Evaluation of Criteria, Methods, and Practices Used for System Design, Planning, and Analysis Response to NERC Blackout Recommendation 13c

Appendix C — Regional Summary Reports on Planning Practices and Procedures
In general, ECAR performs assessments for summer and winter peak load periods. These are done seasonally and under the direction of the ECAR Transmission System Performance Panel (TSPP). Summer peak load periods for future time frames are also assessed annually. These assessments do include analyzing contingencies. ECAR periodically performs special studies that include multiple/extreme contingencies.

ECAR has not specifically solicited its Members for this survey, but did collect study criteria for voltage limits and conducted site audits that address the ratings issue in this request. The results of the criteria collection indicated that the Member companies do not all use the same criteria in performing their internal studies.

The ECAR Executive Office maintains the Raw Machine Database (RAWMAC) that includes generator data used in power flow base cases. That database does contain a sequential list for generation dispatch, along with other information such as Pmin, Pmax, Qmin, Qmax, voltage schedule of the controlled bus, and minimum voltage for operation.

1. **Contingencies analyzed** – Before any ECAR assessment study is performed, the TSPP reviews and approves the contingencies that will be considered in the upcoming study. This includes both seasonal and future assessments.

ECAR has historically maintained a contingency database that contains outages for simulation in a given study. This database previously organized these contingencies under ten (10) outage types (Types 1 through 10), which corresponded to the single and multiple contingency events that are referenced in ECAR Document No. 1. As part of the 2005 Summer assessment effort, this database is being converted to coincide with the contingency categories outlined under Table I in the NERC Planning Standards.

The list of contingencies simulated in a given seasonal assessment is contained in the appendix of the associated report (e.g., Appendix I of report 04-TSPP-3, attached). For the summer of 2004, the contingencies simulated were single circuits, single circuit segments of multiple terminal circuits (circuit segments that can be outaged by automatically sectionalizing multiple terminal circuits), multiple terminal circuits (single circuit segments that are outaged together by normal circuit breaker action), and selected double-circuit towers.

The list of contingencies simulated in a given future assessment is also contained in the appendix of the associated report (e.g., Appendix I of report 02-TSPP-55, attached). The contingencies simulated in that study are similar to those of the seasonal assessment noted above. An extreme contingency future study for 2003 summer that was completed in 2000 simulated selected NERC Category C and D contingencies (ECAR Types 4 through 8), as documented in the attached 00-TSPP-55 report. ECAR has completed the simulation portion and is drafting the documentation report for an extreme contingency future study for 2009 summer that considered ECAR outage Types 1 through 10 (NERC Categories A through D).
ECAR also directs the seasonal and future peer review assessments conducted by its Members, which also address the NERC Category A through D contingencies, as summarized in the attached 04-TSPP-3S and 04-TSPP-55S reports.

2. **Load levels studied** – In general, ECAR uses the load levels that the Members incorporate into their base case models that are developed as part of the annual ECAR and NERC MMWG base case development efforts. ECAR is mostly concerned with summer peak load levels, and these are the ones most frequently studied.
   a. ECAR has not solicited its Members to account for how their load levels are determined. The general expectation is that most (if not all) use a 50/50 forecast in their ECAR base cases, although some have used higher (e.g., 90/10) load levels in their ECAR peer review assessments.
   b. ECAR has not considered off-peak load levels, except for the Y2k event, but is looking to incorporate such analyses to address performance issues under pumping load conditions.
   c. The ECAR Members determine their load forecasting methods and ECAR has not solicited them for information related to this request.
   d. This item was addressed through recent TSPP ratings audits of Members to satisfy Blackout Recommendation 15.D.2 from the U.S.-Canadian Task Force. Most ECAR Members use actual metered MW and MVAR values in their load forecasts that are modeled in the power flow base cases.

3. **Voltage limits applied** – The ECAR Members have different voltage study criteria of their own and therefore, ECAR must determine a single criterion to use in its studies.
   a. The ECAR TSPP determines the voltage limits that will be used in a given ECAR study. Typical ECAR voltage study screening criteria include voltage levels falling below 90%, voltage drops greater than 10%, and voltage levels falling below a given generating facilities minimum operating voltage as specified by the ECAR Members in the ECAR RAWMAC Database.
   b. ECAR assessments typically consider voltage drop limits after the transformer taps are automatically adjusted in the base case solution.
   c. ECAR does not have, and thus, does not apply a voltage dip duration criterion.
   d. Voltage stability limits are typically addressed in ECAR either through the loadability ratings some of the ECAR Members assign to their applicable facilities in the power flow base case models, or through the PV-curve analyses that are conducted as part of the ECAR working group and peer review assessments.

4. **Methods used for rating conductors and equipment** – ECAR does not require its Members to use a certain methodology to rate conductors or equipment. Each Member uses their company-determined methodology. However, ECAR has published reports on how to calculate conductor and equipment ratings, that some Members do reference and use in their methodologies, even though not required.
a. ECAR has the following Regional reports on conductor and equipment rating methodologies:
   i. 68-TAP-28 – “Transmission Conductors, Thermal Ratings”
   ii. 88-EEP-42 – “Determining the Loadability of Line Terminal Equipment”
   iii. 89-TFP-28 – “Transmission Conductors, Thermal Ratings”, revised

b. From ECAR reports 68-TAP-28 and 89-TFP-28, sample rating calculations for transmission line used an ambient temperature of 30 degrees C, wind speeds of both 2 and 3 mph, and the angle between normal to conductor axis and wind direction varied from 0 to 90 degrees. Tables of ratings are included in the reports that vary these factors in the calculation of ratings at different temperatures and wind speed and direction.

From ECAR report 88-EEP-42, sample rating calculations for substation conductor used a range of ambient temperatures (-20 to +40 degrees C), and wind speeds of both 2 and 3 mph. Tables of substation bus conductor ratings are included in the report and vary the wind speed and ambient temperature in the calculation of the ratings.

c. Conductor loss of strength is discussed in ECAR report 89-TFP-28 on page 4, and in ECAR report 68-TAP-28 on page 5. A separate ECAR report, 74-TFP-37 “Transmission Conductors, Loss of Strength Due to Elevated Temperature” also discusses this topic in detail.

d. The Members coordinate the various circuit components to determine the overall facility ratings, ECAR as a Region, does not. Most have databases to store and coordinate their facility ratings.

e. ECAR, as a Region, does not use dynamic ratings. Some Members use dynamic ratings in operations and those are based mostly upon ambient temperature.

f. Facility ratings are communicated to ECAR by the Members via their power flow models. ECAR also uses a tieline database to coordinate tieline ratings among the ECAR Members that are used in the power flow models. ECAR does not coordinate ratings with the RTOs. The Members coordinate ratings between their planning and operations personnel and their respective RTO.

g. The ECAR Members translate any voltage or stability limits they have into the MW ratings they assign to the applicable facilities in their power flow base case models.

5. **Interchange modeling (power transfers)** – The ECAR Members determine what firm transfers should be modeled in the ECAR power flow base cases in coordination with their ECAR and non-ECAR neighbors. ECAR then uses these base cases to create additional transfer-biased base cases for use in the ECAR working group studies. Additional interchange variations may also be modeled by the Members in the base cases they use in their ECAR peer review assessments.
ECAR Response to NERC TIS Request due 2/18/2005
NERC Blackout Recommendation 13c

a. ECAR working group and peer review studies consider both simultaneous and non-simultaneous transfers. All interregional study groups that ECAR is associated with study both simultaneous and non-simultaneous transfers. Regarding the analysis of simultaneous transfers, ECAR performs these analyses by simulating a non-simultaneous incremental transfer scenario on a transfer-biased base case that already reflects a different non-simultaneous transfer scenario, whereas interregional studies choose to simulate those same two non-simultaneous incremental transfer scenarios concurrently using a non-transfer-biased base case.

b. The modeling of firm and non-firm transactions in the power flow base cases are tracked through the interchange spreadsheets that accompany the ECAR and NERC MMWG power flow base cases. The ECAR Members provide input to the ECAR, NERC MMWG, and interregional base case development efforts (such as MEN/VEM) through ECAR. The NERC MMWG Procedural Manual contains the procedures that are used by ECAR.

c. The sources of interchange information are the transmission planners from the ECAR Members, which are non-market areas. However, to the extent possible, these transmission planners attempt to access and utilize the latest available market information in compiling their interchange data.

6. Generation dispatch practices –
   a. MW – The generation dispatch that is modeled in the ECAR base cases is provided by the ECAR Members, typically from their non-market transmission planners, and reflect varying combinations of historical, economic, and market considerations. Depending on the analysis being conducted, the generation dispatch that is used to simulate the incremental transfers may reflect the same considerations as documented by the ECAR Members in the dispatch order that is maintained in the ECAR RAWMAC Database. It should be noted that efforts are also underway to incorporate more market dispatch considerations in the ECAR studies to the extent such information is available.

   b. MVAr – The ECAR Members provide the voltage and reactive schedule information that is reflected in the ECAR base cases. ECAR also maintains this information in the ECAR RAWMAC Database to facilitate the use of this information in the ECAR studies.

   c. IPP treatment – The ECAR Members provide all generator modeling data, for both IPP and "traditional" generating facilities connected to their system, through their transmission planners. However, ECAR does collect generator power flow data from one generation-only control area.

7. Substation configuration – ECAR does not have any Regional criteria, nor has ECAR solicited information from the ECAR Members on this topic.
Attached supporting files:

04-TSPP-3, “2004 Summer Assessment of Transmission System Performance”
02-TSPP-55, “2005 Summer Assessment of Transmission System Performance”
00-TSPP-55, “2003 Summer Multiple Contingency Assessment of ECAR Transmission System Conformance to ECAR Document No. 1”
04-TSPP-3S, 2004 Summer Supplemental Report, Peer Review of Individual Company Assessments
04-TSPP-55S, Future Assessment, Report for Peer Review of Individual Company Assessments

68-TAP-28, “Transmission Conductors, Thermal Ratings”
89-TFP-28, supplemental “Transmission Conductors, Thermal Ratings”
74-TFP-37, “Transmission Conductors, Loss of Strength Due to Elevated Temperature”
88-EEP-42, “Determining the Loadability of Line Terminal Equipment”
Transmission and System Planning in ERCOT

The Electric Reliability Council Of Texas (ERCOT) was originally created in 1941 as the Texas Interconnected System. It presently has 135 members that represent independent retail electric providers; generators; and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking (approximately 61,000 MW) region responsible for about 85% of the electric load in the state of Texas. ERCOT serves a population of more than 15 million in a geographic area of about 200,000 square miles with more than 76,000 MWs of generating capacity including approximately 1,300 MWs of wind and 37,500 miles of transmission lines. It is tied to other regions through three Direct Current Ties. Additional details are available on the ERCOT website (http://www.ercot.com).

Through its planning authority role, all significant projects are independently studied by ERCOT in an open and non-discriminatory manner. ERCOT coordinates studies with affected Transmission and Distribution Service Providers (TDSPs) by leading three regional planning groups (RPGs): North, South, and West. Projects or studies can be proposed by any Market Participant, Transmission Owner or ERCOT Staff. Stakeholders have the opportunity to comment on proposals and offer alternative solutions. ERCOT staff facilitates the consideration and review of proposed Transmission projects to address transmission constraints and other system needs. There are two basic types of projects. Reliability Driven Projects are defined as system improvements primarily intended to resolve current or projected levels of reliability criteria violations that cannot be met by redispatch of existing generation. Economic Projects are defined as system improvements primarily intended to resolve current or projected levels of reliability criteria violations that could instead be solved by preemptive redispatch of existing generation but have been initiated because they are projected to result in a net economic benefit to the market based on ERCOT-wide impacts. The criteria for determining whether a project is economic is the increase in economic value to the market due to the project, as measured by an expected reduction in the market production cost due to the project that exceeds the cost of the project.

Currently, market forces will encourage the proposal of Generation projects on which ERCOT will perform Interconnection Studies. ERCOT has recently adopted computer simulation tools and developed processes to project congestion costs based on wholesale market fundamentals. These new tools and processes are being applied to determine the cost effectiveness of major transmission additions in the RPG process. ERCOT Staff makes an independent recommendation to the Board of Directors for major projects. ERCOT Board determines whether project will receive ERCOT endorsement based on Staff recommendation. ERCOT recommends and the TDSPs build transmission infrastructure that has been fully analyzed through the open RPG process. We emphasize fairness and openness with stakeholders that may be impacted by these facilities – balancing their concerns with the need for reliability. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and Public Utility Commission of Texas (PUCT) staff.

Contingencies Analyzed
Interconnected system planning includes steady state and dynamic simulated contingency screening by ERCOT as well as TDSPs to represent specific occurrences for each type of contingency specified below or listed in Table I of the NERC Planning Standards. Contingency tests are performed on a series of Short Term (Data Set A) cases based on projected loads for the upcoming summer and winter seasons and a series of Longer Term (Data Set B) cases ranging from a two to five-year planning horizon. Testing is performed for reasonable variations of load level, generation schedules, and anticipated power transfers. Due to the uncertainty of generation patterns, cases beyond the five year planning horizon are not developed. The ERCOT TDSPs plan to resolve any unacceptable contingency results through the provision of transmission facilities, the temporary alteration of operating procedures (Remedial Action Plans), temporary Special Protection Systems until permanent transmission upgrades are possible, or other means as appropriate.

ERCOT Planning Criteria states the fundamental minimum requirements for planning and constructing reliable interconnected electric systems under:

**Normal Conditions**
- Must meet NERC Category A

**Single Contingency Conditions**
- Must meet NERC Category B
  - Includes the contingency loss of single faults resulting in multiple elements (SFME) out
  - Includes the contingency loss of a double-circuit transmission line that exceeds 0.5 miles in length. Double circuit = Single contingency = Category B.
  - Includes the contingency loss of any single generating unit as unavailable, and with any other generation preemptively redispatched, the contingency loss of a single transmission element. Generator + Single contingency = Category B.

**Multiple Contingency Conditions**
- Must meet NERC Category C & D
- Allows generation, load and/or manual system adjustment

"Manual System Adjustments" include only operator actions which a) would be made not later than 1 hour after clearing of the first fault, b) are made using remote control capability or communications with other operators having such capability, c) include circuit switching, changes in the schedules of generating units operating at clearing of the first fault, and changes in the schedules of other generating units which can contribute within 1 hour, and d) exclude the physical repair or replacement of damaged equipment and the starting of any generating unit which cannot contribute within 1 hour.

All load interruption, generator tripping, or generation schedule changes must be either automatic or prearranged (with associated written operating procedures). Actions must be
executable in time to avoid any equipment damage or safety violations, but in any case within 30 minutes of fault clearing.

Cascading outages are defined as the uncontrolled loss of any system facilities or load, whether because of thermal overload, voltage collapse, or loss of synchronism, except those occurring as a result of fault isolation.

Evaluation of all the possible combinations of facility outages under Category C is not required. Each TDSP with bulk transmission facilities will evaluate one or more Category C contingencies annually. The contingencies selected may be based on the results of related studies or actual events and which, in the engineering judgment of the facility owner, ERCOT, or any TDSP, may have unacceptable consequences.

Evaluations of Category D contingencies are not required to be performed annually. Evaluations should be performed for the following:

- Contingencies previously studied for which the conditions assumed in the study have changed significantly and which may adversely affect the results of the study.

- Contingencies not previously studied that, based on the results of related studies or actual events may in the engineering judgment of the facility owner, ERCOT, or any TDSP, have unacceptable consequences.

ERCOT Staff performs both an Annual Transient Stability Screening Study and an Annual Voltage Stability Screening Study of the System. This study is a Protected and Confidential Report (CEII). A dynamic load model is used. Transfers between Congestion Management Zones are modeled along with Generation to Load transfers. Category B, C and D contingencies are applied to the 345 kV system to show locations of system weakness or voltage collapse. All bus and line contingencies are ranked using Extended Equal Area Criterion (EEAC). Identified critical locations are requested to be reviewed by the transmission owner. The goal is to identify potential problems and try to prevent large disruption of load.

