Southwest Power Pool

CRITERIA

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Southwest Power Pool Criteria

FOREWORD i

INTRODUCTION ii

1.0 LOAD AND ENERGY FORECASTS 1-1

2.0 CAPACITY MARGIN 2-1
- 2.1 Definitions 2-1
  - 2.1.1 Load Serving Member 2-1
  - 2.1.2 Firm Power 2-1
  - 2.1.3 System Capacity 2-1
  - 2.1.4 Net Load 2-2
  - 2.1.5 Capacity Year 2-2
  - 2.1.6 System Peak Responsibility 2-2
  - 2.1.7 Capacity Margin 2-3
  - 2.1.8 Percent Capacity Margin 2-3
  - 2.1.9 Minimum Required Capacity Margin 2-3
  - 2.1.10 System Capacity Responsibility 2-3
  - 2.1.11 Capacity Balance 2-3
  - 2.1.12 Firm Transmission Service 2-3
- 2.2 Capacity Responsibility 2-3
- 2.3 Records 2-4
- 2.4 Generation Planning 2-5
  - 2.4.1 Design Features 2-5
  - 2.4.2 Fuel Supply 2-5

3.0 REGIONAL TRANSMISSION PLANNING 3-1
- 3.1 Concepts 3-1
- 3.2 Definitions 3-1
- 3.3 Coordinated Planning 3-1
  - 3.3.1 Planning Criteria 3-2
  - 3.3.2 Planning Assessment Studies 3-2
  - 3.3.3 Benchmark SPP Models 3-3
- 3.4 Transmission Contingency 3-3
  - 3.4.1 Adequacy 3-3
    - 3.4.1.1 Base Case 3-3
    - 3.4.1.2 Loss of Single Component 3-3
    - 3.4.1.3 Loss of Two or More Components 3-4
    - 3.4.1.4 Extreme Event 3-4
  - 3.4.2 Study Requirements 3-4
  - 3.4.3 Mitigation Plans 3-5
  - 3.4.4 Reporting Requirements 3-5
- 3.5 Protective Relaying, Monitoring And Controls 3-5

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY 4-1
- 4.1 Definitions 4-2

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL) 4-2
4.1.2 Capacity Benefit Margin 4-2
4.1.3 Contractual Limit 4-2
4.1.4 Critical Contingency 4-2
4.1.5 Designated Network Resources (DNR) 4-2
4.1.6 Emergency Voltage Limits 4-2
4.1.7 Firm Available Transfer Capability (FATC) 4-3
4.1.8 First Contingency Incremental Transfer Capability (FCITC) 4-3
4.1.9 Flowgate 4-3
4.1.10 Line Outage Distribution Factor (LODF) 4-4
4.1.11 Local Area Problem 4-4
4.1.12 Monitored Facilities 4-4
4.1.13 Non-firm Available Transfer Capability (NFATC) 4-4
4.1.14 Normal Voltage Limits 4-4
4.1.15 Open Access Transmission Tariff (OATT) 4-4
4.1.16 Operating Horizon 4-4
4.1.17 Operating Procedure 4-4
4.1.18 Outage Transfer Distribution Factor (OTDF) 4-5
4.1.19 Participation Factor 4-5
4.1.20 Participation Points 4-5
4.1.21 Planning Horizon 4-5
4.1.22 Power Transfer Distribution Factor (PTDF) 4-5
4.1.23 Power Transfer Voltage Response Factor (PTVF) 4-5
4.1.24 Open Access Transmission Tariff (SPP OATT) 4-5
4.1.25 Transfer Distribution Factor (TDF) 4-5
4.1.26 Transfer Test Level 4-6
4.1.27 Transmission Owner (TO) 4-6
4.1.28 Transmission Provider (TP) 4-6
4.1.29 Transmission User (TU) 4-6
4.1.30 Transmission Reliability Margin (TRM) 4-6
4.1.31 TRM multipliers (a & b) 4-6
4.2 CONCEPTS
4.2.1 Transfer Capability 4-6
4.2.2 Available Transfer Capability 4-7
4.2.3 Response Factors 4-8
4.2.4 Transfer Capability Limitations 4-9
4.2.5 Invalid Limits 4-11
4.2.6 Flowgates 4-11
4.2.7 Total Flowgate Capacity (TFC) 4-12
4.2.8 Flowgate Capacity 4-13
4.2.8.1 Total Flowgate Capacity (TFC) 4-13
4.2.8.2 Available Flowgate Capacity (AFC) 4-13
4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC) 4-13
4.2.9 System Impacts 4-13
4.2.9.1 Impacts of Existing Commitments 4-13

4.2.9.2 Positive Impacts....4-14
4.2.9.3 Counter Impacts....4-14
4.2.10 Monitored Facilities....4-15
4.2.11 Critical Contingencies....4-15
4.3 RELIABILITY MARGINS....4-15
4.3.1 Transmission Reliability Margin (TRM)....4-16
4.3.2 TRM Coordination....4-17
4.3.3 TRM Availability for Non-firm Service....4-18
4.3.4 TRM Calculation Frequency....4-18
4.3.5 Capacity Benefit Margin (CBM)....4-18
4.4 FLOWGATE AND TFC DETERMINATION....4-19
4.4.1 Flowgate Updates....4-19
4.4.2 Annual Review....4-20
4.4.2.1 Power Flow Models....4-20
4.4.2.2 Parameters supplied by the Transmission Owners....4-21
4.4.2.3 Default Parameters....4-22
4.4.2.4 Voltage Limits....4-22
4.4.2.5 Linear Analysis and AC Verification....4-22
4.4.2.6 Operating Procedures....4-23
4.4.2.7 Identification of Flowgate Changes....4-23
4.4.2.8 Review and Coordination with Transmission Owners....4-23
4.4.2.9 Initiating Interim Review of Flowgate List....4-24
4.4.3 Dispute Resolution....4-24
4.4.4 Coordination with Non-SPP Members....4-25
4.4.5 Feedback to SPP Members....4-25
4.5 ATC CALCULATION PROCEDURES....4-26
4.5.1 Calculation and Posting Timeframes....4-26
4.5.2 Power Flow Models....4-27
4.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)....4-27
4.5.4 Transfer Distribution Factor Determinations (TDF)....4-27
4.5.5 Existing Commitments and Netting Procedures....4-28
4.5.5.1 Yearly Calculations (whole years, starting 60 days out)....4-28
4.5.5.2 Monthly Calculations (months 2 through 16)....4-28
4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)....4-28
4.5.5.4 Hourly Calculations (Day 1)....4-29
4.5.6 Partial Path Reservations....4-29
4.5.7 ATC Adjustments Between Calculations....4-29
4.5.8 Coordination of Transmission Commitments with Neighboring Organizations 4-30
4.5.9 Margins....4-30
4.5.10 ATC Determination....4-30
4.5.10.1 Firm Base Loading (BL)....4-30
4.5.10.2 Non-Firm Base Loading (NFBL)....4-30
4.5.10.3 Firm Available Flowgate Capacity (FAFC)....4-30
4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon)....4-30
4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning

Horizon) 4-31
4.5.10.6 Firm Available Transfer Capability (FATC) 4-31
4.5.10.7 Non-Firm Available Transfer Capability (NATC, Operating Horizon 4-31
4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon 4-31
4.5.11 Annual Review of ATC Process 4-31
4.5.12 Dialog With Transmission Users 4-32

5.0 SECURITY COORDINATION CENTER 5-1
5.1 Information Exchange 5-1
5.2 Security Coordination 5-1
5.2.1 Member Responsibilities 5-1
5.2.2 Operatiing Reliability Working Group 5-2
5.2.3 SPP Staff 5-2
5.2.4 Reliability Authority Responsibilities 5-2
5.2.4.1 Daily Reliability Assessment 5-2
5.2.4.2 Daily Operational Coordination 5-2
5.2.4.3 Compliance Monitoring 5-3
5.2.4.4 Emergency Procedure Implementation 5-3
5.2.4.5 Interregional Coordination 5-3
5.2.5 Reliability Authority Authorities 5-3
5.2.6 Reliability Authority Performance Standards 5-3

6.0 OPERATING RESERVE 6-1
6.1 Purpose 6-1
6.2 Definitions 6-1
6.2.1 Balancing Authority 6-1
6.2.1.1 Balancing Authority Area 6-2
6.2.2 Balancing Authority Daily Peak Load Obligation 6-2
6.2.3 Operating Capacity 6-2
6.2.4 Operating Reserve 6-2
6.2.4.1 Regulating Reserve 6-2
6.2.4.2 Contingency Reserve 6-2
6.2.5 Spinning Reserve 6-3
6.2.6 Ready Reserve 6-3
6.2.7 Assistance Period 6-4
6.2.8 Group 6-4
6.2.9 Contingency Area 6-4
6.2.10 Assisting Areas 6-4
6.2.11 Daily Load and Capability Report 6-4
6.2.12 Firm Power 6-5
6.2.13 Other Extreme Conditions 6-5
6.2.14 Operating Reserve Contingency 6-5
6.2.15 Reserve Sharing Group 6-5
6.3 Minimum Daily Reserve Requirement 6-6
6.4 Procedures 6-7

6.4.1 Normal Daily Operation 6-7
6.4.2 Contingency Operation 6-8
6.4.3 Subsequent Contingencies 6-10
6.4.4 Assistance Reports 6-10
6.4.5 Other Extreme Conditions Events 6-11
6.5 Compensation for Assistance 6-12
6.5.1 Energy Charge 6-12
6.5.2 Accounting 6-12
6.5.3 Transmission Service 6-12
6.6 Responsibilities 6-12
6.6.1 Balancing Authorities 6-12
6.6.2 Operating Reliability Working Group 6-12

7.0 SYSTEM PROTECTION EQUIPMENT 7-1
7.1 Disturbance Monitoring Equipment 7-1
7.1.1 General Minimum Technical Requirements 7-1
7.1.1.1 DFR Minimum Technical Requirements 7-2
7.1.1.2 SOE/SER Minimum Technical Requirements 7-3
7.1.1.3 DDR Minimum Technical Requirements 7-3
7.1.2 Required Location for Monitoring Equipment 7-4
7.1.3 Requirements for Testing and Maintenance Procedures 7-5
7.1.4 Periodic Review of Disturbance Monitoring Equipment 7-5
7.1.5 Requests for Disturbance Data and Retention Requirements 7-6
7.2 Transmission Protection Systems 7-6
7.2.1 Introduction 7-6
7.2.2 Protection System Review 7-7
7.2.2.1 Assessment of System Performance 7-7
7.2.2.2 Reviews of Components And Systems 7-7
7.2.3 System Redundancy 7-8
7.2.4 Monitoring, Analysis And Notification of Misoperations 7-9
7.2.5 Transmission Protection System Maintenance And Testing Programs 7-10
7.2.6 Requests for Transmission Protection Systems Data 7-11
7.2.7 Transmission Protection Systems Criteria Updates 7-11
7.3 Under - Frequency Load Shedding and Restoration 7-11
7.3.1 Automatic Load Shedding 7-11
7.3.1.1 Operating Reserve 7-11
7.3.1.2 Operating Principles 7-11
7.3.1.3 Implementation 7-12
7.3.1.4 Required Location and Model Data Reporting for Under-Frequency Load Shedding Equipment 7-16
7.3.1.5 Requirements for Testing and Maintenance Procedures 7-16
7.3.1.6 Periodic Review of Under-Frequency Load Shedding Equipment 7-17
7.3.1.7 Requests for Under-Frequency Load Shedding Data 7-17
7.3.1.8 Restoration 7-18
7.3.2 Requirements of a Regional Under-Frequency Load Shedding Program 7-18

7.3.2.1 SPP's Coordination of Under-Frequency Load Shedding Program 7-18
7.3.2.2 Coordination of Under-Frequency Load Shedding Programs and Analyses with SPP 7-19
7.3.3 Manual Load Shedding 7-19
7.3.3.1 Conservation 7-19
7.3.3.2 Service Interruption 7-20
7.4 Special Protection Systems Equipment 7-21
7.4.1 Operating Requirements and System Redundancy 7-21
7.4.2 Location & Data Reporting For Special Protection Systems Equipment 7-22
7.4.3 Testing And Maintenance Procedures 7-22
7.4.4 Periodic Review of Special Protection Systems Equipment 7-23
7.4.5 Requests for Special Protection Systems Data 7-23
7.4.6 Submittals of Special Protection Systems Misoperations 7-24
7.4.7 Submittals for New And Modified Special Protection Systems 7-24
7.5 Undervoltage Load Shedding 7-26
7.5.1 Program Participants 7-26
7.5.2 Operating Reserve And Principles 7-26
7.5.3 Location And Data Reporting 7-27
7.5.4 Monitoring, Analysis And Notification of Misoperations 7-28
7.5.5 Testing And Maintenance Procedures 7-29
7.5.6 Periodic Review of Undervoltage Load Shedding Equipment 7-29
7.5.7 Requests for Undervoltage Load Shedding Data 7-29
7.5.8 Coordination of Undervoltage Load Shedding Programs 7-30
7.6 Automatic Restoration of Load 7-30
7.6.1 Program Participants 7-30
7.6.2 Operating Reserve And Principles 7-31
7.6.3 Location And Data Reporting 7-32
7.6.4 Monitoring, Analysis And Notification of Misoperations 7-33
7.6.5 Testing and Maintenance Procedures 7-34
7.6.6 Periodic Review of Equipment 7-35
7.6.7 Requests for Data 7-35
7.6.8 Coordiation of Programs 7-36
7.6.9 Submittals For New And Modified ARL Systems 7-36
7.7 Generation Control and Protection 7-37
7.7.1 Reviews Of Components And Systems 7-38
7.7.2 Monitoring, Analysis And Notification of Misoperations 7-39
7.7.3 Generation Protection System Maintenance And Testing Programs 7-40
7.7.4 Requests for Data 7-41
7.7.5 Coordination of Programs 7-41
7.7.6 Generation Protection Systems Criteria Updates 7-42
7.8 Generator Controls - Status and Operation 7-42
7.8.1 Generator Excitation System Control Operations 7-42
7.8.1.1 Reporting Procedures 7-42
7.8.1.2 Exempt Generators 7-42
7.8.2 Generator Operation for Maintaining Network Voltage 7-43
7.8.2.1 Control Area Responsibilities 7-43

7.8.2.2 Generator Owner/Operator Responsibility 7-43
7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings 7-43
7.8.3.1 Reporting Procedures 7-44
7.8.4 Generator Performance during Temporary Excursions 7-44
7.8.4.1 Excursions in Frequency and Voltage 7-44
7.8.4.2 Excursions in Real and Reactive Power Output 7-45
7.8.4.3 Exempt Generators 7-45
7.8.5 Generator Voltage Regulator Controls and Limit Functions 7-45
7.8.5.1 Reporting Procedures 7-46
7.8.6 Governor Control Operation 7-46
7.8.6.1 Reporting Procedures 7-46
7.9 Inter-Connection Revenue Metering 7-47
7.9.1 Meter Technical and Data Reporting Protocols 7-47
7.9.2 Revenue "Meter Technical and Data Reporting Protocols" Cross Reference 7-47

8.0 CONTROL AREA CERTIFICATION 8-1

9.0 BLACK START 9-1
9.1 Responsibilities 9-1
9.1.1 Members 9-2
9.1.2 SPP Reliability Coordinator 9-3
9.2 Elements of Balancing Authority/Transmission Operator Black Start Plans 9-3
9.3 Restoration Priorities 9-4
9.4 Information Communication 9-5

10.0 EMERGENCY COMMUNICATION 10-1
10.1 SPP Emergency Communication Network 10-1
10.2 Information Priority During Emergencies 10-1

11.0 SYSTEM DISTURBANCE REPORTING 11-1
11.1 Reporting Requirements 11-1
11.2 Report Types 11-1
11.2.1 First Notification 11-1
11.2.2 Power System Major Disturbance Report 11-1
11.2.3 Oral Report 11-2
11.2.4 US DOE/EP Power System Emergency Report 11-2
11.2.5 Detailed Disturbance Analysis Report 11-2
11.2.6 Report Submitted to NERC 11-2

12.0 ELECTRICAL FACILITY RATINGS
12.1 Rating of Generating Equipment 12-1
12.1.1 Capability Test 12-1
12.1.2 Operational Test 12-2
12.1.3 Frequency of Testing 12-2
12.1.4 Rating and Testing Conditions 12-2
12.1.5 Procedures for Establishing Capability Ratings 12-3
12.1.5.1 External Factors 12-3

12.1.5.2 Seasonality 12-4
12.1.5.3 Rating Adjustments 12-5
12.1.6 Reactive Capability Verification 12-7
12.1.6.1 Verification Required Every Five Years 12-7
12.1.6.2 Entity Responsible for Verification 12-7
12.1.6.3 Leading and Lagging Capabilities 12-7
12.1.6.4 Method of Verificaiton 12-7
12.1.6.5 Reactive Capability Test/Verification 12-8
12.1.6.5.1 Test/Verification Objective 12-8
12.1.6.5.2 Test/Verification Conditions 12-8
12.1.6.5.3 Test/Verification Procedure 12-9
12.1.6.6 Test/Verification Results 12-10
12.2 Rating of Transmission Circuits 12-10
12.2.1 Power Transformer 12-11
12.2.2.1 Normal Rating 12-11
12.2.1.2 Emergency Rating 12-12
12.2.1.3 Loss of Life 12-12
12.2.1.4 Ambient Temperature 12-12
12.2.2 Overhead Conductor 12-13
12.2.2.1 Conductor Properties 12-13
12.2.2.2 Line Geographic Location 12-13
12.2.2.3 Radiation Properties 12-13
12.2.2.4 Weather Conditions 12-15
12.2.2.5 Maximum Conductor Temperature 12-15
12.2.2.6 Determination of Maximum Conductor Temperature 12-15
12.2.2.7 Hours of Operation at Emergency Rating 12-17
12.2.3 Underground Cables 12-18
12.2.3.1 Cable Ampacity 12-18
12.2.3.2 Conductor Temperature 12-18
12.2.3.3 Ambient Temperature 12-19
12.2.4 Switches 12-20
12.2.5 Wave Traps 12-21
12.2.6 Current Transformers 12-21
12.2.6.1 Separately Mounted Current Transformers 12-21
12.2.6.2 Bushing Current Transformers 12-21
12.2.7 Circuit Breakers 12-22
12.2.8 Ratings of Series and Reactive Elements 12-22
12.2.9 Ratings of Energy Storage Devices 12-22
12.2.10 Circuit Rating Issues 12-22
12.2.10.1 Dynamic (Real Time) Ratings 12-23
12.2.10.2 Non-Thermal Limitations 12-23
12.2.10.3 Tie Lines 12-23
12.2.10.4 Rating Inconsistencies 12-23
12.2.10.5 Damaged Equipment 12-24
12.2.11 Reporting Requirements 12-24

