss with SPP Compliance if TOs will be held accountable for modeling outages that don't happen in real-time.

Adjourn Meeting

With no further business to discuss, Scott Schichtl motioned to adjourn the meeting. Reené Miranda seconded the motion. The MDWG adjourned at 2:27 p.m.

Respectfully submitted,

Anthony Cook
SPP Staff Secretary

Southwest Power Pool, Inc.

MODEL DEVELOPMENT WORKING GROUP

May 21-22, 2014

Crowne Plaza Kansas City Downtown
Kansas City, Missouri

• AGENDA •

Wednesday 1:00 p.m. – 5:00 p.m.
Thursday 8:00 a.m. – 12:00 p.m.

1. Administrative Items .... Joe Fultz (15 min)
    a. Call to Order
    b. Introductions
    c. Proxies
    d. Previous Meeting Minutes (Action Item)
        i. November 11, 2013 Face-Face
        ii. April 16, 2014 Net Conference
    e. Agenda Review (Action Item)
    f. Meeting Materials

2. Review of Past Action Items .... Anthony Cook (10 min)

3. NERC Reliability Standards Updates .... Shannon Mickens (30 min)

4. Modeling Contacts Updates .... Anthony Cook (5 min)

5. MDWG Member Survey Results .... Anthony Cook (10 min)

6. MDWG Charter Updates (Action Item) .... Anthony Cook (20 min)

7. MDWG Model Building Activities .... Staff (1 hr)
    a. 2014 Series
        i. Dynamics
            1. Schedule Updates (Action Item)
        ii. Powerflow and Short Circuit
            1. Reoccurring Docucheck Issues
            2. Member Accountability Improvements
    b. 2015 Series
        i. Model Selection (Action Item)
            1. MMWG
            2. TPLTF
        ii. Schedule (Action Item)
            1. Powerflow
            2. Short Circuit
            3. Dynamics

8. MDWG Modeling Practice Improvements .... Staff (1 1/2 hrs)
    a. Gross vs. Net Pmax, Aux Load (Action Item)
    b. Modeling of Mothballed/Retire/Decommissioned Units (Action Item)
        i. MOD Profiles Pmax/Qmax/Qmin = 0
        ii. Removal
    c. Generator Ids
        i. Leading Zeroes
    d. Parallel Three Winding Transformer Ids
        i. ASPEN Error
    e. Modeling Transactions

9. New BES Definition ....Scott Jordan (15 min)

10. TPL-001-4.. Nathan McNeil (30 min)
    a. R 1
    b. R 2.3

11. Model Development Procedure Manual .... All (1 hr)
    a. General Updates
    b. Generator Modeling Parameters
    c. BES Definition
    d. TPL-001-4

12. NERC Standards .... Staff (30 min)
    a. MOD 25, 26, 27
    b. MOD 32 (MOD B)
    c. TPL 007-1

13. Modeling Entity Expansion .... Chris Haley and Anthony Cook (30 min)

14. MOD Training .... Anthony Cook (15 min)

15. Other..All (10 min)

16. Summary of Action Items .... Anthony Cook (10 min)

17. Discussion of Future Meetings .... Joe Fultz (10 min)
    a. Next Meeting: November 10 or 12 – Little Rock, Arkansas

	Action Item	Responsible Parties	Date Originated	Date Updated	Progress	Notes
42	Review the new MOD standards approved by FERC and how they will apply to the MDWG and SPP planning modeling	SPP Staff	3/1/2010	5/19/2014	In Progress	Further review with the new NERC MOD standards being developed.
50	Reformat the MDWG procedure manual and add hyperlinks for referenced documents	Anthony Cook	8/6/2010	5/19/2013	In Progress	Currently working on updates from the MMWG manual. To be updated some during the May 2014 Meeting. Table until June 2014.
57	Determine the standards for stability load data	Scott Jordan	8/6/2010	5/21/2014	In Progress	Scott to give update of TSTF discussion at May 8, 2012 meeting. Being discussed at the MMWG.
72	Staff to provide background information on reasons for choosing 20 MVA for machines and aggregate plant capacity for Uniform Generation Modeling when modeling auxilary load	Staff	11/8/2011	5/8/2012	In Progress	This has been pushed back to the MITF for justification per the 12/6 meeting.
76	Look for ways to shorten the Dynanamic Build.	Scott Jordan	2/8/2012	5/21/2014	In Progress	Internal Build? When could that take effect? Scott Jordan is attending training. Internal build of the 2014 Series is currently being performed.
84	RTO/RE staff and MDWG to address data reporting requirements and enforceability for independently owned generation and transmission assets.	MDWG/Staff	8/29/2012	11/13/2012	In Progress	TWG action item: Who is responsible, When data exchange is required, How to enforce data exchange.

NERC Reliability Standard Activities Update – May 16, 2014

Posted for Ballot

Project 2007-11 Disturbance Monitoring: The Disturbance Monitoring Standard Drafting Team (SDT) has posted revisions to PRC-002-2 Disturbance Monitoring for a 45-day Formal comment period along with an additional ballot and non-binding poll ending on June 23, 2014. This project intends to address FERC concerns in Order 693, specifically PRC-002-1, PRC-018-1 Standards. A SAR to initiate the project was initially posted in 2007 with a scope of reviewing both standards and merging them into one replacement standard. A standard drafting team was appointed by the Standards Committee in 2007, who drafted PRC-002-2, which was posted for a 45-day formal comment period in early 2009. The standard was posted for initial comments during February and March of 2009. In 2010 the Standards Committee decided to prioritize its work, which resulted in moving Project 2007-11 Disturbance Monitoring to informal development. Responses to the comments for the 45-day formal posting were developed, but not posted because of the change to informal development. In its 2013 work plan, the Standards Committee changed the status to formal development as part of the effort to address pending projects. The SPP Reliability Standards Department plans to schedule a WebEx/Conference Call in order to compile member and staff comments on the proposed standard for filing with the drafting team prior to the end of the comment period.

Project 2007-17.3 Protection System Maintenance and Testing Phase 3 (Sudden Pressure Relays): The Protection System Maintenance and Testing Standard Drafting Team (SDT) has posted a draft PRC-005-X Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance standard for a 45-day formal comment and ballot period ending on June 2, 2014. This standard responds to a directive from FERC directing NERC to include transformer sudden pressure relays in PRC-005-3. As a follow-up to this ruling, the Planning Committee studied sudden pressure relays and issued a technical report, which recommends moving ahead with the standard. Specifically, the System Protection and Control Subcommittee (SPCS) completed a technical report recommending that the SDT modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard. The SPP Reliability Standards Department has scheduled a WebEx/Conference Call for Thursday afternoon, May 22, 2104 during which member and staff comments on the proposed standard will be compiled for filing with the drafting team prior to the end of the comment period.

Project 2010-02 Connecting New Facilities to the Grid: The FAC Standard Drafting Team has posted revisions to FAC-001-1 Facility Connection Requirements and FAC-002-1 Coordination of Plans for New Facilities for a 45-day comment and initial ballot period ending on May 15, 2014. In line with the recommendations of the 5 Year Review Team (5YRT), the FAC SDT has proposed changes to add clarity, remove redundancy, retire requirements with no impact on the reliable operation of the BES, and bring compliance elements in line with current NERC guidelines. The

SDT has also addressed SAR comments, Order 693 directives related to FAC-002-0, the recommendations of the Independent Experts Review Panel, Phase 1 Paragraph 81 suggestions, and the recommendations of the Integration of Variable Generation Task Force. The SPP Reliability Standards Department held a WebEx/Conference Call on Thursday, May 8, 2014 during which member and staff comments on the revised standards were compiled. Thirty (30) people registered for the call with Twenty (20) actually participating on the call. The comments will be filed with the drafting team prior to the end of the comment period.

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings: The first draft of PRC-026-1 Relay Performance During Stable Power Swings has been posted for a 45-day formal comment period ending on June 9, 2014. Initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted May 30 – June 9, 2014. Ballot Pools are also currently being formed through May 27, 2014. Phase 3 of the project is focused on developing a new Reliability Standard, PRC-026-1 – Stable Power Swing Relay Loadability, to address protective relay operations due to stable power swings. This Reliability Standard will establish requirements aimed at preventing protective relays from operating unnecessarily due to stable power swings by requiring the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases-out relays that cannot meet this requirement. The SPP Reliability Standards Department has scheduled a WebEx/Conference Call on Friday morning, May 30, 2014 during which member and staff comments on the proposed standard will be compiled for filing with the drafting team prior to the end of the comment period.

Project 2012-13 NUC – Nuclear Plant Interface Coordination: The NUC-001-3 Standard Drafting Team has posted a draft of the NUC-001-3 Nuclear Plant Interface Coordination Reliability Standard for a 45-day comment and initial ballot period ending on May 22, 2014. The SDT is working to implement the recommendations of the NUC 5 Year Review Team for modifications to NUC-001-2.1. The standard is being revised to provide greater clarity and to sharpen industry focus on tasks that have a more direct impact on reliability. As in the previous posting of the SAR for this project, due to the limited audience for member participation in this project (only OPPD, NPPD and Westar operate nuclear units) the SPP Reliability Standards Department will not host a call for this standard and will defer to the individual members to file comments associated with their individual positions.

Recently Posted for Ballot

Project 2010-04 Demand Data (MOD C): The Demand Data (MOD C) Standard Drafting Team posted a revised MOD-031-1 Demand and Energy Data standard for a 45-day formal comment and additional ballot period ending on April 10, 2014. This version of the proposed standard contains revisions based on stakeholder comments received during its last posting in November 2013. This standard proposes to eliminate five (5) existing standards – MOD-016-1.1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net energy for Load and Controllable Demand-Side Management, MOD-017-0.1 Aggregated Actual and

Forecast Demands and Net energy for Load, MOD-018-0 Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net energy for Load, MOD-019-0.1 Reporting of Interruptible Demands and Direct control Load Management and MOD-021-1 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts and consolidate their requirements into a single standard. The draft standard successfully passed ballot with an approval rating of over 83% from a quorum of almost 77%. The drafting team subsequently decided that the changes made to the standard were non-substantive and posted the standard for a 10-day final ballot on April 25, 2014. The ballot ended on May 5, 2014. The standard successfully passed final ballot with an approval rating of 90% from a quorum of over 80%. The standard will now go to the BoT for adoption.