**Load Level Studied**

ERCOT is responsible for gathering load data, for use in the ERCOT load flow cases via the Annual Load Data Request (ALDR). Each ERCOT Distribution Service Provider (DSP) directly interconnected with the transmission system (or its agent so designated to ERCOT) shall provide annual load forecasts to ERCOT as outlined in the ERCOT ALDR Procedures. For each substation not owned by either a Transmission Service Provider (TSP) or a DSP, the owner shall provide a substation load forecast to the directly-connected TDSP sufficient to allow it to adequately include that substation in its ALDR response. On a yearly basis ERCOT in conjunction with the TDSPs develops load flow cases which cover the upcoming year’s peak, off peak and shoulder month cases (Data Set A Cases) along with summer peak cases for a five year time frame (Data Set B Cases). Each TDSP uses it’s own methodology to predict load levels as well as power factors which are used in these cases.

**Voltage Limits Applied**
Transmission voltages should not exceed 105% nor fall below 95% of the nominal voltages during normal (Category A) operation of the system. Transmission voltages during emergencies should not exceed equipment overexcitation ratings. Transmission voltages during emergencies should not result in customer voltages exceeding or falling below prescribed limits at distribution substations on the transmission system. Transmission voltage should not exceed 105% nor fall below 90% of nominal voltage during emergencies. The low limit can be lower if voltage-regulating equipment maintains voltage to the customers within prescribed limits at distribution substations involved without causing voltage problems at nearby loads.

Voltage stability margin shall be sufficient to maintain post-transient voltage stability within a defined importing (Load) area under the following study conditions:

- Peak Load conditions, with import to the area increased by five percent (5%) of the forecasted area Load, and NERC Category A or B operating conditions (see NERC Table I in ERCOT Planning Criteria); and

- Peak Load conditions, with import to the area increased by two and one half percent (2.5%) of the forecasted area Load, and NERC Category C operating conditions.

**Methods Utilized For Rating Conductors and Other Equipment**

Within ERCOT transmission owners use a variety of documented methods to calculate equipment ratings. Although there is not a region wide standard most use the IEEE Standard 738 for calculating ampacity ratings for conductors. Assumed wind speeds range from 2 to 3 feet per second with wind incidences from 30 degrees to 90 degrees to the conductor. Assumed ambient temperatures range from 77 deg F up to 105 deg F. All owners design their lines such that there is no loss of life for continuous operation. Some do allow some loss of life for contingency conditions when a 2 hour emergency rating is used. Most use nameplate data for the normal and emergency ratings for equipment. Some use 110% above nameplate ratings for the emergency rating of switches and wave traps. For transformers, most use the highest continuous FA rating at 55\(^0\)C rise for the normal rating and the highest continuous FA rating at 65\(^0\)C rise for the emergency rating. The transmission owners determine the maximum overall rating of a transmission line by determining what the most limiting element is which is in series between the breakers at its two end points. In cases where a transmission line is owned by two or more owners, the most limiting rating is used. Unless otherwise limited by equipment ratings installed in the transmission line circuit such as breakers, current transformers, switches, disconnects, wave traps, jumpers, the normal and emergency rating of a transmission line is the conductor normal and emergency ratings.

ERCOT load-flow cases contain fields for three ratings for each branch record. The ratings associated with these three fields are commonly referred to as Rate A, Rate B and Rate C. The following are the ERCOT facility ratings definitions:

*Rate A – Normal Rating*
Continuous Rating: Represents the continuous Most Limiting Series Element (MLSE) MVA rating of a Transmission Facility, including substation terminal equipment in series with a conductor or transformer at the applicable ambient temperature. The Transmission Facility can operate at this rating indefinitely without damage, or violation of National Electrical Safety Code (NESC) clearances.

**Rate B – Emergency Rating**

Emergency Rating: Represents the two (2) hour Most Limiting Series Element (MLSE) MVA rating of a Transmission Facility, including substation terminal equipment in series with a conductor or transformer at the applicable ambient temperature. The Transmission Facility can operate at this rating for two (2) hours without violation of NESC clearances or equipment failure.

**Rate C – Conductor/Transformer Rating**

Emergency Rating of the Conductor or Transformer: Represents the two (2) hour MVA rating of the conductor or transformer only, excluding substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The conductor or transformer can operate at this rating for two (2) hours without violation of NESC clearances or equipment failure.

Ie. Rate C ≥ Rate B ≥ Rate A

**Interchange Modeling**

ERCOT currently has two DC ties totaling 820 MW to SPP and one DC Tie totaling 35 MW to CFE (Mexico). ERCOT conducts coordinated studies to simulate full transfer either direction as part of our normal planning activities.

**Generation Dispatch Practices**

ERCOT will periodically determine the minimum reserve margin required to ensure the adequacy of installed generation capability in ERCOT. ERCOT or the Public Utility Commission of Texas may also approve specific market participant requirements to ensure that the required minimum reserve margin is maintained.

ERCOT maintains a database containing existing and proposed generating capability historical and projected values for demand and energy; and proposed major transmission system additions. This database is updated periodically and the Capacity Demand Reserve (CDR) Working Paper is produced annually.

In order to simulate the future market, the following methodology for generation dispatch has been adopted for building the yearly planning load flow cases.

Existing and planned units owned by the Non-Opt-In Entities (NOIE) are dispatched according to the NOIE’s planning departments; unless a NOIE requests that their units are to be dispatched
according to the order that is described below. Unless contracts are known for the full output of a unit, all remaining MWs of NOIE units will be put into the ERCOT dispatch in their respective order. Self-serve generation is also dispatched independently. It is believed that cogeneration and self-serve units will have a better financial incentive to run than other plants. These plants are turned on at full output unless actual data is available, in which case they are dispatched to an average of their historical output. DC Ties are modeled as load levels or at generation levels based on historical data. All other units are placed in a spreadsheet and sorted by a predefined commitment order (COMMORDER) to create an economic dispatch order. Each COMMORDER is sorted by age with newer plants being placed on top. Generation is turned on to meet the load levels of each case. Spinning reserve is maintained according to ERCOT guides.

The unit commitment order is as follows:

1. Exceptions (Units that can operate in more than one region are dispatched based on historical data, voltage support units (documentation is posted showing voltage problem), DC ties, and must run if any exist).
2. NOIE dispatch (Commorder number is not 2 for NOIE units. It is the number that best matches the unit.)
3. Nuclear - max MW
4. Coal (bituminous, sub-bituminous, lignite) - max MW. Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
5. Hydro (most recent information). Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
6. Other renewable – Wind at historical on-peak and off-peak levels, solar max MW, methane max MW - less than 10 MW is modeled as distributive generation. Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
7. Self-serve. Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
8. Cogeneration. Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
9. Combined cycle. Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
10. Base load natural gas (steam through boiler). Existing units and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed that they will be more efficient.
11. Cycling natural gas (steam through boiler). Existing and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed they will be more efficient.
12. Peaking gas (steam through boiler). Existing and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed they will be more efficient.
13. Combustion turbine – simple cycle. Existing and future units that are expected to be constructed. Future units will be dispatched prior to existing units if it can be assumed they will be more efficient.

If a future unit is not on the ERCOT generation web site, it will not be put in the case unless an agreement has been reached between the TSP and Independent Power Producer (IPP) to do so. Future units that are expected to be constructed must either have signed a Signed Generation Interconnection Agreement (SGIA) or have provided an agreement to reimburse the TSP for expenses incurred toward constructing facilities for their generation if the generation project fails to go forward.

Base load units (supercritical) that do not shut off at night when they are run during the day are left on in the off-peak case at PMIN whenever they are on in the on-peak case (applies only to set A).

Data Set A cases may have generation redispatched to eliminate rate A overloads and maintain voltages at acceptable levels. Rate A overloads and low voltages will be allowed in Data Set B cases. In Data Set B cases, generation will be redispatched when a case will not solve due to excessive overloads and unrealistic voltage levels. The Commercially Significant Constraint (CSC) cases will be redispatched to relieve overloads on the CSCs.

For summer peak cases all commitment order 13 units (peaking units) that were built after January 2000 will be turned on in the case.

Mothballed units are classified in a unique Zone assigned by the TSP.

Minimum case (not the off peak cases) - The wind is modeled at historical levels. Nuclear units are on full. Self serve and cogeneration units are at 75 % of PMAX unless historical data is available to show they will be run at a higher level. Coal is at 70 % of PMAX, however, if there is more than 1 unit at a plant, one or more units may be turned off. Market MWs are not added to the NOIE coal units. If necessary, the combined cycle units will be dispatched with one half of the combustion units online at 50% of PMAX and a proportionate amount of steam.

Dataset B shall consist of two different sets of cases, one case shall be CSC and the other shall be ECO dispatched.

SSWG shall be able to review and modify the generation dispatch based on historical information.

Substation Configuration
There is no standard configuration for substations within ERCOT. Most stations are of a ring bus or breaker and a half scheme.

**Other**

**None**

**NERC Planning Standards**

ERCOT has been notified that it is in “full compliance” on all 2004 planning standards directly monitored by the North American Electric Reliability Council (NERC), Chief Operations Officer Sam Jones announced this week.

The activities required and monitored as part of NERC’s Compliance Enforcement Program include development and maintenance of:

- Regional and interregional reliability assessments
- A library of solved steady state models
- Initialized dynamics systems models
- Regional under-frequency load-shedding programs
- A regional blackstart capability plan.
**FRCC RESPONSE TO BLACKOUT RECOMMENDATION 13 C-TIS REQUEST**

**Role of FRCC**

The Florida Reliability Coordinating Council became the 10th Reliability Region of the North American Electric Reliability Council on September 16, 1996. The purpose of the FRCC is to ensure and enhance the reliability and adequacy of the bulk electricity supply in Florida, now and into the future. The Florida Reliability Coordinating Council (FRCC) encompasses Peninsular Florida, east of the Apalachicola River. It is electrically unique since it is a peninsula and is only tied to the Eastern Interconnection on one side. FRCC is responsible for setting the reliability standards, procedures, and policies that all users of the electric transmission grid must follow when operating in Peninsular Florida.

FRCC members include voting members, adjunct members, and affiliate members. They represent six industry sectors: power marketers, generators, non-investor owned utilities wholesale, load-serving entities, generating load-serving entities, and investor-owned utilities. The FRCC performs reliability studies each year to determine the "health" of our bulk power electric system. Two important studies done each year are the FRCC Load and Resource Plan which evaluates adequacy of generation and interchange resources and the FRCC Ten Year Transmission Study which evaluates adequacy of the transmission grid for representative years of the ten-year planning horizon.

**Introduction**

**FRCC Statistics**

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<th>Type</th>
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</tr>
<tr>
<td>Other</td>
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Winter Peak Load 36,229 MW  
Summer Peak Load 40,475 MW  
Import Limit 3600 MW
The FRCC Planning Committee provides a vehicle for ensuring the development of a robust transmission network within the FRCC Region. The FRCC has recently promoted a supplementary Transmission Planning Process to the scope of our studies. This process is the direct responsibility of the FRCC Planning Committee. This process utilizes the applicable reliability standards and criteria of the FRCC and NERC, as well as the specific design, operating and planning criteria used by FRCC Transmission Owners to the extent these specific design, operating and planning criteria meet or exceed FRCC and NERC reliability standards. The FRCC Transmission Planning Process is intended to meet the existing and future needs of all users of the transmission system requiring Network Integration Transmission Service, firm Point-to-Point Transmission Service, and Generator Interconnection Service.

As stated, performance criteria of the FRCC region interconnected transmission system adhere to NERC Planning Standards 1A –System Adequacy & Security to ensure that transmission plans meet industry standards and regulatory requirements. These criteria require the system be planned, designed and operated at a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, should not result from any reasonably foreseeable contingencies. Assessments to these criteria are evaluated and performed by the Region Transmission and Stability Working Groups (TWG and SWG respectively) composed of experienced technical representatives of member entities and FRCC staff. The TWG and SWG develop coordinated FRCC region wide databases (load flow, dynamic and short circuit using the respective local area transmission expansion plans, generation projects, and latest interchange assumptions. Evaluations include steady state loadflow and appropriate stability simulations. The FRCC working groups utilize the Power Technologies PSS/E loadflow program. The database utilized contains necessary detail for intra and inter-regional assessment studies. These models are also used as submittals for the NERC MMWG models.

FRCC works with its members to ensure consistency across the bulk power system via a website which provides a variety of applications to assist members with a single access source point for purposes of planning, data coordination and sharing. These “tools” include databank manuals, equipment status reports, maintenance/ construction schedules and a line rating database which promotes consistency between planning and operations models and other valuable information. With respect to short circuit analysis, the FRCC regionwide short circuit database is used in the annual planning process by the members to assess short circuit levels relative to their respective equipment ratings.

The summary below outlines a brief review of the FRCC region system design, planning and analysis practices followed by member entities.

**Contingencies analyzed (i.e. N-1, N-2, etc.).**

NERC Planning Standards are followed to assure no system element will experience loading in excess of normal ratings under pre-contingency normal system conditions. The TWG annually conducts studies over the planning horizon that looks at all possible single contingencies to identify any voltage or loading limit violations.

Single contingency violations are studied in further detail to verify if operational procedures can effectively restore grid voltages and loading to within their applicable rating. To the
extent that operational procedures are not effective in mitigating the violation, system upgrades or new facilities are planned for, as appropriate.

The FRCC Transmission Working Group (TWG) on an annual basis performs the C.2 and C.5 contingencies for those contingency scenarios most likely to cause bulk transmission problems. Presently, the TWG addresses C.3 contingencies by modeling one at a time the largest generating units in the state as unavailable, and then running contingency analysis on the case.

The FRCC TWG is currently investigating initiatives to further enhance the C.3 analysis to assess additional scenarios.

The FRCC’s Stability Working Group (SWG) periodically performs power flow and dynamic simulation studies of Category C and D contingency performance. The SWG evaluates C6 through C9 as part of its periodic studies and any other Category C type contingencies referred by the TWG. The SWG evaluates all applicable Category D contingencies. These Category C and D evaluations involve dynamic simulations to assess transient stability and post transient power flow conditions.

These SWG studies focus on the following topics.
- Protection System Adequacy (breaker and relay failure)
- SPS effectiveness
- UFLS adequacy and coordination
- Potential for grid Instability/Cascading
- Replication and analysis of Florida Disturbance Events in order to validate the data and models used in steady state and dynamic analysis as needed.

With respect to unit dynamic models, units are tested (e.g., open circuit test) at time of commissioning to validate the models. Additionally, to the extent that major equipment associated with a unit is later replaced and/or upgraded, testing is also performed at such time.

**Load levels studied**

At this time, the FRCC TWG models 100% peak summer and winter cases. Currently, shoulder months and/or 80% cases are built for members to perform individual loadflow analysis and are not part of the normal FRCC studies. These cases are also provided for MMWG purposes.

The load levels and scenarios used for SWG studies are selected to provide a range of system conditions likely to result in maximum stress for the contingencies being investigated. Most studies will include peak load and 60% of peak load scenarios. Load levels of 40% and 80% are also occasionally used. [Although base transfer interchange schedules are frequently used as study scenarios, the more common practice is to model additional non firm interchange schedules that will increase Florida imports up to the maximum level].

This represents a more adverse grid condition, particularly for Category D performance, SPS operations, and underfrequency conditions.

Load forecasts and Load Forecasting methodologies are developed by individual load serving utilities. These methods and the assumptions used in these individual forecasts are
periodically reviewed by the FRCC Load Forecasting Task Force (LFTF) to ensure methods of individual companies are suitable.

The FRCC maintains a Load and Resource Database and a working group composed of member utilities that populate the data and provide load information to the transmission cases. With respect to the power factor of the load, some FRCC members benchmark actual power factors at peak and/or off peak load levels from time-to-time, while other members use a more structured process to validate the power factors used in the planning models.

**Voltage limits applied**

**Steady State Voltage Limits** - The FRCC members generally use normal and emergency voltage limits that follow industry standards maintaining 95% to 105% of nominal under normal conditions or N-1, N-2 conditions and 90% to 110% under multiple contingency conditions. This is documented in the FRCC TWG Load Flow Databank Procedures Manual as a screening voltage range. Individual utility practices are documented in their FERC 715 filings as well.

Most modeling is done with autotransformer taps fixed with the exception of one member utility has an installed equipment for automatic adjustment of transformer taps. As a normal practice FRCC TWG studies do not identify limits as a before and after analysis of tap adjustments.