13.0 OPEN 13-1

14.0 TRANSMISSION LOADING RELIEF 14-1
14.1 Purpose 14-1
14.2 Definitions 14-1
14.2.1 Flowgate 14-1
14.2.2 Transmission Circuit 14-1
14.2.3 Interconnected Reliability Operating Limit 14-1
14.2.4 System Operating Limit 14-1
14.3 Daily Reliability Assessment 14-2
14.3.1 Control Area Data Reporting 14-2
14.3.2 Overload Evaluation 14-2
14.3.3 Control Area Planning 14-2
14.4 Transmission Loading Mitigation 14-2
14.4.1 Reliability Coordinator Responsibilities 14-2
14.4.1.1 Monitoring 14-2
14.4.1.2 Weather Adjustment of Limits 14-2
14.4.2 Control Area Responsibilities 14-3
14.4.3 Transmission Loading Relief Procedures 14-3
14.5 Subsequent Overload Conditions 14-3
14.6 Curtailment Reports 14-4
14.7 Compensation for Assistance 14-4
14.8 Responsibilities 14-4
14.8.1 Control Areas 14-4
14.8.2 Operating Reliability Working Group 14-4
14.8.3 Reliability Coordinator 14-4

15.0 OPEN 15-1

APPENDICES
More Probable Contingency Assessment Criteria
System Performance Goals ..... Appendix 1
Uniform Rating of Generating Equipment
Determination of Ambient Rating Conditions ..... Appendix 2
SPP Emergency Communication Network
Programming Information Guide ..... Appendix 3
Considerations For Development of Black Start Plans ..... Appendix 4
Major Disturbance Report ..... Appendix 5
Transmission Rating Criteria ..... Appendix 6
Data Dictionary for Electric System Security Data ..... Appendix 7
Generation Reporting Forms ..... Appendix 8
Response Factor Thresholds ..... Appendix 9
Unit Reactive Limits (Lead and Lag) Verification FORM ..... Appendix 10

Southwest Power Pool

CRITERIA

FOREWORD

All members of Southwest Power Pool (SPP) adopted the NAPSIC (now North American Electric Reliability Council or NERC) Operating Guides on March 11, 1970. Over the years, these documents have developed into policies, procedures, principles, criteria, standards and guides. In some instances, the NERC documents are not in sufficient detail to meet specific needs of SPP. Additional necessary details have been adopted by SPP as Criteria. This Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the interconnected electric system is achieved. Reference to SPP in terms of responsibilities for activities means SPP organizational groups which are defined in SPP Bylaws and the SPP Directory. Reference to the SPP bulk electric system means the combined interconnected electric systems of members. Reliability Coordination (Coordinator) and Security Coordination (Coordinator) are used interchangeably in this Criteria.

INTRODUCTION

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. This Criteria presents the characteristics of a well-planned bulk power electric system, describes the basis for model testing and lists the reliability and adequacy tests to be used to evaluate the performance of the SPP bulk electric system, and describes coordinated operating procedures necessary to maintain a reliable and efficient electric system. Reliable operation of the interconnected bulk electric system of SPP requires that all members comply with this minimum Criteria. Compliance with this 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. This Criteria is also intended to serve as a guideline for developing more specific and definitive criteria by each member of SPP.

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.

1.0 LOAD AND ENERGY FORECASTS

Each member shall provide annually to the SPP Office a 10-year forecast of peak demand and net energy requirements. This information is to conform with requirements set by SPP in conjunction with NERC and government agencies. The forecasts so provided shall be produced in accordance with generally recognized methodologies and also in accordance with the following principles.

a. Each member shall select its own load forecasting methodology and establish its own load forecast.

b. Each member shall forecast load based on expected weather conditions.

c. Method used, factors considered and assumptions made shall be submitted along with the forecast.

d. The SPP forecast shall be the total of the member forecasts.

e. High and low growth rate and extreme weather scenario bands shall be produced for the SPP Regional and Subregional demand and energy forecasts.

f. Economic, technological, sociological, demographic and any other significant factors shall be considered in producing the forecast.

2.0 CAPACITY MARGIN

This Criteria requires and provides for the sharing of reserve generating capacity as a means of reducing capacity requirements of each Member and providing reliable electric service to firm customers due to the equitable purchase, sale and exchange of generating capacity among Members.

2.1 Definitions

2.1.1 Load Serving Member

A Load Serving Member shall mean any SPP Member assuming legal obligation to provide firm electric service to a customer or group of customers within SPP.

2.1.2 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined Capacity Margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Power purchased shall only be considered to be Firm Power if Firm Transmission Service is in place to the Load Serving Member for delivery of such power. Firm Power does not include “financially firm” power.

2.1.3 System Capacity

A Load Serving Member’s System Capacity shall be equal to the capability of its generating facilities, including its ownership share of jointly owned units, demonstrated under procedures set forth in SPP Rating of Generating Equipment Criteria, adjusted to reflect the purchase from and/or sale to any other party of generating capacity or SPP defined Operating Reserve, under any appropriate agreement. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Capacity purchases shall only be considered if Firm Transmission Service is in place to the Load Serving Member for delivery of power from such capacity.

Unless reported separately, generating facilities owned by others within the Load Serving Member's system that are obligated to furnish firm power to customers within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements with the host Control Area, the host Control Area will not be required to be responsible for capacity and/or reserve requirements. The reporting of generating facilities owned by others does not constitute an obligation on the Load Serving Member's part to furnish reserves or back up power for that generation.

2.1.4 Net Load

The term Net Load for any Load Serving Member shall mean, for any clock hour:

(a) Net generation by the Load Serving Member's facilities; plus

(b) Net receipts into the Load Serving Member's system; minus

(c) Net deliveries out of such Load Serving Member's system

Unless reported separately, the Net Load of other non-Load Serving Members located within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements, the reporting of these loads does not constitute an obligation on the Load Serving Member's part to furnish reserves, back up power, or incur financial obligations from SPP for that load.

2.1.5 Capacity Year

Capacity Year shall mean a period of twelve consecutive months beginning on October 1 of each calendar year. Any period less than a Capacity Year shall be designated as Short Term.

2.1.6 System Peak Responsibility

System Peak Responsibility of a Load Serving Member for any Capacity Year shall mean the Load Serving Member's greatest Net Load during that Capacity Year plus:

(a) The contract amount of Firm Power sold to others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the sale of a specified amount of Firm Power; and minus

(b) The contract amount of Firm Power purchased from others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the purchase of a specified amount of Firm Power.

In each case, the contract amount governs regardless of the amount actually delivered at the time of a Load Serving Member's greatest Net Load.

2.1.7 Capacity Margin

Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

2.1.8 Percent Capacity Margin

Percent Capacity Margin shall be defined by the formula:

Percent Capacity Margin = (Capacity Margin/System Capacity) x 100

2.1.9 Minimum Required Capacity Margin

Each Load Serving Member’s Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent.

2.1.10 System Capacity Responsibility

A Load Serving Member’s System Capacity Responsibility for any Capacity Year shall mean the sum of that Load Serving Member's System Peak Responsibility and its Minimum Required Capacity Margin.

2.1.11 Capacity Balance

Capacity Balance shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Capacity Responsibility.

2.1.12 Firm Transmission Service

Firm Transmission Service is that service defined in any applicable transmission service provider tariff.

2.2 Capacity Responsibility

(a) Each Capacity Year, each Load Serving Member shall possess System Capacity at least equal to its System Capacity Responsibility.

(b) Prior to the establishment of its System Peak Responsibility for each Capacity Year, each Load Serving Member shall provide System Capacity by one or more of the following means:

(i) Establishing a unit rating consistent with SPP generating equipment rating Criteria, prior to establishing its System Peak Responsibility;

(ii) Reducing its System Peak Responsibility by purchase of Firm Power from any Member or non-Member by separate agreement;

(iii) Separate written agreement with another Member or a non-Member for purchase of a specified amount of capacity; and/or

(iv) Reducing its Net Load.

(c) A Load Serving Member may purchase Short Term capacity to provide a part of its System Capacity or Short Term Firm Power to reduce its System Peak Responsibility subject to each of the following restrictions:

(i) Such Short Term period shall not be less than four consecutive months, and shall include the day the Load Serving Member establishes its System Peak Responsibility. Such period shall begin during May 1 to June 1 or November 1 to December 1;

(ii) The amount of Short Term capacity or Short Term Firm Power purchased shall not exceed 25% of the Load Serving Member's System Peak Responsibility; and

(iii) The Load Serving Member shall purchase such Short Term Capacity or Short Term Firm Power prior to the start of the Short Term period.

(d) A Load Serving Member may sell Short Term Capacity or Short Term Firm Power from resources comprising its Capacity Balance, provided that its System Capacity Responsibility is met.

2.3 Records

Each Load Serving Member, upon request, shall provide accurate and detailed records of information related to this Criteria to the SPP Staff. Except for System Peak Responsibility, all other information shall be provided prior to establishing System Peak Responsibility for a Capacity Year and shall include; validation of System Capacity per SPP Rating of Generating Equipment Criteria, Capacity purchase and sale contracts, Firm Power

purchase and sale contracts, and firm transmission service agreements. The SPP Staff shall verify information supplied by each Load Serving Member. Calculations shall be based on the highest peak load of each of the Load Serving Members during the Capacity Year. All capacity and demand values will be rounded to the nearest whole MW for purposes of this Criteria. All data submitted to SPP related to this Criteria shall be considered confidential by the SPP Staff and shall not be released in any form except by force of law.

2.4 Generation Planning

2.4.1 Design Features

a. In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.

b. Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of loss of external power.

c. In each major load area of SPP, a unit capable of black start shall be provided having the capability of restarting the other units in the area.

d. Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.

2.4.2 Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for capacity margin requirements.

3.0 REGIONAL TRANSMISSION PLANNING

3.1 Concepts

The interconnected transmission system should be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. Electric systems must be planned to withstand contingencies and maintenance outages. Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The *NERC Planning Standards* define specific requirements that provide a high degree of reliability for the large interconnected electric system. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related "Coordinated Planning Procedures" in the *SPP Open Access Transmission Tariff*.

3.2 Definitions

NERC (NAERO – North American Electric Reliability Council (North American Electric Reliability Organization) – An organization of all segments of the electric industry that recommends, sets, oversees, and implements policies and standards to ensure the continued reliability of North America's interconnected electric grids.

Nominal Voltage – 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.

3.3 Coordinated Planning

SPP members operate in a highly interconnected system and shall coordinate transmission planning. This coordination shall include voluntary efforts between interconnected SPP members and non-members. SPP will be the primary responsible party for coordinated transmission planning.

The planning and development of transmission facilities will be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations. The transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

3.3.1 Planning Criteria

Individual members may develop Planning Criteria that shall, at a minimum, conform to *NERC Planning Standards* and SPP *Criteria*. Individual member Criteria shall consider the following:

a. Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any single transmission station shall be avoided.

b. Intra-regional inter-regional, and trans-regional power flows shall not result in excessive risk to the electric system under normal and contingency conditions as outlined in this criteria.

c. Switching arrangements shall be planned to permit effective maintenance of equipment without excessive risk to the electric system.

d. Switching arrangements and associated protective relay systems shall be planned to not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.

e. Sufficient reactive capacity shall 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.

f. Facilities shall be rated as assigned in *SPP Criteria* section 12.

3.3.2 Planning Assessment Studies

Individual transmission owners shall perform individual transmission planning studies and shall cooperate in SPP and Inter-Regional studies. These planning studies are for the purposes of identifying any planning criteria violations that may exist and developing plans to mitigate such violations. Members shall contact the 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 will be conducted on a joint system basis. Reliability studies will examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Updates to the transmission assessments will be performed, as appropriate, to reflect anticipated significant changes in system conditions.

3.3.3 Benchmark SPP Models

SPP staff will benchmark model data against actual SPP system conditions (e.g., generation dispatch, load, and load power factor) which correspond to the time frames for which the models are created. As a minimum the results will be reported semiannually.

3.4 Transmission Contingency

The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Planning Standards* for System Adequacy and Security – Transmission System Table I (hereafter referred to as NERC Table I) and its applicable standards and measurements. Extreme contingency evaluations will be 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.

3.4.1 Adequacy

3.4.1.1 Base Case

The Model Development Working group (MDWG) will assemble and verify base case models. These models will maintain at least the following:

- System facilities shall be modeled to reflect normal operation.
- Line and equipment loading shall be within applicable thermal rating limits.
- Voltage levels shall be maintained within applicable limits.
- All customer demands shall be supplied, and all contracted firm (non-recallable reserved) transfers shall be maintained.
- Stability (dynamic and steady state) of the network shall be maintained.
- Cascading outages shall not occur.

The MDWG shall work with the Transmission Working Group (TWG) to resolve issues not considered data errors.

3.4.1.2 Loss of Single Component

The MDWG will run contingency studies under 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 as specified in 3.3.1e.
- 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.

3.4.1.3 Loss of Two or More Components

The MDWG will run contingency studies under the following:

- Initiating incident may result in two or more (multiple) components out of service.
- Line and equipment loadings shall be within applicable thermal rating limits.
- Voltage levels shall be maintained within applicable limits as specified in 3.3.1e.
- 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.

3.4.1.4 Extreme Event

The TWG will run contingency studies where extreme contingency events could lead to uncontrolled cascading outages or system instability. The TWG shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion recommend such measures and procedures.

3.4.2 Study Requirements

System contingency studies should be based on system simulation models that should incorporate:

- Evaluation of reactive power resources,
- Existing protection systems, and

- Any existing backup or redundancy protection systems.

These studies will assist to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in appropriate Category of NERC Table I.

Studies will consider all contingencies applicable to the appropriate Category, but will evaluate only the most critical, and document the selection rationale. Studies will be conducted or reviewed annually, shall 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. Detailed analyses of the systems will not be conducted annually if changes to system conditions do not warrant such analyses.

The longer-term (beyond five years) simulations will identify concerns that may surface in the period beyond the more certain intermediate year period. Focus of simulations for the longer term will be on marginal system conditions evident from the intermediate year cases. Cases beyond the five-year horizon will be evaluated as needed to address identified marginal conditions.

3.4.3 Mitigation Plans

When simulations indicate an inability of the systems to respond as prescribed by this Criterion, responsible entities must provide a written summary of their mitigation plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon. Mitigation plan summaries should discuss expected required in-service dates of facilities, should consider lead-times necessary to implement plans, and will be reviewed for continuing need in subsequent annual assessments.

3.4.4 Reporting Requirements

Entities responsible for the reliability of interconnected transmission systems shall report annually on the performance of their systems in connection with NERC *Planning Standard* I.A.S1 to the SPP Region. The SPP will annually provide a summary of intra- and interregional studies to the NERC Adequacy Committee (RAS). Regional and interregional reliability assessments shall include the results of the system simulation testing as stated in this Standard I.A.

3.5 Protective Relaying, Monitoring And Controls

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the bulk electric system. Protective Relay Systems (PRS) requirements shall be taken into account during the planning and design of generation, transmission and substation configurations. If configurations are proposed that require PRS that do not conform to this criteria or to accepted IEEE/ANSI practice, then the entities affected shall negotiate a solution. The principles for planning additions in these categories are set forth in this Criteria.

a. The bulk power protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, transmission protection systems shall be installed as specified in Transmission Protection Systems Criteria 7.2.

b. Control areas shall maintain communications systems to their generating stations, operation centers and to neighboring utilities which shall provide adequate communication in the event of failure of any one element of the systems. In general, such communication systems should not be susceptible to failure during an interruption of the A.C. power supply in any part or all of their areas.

c. Loadings on the bulk electric system shall be monitored continually to insure that operation is within safe limits.

d. Suitable instrumentation, and/or other devices, shall be installed to measure appropriate quantities at key points in the electric system with appropriate automatic alarms.

e. Fault recording devices as described in Criteria 7.1 shall be installed at appropriate points within the SPP region so that outages and short circuits can be analyzed and protective relay performance studied. In addition, Disturbance Monitoring Equipment shall be provided to meet Criteria 7.1 so that system disturbances may be analyzed.

f. Underfrequency Load Shedding equipment shall be installed pursuant to Criteria 7.3 for the purpose of maintaining a stable operating frequency.

g. As specified in Criteria 7.4, Special Protection Systems when installed shall detect abnormal system conditions and take pre-planned, coordinated, corrective action to provide acceptable system performance.

h. When Undervoltage Load Shedding equipment is installed by a member system as specified in Criteria 7.5 for the purpose of stabilizing interconnected systems and mitigating the effects of voltage collapse, then this program shall coordinate with all other schemes of which include system protection, Underfrequency Load Shedding, Automatic Restoration of Load and Generation Control and Protection.

i. Given the requirements of Criteria 7.6, Automatic Restoration of Load schemes may be installed by member systems to expedite load restoration. These systems shall be coordinated with all other schemes such as system protection, Underfrequency Load Shedding, Undervoltage Load Shedding, and Generation Control and Protection. These systems shall operate only after underfrequency and/or undervoltage events.

j. Generation Control and Protection schemes shall be designed pursuant to Criteria 7.7 to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect generator equipment from damage.

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported.

This Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry

changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity, with the exception of response factor thresholds for short-term transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical opportunity. The response factor thresholds for short-term and long-term service are included in Appendix 9.

4.1 DEFINITIONS

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

4.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

4.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

4.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

4.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at anytime for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

4.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

4.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff (OATT) or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as:

> "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:
>
> 1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
> 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
> 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

4.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in the Flowgate Determination section.

4.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

4.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

4.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

4.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

4.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

4.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

4.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

4.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

4.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

4.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

4.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is not offered.

4.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

4.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

4.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

4.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF – The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

4.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

4.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

4.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

4.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

4.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

4.1.31 TRM multipliers (a & b)

“a”-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

“b”-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

4.2 CONCEPTS

4.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1. **System Conditions** - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

2. **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3. **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

4.2.2 Available Transfer Capability

NERC Available Transfer Capability Definitions and Determinations, reference document (June 1996) states: “Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above

already committed uses."

SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non-firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

Firm ATC = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(FATC = FAFC/TDF)
of the associated path.

Likewise,

Non-Firm ATC = the non firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(NFATC = NFAFC/TDF)
of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC. However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

4.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Appendix 9.

(1) **Transfer Distribution Factor** - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in the System Limitations section of the criteria.

(2) **Line Outage Distribution Factor** - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) **Power Transfer Distribution Factor** - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable short-term or long-term threshold.

(4) **Outage Transfer Distribution Factor** - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability

limitations. To be considered a valid limit to transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.

(5) **Power Transfer Voltage Factor** - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

4.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

1. **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

2. **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the Planning Criteria section of the SPP

Criteria: Regional Transmission Planning.

3. **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

4. **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time

4.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

- An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
- Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
- The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
- The limiting facility is the result of over-generation/under-generation at a participation point.
- The contingency is considered improper implementation of an operating procedure.
- The facility represents an equivalent circuit.

- The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

4.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

- OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
- PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce.

To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

4.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in the Limitations Section.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be:

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing.

Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

4.2.8 Flowgate Capacity

4.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

4.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the Available Flowgate Capacity (AFC) remaining for path ATC. AFC is classified as firm or non-firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for Available Flowgate Capacity:

(AFC = TFC – FBL – Impacts of existing commitments – transmission margins).

4.2.9 System Impacts

4.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

- Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
- Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.
- Check for proper reflection of capacity profiles of reservations.
- Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

4.2.9.2 Positive Impacts

The scope of "Impacts of existing commitments" in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the "Impacts of existing commitments" in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

4.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

4.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners.

In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

4.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

4.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

4.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM.

- Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas.

Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

- Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

- Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions.
Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TWG shall have the authority to grant or reject requests for the additional TRM requests.

- SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

- Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

4.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TWG.

4.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The ‘a’ and ‘b’ multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

4.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

4.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. As a normal practice, default values for CBM will be zero for calculations of ATC for some or all of the following reasons:

- the existing level of internal capacity margin of each member is adequate
- historical reliability indicators of transmission strength of the SPP area
- Open Access transmission usage environment allows greater purchasing options

Flowgate owner requests for additional CBM may be submitted at any time for consideration at the next TWG meeting. The submittal should include written justification and rational for the requested additional CBM. The TWG shall have authority to reject or grant such requests.

4.4 FLOWGATE AND TFC DETERMINATION

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system.

4.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TWG, the Operating Reliability Working Group (ORWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

- Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

- Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

- All other Flowgates proposed by Transmission Owners must have TWG and ORWG approval. The Reliability Authority can provide interim approval until the TWG and ORWG can convene to assess the request. Examples of such Flowgates are PTDF Flowgates with two or more elements, OTDF Flowgates with three or more elements, or Flowgates involving operating procedures.

There may be times when significant topological changes occur during operations that create unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Reliability Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

4.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TWG using seasonal power flow models. This annual assessment will be performed following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in the "ATC Calculation Procedures" section.

4.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing approximately an 85% load level will be used in the determination process.

Prior to the start of the review all SPP Transmission Owners will submit a list of changes to SPP to adjust the models. These changes should be such that the power flow models used to review the Flowgate list represent the seasonal loads, transmission system configuration, generation dispatch, and transactions that each Transmission Owner expects will occur during

actual seasonal operations. The changes will be submitted to SPP in a common format as outlined in the SPP Load Flow Procedure Manual.

Model changes and parameters for Transmission Owners outside of SPP will be coordinated through the NERC regional councils.

4.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

- A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.
- All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.
- Any additional facilities below 100 kV to be monitored.
- High and low voltage limits for system and/or individual buses.
- All Contractual Requirements.

4.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

- For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.
- The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points. (i.e., PMAX-PGEN).
- For imports, all on-line generators will be decreased prorated by their capable generation (i.e., PGEN-PMIN).
- Transfer directions will be a set of all commercial paths.
- Exports from merchant power plants will be considered in the determination of Flowgates.
- The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.
- All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.
- Voltage limits will be as specified in Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

4.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

4.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC

analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in the “Parameters Supplied by the Transmission Owners” section or “Default Parameters” section as applicable.

4.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

4.4.2.7 Identification of Flowgate Changes

TWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

4.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TWG before being reported.

The Transmission Owner should review the TWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TWG proposed changes should be returned to the TWG. Further dialog and justification may be required of a Transmission Owner if the TWG has concerns about their modifications.

TWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

4.4.2.9 Initiating Interim Review of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TWG for consideration. Should the TWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

4.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

- The contingency used for the Flowgate is not valid.
- There is an operating procedure that corrects the violation that is not being properly taken into account.
- An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TWG will review all of the arguments. Additional analyses will be performed if necessary. SPP TWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

4.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TWG.

4.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

4.5 ATC CALCULATION PROCEDURES

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

- establishes a network representation (power flow model)
- identifies potential limits to transfer (thermal, voltage, stability, contract)
- determines response factors of identified limits relative to transfer directions (TDF)
- determines impacts of existing commitments (firm, non-firm)
- applies margins (TRM, CBM, a & b multipliers)
- determines maximum transfer capabilities allowed by limits and applied margins (ATC, FATC, NFATC)

4.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their

own OASIS nodes.

4.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

4.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate Capacity. However, there are many transactions within the monthly models that are duplicated on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

4.5.4 Transfer Distribution Factor Determinations (TDF)

For export and import participation points all on-line generators, unless otherwise denoted (e.g., nuclear units), will be scaled prorated by their machine base (MBASE). TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

4.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

4.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the transmission system. The long-term threshold is shown in Appendix 9 and is applied to all elements above 60kV.

4.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows
will be determined by the projection models. The impacts of OASIS reservations that are in Study mode will be applied to each Flowgate according to the TDF values determined. Positive impacts on a Flowgate due to Confirmed reservations that are not expected to be scheduled based on actual historical scheduling data will be removed and allowed to increase firm Available Flowgate Capacity. Counter flow impacts of Confirmed reservations that are expected to be scheduled based on actual historical scheduling data will be allowed to increase firm Available Flowgate Capacity. Up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed to increase non-firm Available Flowgate Capacity.

4.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

4.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

4.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates' ATC and posted to the OASIS.

4.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

4.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in the Reliability Margins section.

4.5.10 ATC Determination

The following equations are used in ATC determination:

4.5.10.1 Firm Base Loading (FBL)*, **:

- Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) – (100% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

4.5.10.2 Non-Firm Base Loading (NFBL)*, **:

- Non-Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) – (up to 50% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments)

4.5.10.3 Firm Available Flowgate Capacity (FAFC):

- Firm Available Flowgate Capacity = (Total Flowgate Capacity) – (TRM) – (CBM) – (Firm Base Loading)

4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):

- Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) – (b*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):

- Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) – (a*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.6 Firm Available Transfer Capability (FATC):

- Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

4.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):

- Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):

- Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

* Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The

ATC for requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

4.5.11 Annual Review of ATC Process

The SPP TWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process. The applicable long-term TRM is listed in Appendix 9.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

4.5.12 Dialog With Transmission Users

Transmission Users may contact the TWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TWG. The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Markets and Operations Policy Committee.

5.0 RELIABILITY COORDINATION CENTER

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

5.1 Information Exchange

Control areas shall share operating data as defined in Appendix 7 to the SPP Criteria and approved by the ORWG. Non-Control Areas shall share operating data deemed necessary for assessment of regional reliability. Generator data for all generating units whose size is greater than or equal to the smaller of 10 MW or 5% of the reporting Control Area peak load, transmission circuit data for all interconnections, and transmission facilities operated at 60 kV or greater shall be automatically shared. This data shall be made available to the Reliability Authority and any other entity with immediate responsibility for interconnection reliability. The Reliability Authority shall obtain a signed code of conduct from entities receiving such data ensuring that the data will not be used for marketing purposes. Necessary operational data shall be made available on an interregional telecommunications network to support the requirements in this Criteria. This near real-time data will be exchanged as specified in Appendix 7 and approved by the ORWG.

5.2 Reliability Coordination

5.2.1 Member Responsibilities

Transmission Operators shall determine System Operating Limits (SOLs), as defined in Criteria 14.2.4, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix 7 and notify the Reliability Coordinator of any SOL violations.

Control Areas shall notify the Reliability Coordinator of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled outages of critical transmission facilities shall be approved by the Reliability Coordinator. Scheduled outages of all other facilities greater than 60 kV shall be coordinated with the Reliability Coordinator. The Operating

Reliability Working Group shall be responsible for identifying those facilities classified as critical. Non-control areas shall notify their Control Area of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled transmission outages shall be coordinated with their Control Area.

5.2.2 Operatiing Reliability Working Group

The Operatiing Reliability Working Group shall be responsible for policy oversight of implementation and on-going reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Engineering & Operating Committee.

5.2.3 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

5.2.4 Reliability Authority Responsibilities

On a continuous around-the-clock basis, the SPP Reliability Authority shall be responsible for the following activities:

5.2.4.1 Daily Reliability Assessment

a. Monitor the collection of real-time operating information, schedules and daily forecasts from control areas as specified in Appendix 7.
b. Develop and use an operational model to assess reliability and adequacy of the electric system, including; ability to handle more probable contingencies and remain within operating criteria, anticipating line loading problems, and determining the adequacy of operating reserve.
c. During conditions where system reliability is threatened, notify and work with control areas in determining appropriate control action.

5.2.4.2 Daily Operational Coordination

a. Monitor, coordinate and grant permission for bulk transmission equipment maintenance.
b. Manage the SPP Open Access Same-Time Information System node and ATC calculation.

c. Monitor the NERC Hot line and disseminating information.
d. Initiating time error corrections.

5.2.4.3 Compliance Monitoring

a. Assess and report regional compliance with NERC operating criteria, including; area interchange error, CPS1, CPS2, DCS, frequency response, and inadvertent.
b. Coordinate bilateral inadvertent energy accounting and payback.

5.2.4.4 Emergency Procedure Implementation

a. Monitor and coordinate implementation of Operating Reserve Criteria.
b. Monitor and coordinate implementation of Transmission Loading Relief Criteria.
c. Monitor and coordinate implementation of Load Shedding and Restoration Criteria.
d. Monitor and coordinate implementation of Black Start Criteria.
e. Issue short supply advisories.
f. Issue weather advisories.

5.2.4.5 Interregional Coordination

a. Coordinate normal and emergency operations with other Reliability Authorities.
b. Authoritatively act on behalf of SPP Members to resolve interregional issues.

5.2.5 Other Reliability Authority Responsibilities

The SPP Reliability Authority shall be responsible for the following activities:

a. Confirm transactions during periods of Transmission Loading Relief as outlined in Criteria.
b. Direct implementation of Black Start procedures as outlined in Criteria.
c. Implement Transmission Loading Relief Procedures as required.

5.2.6 Reliability Authority Performance Standards

The SPP Reliability Authority shall have the following performance standards:

a. The SPP Reliability Authority shall act in accordance with Good Utility Practice including NERC Policies and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice, and shall allow SPP members to take any actions required by Good Utility Practice.

b. The SPP Reliability Authority shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency.

c. The SPP Reliability Authority shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Policies and SPP Criteria.

d. The SPP Reliability Authority shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.

e. The SPP Reliability Authority shall be a certified system operator as defined by related SPP Criteria.

The SPP Reliability Authority shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.

6.0 OPERATING RESERVE

6.1 Purpose

In the continuous operation of the electric power network, Operating Capacity is required to meet forecasted load, including an allowance for uncertainty, to provide protection against equipment failure and to provide adequate regulation of frequency and Balancing Authority Area tie line power flow. Operating Reserves are needed to regulate load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales.

This Criteria establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group.

A purpose of this Criteria is to ensure a high level of reliability in the SPP Reserve Sharing Group by assuring that there is available at all times capacity resources that can be used quickly to relieve stress placed on the interconnected electric system during an Operating Reserve Contingency. Another purpose of these Criteria is to utilize efficiently the operating reserve resources of the SPP Reserve Sharing Group.

This Criteria describes practices to be followed by all SPP Reserve Sharing Group members to ensure prompt response to Operating Reserve Contingencies. The methods prescribed by this Criteria to jointly activate Contingency Reserve are intended to ensure that the combined area control error (ACE) of the SPP Reserve Sharing Group is quickly reduced by the Reserve Sharing Group simultaneously scheduling assistance soon after an Operating Reserve Contingency.

6.2 Definitions

6.2.1 Balancing Authority

NERC defines a Balancing Authority as “The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.” A Balancing Authority is required to meet all NERC Reliability Standards, SPP Criteria and the policies of the NERC Regional Reliability Council of which they are a member.

6.2.1.1 Balancing Authority Area

NERC defines a Balancing Authority Area as "The collection of transmission, generation and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

6.2.2 Balancing Authority Daily Peak Load Obligation

Balancing Authority Daily Peak Load Obligation is the peak hour load plus Firm Power sales minus Firm Power purchases during the peak hour for all entities within the Balancing Authority Area.

6.2.3 Operating Capacity

Operating Capacity is the dispatchable capability claimed for any generating source, which will be used for supplying Operating Reserve. Operating Capacity shall include capacity purchases that can be used to supply the buyer's Operating Reserves minus capacity sales that cannot be used to supply the seller's Operating Reserves. Operating Capacity shall recognize any temporary de-ratings, proven loading rates, starting times and equipment limitations including transmission-operating limits. This capacity is not intended to be the tested seasonal net capability; instead it is the normal operating rating of a generator on a given day.

6.2.4 Operating Reserve

Operating Reserve is the sum of Regulating Reserve and Contingency Reserve.

6.2.4.1 Regulating Reserve

Regulating Reserve is an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin. The Balancing Authority minimum Regulating Reserve is equal to an amount necessary to maintain compliance with control performance standards while scheduling all Contingency Reserves to other Balancing Authorities.

6.2.4.2 Contingency Reserve

Contingency Reserve is that Operating Capacity that can be produced and applied to reduce ACE to meet the NERC Disturbance Control Standard (DCS) following the Operating Reserve Contingency. Contingency Reserve is the sum of Spinning Reserve and Ready Reserve.

6.2.5 Spinning Reserve

Spinning Reserve is that unloaded Operating Capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation. The Spinning Reserve allocated to any generating unit shall not exceed the amount of capacity increase that will be realized by prime-mover governor action due to a drop in frequency to 59.5 Hertz (less than or equal to 16.7% of unit capability at a 5% droop setting). At least half of the Contingency Reserve shall be Spinning Reserve.

6.2.6 Ready Reserve

Ready Reserve is that amount of Operating Capacity or the equivalent, some or all of which may not be connected to the interconnected network but which can be connected and fully applied to meet the NERC DCS requirements, such as any or a combination of the following:

a. The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset.

b. That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized.

c. Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use.

d. Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call

e. Interruptible or curtailment of loads under contract.

f. Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction.

g. Generating units operating in a synchronous condenser mode.

h. Interruptible pumping load on pumped hydro units.

i. Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.

j. Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.

6.2.7 Assistance Period

Assistance Period is that time frame when any SPP Reserve Sharing Group member receives Contingency Reserve assistance from other SPP Reserve Sharing Group members. The Assistance Period will normally not exceed 60 minutes. The SPP Operating Reliability Working Group will set the ending time for Assistance Period and may change the length of the Assistance Period.

6.2.8 Group

A Group is defined for each member of the SPP Reserve Sharing Group on a daily basis to include itself and all other members with which there exists contractual interchange agreements, which include provisions for the exchange of Operating Reserve energy. Each member of the Reserve Sharing Group may include any other member, with which they can directly schedule interchange transactions, within their group as long as both members agree.

6.2.9 Contingency Area

The Contingency Area is defined as the Balancing Authority Area suffering an Operating Reserve Contingency.

6.2.10 Assisting Areas

The Assisting Areas are defined as the other Balancing Authority Areas in the SPP Reserve Sharing Group, which are called upon to supply Operating Reserves to the Contingency Area.

6.2.11 Daily Load and Capability Report

The Daily Load and Capability Report is a report which shall be completed by each Balancing Authority. This report shall include actual and forecasted operating information.

6.2.12 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. Power purchased shall only be considered to be Firm Power if firm transmission service is in place to

the load serving member for delivery of such power. Firm Power does not include "financially firm" power.

6.2.13 Other Extreme Conditions

Other Extreme Conditions include but are not limited to the:

a. Interruption of firm transmission service, or

b. An inability to use prescheduled firm transmission service due to transmission loading relief, or

c. When a Balancing Authority requires assistance to prevent shedding firm load or Firm Power sales, or

d. When a Balancing Authority is unable to maintain its Operating Reserves.

6.2.14 Operating Reserve Contingency

An Operating Reserve Contingency is defined as the sudden and complete loss of a generating unit, sudden partial loss of generating capacity, loss of a capacity purchase which a Balancing Authority is unable to replace, or an Other Extreme Conditions.

6.2.15 Reserve Sharing Group

NERC defines a Reserve Sharing Group as "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the areas become a Reserve Sharing Group."

6.3 Minimum Daily Reserve Requirement

The Operating Reliability Working Group will set the Minimum Daily Contingency Reserve Requirement to provide sufficient reserves to cover the most severe single contingency within

the SPP Reserve Sharing Group as determined by at least an annual review by the Operating Reliability Working Group. The SPP Reserve Sharing Group will maintain a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line. Normally, the SPP Reserve Sharing Group will add an additional Operating Reserve Requirement over and above its Regulating Reserve and first Contingency Reserve equal to one-half of the next largest generating unit scheduled to be on-line within the SPP Reserve Sharing Group each day (second Contingency Reserve). In the event that the Minimum Daily Reserve Requirement maintained by the SPP Reserve Sharing Group is less than the most severe single contingency within the Reserve Sharing Group, the Operating Reliability Working Group will establish revised requirements that provide the necessary reserves. A Balancing Authority's Minimum Daily Requirement is equal to a prorated amount of the SPP Reserve Sharing Group Minimum total Daily Contingency Reserve Requirement (first and second Contingency Reserves) based on the previous day's actual Balancing Authority Daily Peak Load Obligation. A Balancing Authority's Minimum Daily Requirement shall be no less than two (2) MW.