Project 2013-04 Voltage and Reactive Control: The Voltage and Reactive Control Standard Drafting Team posted a revised draft of the VAR-002-3 Generator Operation for Maintaining Network Voltage Schedules standard for a 45-day formal comment and additional ballot period which ended on April 14, 2014. This revised draft is based on stakeholder comments received during its last posting in November 2013 when the standard barely missed a successful ballot. (VAR-001-4 was approved on that ballot.) This project started as an informal development effort. An ad hoc team was assigned the task of addressing outstanding FERC directives from Order 693 and other compliance issues. The standard successfully passed ballot with an approval rating of over 82% from a quorum of just over 78%. The drafting team made minor changes to the draft standard based on comments received and subsequently posted the standard for final ballot on April 24, 2014. The ballot closed on May 5, 2014. The standard successfully passed final ballot with an approval rating of over 88% from a quorum of almost 84%. The standard will now go to the BoT for adoption.

Project 2014-04 Physical Security: On March 7, 2014 FERC issued an order directing NERC to '…submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order.' Robert Rhodes has been selected to serve on the drafting team along with John Breckenridge of KCP&L. The drafting team posted a proposed draft of CIP-014-1 Physical Security for an abbreviated 15-day comment and ballot period ending on April 24, 2014. NERC held a series of webinars the week of April 14, 2014 during which the draft standard was presented to industry. The standard successfully passed its initial ballot with an approval rating of just over 82% from a quorum of over 88%. Based on the comments received, the SDT made only minor, clarifying modifications to the standard and posted it for 5-day, final ballot on May 1, 2014. The standard successfully passed its final ballot with an approval rating of over 85%

from a quorum of over 92%. The standard will now go to the NERC BoT for adoption and will be filed with FERC prior to the June 5, 2014 deadline.

Posted for Comment Only

Project 2013-03 Geomagnetic Disturbance Mitigation: The Stage 1 GMD standard, EOP-010-1, was adopted by the NERC BoT at its November 2013 meeting, and is pending regulatory approval. The Geomagnetic Disturbance Mitigation Standard Drafting Team has posted the Stage 2 GMD standard (TPL-007-1 Transmission Planned Performance During Geomagnetic Disturbances) and supporting technical papers on the benchmark GMD event and transformer thermal assessment for a 30-day informal comment period through May 21, 2014. Per FERC Order 779 the Stage 2 standard requires applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system. The standard must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts on the Bulk-Power System. If the assessments identify potential impacts from benchmark GMD events, the standard will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading as a result of a benchmark GMD event. The development of this plan cannot be limited to considering operational procedures or enhanced training alone, but will, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for mitigating the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. The SPP Reliability Standards Department has scheduled a WebEx/Conference Call for Thursday afternoon, May 15, 2014 during which member and staff comments on the proposed standard will be compiled. The comments will be filed with the SDT prior to the end of the comment period.

Recently Posted for Comment Only

Project 2009-03 Emergency Operations: The Emergency Operations Standard Drafting Team (EOP SDT) has posted EOP-011-1 Emergency Operations for a 30-day informal comment period ending April 28, 2014. The SDT merged previous standards (EOP-002-2.1b Emergency Operations Planning, EOP-002-3.1 Capacity and Energy Emergencies and EOP-003-2 Load Shedding Plans) to create EOP-011-1. The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clearer and more concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities. The SPP Reliability Standards Department held a WebEx/Conference Call on Wednesday, April 16, 2014 during which member and staff comments were compiled for filing with the drafting team. Thirty-eight (38) people registered for the call with sixteen (16) actually participating on the call. Thirteen (13) people signed on in support of the comments which were filed with the drafting team April 26, 2014.

Project 2014-01 Standards Applicability for Dispersed Generation Resources: The Standards Applicability for Dispersed Generation Resources Standard Drafting Team has posted a white paper based upon its review of the applicability of certain standards that currently apply to a Generator Owner (GO)/Generator Operator (GOP) and the requirements of certain GO/GOP standards indicating where revisions may be necessary to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). The white paper explains the SDT's analysis process. The SDT seeks industry comment in an informal comment period ending on May 5, 2014. The SPP Reliability Standards Department held a WebEx/Conference Call on Thursday, May 1, 2014 during which member and staff comments on the white paper were compiled for filing with the drafting team. Twenty-five (25) people registered for the call with ten (10) actually participating on the call. Nine (9) people signed on in support of the comments which were filed with the SDT on May 5, 2014.

Drafting Team Nominations Open

There are currently no vacancies on any drafting teams.

Other

NERC BoT Meeting: At its May 7, 2014 meeting the NERC BoT adopted the following standards:

- **MOD-031-1- Demand Data (MOD C).** This standard establishes consistency in data requirements and reporting procedures and provides the authority for applicable entities to collect demand, energy and related data to support reliability studies and data.
- **VAR-002-3 – Voltage and Reactive Control.** This standard ensures generators provide reactive support and voltage control within generating facility capabilities to protect equipment and maintain reliable operation of the interconnection.
- **COM-002-4 – Operating Personnel Communications Protocols.** This standard ensures that reliability-related information is conveyed effectively, accurately and consistently in a timely manner toward mutual understanding by key parties when issuing or receiving emergency and non-emergency operating instructions. The new standard combines COM-002-3 and the draft COM-003-1 in a single standard. The Board also voted to rescind approval of the current COM-002-2 interpretation with the implementation of COM-002-4.

The BoT also applauded the effort of the CIP-014-1 Physical Security Standard Drafting Team and the effort put forth to bring the standard in on the short, 90-day schedule that FERC had placed in its order requiring the standard.

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **May 21, 2014**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

On May 16, 2013 FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances in two stages:

- Stage 1 standard(s) that require applicable entities to develop and implement Operating Procedures were filed in November, 2013.
- Stage 2 standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 standards must be filed by January 2015.

This posting is soliciting informal comments on the draft standard, TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances, being developed to address the stage 2 directives. TPL-007-1 includes requirements for Planning Coordinators, Transmission Planners, Transmission Owners, and Generation Owners with planning areas or transformers connected at 200 kV or higher.

Paragraph numbers in the following questions refer to Order No. 779.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions on Draft 1 of TPL-007-1

1. **Applicability**. The draft TPL-007-1 standard applies to Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater. The drafting team believes these are the correct functional entities to meet the directives in Order No. 779 to evaluate the effects of GICs on Bulk-Power System transformers and other equipment (P.67), consider wide-area effects and coordinate across regions (P.67), and develop plans to address potential impacts (P. 79). Justification for the 200 kV voltage threshold may be found in the whitepaper that was developed by the drafting team for the stage 1 standard, EOP-010-1 – Geomagnetic Disturbance Operations. Do you agree that these are the correct functional entities to perform the functions required in the draft standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☒ No

   Comments:

   'High side' is not hyphenated in Applicability sections 4.1.1 thru 4.1.4. It is hyphenated in Requirement R7 and in the Comment Form. It is not hyphenated in the Implementation Plan. We suggest the drafting team be consistent in the handling of this term, whichever it chooses to use.

   Generation Owner in 4.1.4 should be Generator Owner.

2. **Technical basis**. Directives in Order No. 779 specify that the assessments required by the stage 2 standard should account for several parameters including the use of studies and simulations to evaluate the effects of GIC on the Bulk-Power System transformers (P. 59). The drafting team believes that the studies and analysis required by the standard meet the assessment parameters directed by FERC and are supported by the technical guides referenced in the standard. Do you agree that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment and are supported by the technical guidance? If you do not agree, or you recommend alternative language in these requirements or additional technical material, please provide specific suggestions in your comments.

   ☐ Yes
   ☒ No

   Comments:

FERC Order 779 requires assessments of Bulk-Power System transformers. The proposed standard establishes a threshold of 200 kV for the applicable transformers. Question 1 references the whitepaper associated with EOP-010-1 which provided the justification for the threshold in that standard. We concur with the 200 kV threshold but suggest that the drafting team make the linkage between that whitepaper and TPL-007-1 more clear, specifically referencing the previous whitepaper. Otherwise, it appears that the proposed standard falls short of the FERC Order.

Requirement R3 requires the development of a Corrective Action Plan. Current TPL standards require Corrective Action Plans for N-1 and N-2 conditions but do not require them for N-3 and beyond. If impacts from a GMD event create N-3 or beyond conditions, this standard goes beyond existing practice to require Corrective Action Plans. Shouldn't there be consistency within the standards in this area?

Requirement R6 requires the responsible entities to provide GMD assessment results to any functional entity with a reliability related need within 30 days of the request. This requirement is too broad and open-ended. How does one determine what a valid reliability related need is? What qualifies that need as valid? Without additional clarification by the drafting team this could open Pandora's box.

Here are some additional typo/grammatical suggestions for the proposed standard.

Replace 'New' with 'Newly' in Requirement R1, Part 1.3.

In multiple places throughout the requirements and in the VSLs, terms such as 30-calendar days, 90-calendar days and 60-calendar months should be hyphenated as shown. Also, in those places where the reference to 'calendar' has not been included, it should be included. This applies to all posted documents.

In Requirement R2, the term 'steady state' is not hyphenated. In other places throughout the documents, the term is hyphenated. We encourage the drafting team to be consistent with the correct format throughout the posted documents.

We believe the use of subparts is currently on the out at NERC. As used most recently in CIP-014-1, we suggest removing subparts 2.1.1 and 2.1.2 and replace them with bullets. In that case in the two bullets under Part 2.1, capitalize 'Term' in '…Near-term Transmisssion Planning Horizon.' as it is a defined term in the NERC Glossary.

Replace the 'by' in the 1st line of the Rationale Box for R4 with 'be'.

In Measure M5 'e-mail' is hyphenated. In Measures M6 and M8 'email' is used. We again encourage the drafting team to be consistent with the correct format whichever it may be.

Replace the reference to Requirement R5 at the end of Measure M6 with Requirement R6.

Delete ‘wye’ in the 4th line of Measure M8.