**Transient Voltage Limits** - With respect to the SWG, there are no specific performance requirements for transient voltage dips. A bulk transmission switching station voltage dip associated with a power swing that goes below 70% of nominal however would be regarded as a possible indication of an unstable response. The controlled separation SPS schemes in the FRCC are generally designed to initiate separation at or above 70% of nominal voltage.

**Methods utilized for rating conductors and other equipment**

FRCC member facility ratings utilized in system planning, design and operation are based on criteria specified by individual FRCC region transmission owners. Most follow the IEEE Standards for calculating the rating of conductors, other equipment and associated facilities.

Members also provide some detail of rating methodologies with the annual FERC 715 submission. Copies of member line rating methodologies are on file at the FRCC offices.

**Interchange modeling (power transfers)**

Due to the geographic nature of Florida as a peninsula, interregional studies such as the Florida/Southern Interface are studied in a non-simultaneous manner.
FRCC Regional studies assume base assumptions of firm contracts that are provided at the onset of the databank creation and incorporated into the study cases. Contingency analysis complies with Category A and B criteria and model firm transactions.

Non-firm transactions are modeled for primarily ATC studies on short-term one year or less basis. Transfer capabilities are calculated over the planning horizons based on specific requests for long-term firm transmission service. Additionally, as part of the planning process, individual members may assess the power transfer capabilities into major load areas to determine load-serving capabilities under extreme conditions.

**Generation dispatch practices**

FRCC models all cases assuming economic dispatch of MW for each member area. Voltage schedules are implemented for reactive power dispatch, while most generators represented are modeled to hold a remote bus within a specific voltage range at the “switchyard”. Currently, planning models incorporate plant Mvar capabilities based on calculations and known specifications associated with plant technical parameters. Planning models will incorporate information from tests of plant Mvar capability in the near future in order to obtain consistency in operating and planning models.

For planning purposes, Independent Power Producers (IPP’s) are defined as their own unique control area and controlled by the host utility. Dispatches are based on firm contracts. Voltage and Var control requirements are also outlined by the host utility.

**Identify substation configuration criteria used (i.e., breaker and a half, ring bus, straight bus, etc.)**

Specific substation configuration design is the responsibility of the individual FRCC members. The most common 230 and 500 kV station arrangement is breaker and a half although there are also a number of stations with double breaker/double bus and ring configurations. Individual bus sections and circuit breakers are not generally modeled in the FRCC’s Planning models due to the issue of limited zero impedance lines in the PTI program. The present model has restrictions of zero impedance lines availability.
MAAC REGION REVIEW

NERC-TIS MEETING

FRCC Offices
Tampa, FL

Bill Whitehead, PJM
February 16, 2005
MID-ATLANTIC COORDINATING COUNCIL ("MAAC")

The MAAC mission is to preserve reliability in a restructured and competitive electric industry. To that end, under the MAAC Agreement, PJM members with assets in the MAAC region are MAAC members and are obligated to comply with MAAC and NERC operating policies and planning standards. As parties to the PJM Operating Agreement and in accordance with the PJM Tariff, MAAC members coordinate their operations, planning, and integration of generation and transmission facilities.

**Planning Principles**

MAAC has developed a set of guiding principles and standards for planning the bulk power system to ensure that system reliability is preserved. To meet that mission, the bulk electric supply system shall be planned and constructed in such a manner that it can be operated so the more probable contingencies can be sustained with no widespread loss of load and without impacting the overall security of the interconnected transmission systems. Less-probable contingencies will be examined to determine their effect on system performance. These standards apply only to those facilities that affect reliability on the MAAC system (MAAC facilities list) and not to facilities affecting the reliability of supply only to local system loads.

**Reliability Assessments**

Assessments of these criteria, and compliance of the MAAC system with these criteria, are performed on an annual basis (MAAC Reliability Assessment). The PSS/e load flow program linked to a detailed relational database is used to perform these assessments.

Assessments and compliance are a cooperative effort between MAAC and its Members, as well as with the Regional Transmission Organization – PJM Interconnection, LLC.
MAAC Standards, Documents, and all related reports are posted on the MAAC Website.

The Regional Managers of MAAC, ECAR and MAIN have been authorized to pursue a merger of these organizations to create a single, large regional reliability council. The current schedule calls for this organization to be in place, at a high level, by the end of 2005.

This will impact the MAAC principles, procedures and compliance efforts going forward.
More than 44 million people served in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia
- 108,000 megawatts of peak load
- 134,000 megawatts of generation capacity
- 49,000 miles of transmission lines
- 980 generation sources with diverse fuel types
- 300 plus members
**Contingencies Analyzed for Transmission Security**

MAAC Reliability Standards specify that the bulk transmission system shall be developed such that:

1. With all transmission facilities in-service and normal scheduled generator maintenance, the loadings of all system components shall be within normal ratings, stability limits and voltage limits, and

2. With the following unscheduled contingencies, and at all forecasted load levels and firm transfers, the system shall be operated without instability, cascading or widespread interruption of load.

   A. For the loss of any single transmission line, generating unit, transformer, bus section, circuit breaker, Phase Angle Regulator or single pole of a bipolar DC line in addition to normal scheduled outages of bulk electric supply system facilities, all facilities remain within emergency ratings and within voltage criteria and the system must be capable of re-adjusting to within normal ratings and voltage limits.

   B. After the occurrence of a contingency outage and the readjustment of the system specified in A., for the subsequent contingency outage of any remaining generator, line, Phase Angle Regulator or transformer, all facilities remain within short-time emergency ratings and voltage criteria and the system must be capable of re-adjusting to within applicable emergency ratings and voltage criteria for the probable duration of the outage.

   C. For a double circuit tower line or line fault with stuck breaker, all facilities remain within emergency ratings and voltage criteria and the system must be capable of re-adjusting to within applicable emergency ratings for the probable duration of the outage.
Load Levels Analyzed
The following load levels are analyzed in performing system reliability studies:

1. For load flow studies, a diversified 50/50 summer peak and an intermediate summer load (75% summer peak).
2. For stability studies, a load level that represents the most severe condition, generally light load.

The load forecast is developed by the Transmission Owners and aggregated by the Load Analysis Subcommittee (the procedure is being revised – PJM will determine load forecast beginning next cycle). While a variety of methods are used to develop load forecasts, the PJM forecast will use an econometric model (GDP). A constant MVA load model is used for load flow studies.

Sufficient network resource capacity shall be provided in the form of firm contracts or installed generation and shall be deliverable to system load to ensure that, in each year for the MAAC system, the probability of occurrence of daily forecasted peak load and firm transfers exceeding the available network resources shall not be greater, on the average, than once in ten years.

Voltage Limits Applied
The following voltage criteria are observed in performing system reliability studies:

1. Voltage drop – same as used in Operations (Transformer taps are fixed, shunt capacitors cannot be switched post contingency)
2. Voltage magnitude – same as used in Operations

Sufficient reactive capability with adequate controls shall be provided to supply the reactive load and loss requirements in each area of MAAC in order to maintain acceptable emergency transmission voltage during all contingencies. Voltage stability analysis is being phased-in and P/V analysis is being phased-in.
Conductor/Equipment Ratings

The following conductor and equipment ratings are observed in performing system reliability studies:

Conductor and equipment ratings are determined by the respective transmission owners. The equipment rating philosophy is determined by the Transmission & Substation Design Subcommittee and contained in documents published on the Website. Some assumptions may be adjusted by the transmission owner. All equipment ratings are submitted through the eDART system and used by both operations and planning.

No dynamic ratings are currently applied, however several transmission owners have used dynamic rating equipment on a trial basis.

Probabilistic risk assessment is being studied for determining aging infrastructure replacement. Additional PRA will be pursued pending results of this program. The spare equipment group reviews spare transformer needs/availability on an annual basis.

Interchange Modeling (Power Transfers)

The following interchange modeling parameters are observed in performing system reliability studies:

1. All firm transfers are modeled.
2. Non-Simultaneous transfers modeled between regions (MEN/VEM Studies).
3. Load Deliverability Studies model transfers between sub-regions within MAAC and are combined with thermal and voltage studies.

Sufficient subarea tie capability shall be planned and constructed to insure that for each geographic subarea the probability of occurrence of daily forecast peak load and firm transfers/transactions exceeding the available capacity resources due to insufficient tie capability shall not be greater, on the average, than once in 25 years.
Load Deliverability - the ability to deliver energy from the aggregate of capacity resources to an electrical area experiencing a capacity deficiency.
PJM Load Deliverability
The PJM Reliability Assurance Agreement states that Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system that may have a capacity deficiency at any time. PJM determines the Regional Capacity Requirement to achieve this reliability objective assuming sufficient network transfer capability will exist. The energy from generating facilities that are ultimately committed to meet this capacity requirement must be deliverable to wherever they are needed in a capacity emergency. Therefore, there must be sufficient transmission network capability within PJM. PJM determines sufficiency of network transfer capability through a series of Deliverability tests. Deliverability ensures, only, that the aggregate of capacity resources can be utilized to deliver energy to the aggregate of load.

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of PJM in two ways. First, energy must be deliverable, from the aggregate of resources available to load in portions of the applicable PJM region experiencing a localized capacity emergency, or deficiency. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM within some bounds that separate the reliability requirements of PJM from the reasonable economic function of the market place. PJM has developed testing methodologies to verify compliance with each of these deliverability requirements.

The acceptable loss of load expectation (LOLE) for PJM due to inadequate generation resources is one day in 10 years (1/10). This is used to determine the PJM installed reserve margin.

The acceptable loss of load expectation for PJM due to inadequate internal transmission is one day in 25 years (1/25). The Load Deliverability procedure is used to test the adequacy of the transmission system.
The capacity emergency transfer objective (CETO) represents the amount of energy that a given study area is required to import to remain within a LOLE of 1/10.

The capacity emergency transfer limit (CETL) represents the ability of the transmission system to support deliveries of energy to an electrical study area experiencing a capacity emergency.

A study area passes the load deliverability test if the CETL is greater than the CETO.

Each study area is assumed to be experiencing a capacity emergency independent of the remaining system. Therefore, the remainder of PJM and adjacent systems are assumed to be able to supply the study area with emergency power.

The study area CETL analysis should always reflect actual PJM emergency operating procedures. Such operating procedures include:

1. Activation of active load management (ALM),
2. Modification of basecase transfers, and
3. PAR adjustments (within existing agreements).
Global Study Areas

Eastern Mid-Atlantic Area – comprises all load and generation connected at 500kV and lower in JCP&L, PECO, PSE&G, Delmarva, AE and RECO.

Southern Mid-Atlantic Area – comprises all load and generation connected at 500kV and lower in BG&E and PEPCO.

Western Mid-Atlantic Area – comprises all load and generation connected at 500kV and lower in Penelec, Met-Ed and PPL.

Mid-Atlantic Region – comprises all load and generation connected at 500kV and lower in all MAAC companies.

Western Region – comprises all load and generation connected at 765kV and lower in ComEd, AEP, Dayton, Duquesne and AP.

Zonal Study Areas

Met-Ed, PPL, BG&E, PEPCO, JCP&L, PECO, AE, PSE&G, Penelec and Delmarva – each zone listed is an independent study area and all load and generation connected below 500kV is included.

ComEd, AEP, Dayton, Duquesne, and AP – each zone listed is an independent study area and all load and generation connected at 765kV and below is included.

Sub-Zonal Study Areas

Delmarva South and PSE&G North – each sub-zone listed is an independent study area and all load and generation connected below 500kV is included.
PJM Load Deliverability Assumptions

The following assumptions are utilized in performing load deliverability analyses:

1. The study area is modeled at 105% of the 50/50 peak load (approximately 90/10 load). The additional 5% load adder is modeled at a 0.8 power factor.

2. Generation in PJM external to the study area is reduced by the PJM average forced outage rate.

3. Behind the meter and energy only resources will be modeled at the average historic MW output based on the previous year’s 10 highest load hours.
**Generation Dispatch Practices**

The following generation dispatch practices are utilized in system reliability studies:

1. For most purposes, economic dispatch based on market data.
2. MVAR for existing units is based on capability or actual data, whichever is more limiting.
3. Total amount of generation outaged is based on 5-year average EEFORd data.
4. MVAR for new units is based on the capability curve.
5. Generators are currently required to test annually for MW.
6. MVAR testing of generators was recently approved, future studies will use test data.

**Substation Configuration**

The following substation configuration practices are utilized in system studies:

1. Substation configuration is determined by the transmission owner.
2. Guidelines are developed by the Transmission & Substation Design Subcommittee and are published on the Website.
3. There is no predominant arrangement, some breaker and one-half and some double breaker arrangements.
MAIN Response to Blackout Recommendation 13c TIS Request

“The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, results, methods, and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC Board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.”

Introduction

Mid-America Interconnected Network, Inc. (MAIN) is one of the ten electric reliability councils that comprise the North American Electric Reliability Council (NERC).

MAIN's Regular Members include investor-owned utilities, cooperative systems, municipal power agencies, independent power producers, power marketers, and municipal systems. Together they provide electricity to 21 million people living in the 145,000 square miles the Region encompasses. This Region includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. The Associate Members serve customers in several other states. The 8 million customers in the Region represent a cross section of Mid-America: commerce, industry, agriculture, education, research, recreation, and residences in cities, suburbs, small towns, and rural areas.

Role of MAIN

The purpose of Mid-American Interconnected Network, Inc., as set forth in its Articles of Incorporation, is to serve as a commercial and industrial association for the purpose of preserving and enhancing service reliability and economy of operation among electric utilities in the Midwest, and to assess the adequacy and ensure the reliability of the interconnected bulk electric system in the MAIN Region for the benefit of all end-users of electricity and all entities engaged in providing electric services in the MAIN Region, with due regard for safety, environmental protection and economy of service, through coordination of planning, construction, maintenance and operation of generation and transmission facilities on a regional basis.
MAIN

July – August
Peak Load
~ 60,000 MW

**Miles of Transmission**
(by class)

- 765 kV - 90 mi.
- 345 kV – 5,879 mi.
- 230 kV – 226 mi.
- 161 kV – 2,159 mi.
- 115 kV – 850 mi.
MAIN’s Transmission Planning Organization

MAIN is comprised of ten Transmission Owners (TOs), four of which make up approximately 98% of the transmission mileage between 115 kV and 765 kV.

Much of the planning activity within MAIN is performed by the TOs themselves, as well as the two Regional Transmission Operators (RTOs) within MAIN, the Midwest Independent System Operator (MISO) and PJM.

MAIN performs studies on an annual, as well as on an ad hoc basis. MAIN has adopted the NERC Reliability Standards and has several standing study groups, coordinated by the Planning Committee (PC) and the Transmission Task Force Steering Committee (TTF), that perform these analyses. These include the Transmission Assessment Study Group (TASG), the Future Systems Study Group (FSSG), the Voltage Security Working Group (VSWG) and the MAIN Data Bank Group (MDBG). Studies performed by the TTFSG, TASG and FSSG include liaison members from four adjoining regions.

The MAIN PC undertakes all activities relating to system or facility planning that contribute to electric service reliability and adequacy through system studies and the coordination of long-range plans developed by members of MAIN individually or as part of sub-regional, statewide, interregional or multiparty groups.

The PC monitors compliance with MAIN Guides and other standards and requirements. These Guides and requirements may be found at www.maininc.org. It is responsible for oversight of current and future regional transmission system simulation studies for normal and emergency system conditions, reviewing and recommending appropriate changes to MAIN Guides, conducting studies of required reserve generating capacity for the areas served by members and reviewing and assessing the overall reliability of the MAIN bulk electric system, both existing and planned, to ensure the system conforms to the MAIN Guide provisions, as well as coordinating the activities of the Relay Task Force (RTF) and the MAIN Guide 6 Working Group.

The MAIN TTF is comprised of its own chairman and the chairmen of the following groups: MAIN Databank Group, FSSG, TASG and VSWG. The TTF acts as the steering committee, and provides oversight and direction for model building, power system analysis, for steady state, dynamic and transfer conditions, for current and anticipated conditions.

The primary purpose of the MAIN Data Bank Group (MDBG) is to coordinate, in a timely manner, the development of designated power flow base case models and dynamic models for MAIN and NERC, which simulate bulk power electric system behavior in the Eastern Interconnection, as described and detailed in the NERC / MMWG Procedural Manual. The model requirements for dynamic simulations are also included in the NERC/MMWG Procedural Manual. The manual, developed by the MAIN MDBG, is intended to be a supplement to the NERC MMWG Procedural Manual, which also
includes procedures for modeling for dynamics. The manual also includes procedures for screening model data.