Under emergency operating conditions, the Minimum total Daily Contingency Reserve Requirement may be raised to the generating capability of the two largest generating units scheduled to be on-line upon the concurrence of the chair or vice chair of either the Markets and Operations Policy Committee or the Operating Reliability Working Group.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total first Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

6.4 Procedures

All SPP Reserve Sharing Group members shall participate in this procedure to jointly activate Contingency Reserve.

6.4.1 Normal Daily Operation

a. Each Balancing Authority shall complete the Daily Load and Capability Report. Based on

the information contained in this report, the Contingency Reserve Requirement for the next day shall be calculated and notification distributed. Previous annual maximum data shall be used in reserve responsibility calculations for members who fail to report daily information. A Balancing Authority may elect to enter an amount of Contingency Reserve Requirement on the daily report, which, if in excess of its minimum requirement as calculated by the SPP computer communication system, shall be available for allocation during Assistance Periods. No portion of this additional reserve is required to be spinning.

b. Each Balancing Authority's Operating Reserve shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings, transfer limitations, or a unit's capability to apply the reserve to meet the NERC DCS requirements.

c. Each Balancing Authority shall schedule Operating Capacity and firm obligations so its requirements for Operating Reserve are met at all times.

d. Energy associated with Ready Reserve, except Assistance Schedules, may be sold with the understanding that it is recallable to meet the NERC DCS requirements. The buyer shall therefore maintain resources to support the withdrawal of this energy in addition to meeting its Operating Reserve Requirement.

e. Generating capacity associated with the required Spinning Reserve shall not be sold unless allocated during an Assistance Period.

f. Each Balancing Authority may contract with another Balancing Authority to provide part or its entire Operating Reserve obligation, provided the Balancing Authority accepting this additional Operating Reserve obligation maintains the Operating Reserve obligation of both Balancing Authorities and the firm transmission service required to deliver Operating Reserve energy is obtained.

g. When a Balancing Authority foresees it will be unable to provide its Minimum Daily Reserve Requirement with available resources because load is greater than anticipated, forced outages or other limitations, it shall obtain Operating Capacity and firm transmission service. Such capacity shall not be from another Balancing Authority's Minimum Daily Reserve Requirement.

6.4.2 Contingency Operation

These procedures shall be implemented immediately following the occurrence of an Operating Reserve Contingency of the type and magnitude as follows.

- A complete loss of a generator rated at 50 MW or greater, or
- A partial loss of generating capacity of 75 MW or more, or
- A partial loss of generating output of 50 MW or more or
- A loss of a capacity purchase of 50 MW or more, or
- Any “Other Extreme Conditions” event.

These procedures may be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude, as system conditions warrant, by the Contingency Area. These procedures are to be implemented in a non-discriminatory manner.

a. Immediately following an Operating Reserve Contingency, the Contingency Area shall report the occurrence via the SPP computer communication system. This report shall contain a description of the contingency; the net MW lost due to the contingency and any MW amount of Contingency Reserve being carried on the contingency unit. For those generating units whose station auxiliaries do not decrease to essentially zero or increase after a unit trip, gross MWs lost shall be used instead of net MWs lost. The operating owner of jointly owned generating units shall be responsible for reporting outages and the MW amount lost by each owner.

b. Within the constraints described in this Criteria, allocation magnitudes shall be determined and notices distributed to the members of the Reserve Sharing Group

c. The maximum amount assigned to any Balancing Authority for any single Operating Reserve Contingency shall not exceed its Spinning Reserve requirement unless the contingency reserve requirement exceeds the available Spinning Reserve of the SPP Reserve Sharing Group. The additional responsibility shall be allocated to other members of the SPP Reserve Sharing Group until the total Spinning Reserves are exhausted. Any remaining responsibility shall be allocated to the SPP Reserve Sharing Group by a similar procedure as the initial allocation out of the total Ready Reserve. The Operating Reliability Working Group may adjust for any single member or for all members the maximum amount allocated.

d. The Assistance Schedule becomes part of each Assisting Area's scheduled net interchange and shall therefore be reflected in its ACE. The schedule shall be implemented at a zero time ramp rate immediately following allocation notification. If

obvious and significant errors exist in assistance schedules, the Contingency Area system operator shall dictate appropriate corrective action during the Contingency Period, and notify the SPP.

e. Assisting Areas shall immediately acknowledge receipt of the allocation notice via the SPP computer communication system. If a Contingency Area fails to receive acknowledgment from an Assisting Area, the SPP Reliability Coordinator shall notify the Assisting Area of the assistance schedule.

f. The Contingency Area(s) and Assisting Areas shall provide the requested assistance within the requirements established in the Disturbance Recovery Criterion of the NERC Reliability Standards.

g. After the implementation of the allocation, the Contingency Area and Assisting Areas shall report to the SPP, when their ACE returned to zero or it's pre-contingency level whichever is achieved first.

h. The Contingency Reserve Requirement of each Balancing Authority involved in the Assistance Period shall be updated to reflect the reduction of responsibility until the end of the Assistance Period.

i. All allocations shall be rounded to the nearest whole MW with a minimum of 2 MW and the smallest amount of energy to be allocated shall be one MWH.

j. After the contingency notification has been completed, the Contingency Area shall promptly make arrangements to replace the energy requirement created by the Operating Reserve Contingency (including its Contingency Reserve Allocation) prior to the end of the Assistance Period. The Contingency Area shall make a reasonable effort to purchase capacity and firm transmission service after utilization of its own resources.

k. If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, then this becomes an Other Extreme Condition and shall be reported as a separate contingency.

l. Each transmission provider shall immediately notify the SPP of the loss of transmission interconnection capability affecting its interchange transfer capability. The SPP shall update Group assignments for use during subsequent Assistance Periods. Each transmission provider is responsible for notifying the SPP once the contingency loss in the interchange transfer capability has been restored so that Group assignments can be updated.

m. For each reportable contingency (as defined by the Operating Reliability Working

Group), the Contingency Area and Assisting Areas will send to SPP an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data. If electronic data is not available, this data will be supplied on the NERC required charts.

6.4.3 Subsequent Contingencies

In the event that a subsequent Operating Reserve Contingency occurs during a period when assistance is already in progress, the same procedures shall be followed to allocate responsibility for the additional Operating Reserve Contingency.

6.4.4 Assistance Reports

Energy and transmission service reports shall be issued following the Assistance Period. These reports shall be used as verification of associated energy schedules and transmission service reservations. The Operating Reliability Working Group shall distribute monthly summary reports of Other Extreme Conditions activity for use.

SPP Staff will report to NERC quarterly the performance of the SPP Reserve Sharing Group. Performance will be calculated based on the data that Balancing Authorities provide and any additional data required for each reportable contingency. At a minimum, reportable contingencies will be of a magnitude between 80% and 100% of the capacity of the largest generating unit scheduled to be on-line within the SPP each day. The Operating Reliability Working Group may lower the 80% factor in order to provide a more realistic picture of the performance of the SPP Reserve Sharing Group.

6.4.5 Other Extreme Conditions Events

The SPP Reserve Sharing Group member seeking assistance through Other Extreme Conditions must submit a written report to the SPP within 2 business days of the event. The written report will describe the operating conditions that precipitated the request for assistance. If a Balancing Authority's only other choice was to shed firm load or Firm Power sales, the Balancing Authority must demonstrate this condition by taking the following steps, where appropriate, before requesting Other Extreme Conditions:

a. All generation capable of being on-line in the time frame of the generation deficiency must be on-line, including quick start and peaking units regardless of the cost.

b. All firm and non-firm purchases have been made without regard to cost.

c. All non-firm sales have been curtailed within the provisions of the sale agreement.

d. Interruptible load has been curtailed where contractual restrictions have been met or the interruptible load is considered as part of the Balancing Authority's Operating Reserves.

e. Have implemented all other load reductions programs that can be implemented within the time frame of the generation deficiency (i.e. voltage reductions, public appeals, etc.).

Any member not having their full Operating Reserves shall enter an Other Extreme Conditions for the amount of the deficiency.

Any member requesting an Other Extreme Conditions shall also request the appropriate NERC Energy Emergency Alert (EEA) through the member's Reliability Coordinator. Other Extreme Conditions initiated in response to a lack of full Operating Reserves shall require an Energy Emergency Alert 2. In the event that firm load interruption is imminent or in progress, the Contingency Area shall request an Energy Emergency Alert 3.

Other Extreme Conditions shall be investigated as required by the SPP Operating Reliability Working Group to ensure compliance with SPP Criteria and NERC Reilability Standards.

6.5 Compensation for Assistance

6.5.1 Energy Charge

The charge for energy assistance delivered by Assisting Areas under the application of this Criteria shall be determined by interchange agreements between the members involved in the Reserve Sharing Group.

6.5.2 Accounting

All compensation for energy associated with the application of this Criteria shall be handled by contractual agreements and standard accounting procedures being utilized by the SPP Reserve Sharing Group members. All energy billing shall take place between SPP Reserve Sharing Group members and shall not involve the SPP computer communication system or the SPP Staff.

6.5.3 Transmission Service

All compensation for transmission service shall be in accordance with the appropriate transmission

service tariffs. The SPP staff shall be responsible for all billings for transmission service provided under the SPP Regional Transmission Tariff. The individual transmission provider shall be responsible for all billings under the transmission provider's transmission tariff. It shall be the SPP staff's responsibility to provide the required transmission service information to the transmission provider for all transmission service under an individual transmission provider's transmission tariff.

6.6 Responsibilities

6.6.1 Balancing Authorities

It shall be the responsibility of each Balancing Authority to observe the policies and procedures contained herein; maintaining Operating Reserve, ensuring connectivity to the SPP computer communications system, reporting daily information, identifying and reporting an Operating Reserve Contingency within its Balancing Authority Area, acknowledging schedules and supplying assistance to members of the SPP Reserve Sharing Group.

6.6.2 Operating Reliability Working Group

In order to review the adequacy in SPP Reserve Sharing Group, reports shall be compiled and distributed by the SPP for review by members and the Operating Reliability Working Group. These reports shall contain compliance information and a summary of Assistance Period events

7.0 SYSTEM PROTECTION EQUIPMENT

7.1 Disturbance Monitoring Equipment

'Disturbance Monitoring Equipment' (DME), as the term is used in this Section, refers to equipment such as Digital Fault Recorders (DFR), Sequence of Events Recorders (SOE and/or SER), Dynamic Disturbance Recorders (DDR), and other devices connected to the power system for the purpose of monitoring performance of the system. This equipment is used to capture data during disturbances defined as (i) any perturbation to the power system, or (ii) the unexpected change in the power system that is caused by the sudden loss of generation, transmission or interruption of load. Disturbance monitoring equipment collect and store (a) "fault data" from a line or equipment trip for abnormal conditions, or (b) "disturbance data" for power system performance swings or deviations outside of a predefined operating range (frequency, voltage, current, power, transients, etc.). Digital fault recorders (DFR) are capable of producing date and time stamped fault records, consisting of instantaneous values of power system quantities collected many times per cycle, for a specific period of time. In general, DFR's are continuously monitoring devices that use triggering methods to capture, over a period of several cycles, specific system events, such as line trips for fault conditions. Sequence of Events Recorders (SER) capture and time stamp events in the sequence in which they occur. The facility owner should be responsible for interpreting the information from SER's due to the equipment specific and detailed nature of these records. Typically, SER's record the sequence of breaker operations needed for higher-level event reconstruction and analysis. Information provided by SER's may be obtained from other devices such as fault recording equipment, SCADA, or other real time computer records. Dynamic disturbance recorders (DDR) record date and time stamped incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz-3Hz) oscillations and abnormal frequency, power, current, or voltage excursions. DDRs are also commonly referred to as dynamic swing recorders (DSR).

7.1.1 General Minimum Technical Requirements

Disturbance Monitoring Equipment, as a minimum, must be capable of producing time stamped event records (some pre-fault and some post-fault data) including waveforms for voltages and currents as well as power circuit breaker position indications. All DME including DFRs, SERs, and DDRs as required in 7.1.2 shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC). Recorded data from each disturbance shall be retrievable for at least ten calendar days per PRC-018-1, R1-2. The Disturbance data reporting after 5-1-2007 shall be in a format which is capable of being viewed, read and analyzed with a

generic Common Format for Transient Data Exchange for Power Systems (COMTRADE) or its successor standard. Per PRC-002-1, new DME required per 7.1.2 shall include naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files effective 6 months after IEEE C37.232 is approved.

Disturbance Monitoring Equipment will also be required to meet the NERC PRC-002-1 and PRC-018-1 Reliability Standards.

7.1.1.1 DFR Minimum Technical Requirements

DFRs as required in 7.1.2 shall be capable of recording at least 5 events of not less than 30 cycles in duration with a sampling rate of not less than 64 samples per cycle. Event data shall be retrievable within a period of not less than 72 hours. A minimum of three (3) cycles of pre-disturbance data shall be recorded with each event. Disturbance records shall be continuous until the system returns to a non-faulted condition, or the 30 cycle minimum record duration has been reached. DFRs shall record, at a minimum, the quantities listed below in a single recording system. This single recording system shall be capable of and configured to simultaneously capture and time synchronize all required quantities at a substation for each event in a single record.

1) One set of voltages for each operating voltage at 100 KV and above in a substation. A set of voltages shall consist of each phase voltage waveform. If potential devices are not required for protection or metering purposes at a particular voltage level, then this particular voltage level need not be monitored.
2) For all lines, operating at 100KV and above either three phase current waveforms or two phase current waveforms and neutral (residual) current waveform.
3) For all autotransformers, current waveform for three phases and either neutral/residual current waveform or current waveform in delta windings.
4) Status – circuit breaker trip circuit energization for all breakers operating at 100KV and above.
5) Status – carrier transmit/receive if carrier relaying is used for all lines operating at 100KV and above.
6) Date and time stamp.
7) For equipment installed after 1-1-2007, frequency, MW and MVARS shall be recorded and displayed or be able to be derived from collected information, using

industry standard software. Sampling rate minimum for this data shall be one sample per cycle.

8) For equipment installed after 5-1-2007, polarizing currents and voltages, if used, on lines operating at 100KV and above.

Regarding event triggering thresholds, quantities as derived from SPP or members' studies, when available, shall be used in lieu of those defined below. If none are clearly defined from load flow and stability studies, then the following requirements shall be used as a guide:

1) Phase current greater than or equal to 150% of the equipment rating.
2) Neutral (residual) current greater than or equal to 20% of the rating of the equipment.
3) Voltage excursions greater than or equal to 10% from operating range of equipment.

7.1.1.2 SOE/SER Minimum Technical Requirements

SER's, as required in 7.1.2, as a minimum, must be capable of producing time stamped power circuit breaker position indications. Sequence of Events Recorders may not be required as long as an appropriate monitoring device provides breaker indication and meets the general technical requirements in 7.1.1

7.1.1.3 DDR Minimum Technical Requirements

DDRs as required in 7.1.2 shall be capable of recording 960 samples per second and shall record the true RMS value of electrical quantities at a rate of at least 6 records per second. For DDR's installed after January 1, 2009 continuous recording shall be required. DDRs shall be capable of recording electrical quantities for each monitored element sufficient to determine and display voltage, current, frequency, megawatts and megavars. DDRs shall record, at a minimum, the quantities listed below:

1. One set of voltage and current for each line operated at 100kV and above. A set shall consist of phase to neutral voltage and the corresponding phase line current.
2. One set of voltage and current for each auto-transformer with a secondary voltage operated at 100kV and above. A set shall consist of phase to neutral

voltage and the corresponding phase line current.

3. Date and time stamp.
4. Frequency, MW and MVARS shall be recorded and displayed or be able to be derived from collected information, using industry standard software.

7.1.2 Required Location for Disturbance Monitoring Equipment

DFR and SER capabilities are required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2002. In addition, any new substation placed in service after January 1, 2002 containing six (6) or more lines operating at 100 KV and above will be required to have DFR, and SER capabilities. However, when additional lines placed in service after January 1, 2002 are added to an existing substation that results in six (6) or more total lines, then DFRs and SERs shall be required for monitoring all elements within the substation as defined in 7.1.1. 1 and 7.1.1.2. These requirements may be waived at SPP's discretion, if a DFR is already located at an adjacent substation.

DDR capabilities are required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2008. In addition, any new substation placed in service after January 1, 2008 containing six (6) or more lines operating at 100 KV and above will be required to have DDR capabilities. However, when additional lines placed in service after January 1, 2008 are added to an existing substation that results in six (6) or more total lines, then DDR shall be required for monitoring all elements within the substation as defined in 7.1.1.3 These requirements may be waived at SPP's discretion.

The number, type and location of disturbance monitoring equipment will normally be the responsibility of the facility owners based on recommendations by the owners' studies and this criteria. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in a database by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor this database. The Transmission Working Group and Operating Reliability Working Group will review the database to recommend that equipment with adequate

capabilities -- including digital fault recorders and dynamic disturbance recorders --be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

7.1.3 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the Disturbance Monitoring Equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. For newer DME's with self-monitoring, having SCADA reporting for a DME failure, and with successful downloading of events occurring at least annually, then such activity and application shall satisfy the testing and maintenance procedure requirements. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.1.4 Periodic Review of Disturbance Monitoring Equipment

SPP members shall maintain a list of substations where Disturbance Monitoring Equipment is located for generation and transmission facilities including those designated as being critical by the Transmission Assessment and Security Working Groups. The facility owner shall be responsible for providing required data on a form developed by the System Protection & Control Working Group and supplied by SPP. Required data should include type of DME, make and model of equipment, installation location, operational status, date last tested, monitored elements, monitored devices, and monitored electrical quantities. Each facility owner shall provide updates to the SPP upon request. The SPP staff will maintain and update the Disturbance Monitoring Equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.1.2. The SPCWG will update, if necessary, this System Protection Equipment Criteria every three (3) years.

7.1.5 Requests for Disturbance Data and Retention Requirements

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility owners shall provide requested equipment lists and disturbance data within 30 business days with a copy of the requested information forwarded to the SPP. SPP shall provide installation and reporting requirements to other regions and NERC within five (5) business days. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

A narrative description of each disturbance, pursuant to the requirements of SPP Criteria 11 addressing System Disturbance Reporting, to be provided by the facility owner shall include, at a minimum, a brief description of the event as identified on a form supplied by SPP. Additional items that shall be included are the cause of the incident, its consequences, service interrupted, corrective actions taken and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. Attachments shall be provided including relevant information from the DME that substantiates the determination of cause(s) of the disturbance. This information shall include all quantities based on the equipment requirements specified in 7.1.1, Minimum Technical Requirements. Facility owners shall retain disturbance data for a period of not less than one (1) year in a common format to the extent possible given the different manufacturers and types of equipment. Disturbance data recorded after 5-1-2007 shall be stored in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool or its successor standard. However, the units of the data and source such as line, transformer and generator terminal shall be clearly identifiable in a consistent, time-synchronized format.