In Table 1, insert an ‘a’ between ‘of’ and ‘P8’ in item b. under Steady State.

The following are in Attachment 1:

In the 3rd line of the 2nd bullet on Page 10, replace ‘geolectric’ with ‘geoelectric’.

Insert a comma in the date at the top of Page 13; March 13-14, 1989.

The following refer to the VSLs:

Capitalize ‘Parts’ in the High and Severe VSLs for R3 and the Moderate and High VSLs for R7.

3. **Benchmark GMD Event**. In Order No. 779, FERC directed that NERC specify the benchmark GMD event to be used by entities for assessing potential impact on the Bulk-Power System through the standards development process (P.54). Accordingly, the drafting team has posted the proposed Benchmark GMD Event Description whitepaper on the project page along with the standard for comment during this comment period. The drafting team believes the proposed benchmark GMD event is consistent with existing utility best practices, provides the consistent assessment criteria required by the FERC order, and supports assessment of the parameters specified by the directives.

   Do you agree that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779? If you do not agree, please provide specific technically justified alternatives or suggestions for the drafting team to consider.

   ☐ Yes
   ☒ No

   Comments:

   We believe the 2nd ‘conductivity’ in the 7th line of the last paragraph under the Statistical Considerations section on Page 9 should be deleted.

In the 4th line of the 1st paragraph under the Extreme Value Analysis section on Page 12, 'geo-electric' is hyphenated. No where else in any of the documents is this term hyphenated. We suggest the drafting team be consistent with the use of this term throughout the documents.

In the 1st paragraph under Table 1-1 on Page 13, replace'geolectric' in the 2nd line with 'geoelectric'.

Insert a comma in the date in the last line of the paragraph under the Impact of Waveshape on Transformer Hot-spot Heating at the bottom of Page 16; March 13-14, 1989.

Although this document mentions the difference between geographical and geomagnetic latitude, we suggest that the drafting team include support for the apparent 10 degree difference between the two quantities.

4. **Implementation**. Order No. 779 does not direct a specific Implementation Plan, but sets an expectation for a multi-phased approach and consideration for the availability of tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments. The drafting team is proposing a phased implementation of TPL-007-1 over a 4-year period. The Implementation Plan provides 1) time for entities to develop the required models; 2) proper sequencing of assessments; and 3) time for development of viable Corrective Action Plans, which may require entities to develop, perform, and validate studies, assessments, and procedures. Do you support the approach taken by the drafting team in the proposed Implementation Plan, and if you are an applicable entity in the proposed standard is the proposed time frame and sequencing realistic?

☐ Yes
☒ No

Comments:

A 12 month implementation for Requirement R1 may be too short. This is for model development and it may take more than a year to research and establish the needed models. We suggest that the implementation for R1 be changed to 18 months and that it be coordinated with the MMWG effort. Since the assessments required in Requirement R2 cannot be conducted until the models have been developed, the implementation for R2 should also be extended by 6 months to 30 months and should be tied to the development of the models in R1. For consistency with the remaining requirements we suggest extending all the implementation periods by 6 months.

Thank you for completing the comment form for Project 2013-03
Verification Code: GMD

SPP MODELING CONTACTS

Last Updated: 5/21/2014

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		Jennifer Goertzen	417-625-6579	417-625-5165	JGoertzen@empiredistrict.com
545	INDN	David Macey (Consultant)	816-325-6280		Dmacey@indepmo.org
		Daniel Benedict	816-325-7498		DBenedict@indepmo.org
546	SPRM	John Boshears*	417-831-8512	417-831-8402	John.Boshears@cityutilities.net
		Jerry Bradshaw			Jerry.Bradshaw@cityutilities.net
		Jeff Knottek	417-831-8920	417-831-8402	Jeff.Knottek@cityutilities.net
550	KEPCO	John Payne	785 271-4825	785 271-4888	jpayne@kepco.org
640	NPPD	Dustin Betz	402-563-5313	402-563-5941	ddbetz@nppd.com
		Jason Hofer (Alt.)		402-563-5941	jkhofer@nppd.com
	MEAN /HAST	Billy Cutsor	402-474-4759	402-474-0473	bjcutsor@nmppenergy.org
		Jill Jones (Alt.)	402-474-4759	402-474-0473	jjones@nmppenergy.org
	GRIS	Dustin Betz*	402-563-5313	402-563-5941	ddbetz@nppd.com
		Jeff Mead (Alt.)	308-385-5465	308-385-5449	jmead@grand-island.com
		Travis Burdett (Alt.)	308-385-5466	308-385-5449	tburdett@grand-island.com
	WAPA	Holli Krizek (Primary)	406-255-2835	406-247-7408	krizek@wapa.gov
	WAPA	Gayle Nansel	406-255-2830	406-255-2900	nansel@wapa.gov
	WAPA	Ben Hammer	406-255-2831		hammer@wapa.gov
	BEPC / TSGT	Wayne Haidle	701-355-5643	701-224-5332	Whaidle@bepc.com
		Dave Rudolph (Alt.)	701-355-5722	701-224-5332	drudolph@bepc.com
645	OPPD	John Mayhan	402-552-5173	402-552-5679	jmayhan@oppd.com
		Jon Shipman	402-552-5174	402-552-5679	jeshipman@oppd.com
		Dan Lenihan	402-552-5126	402-552-5679	djlenihan@oppd.com
		Dave Dieterich	402-552-5176	402-552-5679	dmdieterich@oppd.com
650	LES	Alan Burbach	402-473-3374	402-475-1716	aburbach@les.com
		Clinton Bruhn (SC)	402-467-7598		cbruhn@les.com
803	Central Valley	Chuck Pinson	575-746-3571		cpinson@cvecoop.org
803	Central Valley	Russ McKee	575-746-3571		
811	Lea Electric	Gregory Faith	575-396-9172		GregFaith@lcecnet.com
813	LP&L	Eduardo Rodriguez	806-775-3516		erodriguez@lpandl.com
821	GSEC	Mark Reinart	806-349-6562		mreinart@gsec.coop
		Shane McMinn	806-337-1297		smcminn@gsec.coop
849	ITCGP	Gimod Olapurayil	785-506-8290		golapurayil@itctransco.com
		Alan Myers	785-215-0595		amyers@Itctransco.com
OTHER	ETEC	John Chiles	770-425-8100	770-426-0303	john.chiles@gdsassociates.com
	Redbud	Rob Janssen	202-249-0215		rob.janssen@kelsonenergy.com
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	Rayburn	Eddy Reece	214-668-3685		ereece@rayburnelectric.com
SPP Staff	Powerflow	Anthony Cook*	501-688-1670		acook@spp.org
	Short Circuit	Brandon Hentschel	501-688-1603		bhentschel@spp.org
	Dynamics	Scott Jordan	501-614-3985	501-821-3245	sjordan@spp.org
SERC	SERC	Kim Thomas	704-357-7372		kthomas@serc1.org
330	AECI (powerflow)	Mark Moor (primary)	417-885-9256		mmoor@aeci.org
		Tony Gott (alt.)	417-885-9365	417-885-9229	tgott@aeci.org
		Jared Yust	417-885-9232		jyust@aeci.org
		Zach Stica	417-885-9328		zstica@AECI.org
332	LAGN	O J Brouillette	225-618-4423	225-618-4330	o.j.brouillette@nrgenergy.com
333	CWLD	Ryan Williams	573-874-7483		RPWillia@GoColumbiaMO.com
346	SOUCO	Katrina Swanson	205-257-3755		KESWANSO@southernco.com
346	SOUCO(VST)	DuShaune Carter	205-257-5775	205-257-1040	ddcarter@southernco.com
347	TVA	James Normansell	423-751-4654		jrnormansell@tva.gov
		Brett Guy	423-751-3967		baguy@tva.gov
		William Tiller	423-751-7784		wrtiller@tva.gov
351	ENTR (powerflow)	Bill Hamilton	601-985-2263		whamil1@entergy.com
	ENTR (ties)	Jared Shaw	601-985-2253		jshaw@entergy.com
		Tim Hall (SC)	985-640-5232		thall2@entergy.com
356	AMRN	Eric Burkey	314-554-3097		eburkey@ameren.com
		Jason Genovese	314-554-2561		jgenovese@ameren.com
635	MEC (powerflow)	Daniel Rathe (primary)	563-333-8171		DARathe@midamerican.com
		Daniel Custer (alt.)	563-333-8162		DECuster@midamerican.com
		Luke Erichsen (alt.)	563-333-8266		Lerichsen@midamerican.com
635	MEC (short circuit)	James Wilson	563-333-8154		JFWilson@midamerican.com
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MAIN	MAIN	Anthony Jablonski	630-261-2618		aej@maininc.org
MAPP	MAPP	Larry Brusseau	651632-8429		le.brusseau@mapp.org
MRO	MRO	Salva Andiappan	651-855-1719		sr.andiappan@midwestreliability.org
		Ben Lewiski	651-855-1761		bt.lewiski@midwestreliability.org
		Samuel Zewdie	651-855-1727		ss.zewdie@midwestreliability.org

Model Development Working Group	2013	2012	2011	2010
Number of members	13	13	13	13
Number of responses	13	10	13	12
Response rate	100%	77%	100%	92%
Overall effectiveness score	4.0	4.0	3.9	3.9
Lowest score				
Highest score				