The primary responsibility of the TASG is to investigate the adequacy of the interconnected transmission system of MAIN and its surrounding regions to transfer power under the expected system conditions during the next seasonal peak load period. Results of this investigation are reported in a published report, which must be approved by the MAIN TTFSC and the MAIN PC. The TASG studies both summer and winter peak load periods on a bi-annual basis; however, other studies are also performed as requested by the MAIN TTFSC.

The purpose of the TASG Procedural Manual is to set forth the guidelines, philosophies, and procedures used to complete each seasonal transmission assessment report with accuracy and uniformity. MAIN TASG reports are made public on the MAIN website, and it is the responsibility of the TASG to review this manual periodically to ensure that it reflects the procedures currently in practice.

The TASG studies are performed for both the summer and winter peak periods annually. This analysis results in the determination of non-simultaneous first contingency incremental transfer capability values. Operating guides and procedures, including the effects of re-dispatch are included. Voltage stability and simultaneous transfer capability are also assessed.

The TASG studies involve representatives from four regions outside of MAIN – ECAR, MRO, SPP, and SERC, as well as PJM and MISO. This level of involvement ensures that a robust peer review process is available.

The MAIN Future Systems Study Group (FSSG) is responsible for conducting power flow analysis, under steady state, dynamic and transfer conditions, for system conditions anticipated in the future. It assesses the modeled state against MAIN and NERC Standards, Measures, and Guides. It performs its work under the direction of the MAIN TTFSC.

Within the past two years the FSSG performed the 2009 summer transfer capability analysis. This analysis determined the first contingency incremental transfer capability values, utilizing operating guides and for the steady state system. It also performed an analysis of the 2009 summer peak conditions with dynamic studies based on categories ‘C’ and ‘D’ of the NERC Reliability Standards. This analysis included a study of voltage stability. The group is currently conducting a 2014 summer peak dynamic study, including voltage stability, of categories ‘C’ and ‘D’ of the NERC Reliability Standards. As with the TASG, there is inter-regional participation in the study group from ECAR, MRO, SPP, TVA, and SERC, as well as MAIN. Peer review is ensured with the representation of five TOs in MAIN as well as the five representatives from the surrounding regions.
The MAIN Voltage Stability Working Group (VSWG) is responsible for establishing operating and planning limits and/or guidelines and methodologies for the MAIN region that will safeguard voltage security. Throughout its studies and analyses, done under the direction of the MAIN TTFSC, and PC, it must comply with the NERC Standards and Measures, as well as the MAIN Guides.

The most recent study effort of the VSWG involved the MAIN response to NERC Blackout Recommendation 8b, which involved the feasibility and benefits of additional installation under voltage load shedding capability. The analysis was primarily focused on NERC category ‘D’ events for an expected summer peak load period in year 2010. Last year, the VSWG studied whether voltage stability limits were more constraining than the thermal transfer limits within MAIN. This analysis was performed in 2003. The VSWG and the FSSG together are building a ‘library’ of studies to cover the near and long term time frames.

The MAIN Relay Task Force (RTF) is a subcommittee of the MAIN PC and deals with compliance of the NERC Reliability Standards that relate to protective relaying of the interconnected system and the generators connected to it. The RTF collects and analyzes the NERC-required trip reports, reviews and approves Special Protection Schemes (SPS) and keeps a database of all SPSs within MAIN, collects and reviews members’ underfrequency and undervoltage load shedding schemes, periodically assesses the effectiveness of the MAIN UFLS and UVLS programs, and maintains a database of disturbance monitor installations.

The RTF is responsible for preparing revisions to MAIN Guides 1B, 10 and 12 and their appendices (member requirements for UFLS, protective relaying and disturbance monitoring) and presenting for approval. The RTF monitors trip operations / misops / corrections for trends and continuing SPS review. The RTF also may, from time-to-time, receive special assignments for the PC, such as preparing MAIN responses to NERC, FERC, or FCC issues that relate to relaying, study and report on large disturbances, etc. Peer review is utilized as a part of the RTF process through the involvement of six MAIN TOs, ten control areas and two generation owners.

There are other study groups within MAIN that perform reliability functions, including the MAIN Guide 6 Working Group, which performs generating reserve and import requirement calculations, the Emergency Response and System Restoration Working Group, which is responsible for the blackstart capability plan and conducting operational blackstart drills, and other ad hoc groups formed on an as needed basis to address emergent issues, such as the recent review of the MAIN Guide addressing under frequency load shed program.

Compliance monitoring of the NERC Planning Standards verifies consistent planning across MAIN and helps to discuss different practices. Each TO is required to perform an annual submittal describing their study of a MAIN-wide benchmarking process of at least three cases. The required analysis typically consists of a near term, longer term and a seasonal case. This submittal is usually made in early April and includes a confirmation
of compliance with Table 1A, an expected ten year reinforcement plan and a discussion of additional in-house studies performed. MAIN also performs a more extensive on-site review every three years to ensure adherence to the NERC Standards.

The following sections specifically describes the MAIN practices for the issues requested by the NERC TIS:

**Contingencies Analyzed**

Many studies are performed by the individual TO. The MAIN study groups also perform a variety of studies utilizing many contingencies, especially of category ‘C’ and ‘D’ of the NERC Reliability Standards. Reliability studies are also performed by MISO and PJM. All of the MAIN companies adhere to NERC Table 1A at a minimum. Some of the smaller entities utilize a ‘portfolio’ approach, whereby they study certain scenarios over a period of several years in order to develop a library of studies. Most of the larger entities utilize several model years and a variety of contingencies for their annual modeling requirements. In general, there is less dependency on MAIN studies by the larger entities.

Some companies specify that their criteria are to assess their transmission systems for certain Category ‘C’ contingencies while using Category ‘B’ performance measurements. Examples of this include (i) two underground transmission lines and (ii) generator and certain transmission element combinations. Also, some entities exceed NERC Table 1A with the analysis of Category ‘D’ contingencies evaluated through Category ‘C’ performance requirements. Category ‘D’ contingencies do not require reinforcement, but individual entities may indeed undertake reinforcements for certain of these contingencies, for example the case of a three phase fault with delayed clearing.

Generally, contingencies for Category ‘C’ and ‘D’ analysis are selected based on engineering judgment by the participating TOs. Also, the entities generally study varying combinations of scenarios, including load levels and outaged elements, during each year in order to develop a library of cases and a broad understanding of system response over a wide range of contingencies.

Many of the TOs in MAIN are members of Regional Transmission Organizations (RTOs) which perform studies to determine compliance with NERC Planning Standards.

For one of the MAIN members, PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. The enhancement recommendations revealed by System Impact Studies become part of the RTEP approved by the PJM Board of Managers and published in the posted RTEP Report.

Some MAIN members belong to the Midwest Independent System Operator (MISO), which annually develop the MISO Expansion Transmission Plan (MTEP) based on the
base line reliability studies and, in collaboration with TOs, develops system expansion plans. The MTEP report includes reinforcement plans, which are approved by the MISO Board. MISO also processes generation connection and requests for System Impact Facilities Studies.

One of the MAIN TOs participates in an annual MAPP / MISO reliability assessment performed by the MAPP TRAWG. This study assesses the thermal, voltage and dynamic stability limits for Categories A, B, C and D events from NERC Table 1A. All category B events are studied. Selective Category C and D events are studied based on experience. This analysis is based on near-term (years two through five) and longer-term (years six through ten) planning horizons.

Some entities have augmented their library of analysis through the use of outside contractors in order to perform specific analysis. One of these studies for example involved the TOs system covering years 2006 through 2011 and included seven different generation growth scenarios for two different load growth projections.

One of the MAIN TOs incorporates the concept of incremental transfer capability (ITC) in planning. The use of the ITC criteria in planning provides a margin between projected contingency loading and facility ratings to take into consideration uncertainties in load levels, interchange schedules, generation dispatch, transmission commitments made by the transmission provider, and regional load diversity. A trend in transfer (import/export) capability is considered; that is, a declining trend over several years may indicate the need for system reinforcement.

As stated earlier, MAIN also performs contingency studies through its various study groups.

The MAIN TASG studies are performed for both the summer and winter peak periods annually. This analysis results in the determination of non-simultaneous first contingency incremental transfer capability values. Operating guides and procedures, including the effects of re-dispatch are included. Voltage stability and simultaneous transfer capability are also assessed.

The TASG studies involve representatives from four regions outside of MAIN – ECAR, MRO, SPP, and SERC, as well as PJM and MISO. The level of involvement ensures that a robust peer review process is available.

Within the past two years the MAIN Future Systems Study Group performed the 2009 summer transfer capability analysis. This analysis determined the first contingency incremental transfer capability values, utilizing operating guides and for the steady state system. It also performed an analysis of the 2009 summer peak conditions with dynamic studies based on categories ‘C’ and ‘D’ of the NERC Reliability Standards. This analysis included a study of voltage stability. The group is currently conducting a 2014 summer peak dynamic study, including voltage stability, of categories ‘C’ and ‘D’ of the NERC planning standards. As with the TASG, there is inter-regional participation in the study.
group from ECAR, MRO, SPP, TVA, and SERC, as well as MAIN. Peer review is ensured with the representation of five TOs in MAIN as well as the five representatives from the surrounding regions.

An example of the types of contingencies studied by the MAIN Voltage Stability Working Group includes analysis primarily focused on NERC category ‘D’ events for an expected summer peak load period in year 2010 performed this year. Last year, the VSWG studied whether voltage stability limits were more constraining than the thermal transfer limits within MAIN.

**Load Levels**

All of the MAIN transmission owners perform studies at an expected peak or ‘50/50’ load level. Studies performed by the MAIN study groups, described above, as well as the TOs themselves evaluate performance at summer and winter peak loading conditions. These studies also are performed for present, and for the five and ten year out period conditions.

A number of MAIN TOs also perform analysis utilizing a ‘90/10’ projected load level. This is above the expected peak load level for a given time frame, as there is a 90% probability that the actual load level will be below that used. While studies performed at these higher load levels are usually performed for shorter range or operational or special studies, there are TOs that perform analysis for the ‘90/10’ load level for longer-term studies routinely.

One of the TOs utilizes ‘one-in-two’ load levels for routine planning studies, MAIN studies and other transfer capability studies, while utilizing ‘one-in-ten’ load levels for analyzing short-term operational studies and for specific local area bulk supply studies as well as for their Transmission Outage Voltage Analysis (TOVA) studies.

Studies are performed for periods other than winter and summer peak generally on an as needed basis, and include shoulder peak studies, including pump storage, spring and fall, and light load, which are usually for generating unit stability studies. The reliability assessment performed consider both summer and winter peak cases (50/50) for each of the three years analyzed representing the present, near-term and longer-term planning horizons.

Load forecasting is generally performed by the individual TOs and rolled up into the regional and MMWG models. In general, econometric modeling is utilized with only the smallest entities utilizing a trending methodology. There is not a formal peer review performed regarding the various methodologies utilized. MAIN does compare the load levels over a monthly and annual basis and provides comparisons in reports provided to DOE and NERC.
Power factors are determined by the TOs and are usually provided by the distribution companies / providers. They are usually based on EMS / actual metered data and don’t typically change for load level for most studies.

**Voltage Limits**

There are no MAIN-wide voltage limits. The steady state voltage limits are determined by the TO.

For system normal conditions, about 2/3 of the TOs adhere to a 95% to 105% range, with the remaining 1/3 adhering to a 100% to 105% range. For system emergency conditions, about 2/3 of the TOs adhere to a 90% to 110% range, with about 1/3 adhering to a 95% to 110% range. There is not a MAIN-wide criterion for voltage drop.

Load tap changing is typically on the transmission to distribution interface or on the distribution system. PV analysis is performed by the major TOs and the MAIN study groups when analyzing voltage stability. The voltage methodology is primarily based on meeting the state regulatory requirements for end-use customers. Most TOs adhere to IEEE Standard 519 with regards to dynamic voltage dip limits, with the exception of one TO which has developed a more detailed set of limits for dynamic dip voltage limits.

Generally, because of the density of the transmission network in MAIN, thermal limits appear before voltage limits in study results. One TO is considering a need for reactive margins and simultaneous import capability by testing for the outage of several generating units while maintaining a distribution voltage of 95%.

**Ratings**

There is no regional database for ratings other than the data compiled in the power flow models. Some of the TOs have developed a multiple set of ratings for equipment as a function of time and / or preload conditions. Tie line ratings within MAIN are coordinated and agreed upon by both parties. This agreement is reinforced by the TASG study process. Many of the TOs have a ratings database, and the ratings are communicated to RROs, RTOs, other TOs and others through the MMWG model building process and data requests as well through other study efforts during the year.

IEEE or House and Tuttle rating methodologies are generally utilized. At least one TO utilizes the equipment nameplate rating without adjustment.

There are a number of ambient conditions assumed in these methodologies, including wind velocity, summer and winter ambient temperatures, angle between wind and conductor, conductor elevation above sea level, conductor direction, conductor latitude, local sun time, seasonal atmosphere, conductor emissivity and conductor absorptivity. The summer temperature ranges from 32 to 40 degrees C, the winter temperature ranges from 10 to –1 degrees C, the wind velocity ranges from 2 to 4.4 fps and the sun / cloud
and time conditions are often considered. The stated TO methodologies reference industry standards.

There are various considerations given to loss of life or strength, including minimum of no significant loss, no more than 1% per event, and a maximum of 10%. One TO places a greater emphasis on the thermal capability of splices and conductor connection hardware to withstand the temperatures encountered than on the loss of life calculation for the conductor itself. All of the TOs utilize the most limiting component in series as the rating for the entire facility, as required by the NERC standard.

The tie line ratings are coordinated between the TOs and the lower of the two ratings is utilized for the entire line, as also required by the NERC standards. There are no dynamics ratings routinely utilized, although changing ratings on a published basis may occur if necessary. Operations may use known ratings based on ambient conditions. Also, the EMS systems may not be equipped to handle these ratings. One TO does convert voltage and stability limitations to effective MW ratings in certain cases.

**Interchange Modeling**

All of the TOs in MAIN include all of the ‘traditional’ transactions in their studies, as do the MAIN study groups. Most of that data is derived from OASIS. There are differing practices regarding the implementation of ‘rollover rights’ in the model. The MAIN Supply Audit Task Force does check for firm transmission. One TO utilizes incremental transfer capability requirement as a proxy for uncertainties when using a ‘pristine’ base case.

One of the TOs is a member of PJM, which utilizes a locational marginal pricing market methodology to enable transactions throughout the PJM footprint. All of the ‘traditional’ inter-PJM market transactions are explicitly modeled.

Much of the MAIN transmission reservation process is administered through the MISO and PJM RTOs.

All of the MAIN TOs are represented in the MAIN TASG interchange capability studies, described above. These studies determine the import and export capability with consideration given to existing transfer levels.

**Generation Dispatch**

The generation dispatch in models utilized by MAIN and its members has traditionally been economic based. There is an increased use of re-dispatch being utilized with the transition to increased RTO participation. There is also a mechanism within the RTOs to handle proposed generation retirements and ‘must run’ units.

The Mvar generation has traditionally been based on network voltage schedules provided by planning. Exceptions may be made for problem local voltage conditions.
IPP generation are treated the same as ‘traditional generators’ and designated resources are modeled as being available to run.

MAIN conducts an annual supply audit among its members to insure that an adequate amount of generating resources have been reserved to serve the forecast summer peak load.

**Bus Layout / Other**

There is not a MAIN Guide or procedure that stipulates specific bus design. Some of the TOs provide for a ring bus if there are multiple terminations, from three to six or more, at 345 kV. Some TOs use a ‘breaker and a half’ scheme for bulk transmission and generation involving six or more terminations. Smaller TO layout and some older installations tend to be of the straight bus design.

Any bus layout design is expected to be analyzed and meet the performance requirements of NERC Planning Standards TPL001-004.