7.2 Transmission Protection Systems

7.2.1 Introduction

The goal of Transmission Protection Systems (TPS) is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network to preserve electric system integrity. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred. The need for redundancy in protection systems should be based on an

evaluation of the system consequences of the failure, misoperation of the protection system, and the need to maintain overall system reliability. All reviews of facilities as included in Criteria 7.2 shall be for those operated at 100kV or above.

7.2.2 Protection System Review

7.2.2.1 Assessment Of System Performance

The transmission or protection system owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of Standard I.A. (NERC Planning Standard). These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in NERC Standard I.A. and associated Table I. Therefore, the relative effects on the interconnected transmission systems due to a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters. All non-compliance findings shall be documented including a plan for achieving compliance. These assessments should be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems within 30 days of the request.

7.2.2.2 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the transmission protection system to assure that components and systems function as desired to minimize outages. All non-compliance findings, as a result of this review, shall be documented including a plan for achieving compliance. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.2.4. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, switches, fuses, etc.).
4) Breaker failure and transfer trip schemes.
5) Communications systems used in protection.

Models used for determining protection settings should take into account significant mutual and zero sequence impedances. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generation and

transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered. Protection system applications and settings should not normally limit transmission use. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible. Communications systems used in protection should be either continuously monitored or alarmed, or automatically or manually tested.

7.2.3 System Redundancy

Transmission Protection Systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I (NERC). Each Transmission or Protection System Provider shall develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Where redundancy in the protection systems (due to single protection system component failures) is necessary to meet the system performance requirements (of the I.A. Standards on Transmission Systems and associated Table I), the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated.

Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault while maintaining performance requirements. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition. When two independent protection systems are required, dual circuit breaker trip coils should be considered. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each

system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

7.2.4 Monitoring, Analysis And Notification Of Misoperations

Each Transmission or protection system owner shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations. Any of the following events constitute a reportable TPS misoperation:

1) Failure to trip – Any failure of a TPS to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device.
2) Slow Trip – A correct operation of a TPS for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip During a Fault – Any relay initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection.
4) Unnecessary Trip Other Than Fault – The unintentional operation of a TPS which causes a circuit breaker to trip when no system fault is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.
5) Failure to Reclose – Any failure of a TPS to automatically reclose following a fault if that is the intent.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. An operation of a TPS that only has an effect on a non-transmission component operated at less than 100kV need not be reported. Documentation of all protection trip <u>misoperations</u> shall be provided to SPP and NERC within five (5) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all TPS trip operations. It shall also provide consistent documentation of all TPS trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided to SPP and include all fault and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.2.5 Transmission Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing and that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request. Each facility owner shall periodically test the protection system components and system on a frequency as needed to assure that the system is functional and correct. Protection System component maintenance and testing shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer TPS with self-monitoring, having SCADA reporting for a TPS failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements. The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Transmission protection system identification.
2) Summary of testing procedures.

3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.2.6 Requests for Transmission Protection Systems Data

SPP shall function as a requesting agent and clearinghouse for the collection of TPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.2.7 Transmission Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Transmission Protection Systems Criteria every three (3) years.

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at

which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Under-frequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. The accepted practice of the electric industry is to shed load in a minimum of three steps. Should the frequency continue to decline after these three steps of load shedding, additional action may be required to protect generating machinery from mechanical damage. The actions may include opening of tie-lines, removal of generating units from the bus, additional steps of load shedding, or "island" operation may be utilized automatically with enough load left on a machine or plant to keep it in operation. A member can elect to use any one or a combination of these actions. It is recommended that this operation be performed at 58.5 Hz. Whatever is done by any one member shall be coordinated with neighboring members. A map or chart which shows additional actions that will be taken below a frequency of 58.7Hz shall be furnished to SPP.

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, an accumulated minimum of thirty (30) percent of a member's current load. Current load shall be deemed as the one-minute average of the member's load prior to the first under-frequency relay action taken at 59.3 Hz. If system frequency decay is permanently

stabilized to 60 Hz after UFLS implementation of Step 1 or Step 2 of the three steps of under-frequency load shedding (UFLS), it is not required to continue with the additional UFLS step(s).

This requirement shall be achieved as follows:

a. A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, **or**
b. A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding an accumulated minimum of thirty (30) percent of the member's current load up to a maximum of forty-five (45) percent. The relays shall be set to shed the accumulated minimum of thirty (30) percent total up to a maximum of forty-five (45) percent as indicated in the chart below. Ideally, members would shed load in three increments of 10% each; however, due to varying load profiles, it is acceptable to shed increments of load as indicated in the chart below. At Step 1 the member is required to shed at least 10% of their current load but no more than 15%. At Step 2 the member is required to shed at least 20% of their current load but no more than 25%, and Step 1 load shedding may be considered an integral portion of Step 2. At Step 3 the member is required to shed at least 30% of their current load but no more than 45%, and Step 1 and Step 2 load shedding may be considered an integral portion of Step 3. For UFLS tripping of loads greater than 15% at Step 1, 25% at Step 2 and 45% at Step 3, a waiver must be acquired from SPP and any applicable SPP working group. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

The ideal load shedding progression for a 1000 MW load would be:

Step	Frequency (Hz)	Accumulated Load Relief	Total load dropped (MW)
1	59.3	10% of 1000	100
2	59.0	20% of 1000	200
3	58.7	30% of 1000	300

This should be followed as far as practical.

Step	Frequency (Hz)	Minimum Accumulated Load Relief (%)	Maximum Accumulated Load Relief (%)
1	59.3	10	15
2	59.0	20	25
3	58.7	30	45

The following example is an acceptable progression of load shedding and meets SPP Criteria:

One minute average load prior to first load shedding step is 1000MW

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	120	12	120	12
2	59.0	90	9	210	21
3	58.7	90	9	300	30

The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria to shed a minimum accumulation of 20% of the total load at Step 2:

One minute average load prior to first load shedding step is 1000MW

Does not meet minimum criteria of 20%

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	120	12	120	12
2	59.0	70	7	190	19
3	58.7	110	11	300	30

The following example is not an acceptable progression of load shedding by failing to meet SPP load shedding criteria by exceeding the maximum accumulated load shed

of 15% at Step 1:

One minute average load prior to first load shedding step is 1000MW

Exceeds maximum criteria of 15%

Step	Frequency (Hz)	Load Shed (MW)	Load Shed this Step (%)	Total Load Shed (MW)	Accumulated % Total Load Shed
1	59.3	160	16	160	16
2	59.0	70	7	230	23
3	58.7	70	7	300	30

b. The relays used to accomplish load shedding shall be high speed with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as oil field or irrigation pumping load) which would cause the under-frequency relays to incorrectly operate when the source voltage is removed momentarily due to a transmission line fault.

c. In special cases, some members may elect to shed more than the allowable maximum of the system load on any step, for example, if they have an adverse ratio of load responsibility to generating capability. This situation should not be general and shall be considered on the merits of specific cases. As stated in requirement 2 of 7.3.1.3.a, in such cases, a waiver should be acquired from SPP and any applicable SPP working group.

d. The tripping of any generating unit by under-frequency relays or any other protective device during low frequency conditions shall be so coordinated that these units will not be tripped before the three steps of load shedding have been utilized. Should this not be practical due to the operating characteristics of certain units, then these members shall protect the interconnected systems by shedding a block of load equal to the capability of the generating unit that will be tripped and at the frequency which will remove the unit from service. If the unit is jointly owned, each of the joint owners shall shed a block of load equal to their share of the unit.

e. The coordination among members becomes critical when actions beyond Step 3 are utilized; particularly, on those members which have established extra high

voltage (EHV) terminals as part of their transmission system and/or with generators connected directly to the EHV system. Careful consideration shall be given when opening only one end of an EHV line section which is energized; the open-ended voltage could rise to damaging levels and reactive flow towards the closed-end could have intolerable effects. Further, if generation is connected to the affected portion of the EHV network, that generating capability would be removed from an area where it is sorely needed. Consideration shall be given to the coordination of under-frequency relaying of the EHV transmission to maintain generating units on line and if necessary, carry portions of a neighboring system load to do so. System operators shall be alert to the effects of unloading the EHV network and be prepared to remove portions of the network should the voltage rise to intolerable levels.

7.3.1.4 Required Location And Model Data Reporting For Under-frequency Load Shedding Equipment

The number, type and location of Under-frequency Load Shedding (UFLS) equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least three (3) years. These modeling databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Model Development Working Group, Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities is installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, location, breaker, trip frequencies, amount of load shed by trip frequency, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UFLS programs.

7.3.1.5 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6 Periodic Review of Under-frequency Load Shedding Equipment

SPP members shall maintain a list of substations where UFLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UFLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.3.1.4. The SPCWG will update, if necessary, this UFLS Criteria every three (3) years.

7.3.1.7 Requests for Under-frequency Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners should provide the requested data within five (5) business days with a copy of the requested information forwarded to the SPP. However, it is recognized that significant disturbances may result in a large amount of equipment operations at multiple locations and that some equipment operations must be manually retrieved from the UFLS equipment's locations. These factors may make it impractical to retrieve and properly prepare the records and documentation within five (5) business days. In these cases, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 Requirements of a Regional Under-frequency Load Shedding Program

The SPP shall develop, coordinate, and document a Regional UFLS program

7.3.2.1 SPP's Coordination of Under-frequency Load Shedding Program

This program shall coordinate UFLS programs within the sub-regions, Region, and where appropriate, among Regions. It shall also coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration. For an effective plan, SPP shall coordinate programs including generation protection and control, under-

voltage load shedding, Regional load restoration, and transmission protection and control. Details to be included shall include those specified in 7.3.1.4. SPP shall periodically conduct and document a technical assessment of the effectiveness of the design and implementation of its UFLS program. The first technical assessment of the program shall be completed by SPP no later than June 1, 2001. These assessments shall be completed at least every five years thereafter or as required by significant changes in system conditions. The documented results of such assessments shall be provided to NERC on request.

7.3.2.2 Coordination of Under-frequency Load Shedding Programs And Analyses With SPP

The facility owners and operators of an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates and times consistent with those Regional requirements. When an under-frequency event occurs which is below the initializing set points of their UFLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.3.1.7.

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the

situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have

been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

7.4 Special Protection Systems Equipment

A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. All reviews of facilities as included in Criteria 7.4 shall be for those used to monitor and control transmission facilities operated at 100kV or above.

The SPS design shall not create cascading transmission outages or system instability. One possible SPS may be the automatic and sequential dropping of load, generation, or adjacent high voltage (HV) lines, if a HV line trips. A SPS does not include (a) underfrequency load shedding or undervoltage load shedding as they are addressed under NERC Planning Standards III.D, Criteria 7.3, and III.E or (b) fault conditions that must be isolated or (c) out-of-step relaying. The SPS shall not require operator action, and all actions of the SPS are automatic. SPS shall be automatically armed without human intervention when appropriate. The status indication of any automatic or manual arming of SPS shall be provided as SCADA alarm inputs.

7.4.1 Operating Requirements and System Redundancy

Special Protection Systems shall include redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of NERC I.A. Standards on Transmission Systems in

Categories A, B or C of the associated Table I. Each facility owner shall develop a plan for reviewing the need for redundancy in its existing special protection systems and for implementing any required redundancy. Documentation of these reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Also, the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Category C of Table I of the NERC I.A Standards on transmission systems.

7.4.2 Location And Data Reporting For Special Protection Systems Equipment

The number, type and location of SPS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' and SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least five (5) years. These databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall represent the designed functionality of the system. Documentation by facility owners for each SPS utilized shall include details on its design, its operation, its control, its functional testing, and coordination with other schemes that are part of or impact the SPS.

7.4.3 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the SPS equipment in service. Component testing and maintenance shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests and maintains on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for

maintaining and providing required maintenance data for its facilities for one testing period. SPS shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. Each facility owner will provide updates to the SPP or NERC upon request.

7.4.4 Periodic Review of Special Protection Systems Equipment

SPP members shall maintain a list of substations where SPS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the SPCWG and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the SPS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.4.2. The SPCWG will update, if necessary, this SPS Criteria every three (3) years.

Based upon (a) a five year interval or other interval as required by electric system changes, or (b) if a new SPS, or (c) if a modified SPS, each facility owner will review and document their SPS for compliance with Regional planning criteria and guides, and the NERC Planning Standard I.A including the associated Table I. This review shall include system studies to evaluate the consequences of: 1) the proper operation of the SPS, 2) the failure of an SPS to operate due to a single component failure of the SPS, and 3) the misoperation, incorrect operation, or the unintended operation of an SPS when considered by itself without any other system contingency. These consequences shall not include cascading transmission outages or system instability. These studies shall include the date that they were performed, who performed them, the methodology of the study, the results of the study, and when the next study is anticipated.

7.4.5 Requests for Special Protection Systems Data.

SPP shall function as a requesting agent and clearing house for the collection of SPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also

formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.4.6 Submittals Of Special Protection Systems Misoperations.

All misoperations of a SPS shall be reported to the SPP within five (5) business days after receipt of the request, or as soon as possible thereafter. Any of the following events constitute a reportable SPS misoperation:

1) Failure to Operate – Any failure of a SPS to perform its intended function within the designated time when system conditions intended to trigger the SPS occur.
2) Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.
3) Unnecessary Operation – Any failure of a SPS that occurs without the occurrence of the intended system trigger condition(s) including human error.
4) Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s).
5) Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

Misoperations at lower voltages that cause an operation of a SPS, in systems 100kV or higher, shall be reported. A detailed analysis of the misoperation, its consequences, and the corrective actions taken to prevent a reoccurrence will be reported to the SPP within thirty (30) days. SPP shall be notified of any delay and the anticipated date of forwarding the required data. This analysis to be provided by the facility owner shall include, at a minimum, the description of facility as identified on a form, developed by the SPCWG and supplied by SPP, including a complete summary report of the misoperation, its consequences, corrective actions taken, and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. The analysis and corrective actions shall be reviewed by the SPCWG. If these reported corrective actions are deemed inadequate, then the corrective actions that SPP recommends shall be completed as soon as possible subject to equipment availability.

7.4.7 Submittals For New And Modified Special Protection Systems

The owner of the SPS shall notify SPP of its intent to construct a new or modify an existing SPS

with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the SPS would have local, inter-company, inter-area or interregional consequences, when the SPS is planned for service, how long it is expected to remain in service, what specific contingency(s) it is designed to operate for and whether the SPS will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified SPS prior to construction of facilities, three (3) copies of all applicable studies supporting the design requirements of the SPS and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and Operating Reliability Working Groups will assess the SPS's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the SPS.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.5 UNDERVOLTAGE LOAD SHEDDING

One characteristic of electric systems that experience heavy loadings on transmission facilities with relatively limited reactive power control is the susceptibility to voltage instability. Such instability can cause tripping of generation and transmission facilities resulting in loss of customer demand as well as collapse of the bulk transmission system. A major disturbance among the interconnected bulk electric systems may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. Since voltage collapse can occur rapidly, operators may not have sufficient time to stabilize the systems. Therefore, a load-shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

7.5.1 Program Participants

Facility Owners who determine it beneficial to install undervoltage load shedding (UVLS) equipment may do so. However, UVLS schemes must coordinate with all protection and underfrequency load shedding schemes for the reliable operation of facilities operated at 100kV and above. Also, members are not required to install such equipment unless deemed necessary by either SPP or NERC to ensure the reliability of bulk transmission systems.

7.5.2 Operating Reserve And Principles

All SPP operating reserve shall be utilized before resorting to shedding firm load. All generator governors and voltage regulators shall be kept in automatic service as much as practical so that generating units may be used to their maximum capability for supplying voltage support during disturbances.

a. To realize the maximum benefit from a load shedding program, the points at which the load is shed in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining voltage. One practical way to remove load from a member in an attempt to stabilize the voltage is to do so automatically by the use of

undervoltage relays. All of the designated undervoltage relays on a member system shall be in service at all times. Undervoltage relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. Loads may be shed in multiple steps. Whatever actions are planned or implemented by one member, including actions other than load shedding, shall be coordinated with neighboring members and SPP. All UVLS programs shall coordinate with underfrequency load shedding requirements of other members and SPP to maintain the reliability of the bulk transmission system operated at 100kV and above.

d. Should the utilization of various assets, such as responsive voltage-supporting resources, generation, capacitors and static var systems, fail to stop a voltage decline, load shedding shall be initiated as determined by the member of which is conditional upon the regional requirements of SPP. The relays used to accomplish load shedding shall be high speed with the necessary external intentional time delay devices employed to eliminate nuisance trips during faults, reclosing delays, etc.

7.5.3 Location And Data Reporting

The determination of the number, type and location of UVLS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, trip voltages, amount of load shed by trip voltage, relay and breaker operating times, and

any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UVLS programs.

7.5.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all UVLS trip operations. Any of the following constitute a reportable UVLS misoperation:

1) Failure to trip – Any failure of UVLS equipment to initiate a trip to the appropriate terminal when a voltage level is less than or equal to a low-voltage set point.
2) Slow Trip – A correct operation of UVLS equipment for a low-voltage condition where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip With Acceptable Voltage – Any relay initiated operation of a circuit breaker when the voltage is within acceptable limits.
4) Unnecessary Trip Within Period Of Time Delay – Any relay initiated operation of a circuit breaker before an intended time delay has expired.
5) Unnecessary Trip, Other– The unintentional operation of a UVLS scheme which causes a circuit breaker to trip when no low-voltage condition is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.5.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UVLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.5.6 Periodic Review of Undervoltage Load Shedding Equipment

SPP members shall maintain a list of substations where UVLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UVLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.5.3. The SPCWG will update, if necessary, this UVLS Criteria every three (3) years.