Question	Average score			
	2013	2012	2011	2010
The agenda reflects the actions to be taken during the meeting.	4.3	4.2	4.5	4.5
Meeting materials are provided in a timely manner.	3.9	3.7	3.8	3.6
The information provided prior to the meeting is utilized during the meeting.	4.2	4.1	4.2	4.2
The information presented in meetings is clear.	4.2	4.1	n/a	n/a
Meeting minutes are an accurate reflection of the meeting.	4.1	4.0	4.4	4.1
Additional comments:				
The meeting minutes need to follow NO MORE than one week after the meeting. Any more time than this and the membership may not remember exactly what was discussed or if the minutes accurately represent the statements of the membership. Ideally the minutes should follow the next day since notes capturing the events and discussions of the meeting are being captured at the meeting.				
Membership represents the diversity of the SPP organization.	4.5	4.0	4.1	4.3
Membership has the necessary expertise and/or skills to accomplish its goals.	4.1	3.8	4.3	4.3
Members come prepared to meetings.	3.8	3.9	4.2	3.6
Members are committed to participate and accomplish the group's goals.	4.1	3.8	4.2	4.1
Members are supportive and respectful of the individual needs and differences of group members.	4.3	4.5	4.3	4.5
Additional comments:				
I feel that the membership has forgotten that SPP is in existance because of the membership and not the other way around. The membership should be driving force for what work is needed form SPP, and not allow SPP to do what they want.				
There is a need for more stability expertise to be present in the meetings so that when questions arise, they can be answered immediately. Training on stability related issues could be of benefit to the group as well.				
Some members are not prepared to discuss agenda topics while others are not engaged.				
Members are focused during discussion.	4.0	3.7	4.3	4.1
Decisions are identified and action is recommended.	4.0	3.9	4.2	3.8
Facilitation is sufficient to guide discussion.	3.8	3.9	4.2	4.0
Dissenting voices are heard.	4.2	3.8	4.2	4.1
I depart with a feeling that we have accomplished something.	3.9	3.9	4.1	3.8
Additional comments:				
The chair seeks input, and organizational group members are able to influence key decisions and plans.	4.0	4.2	4.2	4.3
The chair is supportive and respectful of the individual needs and differences of group members.	4.2	4.3	4.3	4.3
The chair keeps the group on task to achieve appropriate outcomes.	3.8	3.8	4.5	4.2
The chair ensures follow-through on questions and commitments.	3.6	3.7	4.3	3.9
Additional comments:				

Please provide three or more recommendations for improvement of this particular group and/or SPP's overall

1. FINALIZE the MDWG Manual, it seems it is always in DRAFT status. 2. Have central location (dedicate link) where all the MDWG documents (powerflow manual, MOD manual, data participation sheet, yearly schedule, etc.) are located. 3. Need to match topology of wind farms that are used between the powerflow and dynamics models. Every year the dyanimic model topologies do not match the power flow, this has to stop!! It is very difficult for members to update models if all the bus numbers change from what is in the powerflow.

PArticipation from the GOs

SPP needs to push harder on the smaller members and groups of municipals to participate and submit their own data rather than relying on the hos TO's.

Other comments

Quit asking for this survey if the recommendations of the membership, as note in the comments in 26, are not going to be executed. One thing is to listen, but someone needs to make sure it happens.

Southwest Power Pool
Model Development Working Group
Charter
May 21, 2014

Purpose

The Model Development Working Group (MDWG) is responsible for the development and maintenance of transmission system data and planning ~~-~~models ~~and applicable SPP Criteria related to~~ (power flow, short circuit~~ models~~, and ~~associated~~ stability~~ database~~) which represents the current and planned transmission system of the Southwest Power Pool (SPP). Additionally, the MDWG supports the development and maintenance of related Criteria, Tariff, Regional Standards, and Business Practices. ~~It~~The MDWG supports the development of inter-regional transmission system model data for ~~is also responsible to provide~~ the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) models. ~~with data that supports the development of inter-regional transmission system models.~~

Comment [AC1]: Stability or dynamics?

Scope of Activities

In carrying out its purposes, the MDWG will:

1. Review and support development of applicable SPP Criteria, Tariff, Regional Standards, and Business Practices related to the development, maintenance, and coordination of powerflow, short circuit, and~~/or~~ dynamic models in support of: the SPP Intergrated Transmission Planning (ITP), Generation Interconnection (GI), Transmission Service Study (TSS), North American Electric Reliability Corporation (NERC) c~~C~~ompliance, and any other planning activities within SPP.

~~2. Determine the models that should be used in the RTO, basis for the models and how they are modified for their purpose.~~Provide guidance to SPP Staff, organizational groups, and stakeholders regarding the appropriate usage and modification of Transmission System models developed by the MDWG.

~~3. Review and periodically monitor the NERC Reliability Standards impacts on Transmission System planning models within SPP. Identify applicable NERC Standards, SPP Regional Standards, and SPP Criteria. Coordinate response on behalf of SPP.~~Periodically review current and proposed NERC Reliability Standards for impacts on Transmission System models within SPP. Develop or recommend changes to Criteria, Tariff, Regional Standards, and Business Practices as appropriate to ensure compliance by SPP with NERC Reliability Standards related to Transmission System models.

4. Develop and ~~M~~maintain Transmission System ~~planning~~ models that represent the current and planned ~~electric network~~transmission system of SPP.

5. Provide ERAG MMWG with the SPP portion of the Eastern Interconnection current and planned Transmission System planning models and coordinate incorporating ERAG MMWG models into the SPP system models.

6. Ensure that the Transmission System planning models adequately support the needs of SPP, SPP membership and SPP organizational groups.

7. In conjunction with each of its Transmission Planners, will develop steady-state, short circuit, and dynamic modeling data requirements and reporting procedures for the SPP reliability region.

Representation
The MDWG membership consists of a minimum of 8 and up to 12 representatives from the SPP membership, including the chair and vice-chair.

Duration
Permanent.

Reporting
The MDWG reports to the Transmission Working Group (TWG). As necessary the MDWG may appoint a member of the MDWG as a liaison to other working groups for specific issues or action items being coordinated.

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Comment [AC2]: Steady-state or powerflow? Global change possibly needed.

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MDWG DYNAMICS MODELS	**200 days**
2014 Model Updates	**200 days**
Dynamic Build Tech Support	**55 days**
Create RFP for Dynamic Build Tech Support	10 days
SPP Delivers RFP to Dynamic Build Tech Support	5 days
Dynamic Build Tech Support Reviews RFP	10 days
SPP and PLI Finalize Contract	30 days
MMWG 2013 Series Dynamic Models	**1 day**
Receive ERAG MMWG SDDB (Dynamics Database)	1 day
Initial Data Update	**20 days**
Initial Data Update - Build and Post DYRE Files, Wind Farm Data, and Docureport	5 days
Initial Data Update - Members Submit Data Updates	15 days
Initial Data Update - Member Data Due	0 days
Powerflow Adjustments	**10 days**
Powerflow Updates	5 days
Wind Farm Topology and GI Updates	5 days
Dynamic Case Adjustments	**38 days**
Update SDDB (ERAG/MMWG Dynamic Database)	4 days
Duplicate Models	2 days
Generator Data Checks	2 days
SDDB Governor Limits and Small Time Constant Reset	2 days
WMOD/Generic WTG Checks	2 days
CONL & GNET Files Updates	4 days
Post Member Feedback for Dynamic Data & Case Issues	1 day
Members Submit Data Updates	15 days
Member Data Due	1 day
Process SPP Member Updates	5 days
Dynamic Case Initialization	**10 days**
Case & Dyre File Corrections based on Initialization Messages	10 days
Build Final Models	**20 days**
20 Second No-fault Test & Case Adjustment	5 days
60 Second Ring-Down Test & Case Adjustment	5 days
NERC B&C Faults Test & Case Adjustment	5 days
Dynamic Case Reduction	5 days
Dynamic Case Review and Finalization	**31 days**
Post Initial Models	5 days
Member Review of Initial Models	10 days
Member Data Due	0 days
Final Data Update - Build Final Models	5 days
Post Final Models	1 day
Member Review for Finalization of Dynamic Models and MDWG Vote	10 days

12/2/13	**9/16/14**	
12/2/13	**9/16/14**	
12/2/13	**2/20/14**	
12/2/13	12/13/13	SPP
12/16/13	12/20/13	SPP
12/23/13	1/8/14	
1/9/14	2/20/14	SPP
1/20/14	**1/20/14**	
4/22/14	4/22/14	
2/4/14	**3/4/14**	
2/4/14	2/10/14	SPP
2/11/14	3/4/14	Members
3/4/14	3/4/14	Members
4/21/14	**5/2/14**	
4/21/14	4/25/14	SPP
4/28/14	5/2/14	SPP
4/28/14	**6/19/14**	
4/28/14	5/1/14	SPP
5/2/14	5/5/14	SPP
5/6/14	5/7/14	SPP
5/8/14	5/9/14	SPP
5/12/14	5/13/14	SPP
5/14/14	5/19/14	SPP
5/20/14	5/20/14	SPP
5/21/14	6/11/14	Members
6/12/14	6/12/14	Members
6/13/14	6/19/14	SPP
6/20/14	**7/3/14**	
6/20/14	7/3/14	SPP
7/7/14	**8/1/14**	
7/7/14	7/11/14	SPP
7/14/14	7/18/14	SPP
7/21/14	7/25/14	SPP
7/28/14	8/1/14	SPP
8/4/14	**9/16/14**	
8/4/14	8/8/14	SPP
8/11/14	8/22/14	Members
8/22/14	8/22/14	Members
8/25/14	8/29/14	SPP
9/2/14	9/2/14	SPP
9/3/14	9/16/14	Members

Name: Branch Overloads

Data Checked: Branches >= 100kV

Conditions Not Allowed: Branch loading above 100% of RATEA or RATEB

Exceptions Allowed: 10 year cases only

Owner	Area	Number	Name	kV	Area	Number	Name	kV	Ckt
520	520	508297	LSSOUTH4	138	520	508840	WILKES 4	138	1
520	520	510877	FIXCT4	138	520	510948	EARLSBORO 4	138	1
520	520	510948	EARLSBORO 4	138	524	515055	MAUD 4	138	1
524	524	514891	SMITHCO4	138	524	514892	DAYTON 4	138	1
524	524	515044	SEMINOL4	138	524	515178	PARKLN 4	138	1
526	526	524007	ROLLHILLS 3	115	526	524106	NORTHWEST 3	115	1
526	526	525524	TOLK_EAST 6	230	526	525543	TOLK_TAP 6	230	@1
526	526	525531	TOLK_WEST 6	230	526	525543	TOLK_TAP 6	230	@1
526	526	528596	CARDINAL 3	115	526	528605	TARGA 3	115	1
526	526	528603	NA_ENRICH 3	115	526	528605	TARGA 3	115	1
536	536	532853	LAWHILL6	230	536	532854	LEC U5 6	230	1
536	536	533011	HALSTDN4	138	536	533013	MOUND 4	138	1
536	536	533012	HALSTDS4	138	536	533015	BENTLEY4	138	1
536	536	533040	EVANS N4	138	536	533065	SG12COL4	138	1
539	534	539671	FTDODGE3	115	534	539771	NFTDODG3	115	1
652	640	640349	SPENCER7	115	652	652510	FTRANDL7	115	1
803	526	527798	EDDY_NTH 3	115	526	527828	CV-12MH 3	115	1