There is not a MAIN-wide short circuit database, although there is cooperation between the individual TOs regarding this data exchange. Each TO is responsible for maintaining its own spare equipment and there is not a specific MAIN directive to do so.
MRO Response to Blackout Recommendation 13 C TIS Request  
June 17, 2005

The Midwest Reliability Organization (MRO) is one of ten Regional Reliability Councils that comprise the North American Electric Reliability Council (NERC). The MRO is a voluntary association committed to safeguarding reliability of the electric power system in the north central region of North America. The essential purpose of this regional reliability organization is the development, implementation, and enforcement of compliance with North American and regional electric reliability standards. The MRO region includes more than forty members supplying approximately 280,000,000 megawatt-hours to more than twenty million people. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO region spans eight states and two Canadian provinces covering roughly one million square miles.

The expected summer non-coincident peak demand in combined MRO US and MRO Canada is 35,701 MW. The MRO Reserve Capacity Obligation requirement is 15%, which is equivalent to a 13.04% capacity margin requirement. The projected MRO capacity margin is 17.6%, which is equivalent to 21.3% reserve margin. Capacity additions for Summer 2005 are 911.45 MW consisting of gas turbines, internal combustion turbines, and wind turbines. There is a projected net capacity export out of the MRO into other regions. In the MAPP Generation Reserve Sharing Pool (GRSP), resource adequacy is measured through the accreditation rules and procedures. In order to accredit a new resource, and count it toward your reserve obligation, the Accreditation Working Group looks toward the MAPP Design Review Subcommittee or MISO to approve an Interconnection request. Analysis will look at the impacts on constrained interfaces within the region. Wind generation can count toward meeting your reserve obligation in the MAPP GRSP if the appropriate accreditation rules and procedures are followed. This includes an approved interconnection study, confirmed firm transmission reservations, and after-the-fact reporting. In order to determine the accredited capacity of variable capacity generation such as wind, the monthly median generation output must be calculated according MAPP GRSP rules and procedures.

The MRO transmission system is judged to be adequate to meet the firm obligations of the member systems for the 2005 summer season. The reliability of the transmission system is currently measured by determining thermal, voltage, small-signal and transient stability limitations and by studying the historical performance of the transmission system. Several steady-state studies, which provide an indication of transmission system strength and the necessary data to facilitate analyses of the MRO network, are conducted annually. The existing transmission system within MRO is comprised of 12,027 miles of 230 kV, 5,742 miles of 345 kV, and 473 miles of 500 kV transmission lines as well as 2030 miles of HVDC lines.

Great River Energy: Coal Creek - Dickenson ±400KV (436 miles)
Minnesota Power: Squarebutte - Arrowhead ±250KV (455 miles)
Manitoba Hydro: Radisson – Dorsey ±450KV (556.5 miles)
                Henday - Dorsey ±500KV (582.5 miles)
MRO members continue to plan for a reliable transmission system. Coordination of expansion plans in the Region takes place through joint model development and study by the MAPP Regional Transmission Committee and Midwest ISO. MRO staff is preparing a list of studies for regional reliability and compliance that need to be completed. Some of these studies are annual and other are repeated every 3 to 5 years. This list of studies and a schedule for completion will be given to the MAPP RTC (for those non-MISO MAPP members) and to MISO-West (for those MISO MAPP Members). The MRO expects that the RTC and MISO will budget and perform these studies.

The MAPP RTC uses a bottom up approach for transmission planning. Entities bring their transmission plans to the Subregional Planning Groups (SPG) for review and discussion. Once accepted, each SPG then brings their coordinated plan to the Transmission Planning Subcommittee (TPSC). The TPSC combines these plans to produce the MAPP 10 year Transmission Plan. The TPSC performs simulations with all the proposed improvements to determine the regional impacts and if appropriate suggest regional improvements. The TPSC also looks at the TLRs called in the regions for areas that may require enforcements. While the entities are submitting their plans to the SPG, they will also submit their plans to the MAPP Design Review Subcommittee (DRS). The DRS reviews the utility’s planning studies to ensure that it meets NERC standards and the MAPP Member Reliability Criteria and Studies Procedure Manual. The DRS reviews interconnection agreements, new facilities, upgrades and long-term firm transmission service requests. Once the DRS has accepted the planning study, the entity is required to bring operating studies to the Transmission Operation Subcommittee (TOS) prior to going operational. These studies must also meet NERC standards and the MAPP Member Reliability Criteria and Studies Procedure Manual.

Annually, the model-building group produces a set of 16 base case power flows and corresponding dynamics cases. The modeling building group also maintains the ratings database and a report called “MAPP Transmission Capacity Report”. The 16 base case power flows are given to NERC MMWG, FERC for the 715 and the MRO members.

The MRO compliance program conducts self-certification, on-site reviews and participates in the NERC Readiness Audits. One-Third of the MRO entities are reviewed every year. The MRO tracks compliance through the Compliance Database Management System (CDMS), which includes the NERC Board of Trustees 14 Recommendation, US/Canadian Recommendations and any compliance violations.

Contingencies analyzed (i.e. N-1, N-2, etc.).
The MRO uses Table 1A from the NERC Planning Standards in its studies. The MRO Members annually review the regional contingency list that contains creditable category C and D contingencies. The regional contingency list consists of about 400 category C/D type contingencies. The members select the C/D contingencies based on their own experience and request from other members. All regional committees use the same contingency list and Reliability Criteria/study procedures. The Ten-year assessment consists of near-term (summer peak, summer off-peak and winter peak), a mid-term which is a 5 year model (summer peak, summer off-peak and winter peak) and a long-term model which is a 10 year model (summer peak, summer off-peak and winter peak). Relay models are included in all simulations. The region’s members created a study package called the “User Interface Program (UIP)”. This is the preferred study package for doing studies in the MRO region. Much of the Member’s Criteria is built into this package. It consists of a number of scripts wrapped around PSS/E. MRO members can all run the same power flow and dynamic models along with the exact same contingencies. All models are made available to the members and any non-members would be required to sign a nondisclosure agreement.

Generally, MRO criteria are more stringent than the NERC Planning Standards. MRO does not consider open-ended lines as Category B contingencies. Depending on the specific area within MRO, Members can experience thermal, voltage or stability problems. As part of the study process, MRO monitors and respects SPP and MAIN facility limits. MRO consider contingencies on the neighboring regions/systems which may impact MRO/MAPP reliability through the MAPP-MAIN-SPP studies.

Load levels studied

The model-building group produces Peak models that are 100% non-coincident and Off-Peak models that are 85%(summer operating), 90%(winter operating), and 70%(planning). MRO uses both the peak and off-peak models in its planning processes. No comparison is made of the load forecast to the actual loads. Members supply the load and power factor data; MRO relies on members to verify their own power factors. The MRO load forecast is a sum of the companies.

Load Types
- Seasonal Firm (scalable/non-curtailable)
- Seasonal Interruptible (scalable/curtailable)
- Constant Firm (non-scalable/non-curtailable)
- Constant Interruptible (non-scalable/curtailable)
- Station Service Load

Voltage limits applied
The MAPP Member Reliability Criteria and Study Procedural manual contains the voltage level limits for Pre and Post contingencies. Normal voltages, with all lines in, must be between 95 % and 105 %; after contingencies, voltages must be between 90 % and 110 %. MRO does not use a voltage drop criteria. Both steady state analysis and dynamic analysis are used to determine the voltage limits. In the planning process, if the simulation stops, the scenario is investigated further using PV, VQ and voltage stability software to determine if the contingency results in cascading.

Methods utilized for rating conductors and other equipment

There is no regional rating methodology. Ambient assumptions (air temperature, wind velocity and angle, etc.), conductor rating, wave trap, switch rating, loss of conductor life or strength assumptions are considered by the individual utility rating methodology. Nevertheless, all Members use similar standard rating methods, such as House & Tuttle or IEEE standards. No dynamic ratings are used in the planning process. The region posts a report from its ratings database on the web site. Voltage and transient stability ratings are not translated to an effective MW rating for the planning process. Running stability is the standard process for all studies including the RC studies that are posted on a daily basis. Equipment ratings are not considered above nameplate in reliability assessments and system studies.

PSS/E ratings
- RATE A is the study season normal rating and is defined as the minimum of equipment or conductor
- RATE B is the study season conductor rating and does not consider equipment limits
- RATE C is EMERGENCY rating for the study season and considers equipment as well as conductor limits

In general, Rate C is used as the applicable rating for studies used for NERC category A, B, C assessments and system upgrades.

Interchange modeling (power transfers)

Both simultaneous and non-simultaneous transfers are used in the planning process. Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability reserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies. MAPP Operating Review Subcommittee (ORS) has determined that the amount of transmission capacity reserved for emergency replacement energy on
MAPP flowgates should be included in TRM. Although MAPP procedures allow for use of emergency replacement energy for up to six hours, the amount reserved in TRM for the first 59 minutes assures that sufficient capacity is available for the entire duration of an emergency, without the need for an additional preservation of transmission capacity in CBM. Capacity Benefit Margin is zero in the MAPP region. TTC and TRM are maintained in the planning process. These operational studies are used to develop total transfer capabilities (TTCs) and/or operating limits for the respective flowgate in accordance with the NERC and MAPP planning standards and operating policies, criteria and guides. These operating studies and guides shall document the TTC of the flowgate and the components (CBM, ETC, TRM, and TRM coefficient) to calculate Available Transfer Capability (ATC), in accordance with Section 5 of the MAPP Reliability Handbook. The methodologies and studies used to determine the ATC components for each flowgate in the MAPP Region are reviewed and sanctioned through the MAPP Regional Reliability Committee (RRC). The Operating Review Subcommittee (ORS) is currently vested with the authority to oversee this process. For the planning horizon, the ORS has an established process for flowgate operator(s) to present new or expanded studies for review. These studies typically include a variety of system conditions as required in the MAPP Operating Studies Manual. This manual requires load levels for the entire MAPP area to be modeled at 100% and 85% of peak summer load for summer studies and 100% and 90% of peak winter loads for winter studies.

Inter-regional, regional and sub-regional transfer capability studies are performed. The MAPP Ten-year Reliability Assessment will use as one of its base cases a High Simultaneous transfers (worst Case Scenario), with the simultaneous transfers raised to the Stability Limits (NDEX, MHEX, MWSI). Contingencies from Table 1A will be used in the simulations.

Each member is responsible to determine that they have sufficient import capability to cover load under contingencies, and deliverability of reserves is tested. The import levels are verified through the MMS studies, which uses non simultaneous transfers. The MAPP TRAWG use simultaneous transfers in its studies of import levels.

**Generation dispatch practices**

Engineering judgment is used to schedule units on an economic dispatch basis for the base cases that the model-building group produces. It is uncertain what dispatch model will be used after MISO market start up. The study groups will modify the generation dispatch based on the type of study that they are performing. At all times the study group must maintain the NERC Standards and the MAPP Member Reliability Criteria and Study Procedures.

There are no known fuel reliability problems in MRO, although there is some concern about low water on rivers that provide plant cooling water.

**Substation configuration**
MRO does not have a regional substation design configuration. The individual MRO members have the responsibility to design their substations to their in-house criteria. The MRO does make available the annual outage statistics of the bulk electric system to its members.

**Other**

The MRO validates models by disturbance, if a difference is found the MRO with the help of the owner of the facility in question will change or adjust the model. The last full model benchmark was the June 1998 disturbance. Dynamic parameters responded very closely to the actual disturbance data collected. The MRO participates in the NERC spare equipment program. All the MRO members have access to the planning results. The MRO has liaisons from the neighboring entities that participate in the MRO studies and the MRO participates in the joint MAPP-MAIN-SPP interregional studies. The MRO membership includes RTOs, who participate in the regional studies. The members follow the regional Under Frequency Load Shedding (UFLS) plan, which includes coordination. The MRO also performs UFLS studies. There is no regional Under Voltage Load Shedding (UVLS) program; although some members have their own individual programs. The region creates a short circuit model as part of its model building process. The short circuit model is used by the members in their individual short circuit studies. There is no required MVAr testing of generators; however MRO has a procedural guide that members can use if tests are desired.
NPCC Response to Blackout Recommendation 13C
TIS Request

“The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.”

Introduction
The Northeast Power Coordinating Council (NPCC) is an international electric regional reliability council formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. The geographic area covered by NPCC includes New York state, the six New England states, and Ontario, Quebec, and the Maritime Provinces in Canada. The total population served is approximately 54 million. The area covered is approximately 1 million square miles. NPCC is one of ten Regional Reliability Councils throughout the United States, Canada and portions of Mexico that form the North American Electric Reliability Council (NERC). NPCC is a voluntary, non-profit organization. Its current membership represents Transmission Providers and Transmission Customers serving the northeastern United States and central and eastern Canada. The Membership Agreement allows for non voting membership to be extended to regulatory agencies with jurisdiction over participants in the electricity market in Northeastern North America. It also extends membership to public-interest organizations expressing interest in the reliability of electric service in Northeastern North America.

Role of NPCC
NPCC establishes the processes that assure the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through development and enforcement of regionally-specific criteria that are not inconsistent with NERC broad-based continent-wide reliability standards. NPCC coordinates system planning, design and operations, assesses reliability, and monitors and enforces mandatory compliance with regional reliability criteria. NPCC, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.
**Contingencies Analyzed**

NPCC conducts studies according to the A-02 Basic Criteria for Design and Operation of Interconnected Power Systems. This document may be found on the NPCC website at; http://www.npcc.org/criteria.asp In the document the various design criteria contingencies are outlined. These contingencies include all the entries as outlined in the NERC table found in TPL 001-0. Regarding treatment of an open-ended line, (one open terminal of a multi-terminal line), NPCC Studies consider this an n-1 contingency. NPCC Studies also consider category C and D contingencies and have developed a subset of “worse case” Extreme Contingencies that is based on operating studies and experience. In addition NPCC has additional items in these categories that pertain to multiple circuit tower outages and loss of both poles of HVDC.

NPCC’s Transmission Area Reviews are conducted on an annual basis. The starting point model used is the current year summer season. These Reviews analyze Category C and applies the appropriate re-dispatch to reposition the system and return to normal limits before any STE, (Short Term Emergency) rating is exceeded.

Within NPCC, the Control Areas/Reliability Coordinators assess the seasonal models that are most restrictive, which can consist of summer peak, winter peak, shoulder peak and light load conditions, depending on the Area and what is being studied. Transient stability limits are usually determined at light load. Steady state limits are usually found at peak load, but may also occur at light load. N-2 limits may occur at summer peak, shoulder and light load conditions. Planning studies are conducted over a range of years, depending on the specific goals of the study, which can range from months to many years in the future. Most studies focus on the 3-7 year time frame.

NPCC’s Reliability Coordinator’s Operating Procedures are considered in the future planning for all the Categories listed in the A-02 Document which are not inconsistent with and in some cases more stringent than the NERC Standards TPL-001 through TPL-004.

Regarding uncertainty of inclusion of particular generators, NPCC allows some flexibility in this regard to the Reliability Coordinators to choose what milestone a generator must reach in their permitting and construction to initiate the inclusion of the unit in planning studies. NPCC captures the possible effects of uncertainty a number of ways such as sensitivity studies and severe case scenarios. There is also currently an “Inter-ISO” planning working group, consisting of NPCC and PJM, that NPCC is coordinating which identifies projects with cross border impacts to allow and coordinate the necessary studies to identify required transmission upgrades. Prior to this there will only be interconnection studies performed by the Areas to identify any required system upgrades that may be necessary to at least maintain existing pertinent transfer levels and not degrade the overall system performance i.e. increase the likelihood of voltage collapse or system instability.
To ensure that any risk of a cascading outage is minimized, the NPCC Region conducts an Overall Transmission Review of the Region as a whole on a triennial basis. Studies that include a set of the most extreme contingencies to determine system robustness and identify if there is any potential for cascading large scale outages are performed. Thermal thresholds are considered in this analysis and voltage limits are respected and represented in the cases.

Relay response is considered in the models of protection systems during the simulations for a subset of critical facilities in all planning studies. If an assessment demonstrates a transient low voltage response additional modeling of relays may be included to determine the impact of the potential operation of the relays of the effected facilities.

**Load Level Studied**
NPCC’s portion of the Eastern Interconnection is summer peaking although the Canadian Reliability Coordinator Areas are winter peaking so there are sensitivities done to the capture the winter peaking. NPCC has used previous year load forecasts/profiles in various studies and applied the appropriate standard deviations to capture the actual loads experienced.

Within NPCC there is a requirement to consider load level sensitivities to temperature (as shown by analysis of the expected forecast (50-50) and the severe weather forecast (90-10)). In addition, there may be consideration of other forecast sensitivities, such as economic activity.