7.5.7 Requests for Undervoltage Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all

misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within thirty (30) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.5.8 Coordination of Undervoltage Load Shedding Programs

The facility owners and operators of an UVLS program shall ensure that their programs are consistent with Regional UVLS program requirements including automatically shedding load in the amounts and at the locations, voltages, rates and times consistent with those Regional requirements. When an undervoltage event occurs which is below the initializing set points of their UVLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.5.7.

7.6 AUTOMATIC RESTORATION OF LOAD

Following a disturbance when the frequency and voltage have stabilized, properly coordinated and implemented programs for the automatic restoration of load can be useful to minimize the duration of interrupted electric service. However, the design of such plans must ensure that the automatic restoration of load does not impede the restoration of the interconnected bulk electric facilities operated at 100kV or higher. After the automatic shedding of load by either underfrequency or undervoltage relaying schemes has occurred, the interconnected bulk electric facilities must first be stabilized with regard to both nominal frequency and voltage within appropriate limits prior to arming an automatic restoration of load system. Also, sufficient spinning reserves must be available such that the recreation of an underfrequency or undervoltage condition does not occur when electric service is restored. Then automatic load restoration programs can be used to effectively expedite the restoration of electric service to accommodate customer demands.

7.6.1 Program Participants

Facility Owners who determine it beneficial to install equipment for the automatic restoration of load (ARL) may do so. However, ARL schemes must coordinate with all protection as well as underfrequency (UFLS) and undervoltage load shedding (UVLS) schemes for the reliable operation of facilities operated at 100kV and above while not overloading any of these facilities. Also, members who install such equipment shall meet all requirements of SPP and NERC to ensure that the reliability of bulk transmission systems is maintained.

7.6.2 Operating Reserve And Principles

Available spinning reserves within SPP and each control area must be sufficient to serve the load to be energized by ARL schemes before arming such schemes. To prevent the use of ARL schemes when insufficient spinning reserves are available, ARL schemes shall be armed by automatic generation control systems of which are operated by or are coordinated with the appropriate control area(s). All generator governors and excitation equipment including voltage regulators shall be kept in automatic service when ARL schemes are armed so that the spinning reserve of available generating units may be used to their maximum capability for supplying real and reactive power during restoration. Additional requirements for the application of programs involving the automatic restoration of load are listed below.

a. Whatever actions are planned or implemented by one member involving the automatic restoration of load shall be coordinated with other members, SPP and other Regions. All ARL programs shall coordinate with underfrequency and undervoltage load shedding programs as well as ARL programs of other members to maintain the reliability of the bulk transmission system operated at 100kV and above.

b. An ARL system shall not be armed unless all pre-designated conditions are satisfied within the control area unless a designated island or sub-area is specified. Unless removed from service for testing and maintenance purposes, an ARL system shall be automatically armed and remain so only when 1) indication that an UFLS or UVLS scheme has operated, 2) the governor and excitation systems of available generation are in the automatic mode, 3) spinning reserves of available generation are greater than or equal to the real and reactive power requirements of the pre-event load to be restored, adjusted to the forecasted daily load curve and changes in diversity, plus incremental losses, 4) an adequate system frequency has been achieved, 5) voltages throughout the transmission system are within valid limits, 6) all intended transmission system interconnects are closed, and 7) all intended breakers including those used for islanding are closed. However, operators of an island or control area that has separated from the remainder of the bulk transmission system may arm an ARL system for this specific area if 1) a neighboring system(s) has not achieved or maintained an adequate frequency or voltage levels within acceptable limits, and

2) all of the conditions specified above are met except that all intended transmission system interconnects or islanding breakers may not be closed.

c. The time intervals involved in the automatic restoration of loads is of extreme importance. The restoration of too much load at one or over time relative to the capacity of available generating units given their dynamic characteristics may result in an unstable system. Therefore, loads to be automatically restored over time shall not exceed the ramping capabilities of the available generation. Also, upon being armed, ARL equipment shall restore load in multiple blocks by design to minimize the possibility of causing an underfrequency or undervoltage condition.

d. When any portion of the generation required to serve restored load is physically separated from the load by facilities within another control area, then adequate facilities between the generation and load with sufficient capacity to transfer the power shall be verified and applicable breakers shall be closed before the ARL system is armed.

e. Only those loads interrupted by UFLS and UVLS schemes may be restored by ARL equipment. Therefore, if either a UFLS or UVLS scheme did not interrupt a given load, then the use of ARL equipment shall not be used to restore the load. When UVLS equipment is used to trip loads, then the local voltage shall be within acceptable limits before the local ARL equipment energizes the load.

f. The points at which the load is restored in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be restored can be selected.

g. Should the utilization of spinning reserve fail to adequately stabilize either frequency or voltage in a control area or designated portion thereof after restoring service to loads, or portions thereof, controlled by ARL equipment, the ARL equipment of said area shall be automatically disarmed. ARL schemes shall be designed and installed to restore load only once before being rearmed manually or by system operators via SCADA.

7.6.3 Location And Data Reporting

The determination of the number, type and location of ARL equipment will normally be the

responsibility of the facility owners based on recommendations by the owners' or SPP's studies. The technical assessments of ARL applications conducted by or on behalf of the facility owner shall validate the coordination with underfrequency and undervoltage programs within SPP and other Regions as necessary. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases as well as technical assessments conducted by facility owners and recommend that equipment with adequate capabilities be installed, or removed as necessary, at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, minimum voltage and frequency thresholds, amount of load shed that is to be restored, relay and breaker operating times, and any intentional delay of breaker closing. Also required will be any related generation protection, tie-closing schemes, islanding schemes, or any other schemes that are part of or impact the ARL programs.

7.6.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all ARL closing operations. Any of the following constitute a reportable ARL misoperation:

1) Failure to close – Any failure of armed ARL equipment to initiate a close to the appropriate circuit breaker when a local voltage and/or frequency level is greater than or equal to applicable set points.
2) Slow Close – A correct operation of armed ARL equipment where the relay system initiates closing slower than the system design intends.
3) Unnecessary Close By Unarmed Equipment – Any initiated closing of a circuit breaker when all pre-designated conditions are not met.
4) Unnecessary Close, Other– The unintentional operation of an unarmed ARL scheme that causes a circuit breaker to close when no event had previously

occurred. This may be due to vibration, improper settings, faulty relay, or human error.

Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all closing misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage, frequency and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all closing misoperations.

7.6.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality and availability of the ARL equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

ARL systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than three (3) years to verify the dependability and security

aspects of the design. The maintenance and testing program of the ARL system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker closure testing. All maintenance and testing shall be documented as described below:

1) Automatic Restoration of Load system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.6.6 Periodic Review of Equipment

SPP members shall maintain a list of substations where ARL equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the ARL equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.6.3. The SPCWG will update, if necessary, this ARL Criteria every three (3) years.

7.6.7 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.6.8 Coordination of Programs

The facility owners and operators of an ARL program shall ensure that their programs are consistent with Regional ARL program requirements including automatically restoring load in the amounts and at the locations, range of voltages and frequencies, rates and times consistent with those Regional requirements. When an undervoltage or underfrequency event occurs which initiates the utilization of ARL programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.6.7.

7.6.9 Submittals For New And Modified ARL Systems

The owner of the ARL system shall notify SPP of its intent to install a new or modify an existing ARL with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the ARL system would have local, inter-company, inter-area or interregional consequences, when the ARL system is planned for service, how long it is expected to remain in service and whether the ARL system will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified ARL system prior to installation of facilities, three (3) copies of all applicable studies supporting the design requirements of the ARL system and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and Operating Reliability Working Groups will assess the ARL system's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the ARL.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.7 Generation Control and Protection

The objectives of protective relaying and control schemes within generation facilities are to promptly detect abnormal conditions and isolate or control equipment to minimize damage to equipment. Some of these abnormal conditions which will result in an alarm or tripping of generation include faults, overload, overheating, off-frequency, loss of field, motoring, single-phase or unbalance current operation, and out-of-step. The selection and settings of equipment should not result in erroneous tripping for acceptable operating conditions or for faults outside the intended zones of protection.

Generation Control and Protection Systems (GCP) must be coordinated with excitation and governor controls to minimize generator tripping during disturbance-caused abnormal voltage, current and frequency conditions. Therefore, protection and control schemes should be designed and installed with appropriate settings to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generator equipment from damage. All reviews, monitoring and analysis of each generator, rated at 20MW or above, shall be completed as described in Criteria 7.7.

7.7.1 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the generation protection system to assure that components and systems function as desired to minimize outages. The design and implementation of all new protection schemes shall be in accordance with IEEE and ANSI Standards, Guides and Recommended Practices as well as NERC Standards and Guides. Should it be determined that the design and application of protection equipment do not adhere to such requirements, then these findings, as a result of this review, shall be documented including a plan for achieving the necessary results. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.7.2. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Bus, cables, lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, fuses, etc.).
4) Breaker failure and trip schemes.

The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

All underfrequency, overfrequency, undervoltage and overvoltage protection systems shall be coordinated with system underfrequency and undervoltage load shedding schemes. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B and C of NERC I.A Standards unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Redundant generator protection schemes are required for all new generator installations and all re-powering projects where the generator is rated at 20MW or above. Redundant generator protection schemes for the step-up transformer and the main auxiliary transformer (if any) are

not required but encouraged. Where redundant protection systems are being used, efforts should be made to use separate current transformers, potential transformers, and DC control power circuits to minimize the risk of both systems being disabled by a single event or condition.

The use of dual trip coils, if available, on both generator and unit circuit breakers are required for all new generator installations at 20MW or above. The installation of breaker failure relaying for generator and unit circuit breakers are also required for all new generator installations at 20MW or above. The addition of breaker failure relaying for all generator and unit circuit breakers at existing sites is not required but encouraged.

7.7.2 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Any of the following constitute a reportable misoperation of generation protection equipment and schemes:

1) Failure to trip – Any failure of a GCP to initiate a trip when required.
2) Slow Trip – A correct operation of a GCP slower than the system design intends.
3) Unnecessary Trip– The unintentional operation of a GCP that causes a unit's output to be significantly reduced or causes the unit to trip when not required. This may be due to any number of factors such as equipment failure, incorrect settings, and relay misapplication.

Misoperations occuring prior to synchronization need not be reported, but shall be investigated and corrected to prevent possible misoperations when the unit is synchronized to the system. Documentation of all protection misoperations shall be provided to SPP and NERC within thirty (30) business days of the request.

Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all GCP trip operations. It shall also provide consistent documentation of all GCP trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting

documentation shall be provided and include all fault, disturbance, load and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform documentation format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.7.3 Generation Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing, demonstrating that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request.

The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design.

Each facility owner shall periodically test the protection system components on a frequency as needed to assure that the system is functional and correct. The maintenance and testing of system components, i.e. relays, shall be completed based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation but at least every three (3) years. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer GCP Systems with self-monitoring, having SCADA reporting for a GCP failure, and with successful downloading or viewing

of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements.

The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Generation protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.7.4 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, and 2) an implemented maintenance and testing program. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.7.5 Coordination of Programs

The facility owners and operators of a GCP program shall ensure that their programs are consistent with Regional GCP program requirements effective January 1, 2002. When a disturbance, fault, or misoperation occurs which initiates the utilization of GCP equipment and schemes, the owners or operators shall analyze and document the event. Documentation of all misoperations shall be provided to SPP and NERC on request in the time frames established in 7.7.4. Generator owners/operators shall have a generator protection system maintenance and testing program in place.

7.7.6 Generation Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Generation Control and Protection Systems Criteria every three (3) years.

7.8 Generator Controls – Status and Operation

7.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator.

7.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators' automatic voltage control regulator. The procedures shall include the following.

a. Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the "Generator Owner/Operator Excitation System Summary Report" supplied by SPP, if control area operator does not have its own form.
b. Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar month. Information shall be provided on the "Generator Unit Excitation System Status Report" supplied by SPP, if control area operator does not have its own form.
c. The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

7.8.1.2 Exempt Generators

Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

a. Generator output less than 20MW

b. Other criteria as control area operator deems appropriate.

7.8.2 Generator Operation for maintaining Network Voltage

Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

7.8.2.1 Control Area Responsibilities

a. Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the "Generator Owner/Operator Voltage Schedule Requirements" report supplied by SPP, if the control area operator does not have its own form. This information shall be made available to SPP and NERC on request (30 business days).
b. Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on "Control Area Operator's List of Exempt Generators" report supplied by SPP, if control area does not have its own form.

7.8.2.2 Generator Owner/Operator Responsibility

a. Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator.
b. When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on the "Generator Unit Voltage Schedule Status Report" supplied by SPP, if control area operator does not have its own form.

7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

7.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

a. Owner/Operators shall provide current tap settings, tap setting ranges, and impedence data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on 'Generator Unit Transformer Tap Setting Report" supplied by SPP is control area operator does not have its own form.
b. When tap setting changes are necessary, the control area operator shall notify generator owner/operator with "Generator Unit Transformer Tap Setting Change Request" supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.
c. Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new "Generator Unit Transformer Tap Setting Report" for the affected generating station.
d. Criteria for Generating units whose GSU and AUX transformers would be exempted.
e. List of generating units that meet exemption criteria shall be documented on "Generation Units Exempt from Tap Setting Reporting Procedures" report supplied by SPP, if Control Area Operator does not have its own form.

7.8.4 Generator Performance during Temporary Excursions

7.8.4.1 Excursions in Frequency and Voltage

Generators shall be able to sustain temporary excursions in underfrequency, overfrequency, undervoltage, and overvoltage conditions. The protective relay systems regarding these conditions shall be coordinated with SPP system underfrequency and undervoltage load shedding schemes.

SPP's underfrequency load shedding plan allows for three stages of load shed at frequencies of 59.3, 59.0, and 58.7 Hz. The members shall shed 10% of their load at each stage in an effort to stop the decline in frequency. Control Areas may elect to implement a fourth stage at 58.5 Hz which can call for the opening of tie-lines, removal of generating units from buses, additional

steps of load shedding, or the breakup of the transmission system into predetermined islands with balanced amounts of generation and load in each island. Due to the structure of the underfrequency load shedding plan, it is necessary that generators be able to sustain frequencies to at least 58.5 Hz so that the load shedding plan works as designed. Any generator that must trip off line prior to system frequency declining to 58.5 Hz must have a block of load equal to the generator's output capability tripped at the same frequency as the generating unit.

In the absence of a regional or control area undervoltage load shedding plan, generators shall be able to sustain non-interruptible operation at voltages between 92% and 105% of the nominal transmission voltage at the generator bus. During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

7.8.4.2 Excursions in Real and Reactive Power Output

Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit's Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.

7.8.4.3 Exempt Generators

Generators shall be exempt from this section if they meet the following criteria:

Generator output less than 20MW

7.8.5 Generator Voltage Regulator Controls and Limit Functions

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short term duration capabilities and protective relays.

7.8.5.1 Reporting Procedures

Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the "Voltage Regulator Control Setting Status Report" as supplied by SPP is control area operator does not have its own form.

7.8.6 Governor Control Operation

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors' speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

7.8.6.1 Reporting Procedures

a. Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on "Generator Governor Characteristic Reporting" report supplied by SPP if control area operator does not have its own form.
b. Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on "Non-Functioning Governor Control" report supplied by SPP if control area operator does not have its own form.

7.9 Inter-Connection Revenue Metering

7.9.1 Meter Technical and Data Reporting Protocols

The protection design may also include various types and accuracies of metering and associated equipment. The metering may include, but not be limited to, the following: local station or plant annunciated / displayed metering, SCADA type operational metering exchanged among parties within a station or plant, SCADA type station to control center metering used for operational purposes, control center to control center ICCP type metering, and inter-connection revenue metering. These metering types may or may not have specific SPP criteria requirements. Other metering design requirements may need to be referenced when creating metering and protection design, especially those that include the control center to control center metering and revenue metering. SPP has specific functional and design type requirements for Inter-Connection Revenue Metering.

7.9.2 Revenue "Meter Technical and Data Reporting Protocols" Cross Reference

The Southwest Power Pool (SPP) Market Working Group's (MWG) Settlement Data and Meter Standards Task Force (SDMSTF) subcommittee has jurisdictional control over the power plant and transmission system "inter-connection settlement revenue metering". The SPP System Protection and Control Working Group (SPCWG) and other parties providing inter-connection settlement revenue metering designs in the SPP area must refer to the MWG - - SDMSTF Market Protocol Document "Appendix D: Meter Technical and Data Reporting Protocols" for inter-connection settlement revenue metering equipment design requirements. Per the SPP Market Protocol Document, the inter-connection revenue metering design requirements must be met for all new installations.

8.0 CONTROL AREA CERTIFICATION

An entity seeking to be recognized as a Control Area operating within SPP must be a member of SPP and must attain and maintain Control Area certification. Control Area certification will be performed by SPP pursuant to NERC approved Control Area Criteria and certification procedures to be developed and maintained by the Operatiing Reliability Working Group. These certification procedures will be publicly available by posting on the SPP home page.

9.0 BLACK START

This document provides general guidelines to be followed in the event of a partial or complete collapse of the SPP bulk electric system. Quick implementation of each Balancing Authority/Transmission Operator restoration plan compiled according to this Criteria and the NERC Reliability Standards shall facilitate coordination between member Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator and insure the earliest possible restoration of the electric system. It is impossible to predict all the possible combinations of system problems that may occur after a major electric system failure. It is therefore the responsibility of system operators to restore the electric system applying the general guidelines outlined in this document and in their respective detailed black start plans. Strict adherence to other SPP Criteria is also necessary for a prompt restoration of the electric system. Mutual assistance between members Balancing Authorities/Transmission Operators is highly encouraged. This assistance may include the sharing of black start units. The SPP Reliability Coordinator shall take an active role during electric system restoration as outlined in this Criteria. Each Balancing Authority/Transmission Operator shall have a readily accessible and sufficiently detailed, current restoration plan to assist in an orderly restoration. Restoration shall be aided by communicating to neighboring Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator an accurate assessment of the network conditions throughout the restoration process. Communication shall be established between neighboring operation centers, power plants and the SPP. Mutual assistance and cooperation are essential during restoration activities to avoid reoccurrence of a partial or complete electric system collapse.

9.1 Responsibilities

SPP shall develop and maintain a Regional Black Start Capability Plan and a Regional Restoration Plan in accordance with NERC Reliability Standards. The Regional Black Start Capability Plan and Regional Restoration Plan will be reviewed on an annual basis to ensure the plans maintain effectiveness and accuracy. It is the responsibility of SPP Staff to review and update the plans as required and to bring such proposed updates to the Operating Reliability Working Group (ORWG) for their review and approval. The annual review and any proposed updates are to be submitted to the ORWG no later than April 1.