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102.43	102.26	108.84	108.87	103.92	-	-	-	-
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2014MDWGP7-15G.sav	2014MDWGP8-15G.sav	2014MDWG_FINAL-15G.sav	2014MDWGP1-15L.sav	2014MDWGP2-15L.sav	2014MDWGP3-15L.sav	2014MDWGP5-15L.sav	2014MDWGP6-15L.sav	2014MDWG
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102.7	-	-	-	-	-	-	-	-
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GP7-15L.sav

2014MDWGP8-15L.sav	2014MDWG_FINAL-15L.sav	2014MDWGP1-15S.sav	2014MDWGP2-15S.sav	2014MDWGP3-15S.sav	2014MDWGP5-15S.sav	2014MDWGP6-15S.sav	2014MDWGP7-15S.sav	2014MDW
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GP8-15S.sav

2014MDWG_FINAL-15S.sav	2014MDWGP1-15SH.sav	2014MDWGP2-15SH.sav	2014MDWGP3-15SH.sav	2014MDWGP5-15SH.sav	2014MDWGP6-15SH.sav	2014MDWGP7-15SH.sav	2014MDWGP8-15SH.sav	2014MDWG
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G_FINAL-15SH.sav

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GP1-15W.sav

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-	114.98	-	-	-	-	-	-	-
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GP2-16G.sav	2014MDWGP3-16G.sav	2014MDWGP5-16G.sav	2014MDWGP6-16G.sav	2014MDWGP7-16G.sav	2014MDWGP8-16G.sav	2014MDWG_FINAL-16G.sav	2014MDWGP1-16S.sav	2014MDWGP2-16S.sav	2014MDWG
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113.07	102.36	102.43	-	-	-	-	-	-
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135.12	-	-	-	-	-	-	-	133.7
131.5	-	-	-	-	-	-	-	-
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GP5-16W.sav	2014MDWGP6-16W.sav	2014MDWGP7-16W.sav	2014MDWGP8-16W.sav	2014MDWG_FINAL-16W.sav	2014MDWGP1-20L.sav	2014MDWGP2-20L.sav	2014MDWGP3-20L.sav	2014MDWGP5-20L.sav	2014MDW
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103.17	-	-	-	-	-	-	-	-	
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GP6-20L.sav	2014MDWGP7-20L.sav	2014MDWGP8-20L.sav	2014MDWG_FINAL-20L.sav	2014MDWGP1-20S.sav	2014MDWGP2-20S.sav	2014MDWGP3-20S.sav	2014MDWGP5-20S.sav	2014MDWGP6-20S.sav	2014MDWG
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106.24	-	-	-	-	-	-	-	-
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GP7-20S.sav

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-	-	104.96	104.86	104.85	-	-	-	-

GP8-20W.sav

2014MDWG_FINAL-20W.sav	2014MDWGP1-25S.sav	2014MDWGP2-25S.sav	2014MDWGP3-25S.sav	2014MDWGP5-25S.sav	2014MDWGP6-25S.sav	2014MDWGP7-25S.sav	2014MDWGP8-25S.sav	2014MDW
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-	-	-	129.12	-	-	-	-	-
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G_FINAL-25S.sav

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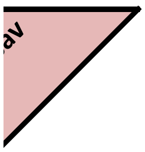
136.69	136.46	136.43	-	-	-	-	-



Member Accountability Process Improvement

1) Update Report Card
    a. Add column to show reoccurring issues per member per pass, add second column to show total issues per member per pass.
    b. Have two projects columns, one for modified projects and one for new projects per member per pass.
    c. Post report card with each pass.
    d. Highlight in red on report card members with zero participation per pass.
    e. Submit report card with every MDWG report to the TWG.

2) Update DocuCheck
    a. Add tab to show number of issues per member per issues category.

3) Posting Email Language Update
    a. Add language to the “Model Posting E-mail” stating DocuCheck issues are required to be corrected at a minimum.
    b. Let the Members know that staff will be contacting them in the event of reoccurring issues.

4) Contact Individual Members
    a. After the build of Pass 2 and continuing to the finalization of Models, contact members by email and phone to prompt correction of DocuCheck issues. Retain documentation of correspondence and actions by the member to correct the issues.
    b. If issues are not corrected by the next pass (Pass 3) then modeling manager is notified and will attempt to contact the member’s supervisor.
    c. In the event of zero participation during any pass modeling staff contacts the members, if zero participation occurs in the next pass modeling manager is notified and will attempt to contact the member’s supervisor.

2015 Series Model Selection						
MMWG		MMWG	MDWG		**MDWG**	
Power Flow Model	**Dynamic Model**	**Year**	**Year**	**Season**	**Power Flow Model**	**Dynamic Model**
		2015	**2015**	**Spring**	**X**	
		2015	**2015**	**Summer**	**X**	
		2015	**2015**	**Summer Shoulder**	**X**	
		2015	**2015**	**Fall**	**X**	
		2015	**2015**	**Winter**	**X**	
X	**X**	**2016**	**2016**	**Light Load**	**X**	**X**
X		**2016**	**2016**	**Spring**	**X**	
X	**X**	**2016**	**2016**	**Summer**	**X**	**X**
X	**X**	**2016**	**2016**	**Summer Shoulder**	**X**	**X**
X		**2016**	**2016**	**Fall**	**X**	
X	**X**	**2016**	**2016**	**Winter**	**X**	**X**
X		**2017**	**2017**	**Spring**	**X**	
X	**X**	**2017**	**2017**	**Summer**	**X**	**X**
X		**2017**	**2017**	**Winter**	**X**	
X	**X**	**2021**	**2020**	**Light Load**	**X**	**X**
X	**X**	**2021**	**2020**	**Summer**	**X**	**X**
X	**X**	**2021**	**2020**	**Winter**	**X**	**X**
X		**2026**	**2025**	**Summer**	**X**	**X**
		2026	**2025**	**Winter**	**X**	

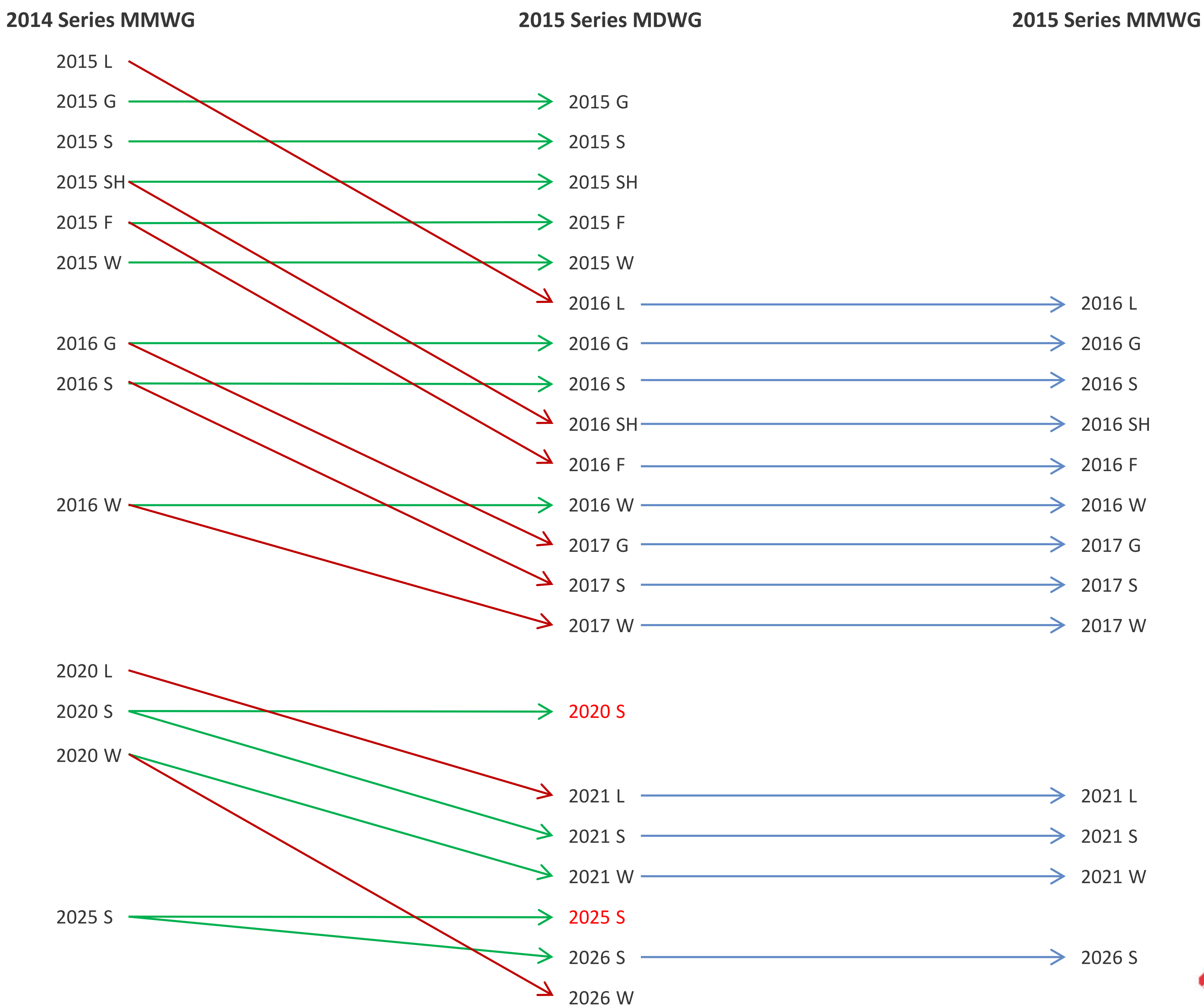
MMWG: Multiregional Modeling Working Group
MDWG: Model Development Working Group

Short Circuit Model
X
X

Model Mapping

SPP Southwest Power Pool

Helping our members
work together to
keep the lights on...
today and in the future



2014 Series MMWG
2015 Series MDWG
2015 Series MMWG
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2020 L
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A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-001-4	R1.	01/01/2015	
TPL-001-4	R2.	01/01/2016	
TPL-001-4	R3.	01/01/2016	
TPL-001-4	R4.	01/01/2016	
TPL-001-4	R5.	01/01/2016	
TPL-001-4	R6.	01/01/2016	
TPL-001-4	R7.	01/01/2015	
TPL-001-4	R8.	01/01/2016	

2015 TPL Powerflow Model and Dynamic Model sets

Background

This document is not intended to replace the NERC TPL-001-4 standard, only complement it. If there is any uncertainty, please refer to the standard directly.