Regarding peer review, NPCC has a CP8 Working Group that has all the RCs within NPCC represented as well as representation from the neighboring Regions. There are all the necessary confidentiality/third party non-disclosure agreements executed to allow free exchange of data and processes. There are other study groups within NPCC such as SS-37 and SS38 who have members from adjoining Regions and coordinate peer review of Transmission studies.

**Voltage limits applied**
Voltage and reactive limits are determined through a wide variety of analyses and methodologies. PV and QV analyses are performed as appropriate to determine system limitations. Based on these analyses conservative margins are determined and acceptable voltage limits are identified for use in load flow analyses. Load flow analyses assess the impact of combinations of post contingency switching and controls of elements that may impact the voltage/reactive response, such as autotransformer and PAR tap changing, capacitor and reactor switching operations, modeling of the droop characteristic of STATCOMs, SVCs, etc. This allows the post contingency system response over a varied range of time to be assessed. Transient stability analyses are also used to assess the susceptibility of large load loss, generation station service loss, and inadvertent relay operation.

Within the NPCC Region, voltage limits are based on both steady state analysis and dynamic analysis.

PV and QV analyses are performed as appropriate to determine the system response to potential voltage instability. Additionally, transient stability analyses are also used to assess the susceptibility of large load loss, generation station service loss, and inadvertent relay operation to determine the system response to potential voltage instability.
NPCC’s RC confirm their load power factors in a number of ways such as metering at Bulk Power Substations, EMS, Scada etc. and there are reports available in different locations on their individual websites.

**Methods utilized for rating conductors and other equipment**
NPCC’s Bulk Power system element ratings are determined by published Transmission Owner individual methodologies in accordance with IEEE and pertinent geographic weather and other influences to those ratings considered. The ratings, which consider various new techniques such as “loss of life acceptance” etc., are provided to our RCs who calculate the system operating limits based on those ratings.

The ratings methodologies are consistent over the TP’s area but not the entire Planning Authority Area due to differences in weather, ambient temperature, and wind speed. In general, these are the only parameters that may vary across the Planning Authority’s Area.

NPCC currently does not have a database specifically for ratings however there are updated ratings contained in the SS37 group basecases and also the FERC 715 cases.

The most limiting element for the line is used to rate the line. Numerous efforts have been made in NPCC to increase line ratings by addressing the “limiting” elements such as wave traps, CTs etc.

**Interchange Modeling**
Firm Transmission capacity is included in the future planning horizons and analyses is conducted considering both source-sink and a partial path model.

In Future planning horizons, within NPCC, CBM is assumed to be zero by all RCs. TRM is calculated as outlined in the NPCC Regional TTC ATC Methodology and is factored into the planning studies.

NPCC participates in the MEN studies every year. This study looks at simultaneous transfer capabilities and presents the results in graphical and tabular format.

NPCC A-02 Criteria “Basic Criteria for Design and Operation of Interconnected Power Systems” identifies simultaneous transfer and how that transfer is determined which must be within all applicable thermal, voltage and thermal limits for the contingencies listed in the document.

The NPCC Region uses the same stability and voltage limits during both normal and emergency system conditions. For internal RC thermal transfer limits during emergency conditions only the single element Normal Contingencies are considered, per NPCC A2. Tie lines during emergency conditions will use the STE ratings instead of the LTE ratings that are used during normal conditions. Interfaces that supply major load areas use the N-2 LTE limits, and will consider the Normal Contingencies that involve the loss of single elements, and double elements that have the potential for inter-Area impact.

NPCC utilizes the seasonal operating study transfer levels determined by the RC Areas and uses them in the planning studies.
**Generation Dispatch Practices**

Within the NPCC Region, sensitivities to numerous combinations of generation dispatch are conducted, so that dispatch sensitive transfer limits can be identified.

NPCC RCs compare historical, typical dispatches to those used in planning assessments.

NPCC A-02 Criteria “Basic Criteria for Design and Operation of Interconnected Power Systems” requires the analyses of various scenarios such as low fuel availability (inadequate gas supply/fuel contingency), loss of pipeline, extreme weather, etc. These are considered as “Extreme Condition” assessments/sensitivities.

*Station Design*

The switching arrangements of all substation bus designs must be designed such that the NPCC A-02 Criteria is met.

**NERC Planning Standards**

NPCC supports the development and inclusion of the Phase III and IV planning standards into the Version 0 set through the NERC ANSI approved open process. NPCC also believes the ATC/CBM Version 0 standards are related to business practices and should be turned over to NAESB for development.

There is a concern that has been expressed within NPCC about having the authority to force the generators to comply and provide information and perform testing if there are no provisions for it already in their Interconnection and Operating Agreements. In response to this NPCC has been conducting workshops on compliance and participating in the Areas’ workshops to promote understanding and achieve compliance of these issues.

NPCC conducts deterministic planning and also has studies that utilize probabilistic methods when appropriate to capture load and resource adequacy issues, loss of load due to hot summer or exceptionally cold winter etc. Both have a role in planning.

NPCC currently has field testing in place to validate system models. The SS-38 Working Group simulates and recreates any system disturbances such as August 14, 2003. System models are reviewed annually for accuracy by SS-37 and SS38 NPCC Working Groups which are also populated with members from adjoining Regions. NPCC RCs typically receive the data and models from the Transmission Owners, then verify and compile it before using it to build the Regional library load flow cases, thermal and stability.

NPCC as a Region does not have or maintain a database of spare equipment for its members. The NPCC members have spare equipment based on their own needs and requirements. Some of NPCC’s members do in fact have a list of spare equipment that is submitted to NERC for inclusion in their database. The TFCO, Task Force on Coordination of Operations will however facilitate and coordinate some information exchange in this regard.

NPCC Regional Planning Studies are only used by the NPCC membership but made available to adjoining Regions and NERC upon request, i.e. NERC Compliance.
Regional operating experience is considered during the development of the annual case libraries by two NPCC Working Groups SS-37 and SS-38. These groups have representation from all the RCs in NPCC and also the adjoining Regions in some cases. Considered from this experience and perspective are any N-2 analysis or assessing long-term outages. These analyses, contingencies to consider, and study assumptions are published in NPCC reports, receive peer review through the Task Force on System Studies and are known throughout the Region and by adjoining Regions.

Inter-Regional planning is addressed though case development by SS-37 and SS-38 working groups and also the MEN (MAAC-ECAR-NPCC) study group. Also the NPCC review of each Area’s “Area Review” and the NPCC “Overall Transmission Review” are considered Inter-Regional planning efforts. The Northeastern ISO/RTO Planning Coordination Protocol provides an additional framework for coordination of inter-Regional planning.

NPCC RCs are involved in a joint effort, the Inter-ISO Planning Working Group. The group has signed and developed a Northeastern Planning Protocol which is in the process of being executed and implemented by New York, New England, and PJM with the Canadian RCs listed, as in support of. This group will identify/address all projects with cross boarder impacts and develop a coordinated northeastern system planning process and plan utilizing stakeholder input in an open forum.

NPCC on a triennial basis conducts a UFLS study that is performed by the SS-38 Working Group. The Working group had members of adjoining Regions participating or reviewing results and providing information such as thresholds, steps, and block sizes.

NPCC currently does not conduct a Region-wide short circuit study however has in its NPCC A-02 Criteria “Basic Criteria for Design and Operation of Interconnected Power Systems”, a requirement to share and coordinate short circuit data between neighboring Areas.

In addition to the studies mentioned here, NPCC RCs conduct rigorous studies on an individual Control Area basis. A list of studies, conducted by New England and whose results were considered in their RTEP 2004 Plan, is included as an appendix. The other NPCC RCs have similar comprehensive studies that are performed regularly in addition to their participation in the Regional studies.
APPENDIX
Sample List of Additional Study Efforts/References – New England RTEP 2004

“Determination of Bulk Power Facilities in New England” (in progress)
“Second New Brunswick Tie Study,” March 2003
“2002/03 Southeast Massachusetts / Rhode Island Export Short-Term Upgrade Analysis, (With sensitivities to East to West Transfers),” October 8, 2002
“Maine Independence Condition 5 Study,” September 24, 2003
“2002/03 Southeast Massachusetts / Rhode Island Export and Short-Term Upgrade Analysis,” October 8, 2002.
“Central Maine Power Company Autotransformer Reliability Assessment Study Interim Status Report,” December 24, 2001. (Currently proprietary.)
“DRAFT Androscoggin Energy Center Steam Unit #4 Addition System Impact Study Stability Report, Revision 0,” June 2003. (Currently proprietary.)
“Northwest Vermont Reliability Project 1,250 to 1,540 MW Study,” January 3, 2002.
The Southeastern Electric Reliability Council (SERC) is the largest of the NERC Regions, as measured by total generation and total load. The SERC region covers an area of about 464,000 square miles and includes parts or all of thirteen southeastern and south central states. SERC is the Regional Reliability Organization (RRO) responsible for promoting, coordinating, and ensuring the reliability and adequacy of the bulk power supply systems in the area covered by its member systems. SERC does this by

- promoting the development of reliability and adequacy arrangements among the member systems;
- participating in the establishment of reliability policies, standards, principles, and guides;
- administering a regional compliance and enforcement program to achieve the reliability benefits of coordinated planning and operations; and
- providing a forum to resolve disputes on reliability issues.

The SERC Region is a committee-based organization. SERC members populate and chair various committees, and SERC staff members facilitate the committee work. The SERC Region is divided into four distinct subregions. Subregions perform a coordination role for data collection, and they also represent their subregional membership on the Regional subcommittees. The SERC subregions are depicted in the following graphic.
SERC has adopted the NERC Reliability Standards (formerly the NERC Planning Standards) in their entirety, and its members are expected to be compliant. By ensuring that its members adhere to the principles laid out in the NERC Standards, SERC ensures the continuing reliability of the bulk electric system within its geographical footprint. SERC has also developed Regional Supplements to the NERC Reliability Standards, which provide additional details and Regional program requirements for compliance with the NERC Standards.

Because SERC is a member-populated, committee-based organization comprised of approximately 320 volunteer members on SERC committees and subcommittees, the majority of transmission planning work is performed at the member level. The individual members develop all detailed planning assessments, design criteria, system protection implementation, and maintenance programs. As such, there is a great deal of latitude for their development. SERC provides an overall coordination of various topics, and all members are bound by the context of the Reliability Standards, but individual member programs vary on a company-by-company basis. Annual planning studies are performed within each of the four subregions. SERC monitors and participates in the compliance process to ensure that the Reliability standards are met, however, and uses a robust audit process to further ensure compliance is achieved and maintained.

The SERC Engineering Committee produces an Audit Report categorizing findings in 5 categories: non-compliance, concerns, suggestions, noteworthy observations and future requirements. [GOOD BUSINESS PRACTICE.] This program began in 2002 with a 3-year cycle, so that one audit was completed for each appropriate member by 2005.

The summary below provides an overview of the system design, planning and analysis practices followed by SERC member entities. Although each member may have variations in their practices, this overview summarizes the typical practices among the membership.

More detailed information about SERC, including load, energy, installed generation capacity and capacity margins for each of the subregions, is provided in Appendix 1 (the second document). Some highlights are:

- Historical load growth at 2% projected to increase to 2.24% in the future
- SERC has 49 members, including associates, divided into 7 segments
- SERC is interconnected with 6 other regions
- Transmission system investments are about $1B/year, which is about twice the depreciation rate on the $19B asset base:

Contingencies Analyzed (i.e. N-1, N-2, etc.)

NERC Reliability Standards TPL-001 through TPL-004 (formerly Planning Standard I.A) are strictly adhered to in order to ensure that all system elements and bus voltages remain within applicable pre- and post-contingency limits. Contingencies include the loss of generation, transmission lines (breaker-to-breaker), and transmission line segments (substation-to-substation).
In some instances, the outages of lines on common r/w, breaker failure, bus outages, etc. are considered to be n-1 contingencies. For load pockets and other specific areas, members often use more stringent testing criteria than NERC Reliability Standards require by setting up extreme pre-contingency base cases before taking n-1 contingencies. In some cases, Category C outages are applied, but performance is evaluated against Category B requirements.

SERC does not specify a minimum set of contingencies to be performed for contingency analysis. SERC requires its Members to be compliant with the attendant NERC Reliability Standards, produces Supplements to the Reliability Standards outlining minimum expectations, and leaves the performance of the appropriate analyses up to the individual members. Some SERC members combine the loss of a generator with the loss of a transmission element or use extreme pre-contingency base cases to represent an N-1 contingency, which may be viewed as exceeding the NERC requirements for N-1 analysis. Some SERC members perform an exhaustive N-2 analysis of the entire system (all combinations of multiple elements), while others study specific combinations known to cause more severe results. [BEST PRACTICE].

Many SERC members perform annual analyses on extreme conditions to meet the requirements of Category D contingencies; all SERC members are required to perform analyses on a frequency basis commensurate with the requirements of TPL-004. All contingency analysis methodologies are validated through the Regional audit process.

Automated operating procedures can be used to mitigate future planning problems. Entergy, for example, will use under-voltage load shedding (UVLS) to mitigate a problem during an interim period before a permanent solution can be completed. Other members have installed special protection systems (SPS) to maintain reliability under certain specific contingency conditions.

Southern evaluates potential for cascading outages by modeling extreme contingencies (Categories C & D) and then tripping lines that exceed 125% of rating or curtailing load at substations where voltage drops below 85%. Southern utilizes the EPRI TRELSS program for this analysis of Category C & D events, as well as considering all N-2 contingencies, performing probabilistic analysis, and conducting cascading analysis of Regional n-3 500 kV line outages. TVA uses a voltage of 90 – 92% for judging possible cascading. While most studies are carried out using PSS/E, Entergy also studies all Category C events using the EPRI POM program. For Category D events, Entergy has an identified list of the most vulnerable contingencies.

SERC members also participate in the VACAR-Southern-TVA-Entergy (VSTE) Study Group, which is comprised of reliability planners from a majority of the SERC member companies. On an annual basis, the VSTE Study Group elects to perform a reliability study that demonstrates overall system performance with one or more of the planning criteria specified in the Reliability Standards. [BEST PRACTICE.] For example, one year the Study Group may elect to perform an extreme contingency (Category D) study for a future year. Another year the Study Group may elect to perform a multiple contingency (Category C) study for a future year. These VSTE studies augment the SERC Member’s individual contingency analysis, and provide added assurance of reliability for the overall interconnected system.
Load Levels Studied

SERC relies on the load flow models created by the VSTE Study Group. These models roll up to the NERC MMWG cases. The VSTE creates all models required by the NERC MMWG, and augments those cases with additional cases of its own. This set of models includes various seasonal peak load levels (summer, spring, fall, winter), and two off-peak cases (shoulder, light load). Individual SERC members also augment the VSTE set of cases with planning models of their own. [BEST PRACTICE] These cases may include additional light load cases (e.g., 50%, 80% load levels), different transfer-level cases, and abnormally high load cases (e.g., 105% forecast).

Load forecasting methodologies are up to the individual SERC Members, as are the type of modeling assumptions (i.e., econometric, trending, etc.), and the load power factor assumptions. Each member’s load forecast methodology is reviewed as part of the regional audit process. Several companies are utilizing forecast models developed for each major customer class based on established econometric regression techniques using the MetrixND software package from Itron. These models incorporate various economic, weather and price factors that have been shown to correlate well to energy sales in the various customer classes. Longer term energy forecasts are developed for the major customer classes through the use of end-use models. The EPRI developed models, Residential End-Use Planning System (REEPS), Commercial End-Use Model (COMMEND), and Industrial End-Use Model (INFORM) are the basis for this longer-term development. The peak demand forecast is generally developed through the use of the Hourly Electric Load Model (HELM), which is an EPRI product developed by ICP Resources, Inc. HELM uses historical hourly load research data for each customer class to derive functions that describe the relationship of load to the corresponding weather profiles and selected day types. The program develops forecasts for all hours of the year, from which the yearly peak demand is derived.

Entergy loads are weather-normalized based on 100 degrees. They also typically use a higher load level for transmission planning than used for generation planning. Southern uses 95 degrees for their load normalization and also typically uses a higher load for transmission planning than used for generation planning. In addition to the typical Summer peak condition transmission planning studies, Southern considers multiple load levels and generation conditions such as: 105% peak load, 93% of peak with hydro generation off, Spring/Fall peak, and Spring/Fall valley conditions. (MMWG cases are at 100% of peak). TVA looks at the immediate 2 future years and adjusts their summer peak load for temperature 4-5 degrees higher than normal.