9.1.1 Members

Each Balancing Authority/Transmission Operator shall develop and maintain a detailed internal black start plan. Each Balancing Authority/Transmission Operator shall review their black start plan annually and shall provide SPP with the latest version of their black start plan whenever changes are made or as requested by SPP Staff. Transmission Operators shall prepare a plan in cooperation with their responsible Balancing Authority designed to assist and coordinate with the Balancing Authority's plan. This applies to cogeneration facilities and independent power producers. A copy of this plan shall be on file at the SPP office. Black start plans shall be verified by a minimum of simulation testing, although actual physical testing is highly encouraged where feasible. Members shall report any testing activities of black start plans to the ORWG.

Balancing Authorities and Transmission Operators shall train appropriate personnel in the implementation and execution of their black start plan.

In the event of an electric system collapse, each Balancing Authority/Transmission Operator shall use the following items as guiding principles for the restoration process.

a. Provide assistance to any and all SPP Balancing Authorities and Transmission Operators as abilities allow, with priority given to the restoration of inter-system bulk electric system ties
b. Make adjustments to interchange schedules between affected areas as necessary to facilitate restoration efforts
c. Take immediate steps to initiate internal restoration plans
d. Supply neighboring Balancing Authorities/Transmission Operators and the SPP Reliability Coordinator with information on network status
e. Coordinate with neighbors the re-connection of Balancing Areas and/or islands.
f. If it becomes apparent that the emergency is of regional magnitude, the focus of restoration action shall shift from individual Balancing Area priorities to bulk network priorities. Priority to a neighboring Balancing Authority/Transmission Operator load may be necessary in order to benefit the overall strength of the bulk

electric system. As generation and transmission facilities become available, systematic restoration of network load shall be initiated with respect to priorities

g. Generation should be made available to all regional utilities for system and customer load restoration as recommended by the SPP Reliability Coordinator

9.1.2 SPP Reliability Coordinator

The SPP Reliability Coordinator shall be familiar with each Balancing Authority/Transmission Operator black start plan that is on file. In the event of a failure of the bulk electric system, the SPP Reliability Coordinator personnel shall take the following action.

a. The SPP Reliability Coordinator has the authority to temporarily suspend normal energy scheduling practices and to restore those practices once an operating emergency has been mitigated.
b. The SPP Reliability Coordinator should recommend sharing of generation available to all regional utilities for system and customer load restoration.
c. Maintain continuous surveillance of the status of the networks of all member Balancing Authorities (refer to section 9.4 for information required).
d. Act as a central information collection and dissemination point for Balancing Authorities/Transmission Operators.
e. Communicate with other regional offices, NERC and the Federal Emergency Management Administration.
f. Communicate/recommend the need for assistance to appropriate Balancing Authorities/Transmission Operators.
g. The SPP Reliability Coordinator shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points.
h. The SPP Reliability Coordinator shall expect notification of Balancing Authority status. It is necessary that this information be recorded and shared with all Balancing Authorities/Transmission Operators. Based on this information, the SPP Reliability Coordinator shall immediately assess electric system conditions and status of communication facilities and inform all Balancing Authorities of the extent of the blackout (refer to section 9.4 for information required).

9.2 Elements of Balancing Authority/Transmission Operator Black Start Plans

Each Balancing Authority/Transmission Operator shall maintain a black start plan that is consistent with the NERC Reliability Standards. All plans and procedures shall be readily available to system operators, plant operators and the SPP Office. System operators shall review these documents on a regular basis. It is suggested that Balancing Authority/Transmission Operator black start plans include the following elements.

a. Philosophies and strategies for Balancing Area restart
b. Identification of the relationships and responsibilities of the personnel necessary to the restoration
c. Identification of black start resources including generating unit resources, sufficient fuel resources, transmission corridors or paths, communication resources and power supplies, mutual assistance arrangements
d. Contingency plans for failed resources
e. Identification of critical load requirements
f. Identification of special equipment requirements
g. Provisions for training and documentation of training for personnel
h. Provisions for simulating and where practical, actual testing and verification of the resources and procedures
i. General instructions and guidelines for system operators, plant operators, communications personnel, and transmission and distribution personnel
j. Provisions for public information
k. Synchronization Guidelines including operating instructions and procedures for synchronizing areas as may be dictated in the restoration plan
l. The functions to be coordinated with neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators
m. Notifications to neighboring Reliability Coordinators, Balancing Authorities, Transmission Operators, and other operating entities as phases of the restoration plan are implemented

Appendix 4 contains a list of items to be considered in the restoration process that may be used in the development or review of black start plans.

9.3 Restoration Priorities

The following actions for system restoration shall be considered by each Balancing Authority and assigned proper sequence and priority.

a. Stabilization of generating units
b. Restoration of inter-system and intra-system bulk electric system ties
c. Restoration and maintenance of intra- and inter-system communication facilities and networks
d. Assessment of Balancing Area condition and SPP electric system condition
e. Contact with public information agencies (Emergency Broadcasting System) to request the broadcasting of pre-distributed appeals and instructions
f. Restoration of units with black start capability
g. Providing service to critical electric system facilities
h. Connection of islands taking care to avoid reoccurrence of a partial or complete system collapse and equipment damage
i. Restoration of service to critical customer loads
j. Restore service to the remaining customers

9.4 Information Communication

Reliable communication between Balancing Authorities/Transmission Operators and SPP Reliability Coordinator will be the key to a safe and timely restoration following a collapse of the SPP network. As part of the initial assessment after a partial or complete system blackout, communication facilities shall be tested and verified. System operators shall establish communication within their area with special emphasis given to power plants and neighboring members. To expedite the recovery process, the SPP Emergency Communication Network (satellite phones) shall be used to convey appropriate information to members. **Balancing Authorities/Transmission Operators shall be prepared to communicate their status once an hour, or when polled by the SPP Reliability Coordinator** Only after voice communication paths have been established shall efforts be directed to re-establishing data communication paths. System status conditions to be surveyed include but are not limited to the following items.

a. Areas of the electric system that are de-energized
b. Areas of the electric system that are functioning
c. Amount of generation and generating reserve available in functioning areas

d. Power plant availability and time required to restart

e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants

f. Status of transmission breakers and sectionalizing equipment at tie points to other areas

g. Status of fuel supply from external suppliers

h. Under-frequency relay operation

i. Relay flags associated with circuits tripped by protective relays

j. Status of communication systems

10.0 EMERGENCY COMMUNICATION

Dependable communication between members is critical to maintaining a reliable bulk electric system. As part of the initial assessment following a network disturbance or after a partial or complete blackout, communication facilities shall be tested and verified. Control Area operators shall establish communication with neighboring members and the SPP Reliability Authority. Control area operators shall establish contact with power stations.

10.1 SPP Emergency Communication Network

Should problems be encountered with any primary communication facilities, the SPP Emergency Communication Network shall be used to convey the appropriate information. Communication is vital to an orderly recovery. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths. The SPP Emergency Communication Network is comprised of Satellite Phones located at each Control Area operating center. General information and operational instructions for these phones is contained in Appendix 3. During emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Authority shall initiate a Group Call and quickly determine the extent of the interruption. Operating personnel shall keep conversations concise to keep channels clear. It is important in emergency situations for system operators to be familiar and comfortable with the phone operation. Each Control Area shall participate in the weekly test of the SPP Emergency Communication Network. Each Control Area system operator and the SPP Reliability Authority should become familiar with the operation of the phone. The Reliability Authority shall instigate and monitor this testing and training process.

10.2 Information Priority During Emergencies

System status conditions to be surveyed include but are not limited to the following items:

a. Areas of the electric system which are de-energized,

b. Areas of the electric system which are functioning,

c. Amount of generation and generating reserve available in functioning areas,

d. Power plant availability and time required to restart,

e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,

f. Status of transmission breakers and sectionalizing equipment at tie points to other areas,

g. Status of fuel supply from external suppliers,

h. Under-frequency relay operation,

i. Relay flags associated with circuits tripped by protective relays.

j. Status of communication systems.

11.0 SYSTEM DISTURBANCE REPORTING

The purpose of this Criteria is to establish uniform procedures for reporting system disturbances. The Disturbance Assessment Working Group is responsible for reviewing system disturbances or unusual adverse operating conditions for lessons to be learned. It is necessary that information about such events be provided promptly and completely to SPP.

11.1 Reporting Requirements

Any disturbance that is described by one or more of the following criteria shall be reported.

a. Loss of 100 MW of load or more than half of the pre-disturbance load, whichever is less, for more than 15 minutes. Members with peak loads of 3000 MW or greater shall report loss of 200 MW load.

b. Interruption of service to over 50,000 customers or more than half of the total customers, whichever is less, for more than three hours.

c. Cascading outages.

d. Equipment or facility failure that affects the adequacy or reliability of the bulk power supply system. An example would be a failure which causes an extended unscheduled power import.

e. Voltage reduction or public appeals to maintain continuity of bulk power supply system.

f. "Near misses" shall also be reported if they provide a "lesson to be learned" or might have been a reportable disturbance under different circumstances.

g. Frequency disturbances of 0.05 Hz or more.

11.2 Report Types

11.2.1 First Notification

System operators shall notify SPP as soon as possible, but no later than 24 hours of a reportable disturbance. This report may be by telephone or preferably through the SPP Computer Communication System. The first notification shall briefly describe the nature of the disturbance and expected restoration time.

11.2.2 Power System Major Disturbance Report

Within 3 days a disturbance report shall be sent to the Disturbance Assessment Working Group Chair containing basic information on time and nature of the incident.

11.2.3 Oral Report

The member(s) involved and the Disturbance Assessment Working Group shall determine if a report should be made at the next semi-annual Engineering and Operating Committee meeting.

11.2.4 US DOE/EP Power System Emergency Report

The Power System Emergency Reporting Procedures IE-0071 is independent of any SPP report. However, copies of form IE-417 can be sent to the SPP President and the Disturbance Assessment Working Group Chair when appropriate.

11.2.5 Detailed Disturbance Analysis Report

The analysis can vary widely in scope depending on the nature of the disturbance. The report shall contain the following information: Pre-disturbance conditions, Disturbance, Restoration, Conclusions, and Recommendations. The report shall also contain any or all of the following technical data as may be necessary: Chronological sequence of events, Oscillographs, Meter charts, and One line diagrams or maps

11.2.6 Report Submitted to NERC

The Disturbance Assessment Working Group shall review major disturbances of national interest within SPP and distribute reports to the NERC Disturbance Analysis Working Group. Inquiries from NERC shall be directed to the member(s) involved. Disturbance reporting is covered in NERC Operating Guide II.G. The NERC Disturbance Analysis Working Group uses 10 topic categories in their analysis which can serve as a checklist for individual members to use: Future Bulk Power System Planning, Bulk Power Supply Facilities, Relaying, System Operating Control & Communications Personnel, Operating Personnel, Near Term Operational Planning, System Reserve Response, Preventative Maintenance, Load Relief, and Restoration.

12.0 ELECTRICAL FACILITY RATINGS

12.1 Rating of Generating Equipment

To provide a basis for comparing operating margin of various entities and to assure reasonable distribution of the margin, generating equipment shall be uniformly and consistently rated to permit accurate planning. Procedures are herein established for rating generating units and establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the ratings established pursuant to these procedures shall be used for SPP purposes, including determining capacity margins for both planning and operating purposes, scheduling maintenance, and preparation of reports of other information for industry organizations, news media, and governmental agencies. These ratings are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is referenced in many NERC documents as net dependable capacity, that is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generating equipment which is designated as a part of the resource for supplying its own peak load and minimum capacity margin requirement of this Criteria. The seasonal net capabilities, gross capabilities, and auxiliary loads shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort. During the capability test the net capability shall be reported. Additionally, the unit’s gross capability and auxiliary load shall be reported. The gross capability and auxiliary load shall be determined from the test or using such methods as use of manufacturer data, commissioning data, performance tracking, etc. Data used to determine net capability shall be obtained from testing.

12.1.1 Capability Test

Capability Tests are required to demonstrate the claimed capability of all generating units, excluding run-of-the-river hydroelectric plants and wind plants. During a Capability Test, a unit shall generate its rated net capability for a specified Test Period following a specified Settling Period. The length of these periods is determined by the type and size of unit. The unit will be within 5% of its rated capability throughout the Settling Period. Only minor changes in unit controls shall be made during this time as required to bring the unit into normal, steady-state operation. The following table specifies the duration of these periods. The reduced duration tests on the specified unit types are generally considered to be a fair and practical demonstration of unit capability. If operating experience for a given unit suggests otherwise, the system shall use this experience in establishing the time periods or use the periods in the table associated with large steam units.

Unit Type	Settling Period	Test Period
Steam > 100 MW net	2.0 hours	2.0 hours
Steam < 100 MW net	1.0 hour	1.0 hour
All other units	0.0 hour	1.0 hour

12.1.2 Operational Test

An Operational Test is used to demonstrate the ability of a generating unit to be loaded to its nominal rating. Operational tests shall be conducted at a minimum of 90% of claimed summer capability for a minimum of 1 hour. Any normal operating hour with the unit at or above 90% of claimed capability may be deemed an Operational Test.

12.1.3 Frequency of Testing

Summer Capability Tests shall be conducted once every 3 years. If the winter capability rating is greater than summer, winter tests shall also be conducted once every 3 years. Operational Tests shall be conducted once every year during the summer season. New units or units undergoing a physical or operational modification which could impact capability shall be given a capability test.

12.1.4 Rating and Testing Conditions

Ambient conditions at the time of running capability tests shall be recorded so that appropriate adjustments can be made when establishing seasonal capabilities. Conditions to be recorded are: dry-bulb temperature, wet-bulb temperature, barometric pressure, and condenser cooling water inlet temperature. Summer Capability Tests are to be conducted at an ambient temperature within 10 degrees Fahrenheit of Rating dry-bulb temperature.

Winter Capability Tests are to be conducted at an ambient temperature equal to or greater than the minimum dry-bulb temperature for winter testing and rating defined in paragraph 2.3.5.2.g.

12.1.5 Procedures For Establishing Capability Ratings

12.1.5.1 External Factors

a. Units dependent upon common systems which can restrict total output shall be tested simultaneously.

b. When the total output of a member's system is reduced due to restrictions placed upon the output of individual generating units through the operation of the Clean Air Act, or similar legislation, then the total of the individual unit ratings of a member's generating resources shall not exceed the modified system capacity.

c. The fuel used during testing shall be the general type expected to be used during peak load conditions or adjustments made to test data if an alternate fuel is used.

d. Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

e. The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a rating by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a rating by apportioning the combined capability among the units.

12.1.5.2 Seasonality

a. 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 adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, scheduled reservoir discharge, and wind speed.

b. The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

c. The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Rating Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

d. The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook, Chapter 27 Climatic Design Information. The handbook is published every four years; 1997, 2001, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in SPP Criteria Appendix 2.

e. If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

f. Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-bulb) and MWB (mean wet-bulb) (Column 2a and 2b, respectively). According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.

g. The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99% (Column 2b). According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and rating shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

h. Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Appendix 2.

i. For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the hottest month of the year, averaged over the past ten years.

j. Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation

as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made.

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

g. The net capability established for wind plants shall be determined on a monthly basis, as follows:

i. Assemble up to the most recent ten years, with a minimum of the most recent five years, of hourly net power output (MW) data, measured at the system interconnection point. Values may be calculated from wind data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific wind data.

ii. Select the MW values occurring during the top 10% of load hours for the SPP

region for each month (e.g., 72 hours for a typical 30 day month).

iii. Select the MW value that can be expected from the plant at least 85% of the time.

iv. A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the host control area's peak load month of the season of interest.

v. The net capability calculation shall be updated at least once every three years.

12.1.6 Reactive Capability Verification

12.1.6.1 Verification Required Every Five Years

Initial verification of the gross and net reactive capabilities (leading and lagging) of each generating unit and synchronous condenser (hereinafter referred to as "unit") within the SPP footprint shall be provided to SPP on or before the in-service date of the unit. Thereafter, documentation verifying the unit's gross and net leading and lagging reactive capability shall be provided on or before the fifth anniversary of the most recent date that verification documentation was submitted. In addition, documentation verifying gross and net reactive capabilities shall be provided after repairs or equipment changes that may affect reactive capability.

12.1.6.2 Entity Responsible for Verification

The unit's operator shall be the entity responsible for verification of the gross and net leading and lagging capabilities of the unit. This data shall be provided to the SPP Member who is responsible for modeling the unit in power flow and stability models. Data should be provided using Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.3 Leading and Lagging Capabilities Verified

Both the leading capability of the unit (the ability of the unit to absorb megavolt-amps reactive (MVAR) from the electric grid) and the lagging capability of the unit (the ability of the unit to inject MVAR into the electric grid) shall be verified as specified in section 12.1.6.4.

12.1.6.4 Method of Verification

Verification of a unit's gross and net reactive capabilities may be demonstrated:

(a) by submitting documentation showing the maximum leading or lagging MVAR produced by the unit during actual operations; or

(b) by submitting an engineering analysis that demonstrates the expected maximum leading and lagging MVAR of the unit; or

(c) by submitting commissioning data provided that no major modifications have been performed to the unit that would affect its MVAR rating; or

(d) by verifying the unit capability as further described in this criteria. In the event a unit is incapable of being verified as specified in criteria, then the unit's gross and net reactive capabilities must be demonstrated using one of the other methods set forth above. If testing is used to verify reactive capabilities, there is no limitation on the time period between the test for leading capability and the test for lagging capability, provided that each of these capabilities are tested/validated at least once every five years.

12.1.6.5 Reactive Capability Test/Verification

12.1.6.5.1 Test/Verification Objective.

(a) Gross and net leading reactive capability. Under system conditions that are likely to induce the maximum leading response (i.e., the point at which the unit absorbs the largest quantity of MVAR from the electric grid), obtain one data point that shows the gross and net leading reactive capability versus energy production (real power) of the unit.

(b) Gross and net lagging reactive capability. Under system conditions that are likely to induce the maximum lagging response (i.e., the point at which the unit injects the largest quantity of MVAR into the electric grid), obtain one data point that shows the gross and net lagging reactive capability versus energy production (real power) of the unit.