January 1, 2015 is the effective date for requirements R1 and R7, as well as the definitions listed in the NERC Implementation Plan for TPL-001-4[1]. Therefore, the 2014 Series MDWG models, built from 8/2013 to 3/2014, must be compliant with requirements R1 and R7. Requirement R1 is related to maintaining System models and the data needed to do so. Requirement R7 is related to defining the individual and joint responsibilities of the Planning Coordinator and the Transmission Planners.

Requirement R2-R6 and R8 of the TPL-001-4 standard has an effective date of January 1, 2016. The 2015 TPL Assessment must be completed before January 1, 2016 and be compliant with the TPL-001-4 standard in full. Requirements R2-R6 outline the model set used and the details of the three analyses: Steady State, Stability, and Short Circuit. Requirement R8 describes how the Planning Coordinator and the Transmission Planners shall distribute its Planning assessment.

Model Content

Requirement R1 states, "The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions." Specifically the models must include:

R1.1.1 Existing Facilities
R1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months
R1.1.3 New planned Facilities and changes to existing Facilities
R1.1.4 Real and reactive Load forecasts
R1.1.5 Known commitments for Firm Transmission Service and Interchange
R1.1.6 Resources (supply or demand side) required for Load

[1] TPL0014RD_Implementation.pdf, page 1: The effective date is the date entities are expected to meet the performance identified in this standard.

2015 TPL Powerflow Model and Dynamic Model sets

Power Flow Model Set Options

There are two main drivers when determining the model set to be used in the 2015 TPL analyses.

First, Year One[2] must be defined in order to derive the year five model. The TPLTF voted during the 5/5/2014 net conference to define year one as the current study year plus one. For example, the TPL study that occurs in the 2015 calendar year would use 2016 as Year One. The standard requires in R2.1.1[3] and R2.1.2[4] that three Near-Term horizon[5] models be built:

1. Year 1 or 2 peak
2. Year 5 peak
3. Year 1 – 5 off-peak

R2.2.1 requires one Long-Term horizon[6] model be built.

1. Year 6 – 10 peak or beyond

Secondly, sensitivity cases must be developed to satisfy R2.1.4[7] for each case in R2.1.1 and R2.1.2. Staff has developed three options for the required 2015 TPL model set. SPP Staff requests that the Task Force review these draft options to ensure compliance with TPL-001-4 with emphasis on R2.1.4:

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[2] The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

[3] System peak Load for either Year One or year two, and for year five.

[4] System Off-Peak Load for one of the five years.

[5] The transmission planning period that covers Year One through five.

[6] Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

[7] For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: Real and reactive forecasted Load, Expected transfers, Expected in service dates of new or modified Transmission Facilities, Reactive resource capability, Generation additions or retirements or other dispatch scenarios, Controllable Loads and Demand Side Management, Duration or timing of known Transmission outages.

2015 TPL Powerflow Model and Dynamic Model sets

OPTION #1 – 2016 Year One, Shoulder Transfer

Requirement	Description	Base case	Sensitivity case (R2.1.4)
R2.1.1	Year 1 or 2 peak	MDWG 2016S	MDWG 2016SH transfer*
R2.1.1	Year 5 peak	MDWG 2020S*	MDWG 2020SH transfer*
R2.1.2	Year 1 - 5 off-peak	MDWG 2016G	MDWG 2016L
R2.2.1	Long-Term horizon peak	MDWG 2025S*	N/A

* Model is not being built during current processes.

OPTION #2 – 2016 Year One, Extreme Summer

Requirement	Description	Base case	Sensitivity case (R2.1.4)
R2.1.1	Year 1 or 2 peak	MDWG 2016S	MDWG 2016S extreme*
R2.1.1	Year 5 peak	MDWG 2020S*	MDWG 2020S extreme*
R2.1.2	Year 1 - 5 off-peak	MDWG 2016G	MDWG 2016L
R2.2.1	Long-Term horizon peak	MDWG 2025S*	N/A

* Model is not being built during current processes.

OPTION #3 – 2016 Year One, ITPNT sensitivities

Requirement	Description	Base case	Sensitivity case (R2.1.4)
R2.1.1	Year 1 or 2 peak	MDWG 2016S	ITPNT 2016SP5
R2.1.1	Year 5 peak	MDWG 2020S*	ITPNT 2020SP5*
R2.1.2	Year 1 - 5 off-peak	MDWG 2016G	ITPNT 2016L5
R2.2.1	Long-Term horizon peak	MDWG 2025S*	N/A

* Model is not being built during current processes.

2015 TPL Powerflow Model and Dynamic Model sets

Dynamic Model Set Options

There are two main drivers when determining the model set to be used in the 2015 TPL analyses.

First, Year One must be defined in order to derive the year five model. The standard requires in R2.4.1 and R2.4.2 that two Near-Term horizon models be built:

1. Year 1 - 5 peak
2. Year 1 – 5 off-peak

R2.5 requires one Long-Term horizon model be built.

3. Year 6 – 10 peak or beyond

Secondly, sensitivity cases must be developed to satisfy R2.4.1 and R2.4.2. Staff has developed two options for the required 2015 TPL model set. SPP Staff requests that the Task Force review these draft options to ensure compliance with TPL-001-4 with emphases on R2.4.3:

OPTION #1 – 2016 Year One

Requirement	Description	Base case	Sensitivity case (R2.4.3)
R2.4.1	Year 1 through 5 peak	MDWG 2016S	MDWG 2016SH
R2.4.2	Year 1 through 5 off-peak	MDWG 2016L	MDWG 2016G*
R2.5	Long-Term horizon peak	MDWG 2025S*	N/A

* Model is not being built during current processes.

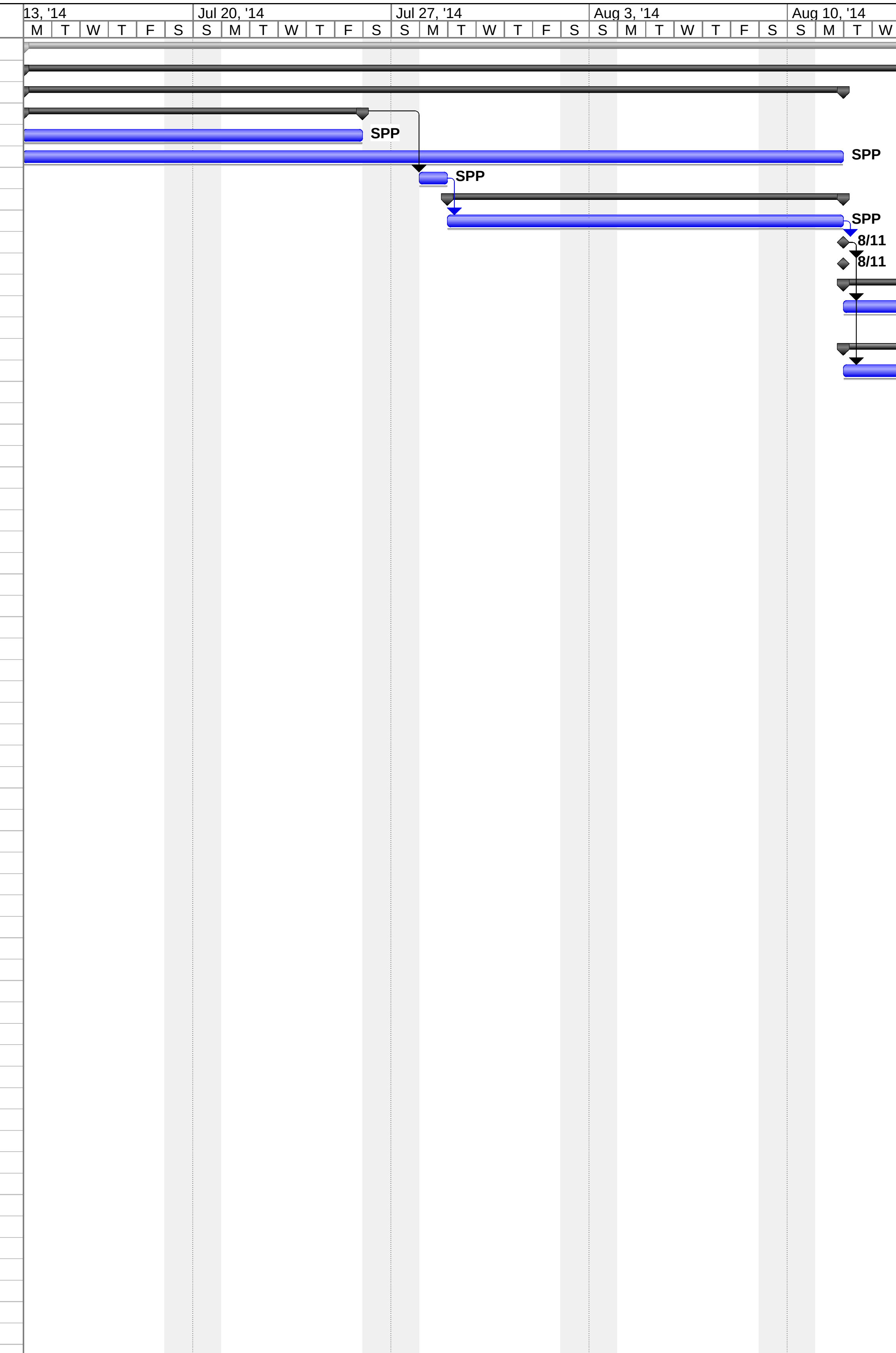
2015 TPL Powerflow Model and Dynamic Model sets