For steady state analysis, loads are represented as constant MVA. For most dynamic analyses, real power loads are primarily represented as constant current. Companies may represent a portion of their load (e.g., 90% of the real power load) as constant current with the remainder represented as constant MVA. Reactive power loads are generally represented as 100% constant admittance in dynamic analyses.

Voltage Limits Applied
Voltage level and voltage drop limits used in planning evaluations for base and contingency conditions are based on good utility practice and the limits listed in ANSI C84-1-1995 (R2001) – Electrical Power Systems and Equipment – Voltage Ratings (60 Hertz). In general, normal system voltages must remain between 0.95 per unit and 1.05 per unit, and contingency voltages must remain between 0.90 per unit and 1.1 per unit after the operation of any load tap changers. Individual SERC members may have more restrictive voltage limits for their system. SERC does not specify minimum criteria for system performance.

When dynamic simulations are performed (with standard load models), transient voltage dips are monitored. Analysis will identify deficiencies of dynamic reactive resources along transmission corridors, such as those associated with large amounts of generation being transported out of a generation rich region. Individual SERC members have specific performance criteria for dynamic simulations. Criteria are sometimes developed by comparing transient voltage dips obtained with a standard load model in a generation rich region with the stability results obtained using more complex load models including induction motors.[Best Practice] When a transient voltage dip is more severe than the criteria allows, transmission system improvements are then recommended.

Because load bus voltage levels are poor indicators of the proximity to voltage collapse, voltage stability planning evaluations are conducted. While low system voltages often precede voltage collapse, acceptable voltage levels have been observed at the point of voltage collapse for highly capacitively compensated systems or for systems with large amounts of high voltage power transfers. Voltage instability which causes cascading is not differentiated from localized voltage instability. However, cascading effects of the system conditions which may cause voltage instability are typically studies per the contingency analyses of TPL-001 through TPL-004.

Individual SERC members generally specify a voltage security margin. If a voltage stability evaluation uncovers a condition where the voltage stability breakpoint could occur within planning voltage level limits, appropriate guidance including margin is provided to Operations. [Best Practice] The guidance provided could be in various forms, but could include an interface or flowgate MW limit, or a minimum dynamic reactive reserve limit from a generating unit or group of units. Voltage security margins are typically not linked to a corresponding reactive compensation reserve.

**Methods Utilized for Rating Conductors and Other Equipment**

SERC member facility ratings utilized in system planning, design and operation are based on criteria specified by each individual member. Most follow the IEEE Standards for calculating the rating of conductors, other equipment and associated facilities. Members must submit a document stating how they comply with ratings methodology. SERC has audited member line rating methodologies. Although rating methods differ among companies, SERC looks for reasonableness of assumptions and uses peer pressure to make changes where appropriate. SERC members use normal and emergency ratings, and each member may use different assumptions in setting emergency ratings. For transformers, members typically may use ratings
above nameplate based on load cycle analysis, and other equipment is applied above nameplate by only some of the members. For conductor ratings, wind angle is typically assumed to be 90 degrees, and sag clearance limits are normally considered in setting emergency ratings. Some members also use dynamic line ratings in certain operational situations instead of a predetermined temperature thermal rating. Thermal ratings and maximum conductor temperatures are dependent upon the conductor used, its particular design, and its specific application. Thermal ratings for facilities are also based on the thermal loading capability of the equipment. A stability rating may sometimes be applied to a facility or a set of facilities, when needed, to ensure that the system is not operated in an insecure state from a stability standpoint. When the loading on the facility or set of facilities is below the stability limit, certain contingencies can occur and the system will maintain acceptable transient, dynamic and voltage stability. Different ratings for tie line equipment generally are coordinated at the time the VSTE data bank cases are developed. The responsible engineers from each area coordinate the ratings of facilities for the “owning” entity and utilize the lowest value in the load flow case.

SERC member use the weakest link to set overall breaker-to-breaker rating; each company maintains records or database to identify the elements that go into the rating. In a ring bus and similar arrangements, the rating is based on the lower of the terminating breakers at each end of line. Intra-regional ratings are coordinated to the lower rating of the two members, and SERC members also try to apply the same approach to inter-regional lines.

**Interchange Modeling (Power Transfers)**

The transmission planning models developed by SERC members are developed using the NERC MMWG models as the appropriate representation for most control areas outside of the SERC Region. Detailed models for various neighboring systems (SPA, PJM, Florida, etc.) and internal load serving entities are used to augment the system representations in the MMWG cases. The interchange developed for these models serves as the bases for most interchange in the internal study cases. In general these interchanges only include transactions that have firm transmission from source to sink (i.e. no partial-path transactions). Some utilities modify the interchange data to include all transactions for which the system has granted firm transmission service, regardless of whether they represent a partial path transaction, in order to provide greater accuracy when performing individual system studies.

Interface studies are performed by SERC Members across control area boundaries, subregional boundaries, and Regional boundaries. Interface studies include a mix of both simultaneous and non-simultaneous transfers. SERC members also participate in the VSTE and VASTE study groups, which evaluate regional and sub-regional transfers in addition to control area to control area transactions. Some members also participate in other Regional study group’s transfer studies.

**Generation Dispatch Practices**

Generation in the planning models is dispatched on an economic basis for each of the primary load serving entities in the Region. However, units may be run out of merit order dispatch
Studies are periodically run to determine if running out of merit order versus transmission construction is the most economical solution for the customers. Units may also be designated as must-run units for reliability purposes, and thus will be run in the model regardless of economic merit. Transmission congestion and reliability-must-run status is typically considered by each individual LSE, and project proposals may be submitted by individual LSEs to upgrade the load serving capability of the network. This ensures that each of the entities serve the load for which they have responsibility. Only generation that has been designated or reserved for future load growth by each of these entities are allowed to participate in this economic dispatch. In addition, all generation with firm transmission service agreements is turned on to deliver the power associated with the agreement to the point of delivery. Generation with an Interconnection Agreement that does not have a firm transmission service or has not been designated as a network resource by a load serving entity is generally modeled connected to the system but not dispatched on in the reference base case. The availability of this generation with non-firm transmission service in the load flow model allows each planning group to run any sensitivities to different generation dispatches that they may wish to perform. Some load serving entities (e.g., Entergy) have an abundance of generation available to the market and a shortfall of utility-owned generation, especially in future years, and thus a non-preferential use of non-firm generation is modeled to serve the remainder of the load.

Units in the planning models are provided with a voltage schedule. Units are expected to provide reactive resources to maintain that voltage schedule within the requirements established by each utility. In addition, each new generating unit connected to the member transmission systems are required to have a required amount of reactive capability based on their ability to produce real power. **[BEST PRACTICE]** Specific MVAR outputs from generation units are not scheduled as such but are required to support the voltage schedule. **[BEST PRACTICE]**

Optimum generation solutions for transmission constraints may be identified during the study process; however, there are no mechanisms to force implementation of such generation solutions. If IPPs are not interested in locating where they can relieve transmission problems, actual construction of new transmission facilities becomes the default solution. Demand-side alternatives are considered based on state requirements.

**Substation Configuration Criteria (i.e., breaker and a half, ring bus, straight bus, etc.).**

Specific substation configuration design is the responsibility of the individual SERC members. Bus configuration decisions must consider reliability, economic and operational issues and include consideration for importance of the station based on the number of customers connected, stability concerns and impact on system voltages. In many cases the straight bus configuration is not considered due to the greater loss of load potential from a line fault with breaker failure or bus fault. Also, additional complexity is introduced in the switching steps when transferring load from one breaker to another in the straight bus configuration. Ring buses (usually not more than 6 elements on a ring bus) are becoming the standard configuration for major substations due to the added reliability and operational flexibility above what the straight bus provides. Generators are usually connected in a ring bus but this is dependent on
where they are connected to the transmission grid. Breaker-and-a-half arrangements are also considered for substation designs, especially for larger configurations.

Other Information

SERC has requirements on data validation; e.g. comparing state estimator against models; validation of transformer tap settings, validation of generator real and reactive capabilities, and power factor validation. [BEST PRACTICE]
SPP REGION REVIEW

NERC-TIS MEETING

Houston, TX

Keith Tynes, SPP
March, 2005
SOUTHWEST POWER POOL IS LOCATED IN THE “SOUTHWEST” CORNER OF THE EASTERN INTERCONNECT.

Southwest Power Pool, Inc.

The values and principles upon which SPP is incorporated and formed include: a relationship-based organization; member-driven processes; independence through diversity of Organizational Group membership; recognition that reliability and economic/equity issues are inseparable; and, deliberate evolutionary, as opposed to revolutionary, implementation of new concepts. These values and principles should guide those serving this organization. The Board of Directors will endeavor to ensure equity to all Members while also assuring the continuous adaptation to controlling conditions within these stated values and principles.
Southwest Power Pool

SPP AND OPERATIONAL AUTHORITY

The bases for SPP’s operational authority are principally derived from the following documents: the SPP Membership Agreement, SPP Criteria, NERC Operating Policies, NERC Planning Standards and the SPP Open Access Transmission Tariff (“the Tariff,” or “OATT”). The following is a breakdown of SPP functional authority as a Planning Authority:

Function – Planning Reliability (SPP Staff)

<table>
<thead>
<tr>
<th>Tasks</th>
<th>TO’s SPP</th>
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<tbody>
<tr>
<td>1. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.</td>
<td>SPP Criteria (3.4.1 –MDWG) MDWG procedure manual, MDWG charter SPP OATT (with revisions) NERC Planning Standards I A M1-M4 &amp; II A M1-M6</td>
<td>SPP Criteria (3.4.1 –MDWG) MDWG procedure manual, MDWG charter SPP OATT (with revisions) NERC Planning Standards I A M1-M4 &amp; II A M1-M6</td>
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<td>2. Maintain and apply methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of</td>
<td>SPP Criteria (Section 3.1 ,3.3 and 3.4 and 12.0) SPP OATT (with revisions) (Attachment O) NERC Planning Standards II A M1-M6 Membership Agreement (2.1.J. and 2.1.5) TWG and GWG charter</td>
<td>SPP Criteria (Section 3.1 ,3.3 and 3.4 and 12.0) SPP OATT (with revisions) (Attachment O) NERC Planning Standards II A M1-M6 Membership Agreement (2.1.J. and 2.1.5) TWG and GWG charter</td>
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1 For Day 1 operations, the Planning Authority Area refers to area encompassing facilities under the SPP OATT.
Southwest Power Pool

| 3. Define and collect or develop information required for planning purposes, including: |
|-----------------|-----------------|-----------------|-----------------|
| a. Transmission facility characteristics and ratings, | TO’s SPP | TO’s SPP | TO’s SPP |
| b. Demand and energy end-use customer forecasts, capacity resources, and demand response programs, | LSE’s (ultimate responsibility) SPP | LSE’s (ultimate responsibility) SPP | LSE’s (ultimate responsibility) SPP |
| c. Generator unit performance characteristics and capabilities, and | Generation Owners | Generation Owners | Generation Owners |
| d. Long-term capacity purchases and sales. | LSE’s | LSE’s | LSE’s Generation Owners, etc. |

| 4. Evaluate plans for customer requests for transmission service. |
|-----------------|-----------------|-----------------|-----------------|
| a. Evaluate responses to long-term (generally one year and beyond) transmission service requests. | SPP | SPP | SPP |
| b. Review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric | SPP (ultimate responsibility) TO’s | SPP (ultimate responsibility) TO’s | SPP (ultimate responsibility) TO’s |

SPP Membership Agreement with revisions NERC Planning Standards II.C SPP Criteria 12.2
SPP Membership Agreement SPP OATT (with modifications) SPP Criteria 2 and 12
SPP OATT Generation 12.1, 2.3 (reporting)
SPP OATT Section 17 & 29 SPP Criteria 4.5 Membership Agreement Section 2.1
SPP OATT Section 19 & 32 SPP OATT Attachment V SPP Criteria 3 Membership Agreement Section 2.1
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<td>5. Review and determine TTC values (generally one year and beyond) as appropriate.</td>
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<tr>
<td>6. Assess, develop, and document resource and transmission expansion plans.</td>
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<tr>
<td>a. Integrate and verify that the respective plans for the Planning Authority Area meet reliability standards.</td>
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<tr>
<td>b. Identify and report on potential transmission system and resource adequacy deficiencies, and provide alternate plans that mitigate these deficiencies.</td>
<td>SPP TO’s/TOP’s</td>
<td>SPP (ultimate responsibility) TO’s/TOP’s</td>
<td>SPP (ultimate responsibility) TO’s/TOP’s</td>
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<tr>
<td>7. Provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.</td>
<td>SPP TO’s</td>
<td>SPP (ultimate responsibility) TO’s</td>
<td>SPP (ultimate responsibility) TO’s</td>
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<tr>
<td>8. Monitor transmission expansion plan and resource plan implementation.</td>
<td>SPP TO’s</td>
<td>SPP (ultimate responsibility) TO’s</td>
<td>SPP (ultimate responsibility) TO’s</td>
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<td>9. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.</td>
<td>SPP</td>
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<td>10. Evaluate the impact of revised strategies.</td>
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**Southwest Power Pool**
<table>
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<th>Transmission and generator in-service dates on resource and transmission adequacy.</th>
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<td>6A, B3 and 9.1 NERC Planning Standards 1.AS.2, SPP Membership Agreement 2.1.3, 2.1.4, and 3.3 SPP OATT (LGIA)</td>
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</table>
Planning and Coordination Principles

A primary purpose of SPP is to facilitate joint planning and coordination in the construction and operation of the generation and transmission network of the individual members so as to provide for increased operating efficiency and continuing service reliability, both in SPP and the contiguous regions. To assist in achieving these objectives, the members of SPP recognize that common criteria and procedures must be used in the planning and operation of the combined electric system for cost effective, adequate and reliable bulk power supply.

Membership compliance with SPP Criteria is considered essential to a well planned and operated electric system, and is mandatory for all SPP members. Adherence can be expected to provide adequate and effective safeguards against the occurrence of uncontrolled area-wide power disturbances and will also provide efficient utilization of the electric system resources.

It is the policy of SPP to maintain as high an interconnection capability with adjoining regions as is economically prudent. Interconnections with adjoining regions shall be designed such that SPP will remain interconnected following all of the more probable transmission and generation outage contingencies. Emergencies that occur in adjoining regions can affect SPP, just as the emergencies within SPP can affect adjoining regions. Therefore, joint studies shall be made on a regular basis to investigate various system emergencies that can occur and their effects on the electric system. In this way, the effectiveness of existing and planned interconnections shall be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability shall be maintained.
Contingencies Analyzed (i.e. N-1, N-2, etc.).

Planning studies identify any planning criteria violations that may exist and plans to mitigate such violations. Members work with the SPP Transmission Working Group whenever new facilities are in the conceptual planning stage so that optimal integration of any new facilities and potentially benefiting parties can be identified. Studies affecting more than one system owner or user are conducted on a joint system basis. Reliability studies examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions.

The transmission system of the SPP region is planned and constructed so that the contingencies as set forth in SPP Criteria meet the applicable NERC Planning Standards for System Adequacy and Security – Transmission System Table 1 and its applicable standards and measurements. Extreme contingency evaluations are conducted to measure the robustness of the transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to understand the risks and consequences of such events and to attempt to limit the significant economic and social impacts that may result.

Base Case

The SPP Model Development Working group (MDWG) assembles and verifies the SPP base case powerflow models annually. These models maintain at least the following:

- System facilities reflect normal operation.
- Line and equipment loading is within applicable thermal rating limits.
- Voltage levels are maintained within applicable limits.
- All customer demands are supplied, and all contracted firm (non-recallable reserved) transfers are maintained.
- Stability (dynamic and steady state) of the network is maintained.
- Cascading outages do not occur.
Loss of Single Component
The SPP MDWG runs contingency studies for the following:

- Initiating incident results in a single element out of service.
- Line and equipment loadings shall be within applicable rating limits.
- Voltage levels shall be maintained within applicable limits.
- No loss of customer demand (except as noted in NERC Table I, Footnote b), nor the curtailment of contracted firm (non-recallable reserved) transfers shall be required.
- Stability (angular and voltage) of the network shall be maintained.
- Cascading outages shall not occur.