These points shall reflect either the maximum leading or lagging MVAR at or near maximum real power or at such other real power output level as may be specified in the interconnect agreement with the transmission owner.

12.1.6.5.2 Test/Verification Conditions.

As discussed in this section, conditions on the grid should be such that the reactive response of the unit will approach the unit's maximum. System conditions for leading and lagging capability verification are diametrically opposed (leading capability is demonstrated during light loading conditions while lagging capability is demonstrated during heavy loading conditions). Therefore, a complete verification for both leading and lagging capabilities will require collection of data points during different seasons.

(a) Unit parameters. During the verification, parameters for unit load, unit temperature, and unit pressure (hydrogen, boiler, etc.) should be as close as practicable to those experienced during normal operating conditions, or as specified by the unit manufacturer.

(b) Power factor and grid conditions. The validation should be conducted at the unit's power factor as specified in the Interconnection Agreement. If the Interconnection Agreement does not specify the unit's power factor, then the verification should be conducted in a manner that will determine the maximum leading or lagging MVAR the unit is capable of producing while it is operating at or near its maximum real power capability. The conditions that will provide this result for leading reactive capability involve light system loads and light transmission line loading during the Spring or Fall. The conditions that will yield this result for lagging reactive capability involve peak or near peak Winter or Summer conditions. When possible, other synchronous machines or power system components should be used to obtain the most advantageous terminal voltage during the verification. Additionally, communication with the transmission provider may help optimize verification conditions.

(c) Data collection point. Unit verification data shall be collected at the point of interconnection to the transmission system.

12.1.6.5.3 Test/Verification procedure.

(a) Procedure for Verification of Unit Reactive Lagging Limits. While operating in a steady state mode at gross and net dependable mega-watt (MW) capability (near rated output), raise excitation in automatic voltage control until one of the following conditions occurs:

i. The 100% megavolt-amp (MVA) rating of the machine is reached (reach capability curve);

ii. Rated field current or field voltage is reached;
iii. Terminal voltage limit is reached (105-110%, depending on unit);
iv. Generator temperature limits are reached;
v. The maximum over-excitation limiter is reached or alarms;
vi. The maximum reference adjuster travel or limit is reached;
vii. Maximum auxiliary bus voltage is reached; or
viii. Transmission constraints prevent any further increase in lagging MVAR.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

(b) Procedure for Verification of Unit Reactive Leading Limits. While operating in a steady state mode at or near gross and net dependable MW capability, lower excitation in automatic voltage control until one of the following conditions occurs:

i. Under-excitation limiters (UELs) are activated;
ii. 100% MVA rating is reached;
iii. Generator temperature limits are reached;
iv. Minimum reference adjuster travel or limit is reached;
v. Minimum auxiliary bus voltage is reached;
vi. Minimum terminal voltage is reached; or
vii. Transmission constraints prevent any further increase in leading reactive power.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.6 Test/Verification Results.

A validation will be rejected if the unit is verified under conditions other than those specified in this criteria. If a test/verification is rejected, the unit must either be revalidated within the next 12 months or gross and net reactive capability demonstrated through one of the alternative methods specified in section 12.1.6.4.

12.2 Rating of Transmission Circuits

Each SPP member shall rate transmission circuits operated at 69 kV and above in accordance with this criteria. A transmission circuit shall 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 shall be 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 will be specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating shall be determined as described in this criteria and members shall maintain transmission right-of-way to operate at this rating. However, SPP members may use circuit ratings higher than these minimums. Each element of a circuit shall have 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 shall compute 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 shall be based upon an ambient temperature (either maximum or average) developed using the methodology described in Appendix A. A member may elect to compute a third set of seasonal ratings for the remaining months of the year (April, May, October and November). If that election is not made, summer ratings shall be used for these remaining months.

12.2.1 Power Transformer

Power transformer ratings are discussed in ANSI/IEEE C57.92-1981, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C

Average Winding Rise and in IEEE Standard C57.115-1991, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65EC Winding Rise). Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55 ^{o}C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

12.2.2.1 Normal Rating

The normal circuit rating for power transformers shall be its highest nameplate rating. The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

12.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.

12.2.1.3 Loss of Life

Using Table 3 in ANSI/IEEE C57.92-1981, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. Using Table 5 in ANSI/IEEE C57.92-1981, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

12.2.1.4 Ambient Temperature

Average ambient temperature is an important factor in determining the load capability of a

transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating. Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher normal and emergency ratings. However, this circuit rating criteria does not call for seasonal transformer ratings. Using Tables 3 and 5 in ANSI/IEEE C57.92-1981, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

a. Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.
b. Average ambient temperature, 30°C.
c. Equivalent load before peak load, 90% of nameplate rating.
d. Hours of peak load, 8 hour load cycle.
e. Acceptable annual loss of life, 1%.

12.2.2 Overhead Conductor

Overhead conductor ratings are discussed in IEEE Standard 738-1993, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex A of IEEE Standard 738-1993 or an equivalent program, such as the DYNMAP program which is part of the EPRI TLWorkstation ™ software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not acceptable.

12.2.2.1 Conductor Properties

Some computer programs used to compute ampacity values have a conductor property library

whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex A of IEEE Standard 738-1993 or another computer program that does not have a conductor property library will obtain conductor properties from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

12.2.2.2 Line Geographic Location

These factors specify the location of the line, its predominant direction and its predominant inclination. These numbers can either be line specific or they can represent a general line within the control area. One ambient temperature shall be agreed upon for tie lines traversing several geographic areas and interconnections among different control areas.

12.2.2.3 Radiation Properties

The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

Solar Absorptivity The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value shall be between 0 and 1. Recommended values are given in the following tables:

COPPER CONDUCTORS	
Oxidation Level	**Absorptivity**
None	0.23
Light	0.5
Normal	0.7
Heavy	1.0

ALUMINUM CONDUCTORS	
Service Years	**Absorptivity**
0<5	0.43
. 5	1.00

Source: Glenn A. Davidson, Thomas E. Donoho, George Hakun III, P. W. Hofmann, T. E Bethke, Pierre R. H. Landrieu and Robert T. McElhaney, "Thermal Ratings for Bare Overhead Conductors", IEEE Trans., PAS Vol. 88, No.3, pp. 200-05, March 1969.

Infrared Emissivity The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value shall be between 0 and 1. Recommended values are given in tables below:

COPPER CONDUCTORS	
Oxidation Level	**Emissivity**
None	0.03
Light	0.3
Normal	0.5
Heavy	0.8

ALUMINUM CONDUCTORS	
Service Years	**Emissivity**
0	0.23
5-10	0.82
10-20	0.88
. 20	0.90

Source: W. S. Rigdon, H. E. House, R. J. Grosh and W. B. Cottingham, "Emissivity of Weathered Conductors After Service in Rural and Industrial Environments," AIEE Trans., Vol. 82, pp. 891-896, Feb. 1963.

12.2.2.4 Weather Conditions

Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Appendix A contains a methodology to compute maximum ambient temperature. Wind speed is assumed at 2 ft/sec (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

12.2.2.5 Maximum Conductor Temperature

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed. The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria specifies a maximum conductor temperature that could be met

by current line design practices, consideration must be given to existing lines that were built according to an earlier standard. This Circuit Rating Criteria specifies a maximum conductor temperature (for both normal and emergency operating conditions) that shall be used for seasonal circuit ratings. For those existing lines that were designed to meet an earlier standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature requirements in section 3.6.2.6, whichever is lower.

12.2.2.6 Determination of Maximum Conductor Temperature

The maximum conductor temperature for normal ratings may be limited by conductor clearance concerns. Normal ratings are at a level where loss of strength is not a concern. The maximum conductor temperature for emergency ratings have both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures shall be used. This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members practices.

	Maximum Conductor Temperature	
	Normal Rating	**Emergency Rating**
ACSR	85^0C	100^0C
ACAR	85^0C	100^0C
Copper	85^0C	100^0C
Copperweld	85^0C	100^0C
AAC	85^0C	100^0C
AAAC	85^0C	100^0C
SSAC	200^0C	200^0C
Note: Annealing of copper and aluminum begins near 100^0C.		

12.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for 4 hours 8 times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1000 hours. For an all aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the emergency rating shall not exceed 4 hours. This load cycle duration for conductors operating at the emergency rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings shall allow transmission lines to achieve a maximum conductor temperature throughout the year, not just days when the ambient exceeds 78^oF.

12.2.3 Underground Cables

Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the circuit is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method. The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

12.2.3.1 Cable Ampacity

Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:

- Peak current and load-cycle shape;
- Conductor size, material and construction;
- Dielectric loss in the insulation;
- Current-dependent losses in conductor, shields, sheath and pipe;
- Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;
- Thermal capacitances of these components of the thermal circuit;
- Mutual-heating effects of other cables and other heat sources; and
- Ambient earth temperatures.

Both steady-state and emergency ampacities depend upon these factors, although emergency ratings have a greater dependency upon the thermal capacitances of each of the thermal circuit components.

12.2.3.2 Conductor Temperature

The maximum allowable conductor temperature is 85EC for high-pressure fluid-filled (HPFF), pipe-type cables and 90EC for crosslinked, extruded-dielectric cables.

The table below summarizes allowable conductor temperatures for different insulation materials.

Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF circuit. The maximum conductor temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

Insulation Material	Maximum Temperature	
	Normal	Emergency
Impregnated paper (AEIC CS2-90 for HPFF and HPGF (AEIC CS4-79 for SCLF)	85^0C (75^0C)	105^0C for 100 hr 100^0C for 300 hr
Laminated paper-polypropylene (AEIC CS2-90)	85^0C (75^0C)	105^0C for 100 hr 100^0C for 300 hr
Crosslinked polyethylene (AEIC CS7-87)	90^0C (80^0C)	130^0C* cumulative for 1500 hr
Ethylene-propylene rubber (AEIC CS6-87)	90^0C (80^0C)	130^0C* cumulative for 1500 hr
Electronegative gas/spacer	Consult manufacturer for specific designs	

* This limit may need to be reduced to prevent damage due to thermal expansion of the insulation

12.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be

used:

Climate	Ambient Air Temperature ^{0}C	Ambient Ground Temperature ^{0}C
Tropical	55	40
Sub-tropical	40	30
Temperature	25	20

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface. This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Appendix B and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in Appendix B.

12.2.4 Switches

Appendix C contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted normal and 4 hour emergency ratings. The summer normal and emergency switch ratings can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature (40°C or the summer maximum ambient temperature determined in Appendix A), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature (0°C or the winter maximum ambient temperature determined in Appendix A).

Appendix C contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Appendix C allows for emergency ratings to be greater than normal ratings. This Criteria does not require the emergency rating to be greater than the normal rating.

12.2.5 Wave Traps

Appendix D contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a 40°C maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four-hour emergency rating that is also a function of the maximum ambient temperature. The newer epoxy encapsulated type does not have an emergency rating.

12.2.6 Current Transformers

Appendix E contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a 30°C average ambient temperature.

12.2.6.1 Separately Mounted Current Transformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings. Separately-mounted current transformers do not have emergency ratings.

12.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer

temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Appendix E. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an emergency rating for bushing current transformers.

12.2.7 Circuit Breakers

Appendix F contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and emergency ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Appendix F would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than doing that, this circuit rating criteria specifies that the nameplate rating shall be used for seasonal normal and emergency ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element in a circuit and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Appendix F to determine the circuit breakers seasonal normal and emergency rating.

12.2.8 Ratings of Series and Reactive Elements

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit. Shunt reactive elements (e.g., capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

12.2.9 Ratings of Energy Storage Devices

The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.

12.2.10 Circuit Rating Issues

12.2.10.1 Dynamic (Real Time) Ratings

The calculation of static thermal ratings specified in Section 3.6.2 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time. Consequently, a static rating may understate the thermal capacity of the circuit. For operation purposes, some members have elected to monitor the factors that affect circuit ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if transmission line ratings are changed dynamically, the required clearances shall still be met.

12.2.10.2 Non-Thermal Limitations

There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

12.2.10.3 Tie Lines

When a tie line exists between two member systems, use of this criteria shall result in a uniform circuit rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member shall follow this criteria to rate the circuit elements owned by them and shall coordinate the rating of the tie line with the non-member system such that it utilizes the lowest rating between the two systems.

12.2.10.4 Rating Inconsistencies

A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon

the thermal capacity of the line or other considerations. Members shall use good faith effort to amend their transmission line agreements to reflect the effects of new circuit ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission circuits in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

12.2.10.5 Damaged Equipment

There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

12.2.11 Reporting Requirements

Each member will administer this Criteria and will make available upon request the application of this Criteria for those facilities that impact another member (i.e. force them to curtail schedules due to line loadings, denies them access to transmission service or requires them to build new transmission facilities or pay opportunity costs to receive transmission service).

13.0 OPEN

14.0 TRANSMISSION LOADING RELIEF

14.1 Purpose

In the continuous operation of the bulk electric power network, certain procedures are necessary to involve those operating entities that impact overloaded facilities. Procedures are included for corrective action and mutual assistance during periods for which Transmission Loading Relief is necessary. These Criteria ensure SPP maintains a high level of reliability using standard procedures to relieve overloaded transmission circuits. The rating of transmission circuits is described elsewhere in SPP Criteria.

14.2 Definitions

14.2.1 Flowgate

A flowgate is a pre-defined proxy for network limitations representing thermal, voltage, and stability constraints of power transfer. Flowgates consist of one or more transmission circuits rated at 60 kV or above.

14.2.2 Transmission Circuit

A transmission circuit shall consist of all load-carrying elements between circuit breakers or comparable switching devices. Transmission circuit rating criteria is described in Criteria 12.

14.2.3 Interconnected Reliability Operating Limit

The North American Electric Reliability Council (NERC) defines Interconnected Reliability Operating Limit (IROL) as "The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."

14.2.4 System Operating Limit

The North American Electric Reliability Council (NERC) defines System Operating Limit (SOL) as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)

- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

14.3 Daily Reliability Assessment

14.3.1 Control Area Data Reporting

Control Areas shall comply with SPP Criteria and NERC Reliability Standards regarding data reporting.

14.3.2 Overload Evaluation

Information collected shall be used by the Reliability Coordinator to evaluate transmission conditions for the current and next day. Single contingency analysis as well as other reviews shall be made daily. The Reliability Coordinator shall report the daily results to SPP Control Areas.

14.3.3 Control Area Planning

Control Areas shall review the daily reliability assessment report. If the report indicates that anticipated conditions could result in excessive loading on a transmission circuit, Control Areas shall consider and plan for internal procedures that can be taken to prevent degradation of system reliability.

14.4 Transmission Loading Mitigation

14.4.1 Reliability Coordinator Responsibilities

14.4.1.1 Monitoring

The Reliability Coordinator will monitor the transmission system. Monitoring and appropriate control action will be performed to ensure the transmission system is operated so that instability, uncontrolled separation, cascading outages, or equipment damage will not occur as a result of the most severe single contingency. Flowgate flows will be closely monitored and compared to applicable SOLs and IROLs.

14.4.1.2 Weather Adjustment of Limits

Some flowgates or transmission circuits have static seasonal ratings that are developed using certain pre-determined weather condition assumptions (see Criteria 12). To the extent that certain weather conditions such as ambient temperature, wind speed, or wind direction are available, the Reliability Coordinator will coordinate with the Transmission Operator to appropriately adjust the SOLs for those flowgates during heavy loading conditions.

14.4.2 Control Area Responsibilities

Control Areas will monitor their own transmission systems for system reliability. They are responsible for identifying and addressing reliability problems and shall work with the Reliability Coordinator, as appropriate, to correct those problems. Control Areas can call for Transmission Loading Relief to relieve excessive transmission loading. Control Areas shall notify the Reliability Coordinator whenever internal procedures are implemented to relieve overloading.

14.4.3 Transmission Loading Relief Procedures

These procedures shall be implemented whenever the Reliability Coordinator or a Control Area observes excessive flows on a flowgate or other transmission circuit.

a. The Reliability Coordinator will verify actual real-time flow readings with the Control Area and compare against the applicable SOL and IROL for the flowgate or circuit.

b. The Reliability Coordinator will determine the contribution of transactions to the excessive loading and will convey the results of this assessment to the Control Area. This information will be used to determine if transaction curtailments or local control actions are necessary to relieve the excessive loading.

c. Upon request by the Control Area, the Reliability Coordinator will initiate a request for Transmission Loading Relief pursuant to NERC Reliability Standards

d. The Reliability Coordinator shall notify Control Areas and other Reliability Authorities of which scheduled interchange transactions, network service, and native load impacts are to be curtailed during the relief period. Control Areas shall acknowledge receipt of scheduled interchange transaction curtailment, curtail the transactions and/or redispatch generation, as appropriate, for the line loading problems.

e. The Reliability Coordinator shall continuously monitor flows, dispatch, and transactions throughout the period of excessive loading. Any request for Transmission Loading Relief will be canceled when the condition of excessive loading no longer exists and termination of Transmission Loading Relief is not anticipated to cause renewed line loading problems.

f. Rerouting curtailed schedules through another path is prohibited.

14.5 Subsequent Overload Conditions

In the event of simultaneous or concurrent requests for Transmission Loading Relief, the same

procedures will be used with due consideration being given to all existing conditions.

14.6 Curtailment Reports

Reports shall be posted on an hourly basis during any period of Transmission Loading Relief. Daily and monthly summary reports shall also be distributed. These reports shall be used as verification of associated energy schedules.

14.7 Compensation for Assistance

This procedure contains no compensation provision for any party, but compensation is not precluded.

14.8 Responsibilities

14.8.1 Control Areas

It shall be the responsibility of each Control Area to follow policies and procedures contained herein; reporting daily information, identifying potential and actual transmission overloads and supplying assistance to members when directed.

14.8.2 Operating Reliability Working Group

The Operating Reliability Working Group shall receive periodic reports of any implementation of Transmission Loading Relief. The Operating Reliability Working Group shall make a report of this information to the Markets and Operations Policy Committee at each regular meeting.

14.8.3 Reliability Coordinator

It shall be the responsibility of the Reliability Coordinator to provide daily analysis and monitor and evaluate real-time flows and voltages against appropriate SOLs and IROLs. The Reliability Coordinator shall be responsible for providing timely 24-hour coordination and implementation during Transmission Loading Relief periods and provide periodic reports to the Operating Reliability Working Group.

15.0 OPEN