Proposed 2015 Series		
MMWG	**MDWG**	**2016 ITPNT**
	15G	15SP0
	15S[Δ]	15SP5
	15SH	15WP0
	15F	15WP5
	15W	16G0
16G	16G	16G5
16L[o]	16L[o]	16L0
16S[o]	16S[o]	16L5
16SH[o]	16SH[o]	16SP0
16F	16F	16SP5
16W[o]	16W[o]	16WP0
17G	17G	16WP5
17S[o]	17S[o]	17SP0
17W	17W	17SP5
21L[o]	21L[o]	17WP0
21S[o]	21S[oΔ]	17WP5
21W[o]	21W[o]	21L0
26S	26S[o]	21L5
	26W	21SP0
		21SP5
		21WP0
		21WP5
		26SP0
		26SP5
		26WP0
		26WP5

[o] Dynamic Model

[Δ] Short circuit Model

ID	WBS	Task Name	Duration	Start	Finish	Predecessors	Resource Names
0	0	**2015 MDWG Powerflow and Dynamics Models**	**276 days**	**Mon 7/14/14**	**Mon 8/10/15**		
1	**1**	**2015 MDWG Powerflow and Dynamics Models**	**276 days**	**Mon 7/14/14**	**Mon 8/10/15**		
2	**1.1**	**Kick-off**	**21 days**	**Mon 7/14/14**	**Mon 8/11/14**		
3	**1.1.1**	**Kick-off - Review MOD Projects**	**10 days**	**Mon 7/14/14**	**Fri 7/25/14**		
4	1.1.1.1	Kick-off - Review MOD Projects	10 days	Mon 7/14/14	Fri 7/25/14		SPP
5	1.1.2	Kick-off - Lock Down MOD	21 days	Mon 7/14/14	Mon 8/11/14		SPP
6	1.1.3	Kick-off - MOD Model Extraction	1 day	Mon 7/28/14	Mon 7/28/14	3	SPP
7	**1.2**	**Kick-off - Build Pass 1 Powerflow**	**10 days**	**Tue 7/29/14**	**Mon 8/11/14**		
8	1.2.1	Kick-off - Build Pass 1 Powerflow	10 days	Tue 7/29/14	Mon 8/11/14	6	SPP
9	1.3	Kick-off - Post Pass 1 Powerflow	0 days	Mon 8/11/14	Mon 8/11/14	8	SPP
10	1.4	Kick-off - Initial Data Request (Contingency List Updates, Transactions, MTL)	0 days	Mon 8/11/14	Mon 8/11/14	9	SPP
11	**1.5**	**Pass 1**	**27 days**	**Tue 8/12/14**	**Thu 9/18/14**		
12	1.5.1	Pass 1 - Members Review/Submit Changes to Pass 1 Models	10 days	Tue 8/12/14	Mon 8/25/14	9	Members
13	1.5.2	Pass 1 - Member Review/Changes Due (Projects, Transactions, MTL, Contingency List)	0 days	Mon 8/25/14	Mon 8/25/14	12	Members
14	**1.5.3**	**Pass 1 - Review MOD Projects**	**15 days**	**Tue 8/12/14**	**Tue 9/2/14**		
15	1.5.3.1	Pass 1 - Review MOD Projects	15 days	Tue 8/12/14	Tue 9/2/14	9	SPP
16	1.5.4	Pass 1 - Lock Down MOD	16 days	Tue 8/26/14	Wed 9/17/14		SPP
17	1.5.5	Pass 1 - MOD Model Extraction	1 day	Wed 9/3/14	Wed 9/3/14	15	SPP
18	**1.5.6**	**Pass 1 - Build Pass 2 Powerflow Models**	**10 days**	**Thu 9/4/14**	**Wed 9/17/14**		
19	1.5.6.1	Pass 1 - Build Pass 2 Powerflow Models	10 days	Thu 9/4/14	Wed 9/17/14	17	SPP
20	1.5.7	Pass 1 - Post Pass 2 Powerflow Models	0 days	Wed 9/17/14	Wed 9/17/14	19	SPP
21	1.5.8	Pass 1 - Pass 2 ACCC Analysis	1 day	Thu 9/18/14	Thu 9/18/14	20	SPP
22	**1.6**	**Pass 2**	**32 days**	**Thu 9/18/14**	**Fri 10/31/14**		
23	1.6.1	Pass 2 - Members Review/Submit Changes to Pass 2 Powerflow Models	10 days	Thu 9/18/14	Wed 10/1/14	20	Members
24	1.6.2	Pass 2 - Member Review/Changes Due	0 days	Wed 10/1/14	Wed 10/1/14	23	Members
25	1.6.3	*Request First Tier external Short Circuit sequence data*	0 days	Wed 10/15/14	Wed 10/15/14		SPP
26	**1.6.4**	**Pass 2 - Review MOD Projects**	**20 days**	**Thu 9/18/14**	**Wed 10/15/14**		
27	1.6.4.1	Pass 2 - Review MOD Projects	20 days	Thu 9/18/14	Wed 10/15/14	20	SPP
28	1.6.5	Pass 2 - Lock Down MOD	21 days	Thu 10/2/14	Thu 10/30/14		SPP
29	1.6.6	Pass 2 - MOD Model Extraction	1 day	Thu 10/16/14	Thu 10/16/14	27	SPP
30	**1.6.7**	**Pass 2 - Build Pass 3 Powerflow Models**	**10 days**	**Fri 10/17/14**	**Thu 10/30/14**		
31	1.6.7.1	Pass 2 - Build Pass 3 Powerflow Models	10 days	Fri 10/17/14	Thu 10/30/14	29	SPP
32	1.6.8	Pass 2 - Post Pass 3 Powerflow Models	0 days	Thu 10/30/14	Thu 10/30/14	31	SPP
33	1.6.9	Pass 2 - Pass 3 ACCC Analysis	1 day	Fri 10/31/14	Fri 10/31/14	32	SPP
34	**1.7**	**Pass 3**	**27 days**	**Fri 10/31/14**	**Wed 12/10/14**		
35	1.7.1	*Pass 3 - Request Review of 2014 ITP IDEVS*	0 days	Fri 11/14/14	Fri 11/14/14		SPP
36	1.7.2	Pass 3 - Members Review/Submit Changes to Pass 3 Powerflow Models	10 days	Fri 10/31/14	Thu 11/13/14	32	Members
37	1.7.3	Pass 3 - Member Review/Changes Due	0 days	Thu 11/13/14	Thu 11/13/14	36	Members
38	**1.7.4**	**Pass 3 - Review MOD Projects**	**15 days**	**Fri 10/31/14**	**Thu 11/20/14**		
39	1.7.4.1	Pass 3 - Review MOD Projects	15 days	Fri 10/31/14	Thu 11/20/14	32	SPP
40	1.7.5	Pass 3 - Lock Down MOD	16 days	Fri 11/14/14	Tue 12/9/14		SPP
41	1.7.6	Pass 3 - Model Update Meeting	2 days	Mon 11/10/14	Tue 11/11/14		
42	1.7.7	Pass 3 - MOD Model Extraction	1 day	Fri 11/21/14	Fri 11/21/14	39	SPP
43	**1.7.8**	**Pass 3 - Build Pass 4 Powerflow Models**	**10 days**	**Mon 11/24/14**	**Tue 12/9/14**		
44	1.7.8.1	Pass 3 - Build Pass 4 Powerflow Models - Merge with 2014 MMWG Series	10 days	Mon 11/24/14	Tue 12/9/14	42	SPP
45	1.7.9	Pass 3 - Post Pass 4 Powerflow Models	0 days	Tue 12/9/14	Tue 12/9/14	44	SPP
46	1.7.10	Pass 3 - Pass 4 ACCC Analysis	1 day	Wed 12/10/14	Wed 12/10/14	45	SPP
47	**1.8**	**Pass 4**	**24 days**	**Wed 12/10/14**	**Wed 1/14/15**		
48	1.8.1	Pass 4 - Members Review/Submit Changes to Pass 4 Powerflow Models	10 days	Wed 12/10/14	Tue 12/23/14	45	Members
49	1.8.2	Pass 4 - Member Review/Changes Due	0 days	Tue 12/23/14	Tue 12/23/14	48	Members
50	**1.8.3**	**Pass 4 - Review MOD Projects**	**12 days**	**Wed 12/10/14**	**Mon 12/29/14**		
51	1.8.3.1	Pass 4 - Review MOD Projects	12 days	Wed 12/10/14	Mon 12/29/14	45	SPP
52	1.8.4	Pass 4 - Lock Down MOD	13 days	Fri 12/26/14	Tue 1/13/15		SPP
53	1.8.5	Pass 4 - MOD Model Extraction	1 day	Tue 12/30/14	Tue 12/30/14	51	SPP
54	**1.8.6**	**Pass 4 - Build Pass 5 Powerflow Models**	**10 days**	**Wed 12/31/14**	**Tue 1/13/15**		
55	1.8.6.1	Pass 4 - Build Pass 5 Powerflow Models	10 days	Wed 12/31/14	Tue 1/13/15	53	SPP
56	1.8.7	Pass 4 - Post Pass 5 Powerflow Models	0 days	Tue 1/13/15	Tue 1/13/15	54	SPP
57	1.8.8	Pass 4 - Pass 5 ACCC Analysis	1 day	Wed 1/14/15	Wed 1/14/15	56	SPP
58	**1.9**	**Pass 5**	**27 days**	**Wed 1/14/15**	**Thu 2/19/15**		
59	1.9.1	Pass 5 - Members Review/Submit Changes to Pass 5 Powerflow Models	10 days	Wed 1/14/15	Tue 1/27/15	56	Members
60	1.9.2	Pass 5 - Member Review/Changes Due	0 days	Tue 1/27/15	Tue 1/27/15	59	Members
61	**1.9.3**	**Pass 5 - Review MOD Projects**	**15 days**	**Wed 1/14/15**	**Tue 2/3/15**		