Loss of Two or More Components
The SPP MDWG runs contingency studies for the following:

- Initiating incident may result in two or more (multiple) components out of service – could be either common right – of –way, structure, etc. or specific scenario as identified by the Transmission Owners.
- Line and equipment loadings shall be within applicable thermal rating limits.
- Voltage levels shall be maintained within applicable limits.
- Stability (angular and voltage) of the network shall be maintained.
- Planned outages of customer demand or generation (as noted in NERC Table I) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
- Cascading outages shall not occur.
- Extreme events (Category C and D) are identified by the Transmission Owners and provided to the SPP for required submittals.

Extreme Event
The SPP Transmission Working Group (TWG) conducts contingency studies where extreme contingency events could lead to uncontrolled cascading outages or system
instability. The TWG documents the measures and procedures to mitigate or eliminate the extent and effects of those events.

*NERC Table I.*

SPP studies consider all contingencies applicable to the appropriate Category, but evaluate and document only the most critical. Studies are conducted or reviewed annually, cover seasonal or expected critical system conditions for near (current or next year) and intermediate (two to five year recommended) planning horizons, and address both intra- and interregional reliability.

The longer-term (beyond five years) simulations identify concerns that may surface in the period beyond the more certain intermediate year period. Powerflow models beyond the five-year horizon are evaluated as needed to address identified marginal conditions. SPP Members can apply operating guides and procedures to category B, C and D events. In these cases, the SPP Transmission Owners are familiar with past studies and analyses of their systems. Changes in network topology, extreme loading or generation shift, etc. may trigger reassessments. SPP OATT Queued Generation projects are not considered in planning studies until firm transmission contracts are in place or projects are actually constructed. Economic analysis may be more liberal in the examination of potential benefits of known future IPP projects.
Load Levels Studied

Load forecasts are performed by the SPP Members using traditional load forecast methodologies considering such components as power factor, load diversity, historical records and analysis of growth trends. The Members exercise the use of the knowledge of their own systems to develop load forecast methodologies that produce what they determine to be the most accurate forecasts possible. Forecast methodologies are not required by SPP to be the same across the SPP Membership companies.

Models developed and used for study in the SPP are governed by: NERC MMWG and the SPP MDWG. The following include load levels modeled in SPP for use in system analyses:

- 2005 FA, Spring, SH, SP, WP
- 2006 April min, FA, G, SH, SP, WP
- 2007 SP, WP
- 10 SP, WP
- 2015 SP
- FA, Fall = 55% of Peak
- April min models “…Sunday morning in April”
- SH, Shoulder = 85% of Peak

SPP Expansion Planning

The SPP Regional Expansion Planning process conducts its reliability and econometric assessments on the upcoming summer peak model and the 5 year out model. Additionally, the 2013 model was used to test the longevity of proposed economic projects. (2005 Summer Peak, 2010 Summer Peak and 2013 Summer Peak)

SPP Open Access Transmission Tariff – Service, Attachment ‘O’ and Interconnection

System Impact Studies (Transmission service)

- Study time frame based on type of service request
  - Short Term
Southwest Power Pool

- Long Term (ROR)

- Interconnection Studies (Gen, Trans, Load)
  - Study time frame of interconnection
  - Interconnection process requires submittal of study to SPP - TWG for review
  - Mandatory coordination with impacted TO’
Voltage Limits Applied

SPP defines Nominal Voltage as – The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV. SPP Planning Criteria goes on to explain that sufficient reactive capacity must be planned within the SPP electric system at appropriate places to maintain transmission system voltages within plus or minus 10% of nominal on load serving buses or as determined by the transmission owner and user under contingency conditions. In SPP, Transmission and Generation Owners plan their own reactive reserve margins and voltage set points and reflect those decisions in the models that are supported and built by the SPP Members themselves.
Methods Utilized for Rating Conductors and Other Equipment

Transmission Circuits

SPP members rate transmission circuits operated at 69 kV and above in accordance with SPP Criteria. A transmission circuit is defined to consist of all elements load carrying between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to this criteria. All circuit ratings are computed with the system operated in its normal state (all lines and buses in-service, all breakers with normal status, all loads served from their normal source). The circuit ratings are specified in "MVA" and are taken as the minimum ratings of all of the elements in series. Minimum circuit ratings are determined as described in SPP Criteria and Members maintain transmission right-of-way to operate at these ratings. Starting with standard conductor and rating calculation data, SPP Members may use additional data based on the specifics of the physical characteristics of the geographic area to fine tune ratings. This can result in a more conservative or liberal rating depending, i.e. 3ft/sec versus 2ft/sec wind speed value.

Each element of a circuit has both a normal and an emergency rating. For certain equipment, (switches, wave traps, current transformers and circuit breakers), these two ratings are identical and are defined as follows:

a. NORMAL RATING: Normal circuit ratings specify the level of power flow that facilities can carry continuously without loss of life to the facility involved.

b. EMERGENCY RATING: Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

At a minimum, each Member computes summer and winter seasonal ratings for each circuit element. The summer season is defined by the months June, July, August and
September. The winter season is defined by the months December, January, February and March. The seasonal rating is based upon an ambient temperature (either maximum or average) developed using the methodology described IEEE Standard 738-1993. A Member may elect to compute a third set of seasonal ratings for the remaining months of the year (April, May, October and November)
Interchange Modeling (Power Transfers)

The transmission planning models developed by SPP members are developed using the NERC MMWG models as the appropriate representation for most control areas outside of the SPP Region. SPP Modeling procedures specify that all transaction data is to be collected and coordinated in the “Model Transaction Workbook”. Detailed models for various neighboring systems (AECI, Entergy, MISO, etc.) and internal load serving entities are used to augment the MMWG cases for system representations. The interchange developed for these models serves as the bases for most interchange in the internal study cases. In general these interchanges only include transactions that have firm transmission from source to sink (i.e. no partial-path transactions). Some utilities modify the interchange data to include all transactions for which the system has granted firm transmission service, regardless of whether they represent a partial path transaction, in order to provide greater accuracy when performing individual system studies.

The SPP Expansion Planning team as well as the SPP Tariff Studies group utilizes the SPP MMWG base models. These models are updated with any new interchange adjustments based on SPP OASIS activity. SPP engineering groups create the necessary transaction cases to account for Long Term SPP Firm Confirmed transmission service. The SPP OATT – System Impact Studies departments integrate Monthly or Long Term Firm Transmission Service requests as necessary in models to study transmission service requests or generation interconnection requests.
Generation Dispatch Practices

Generation in the planning models is dispatched on an economic basis as each of the SPP Transmission Owning Members submit to the Region during the model building cycle. Generation with firm transmission service agreements is turned on to deliver the power associated with the agreement to the point of delivery. Generation that does not have a firm transmission service or has not been designated as a network resource by a load serving entity is generally modeled connected to the system but not available to generate.

Units in the planning models are provided with a voltage schedule. Units are expected to provide reactive resources to maintain that voltage schedule. In addition, each new generating unit connected to the member transmission systems are required to possess a required amount of reactive capability based on their ability to produce real power. Specific MVAR outputs from generation units are not scheduled as such but are required to support the voltage schedule.
Identify Substation Configuration Criteria Used

(i.e., breaker and a half, ring-bus, straight bus, etc.).

Specific substation configuration design is the responsibility of the individual SPP members. Bus configuration decisions must consider reliability, economic and operational issues. In many cases the straight bus configuration is not considered due to the greater loss of load potential from a line fault with breaker failure or bus fault. Also, additional complexity is introduced in the switching steps when transferring load from one breaker to another in the straight bus configuration. Ring buses are becoming the standard configuration for major substations due to the added reliability and operational flexibility above what the straight bus provides. “Breaker and a half” arrangements are also considered for substation designs, especially for larger configurations.
WECC RESPONSE TO BLACKOUT RECOMMENDATION 13 C

Introduction
WECC covers a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Figure 1 shows the WECC in relation to other NERC regions.

Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources. Due to the vastness and diverse characteristics of the region, WECC's members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable and affordable electric service to more than 71 million people in WECC's service territory.

Membership in WECC is voluntary and open to any organization having an interest in the reliability of interconnected system operation or coordinated planning. The Council provides the forum for its members to enhance communication, coordination and cooperation – all vital ingredients in planning and operating a reliable interconnected electric system.

Similar to other regions, WECC is a member-populated, committee-based organization comprised of volunteer members on WECC committees and subcommittees, the majority of transmission planning work is performed at the member level. The individual members develop all detailed planning assessments, design criteria, system protection implementation, and maintenance programs. There are presently over 160 members.

The WECC region is divided into four major reporting subregions as shown in Figure 2.
1. Northwest Power Pool Area (NWPP)
2. Rocky Mountain Power Area (RMPA)
3. Arizona-New Mexico-Southern Nevada Power Area (AZ-NM-SNV), and

The peak load for 2005 is projected to be over 140,000 MW, with a resource capacity of about 190,000 MW. Load growth (peak demand) projected at about 2% for the next ten years.
WECC adopted the NERC Planning Standards and in instances where WECC had more stringent or additional requirements merged its own Reliability Criteria into the NERC Reliability Standards to form a common document referred to as the NERC/WECC Planning Standards. The document can be found on the WECC web site at:
WECC requires its members to comply with the NERC/WECC Planning Standards.
Figure 1  WECC in relation to other Regions

Figure 2  WECC Subregions
In addition to member system studies, WECC performs a Council-wide assessment of its system through its Annual Study Program. The Study Program is the mechanism for the development of study models and typically, 11 models are developed annually for member use. The models generally consist of:

- 5 near-term operating cases
- a 5-year planning case
- a 10-year planning case
- 4 additional future year scenario or planning cases

WECC continues to promote a reliable electric power system in the Western Interconnection, supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.
1. **Contingencies Analyzed** (i.e. N-1, N-2, etc.)

WECC relies on members to adequately assess the performance of their individual systems. Members provide the WECC staff with a status of their compliance with NERC standards on an annual basis as required in the NERC Planning Standards, and spot audits are performed to monitor compliance.

The Annual Study Program is a mechanism to evaluate the overall WECC system. Each year, a variety of disturbances are modeled using the power flow models created during that year. The 2004 Annual Study Program modeled 39 disturbances. Those contingencies were spread throughout the WECC sub-regions and modeled Level B, C, and D category disturbances, with emphasis on Levels C and D. Severe disturbances are simulated including loss of entire substations and entire generating plants to evaluate risk and identify potential deficiencies leading to unacceptable system performance.

In addition to the Annual Study Program, critical transfer paths throughout the Council footprint are analyzed seasonally during the Operating Transfer Capability (OTC) process. Results are provided to regional OTC groups and Council members for review and comment. Seasonal Operating Limits are provided to WECC operating personnel prior to each Summer, Winter, and Spring Operating season. Both Category B and C disturbances are used to establish seasonal path limits.

In 2004 WECC members were asked to evaluate the impacts of bus-tie breaker failure.

WECC does not specify for its members a minimum set of contingencies to be performed for contingency analysis, but does require its Members to be compliant with the attendant NERC Reliability Standards, and leaves the performance of the appropriate analyses up to the individual members. WECC voltage stability methodology recommends that members explore reasonably severe operating conditions, such as a combined loss of a generator with the loss of a transmission element. Multiple element contingencies or failures of remedial action schemes are considered viable disturbances if they have a historical precedent of occurrence.

2. **Load Levels Studied**

WECC develops power system models through its Annual Study Program case development process. The System Review Work Group (SRWG) coordinates the process and outlines the definition of the models that are developed each year. Members provide load-modeling data to regional Area Coordinators, which in turn provide the data to WECC. The Study Program cases represent a wide variety of system load conditions. Operating cases generally represent 90-100% of expected peak load conditions, or desired transfer levels. Other cases represent lighter loads based on seasonal conditions. Scenario cases may represent 105-110% of expected peak conditions.

Individual members determine appropriate load levels for their internal studies and may adjust loads accordingly for their study purposes.
The OTC process verifies seasonal path transfer limits using both heavy and light load models for its assessments.

The WECC Voltage Stability Methodology requires that members use 105% peak load models to establish voltage stability and reactive margin.

Load forecasting methodologies are up to the individual WECC Members, as are the type of modeling assumptions, and the load power factor assumptions.

3. **Voltage Limits Applied**

In general, WECC does not have a set of Council-wide specific requirements for voltage limits. For many WECC members, voltages must remain between 0.95 per unit and 1.05 per unit under normal or system intact conditions, and between 0.90 per unit and 1.10 per unit under contingency conditions. In addition, some members require that voltage does not change more than 0.05 per unit between normal and contingency conditions. However, voltage criteria is member-specific and some members have more restrictive criteria than that mentioned above.

The NERC Planning Standards require performance to meet applicable ratings for voltage and thermal limits. The NERC/WECC Planning Standards are more prescriptive and require that members adhere to criteria that specify allowable effects on other systems. For a Level B disturbance, the transient voltage dip cannot exceed 25% at load buses and 30% at non-load buses. For a Level C disturbance, the transient voltage dip cannot exceed 30% at any bus, and cannot exceed 20% for more than 40 cycles at load buses. The post-transient voltage cannot exceed 5% at any bus for a Level B disturbance, and cannot exceed 10% at any bus for a level C disturbance.

4. **Methods Utilized for Rating Conductors and Other Equipment**

WECC member facility ratings are based on criteria specified by each individual member. Most follow the IEEE Standards for calculating the rating of conductors, other equipment and associated facilities. Members must maintain documentation stating how they comply with ratings methodology.

Members are encouraged to represent their systems in sufficient detail such that the impact of disturbances, whether internal or external to their own systems, can both be adequately evaluated. The level of detail represented should be that used by each member in conducting their own internal bulk transmission system studies or facility rating studies. To accomplish this, every attempt should be made to provide accurate representation of all system elements. It is recognized that a greater level of detail is needed for conducting local area studies, but this additional detail should be added by the individual member once the case is complete. It is important that the level of detail be sufficient to accurately determine path ratings.
WECC requires that all facility ratings be included in data submitted for the 10-year power flow and stability data bank. The WECC System Review Work Group (SRWG) maintains a Data Preparation Procedure Manual (DPPM) that includes criteria for system modeling. The DPPM requires members to use the limiting element (as required by NERC Planning Standards) when calculating and providing line ratings for the system models. Each member maintains records or database to identify the elements that go into the rating. In addition, members are asked to provide eight element ratings for each power flow model, consisting of normal and emergency ratings for each of the four seasons. However, some members have indicated they do not identify or maintain seasonal ratings, and therefore, provide a single rating for each element within their area. Other members use emergency ratings based on a variety of methodologies. Conductor temperature, wind speed and angle, and other typical parameter assumptions as identified in their individual Facility Rating Methodology documentation and used for rating transmission elements vary throughout the Council.

5. **Interchange Modeling (Power Transfers)**

Power transfer targets between power flow control areas are specified for each model prepared by the SRWG. Scenario cases may specify transfers at path transfer limit levels. The OTC evaluates major transfer paths throughout the Council on a seasonal basis.

WECC Voltage Stability Methodology specifies that major transfer paths be evaluated and demonstrate voltage stability at 5% over their specified limits.

Interface studies are performed by WECC members across control area and other regional boundaries. Interface studies include a mix of both simultaneous and non-simultaneous transfers.

6. **Generation Dispatch Practices**

There are no WECC-wide dispatch criteria. In general, generation in the planning models is dispatched on an economic basis for each of the primary load serving entities in the Region.

Generation in near term operating cases is dispatched by the individual entities providing the input data and is typically represented as is anticipated for the upcoming operating season. Generation in the planning cases is dispatched by the entities providing the input data. Units are dispatched to meet load-serving obligations and to achieve the desired transfer targets identified in the individual case description sheets. Units in the planning models are provided with a voltage schedule. Units are expected to provide reactive resources to maintain that voltage schedule. In addition, each new generating unit connected to the member transmission systems are required to have a required amount of reactive capability based on their ability to produce real power.
7. **Substation Configuration Criteria** (i.e., breaker and a half, ring bus, straight bus, etc.).

Specific substation configuration design is the responsibility of the individual WECC members. Bus configuration decisions must consider reliability, economic and operational issues and include consideration for importance of the station based on the number of customers connected, stability concerns and impact on system voltages.

**Other Information**