Project: 2015 MDWG Powerflow and D
Date: Tue 5/13/14

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone

ID	WBS	Task Name	Duration	Start	Finish	Predecessors	Resource Names
62	1.9.3.1	Pass 5 - Review MOD Projects	15 days	Wed 1/14/15	Tue 2/3/15	56	SPP
63	1.9.4	Pass 5 - Lock Down MOD	16 days	Wed 1/28/15	Wed 2/18/15		SPP
64	1.9.5	Pass 5 - MOD Model Extraction	1 day	Wed 2/4/15	Wed 2/4/15	62	SPP
65	**1.9.6**	**Pass 5 - Build Final Powerflow Models**	**10 days**	**Thu 2/5/15**	**Wed 2/18/15**		
66	1.9.6.1	Pass 5 - Build Final Powerflow Models - with ITP NTC IDEVS	10 days	Thu 2/5/15	Wed 2/18/15	64	SPP
67	1.9.7	Pass 5 - Post MDWG 2015 Series Build Final Powerflow Models	0 days	Wed 2/18/15	Wed 2/18/15	65	SPP
68	1.9.8	Pass 5 - Final ACCC Analysis	1 day	Thu 2/19/15	Thu 2/19/15	67	SPP
69	**1.10**	**Final**	**10 days**	**Thu 2/19/15**	**Wed 3/4/15**		
70	1.10.1	Final - Members Review for Finalization of Powerflow Models and MDWG Vote	10 days	Thu 2/19/15	Wed 3/4/15	67	Members
71	**1.11**	**MDWG Short Circuit Models - Build Pass 1 Short Circuit Models**	**21 days**	**Thu 3/5/15**	**Thu 4/2/15**		
72	1.11.1	Pass 1 - Build Pass 1 Short Circuit Models	2 days	Thu 3/5/15	Fri 3/6/15	70	SPP
73	1.11.2	Pass 1 - Post Pass 1 Short Circuit Models	0 days	Fri 3/6/15	Fri 3/6/15	72	SPP
74	1.11.3	Pass 1 - Members Review/Submit Changes to Pass 1 Short Circuit Models	7 days	Mon 3/9/15	Tue 3/17/15	73	Members
75	1.11.4	Pass 1 - Member Review/Changes Due	0 days	Tue 3/17/15	Tue 3/17/15	74	Members
76	1.11.5	Final - Implement Member Changes/Updates to Pass 1 Short Circuit Models	2 days	Wed 3/18/15	Thu 3/19/15	75	SPP
77	1.11.6	Final - Post MDWG 2015 Series Final Short Circuit Models	0 days	Thu 3/19/15	Thu 3/19/15	76	SPP
78	1.11.7	Final - Member Review for Finalization of Short Circuit Models and MDWG Vote	10 days	Fri 3/20/15	Thu 4/2/15	77	Members
79	**1.12**	**MDWG DYNAMICS MODELS**	**177 days**	**Wed 12/3/14**	**Mon 8/10/15**		
80	**1.12.1**	**2015 Model Updates**	**177 days**	**Wed 12/3/14**	**Mon 8/10/15**		
81	**1.12.1.1**	**Dynamic Build Tech Support**	**45 days**	**Wed 12/3/14**	**Thu 2/5/15**		
82	1.12.1.1.1	Create RFP for Dynamic Build Tech Support	10 days	Wed 12/3/14	Tue 12/16/14		SPP
83	1.12.1.1.2	SPP Delivers RFP to Dynamic Build Tech Support	5 days	Wed 12/17/14	Tue 12/23/14	82	SPP
84	1.12.1.1.3	Dynamic Build Tech Support Reviews RFP	10 days	Fri 12/26/14	Thu 1/8/15	83	
85	1.12.1.1.4	SPP and PLI Finalize Contract	20 days	Fri 1/9/15	Thu 2/5/15	84	SPP
86	**1.12.1.2**	**MMWG 2014 Series Dynamic Models**	**1 day**	**Wed 1/21/15**	**Wed 1/21/15**		
87	1.12.1.2.1	Receive ERAG MMWG SDDB (Dynamics Database)	1 day	Wed 1/21/15	Wed 1/21/15		
88	**1.12.1.3**	**Initial Data Update**	**20 days**	**Thu 2/19/15**	**Wed 3/18/15**		
89	**1.12.1.3.1**	**Initial Data Update - Build and Post DYRE Files, Wind Farm Data, and Docureport**	**5 days**	**Thu 2/19/15**	**Wed 2/25/15**		
90	1.12.1.3.1.1	Initial Data Update - Build and Post DYRE Files, Wind Farm Data, and Docureport	5 days	Thu 2/19/15	Wed 2/25/15	67	SPP
91	1.12.1.3.2	Initial Data Update - Members Submit Data Updates	15 days	Thu 2/26/15	Wed 3/18/15	90	Members
92	1.12.1.3.3	Initial Data Update - Member Data Due	0 days	Wed 3/18/15	Wed 3/18/15	91	Members
93	**1.12.1.4**	**Powerflow Adjustments**	**15 days**	**Thu 2/26/15**	**Wed 3/18/15**		
94	1.12.1.4.1	Powerflow Updates	5 days	Thu 2/26/15	Wed 3/4/15	90	SPP
95	1.12.1.4.2	Wind Farm Topology and GI Updates	10 days	Thu 3/5/15	Wed 3/18/15	94	SPP
96	**1.12.1.5**	**Dynamic Case Adjustments**	**42 days**	**Thu 3/19/15**	**Fri 5/15/15**		
97	1.12.1.5.1	Update SDDB (ERAG/MMWG Dynamic Database)	5 days	Thu 3/19/15	Wed 3/25/15	92	SPP
98	1.12.1.5.2	Duplicate Models	2 days	Thu 3/26/15	Fri 3/27/15	97	SPP
99	1.12.1.5.3	Generator Data Checks	2 days	Mon 3/30/15	Tue 3/31/15	98	SPP
100	1.12.1.5.4	SDDB Governor Limits and Small Time Constant Reset	2 days	Wed 4/1/15	Thu 4/2/15	99	SPP
101	1.12.1.5.5	WMOD/Generic WTG Checks	5 days	Fri 4/3/15	Thu 4/9/15	100	SPP
102	1.12.1.5.6	CONL & GNET Files Updates	4 days	Fri 4/10/15	Wed 4/15/15	101	SPP
103	1.12.1.5.7	Post Member Feedback for Dynamic Data & Case Issues	1 day	Thu 4/16/15	Thu 4/16/15	102	SPP
104	1.12.1.5.8	Members Submit Data Updates	15 days	Fri 4/17/15	Thu 5/7/15	103	Members
105	1.12.1.5.9	Member Data Due	1 day	Fri 5/8/15	Fri 5/8/15	104	Members
106	1.12.1.5.10	Process SPP Member Updates	5 days	Mon 5/11/15	Fri 5/15/15	105	SPP
107	**1.12.1.6**	**Dynamic Case Initialization**	**10 days**	**Mon 5/18/15**	**Fri 5/29/15**		
108	1.12.1.6.1	Case & Dyre File Corrections based on Initialization Messages	10 days	Mon 5/18/15	Fri 5/29/15	106	SPP
109	**1.12.1.7**	**Build Final Models**	**20 days**	**Mon 6/1/15**	**Fri 6/26/15**		
110	1.12.1.7.1	20 Second No-fault Test & Case Adjustment	5 days	Mon 6/1/15	Fri 6/5/15	108	SPP
111	1.12.1.7.2	60 Second Ring-Down Test & Case Adjustment	5 days	Mon 6/8/15	Fri 6/12/15	110	SPP
112	1.12.1.7.3	NERC B&C Faults Test & Case Adjustment	5 days	Mon 6/15/15	Fri 6/19/15	111	SPP
113	1.12.1.7.4	Dynamic Case Reduction	5 days	Mon 6/22/15	Fri 6/26/15	112	SPP
114	**1.12.1.8**	**Dynamic Case Review and Finalization**	**31 days**	**Mon 6/29/15**	**Mon 8/10/15**		
115	1.12.1.8.1	Post Initial Models	5 days	Mon 6/29/15	Fri 7/3/15	113	SPP
116	1.12.1.8.2	Member Review of Initial Models	10 days	Mon 7/6/15	Fri 7/17/15	115	Members
117	1.12.1.8.3	Member Data Due	0 days	Fri 7/17/15	Fri 7/17/15	116	Members
118	1.12.1.8.4	Final Data Update - Build Final Models	5 days	Mon 7/20/15	Fri 7/24/15	117	SPP
119	1.12.1.8.5	Post Final Models	1 day	Mon 7/27/15	Mon 7/27/15	118	SPP
120	1.12.1.8.6	Member Review for Finalization of Dynamic Models and MDWG Vote	10 days	Tue 7/28/15	Mon 8/10/15	119	Members

13, '14 | Jul 20, '14 | Jul 27, '14 | Aug 3, '14 | Aug 10, '14

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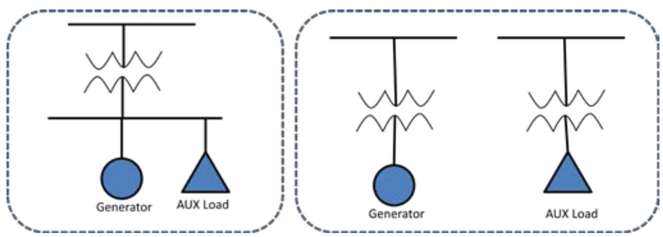
Project: 2015 MDWG Powerflow and D
Date: Tue 5/13/14

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone

SPP Staff Recommendations for Modeling 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. ~~Maximum~~ P_{GEN} value should not exceed~~be based on~~ average historical ~~peak~~ values for the Winter, Spring, Light Load, and Fall Cases.
   b. ~~Maximum~~ P_{GEN} shall not exceed values ~~will be~~ 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 ~~for the EIA-411 reporting~~. In accordance with Attachment 1, Section 5 of MOD-025-02 an exception process 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 ~~and the EIA-411 reporting~~.
      iv. Justification of the change if it is greater than or less than 5% of the MOD-025-02/SPP Criteria testing ~~and the EIA-411 reporting.~~
   b. 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.