UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Services, Inc.,	)	
	)	
on behalf of the Entergy Operating	)	Docket No. RT01-______
Companies: Entergy Arkansas, Inc., Entergy	)	
Gulf States, Inc., Entergy Louisiana, Inc.,	)	
Entergy Mississippi, Inc., and Entergy	)	
New Orleans, Inc.	)	

TESTIMONY

OF

GEORGE R. BARTLETT

ON BEHALF OF

ENTERGY SERVICES, INC.

October 16, 2000

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND TITLE.

A. My name is George R. Bartlett. My business address is 639 Loyola Avenue, New Orleans, Louisiana, 70113. I am the Director of Transmission Operations at Entergy Services, Inc. ("ESI" or "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1976, I graduated from Tulane University with a Bachelor of Science in Electrical Engineering. In 1976, I was employed by Louisiana Power & Light Company ("LP&L"), now known as Entergy Louisiana, Inc. ("ELI"), in the System Planning Department. In 1980, I left LP&L to manage a family owned business. I returned to LP&L in 1987 and was assigned to the Substation Design group as a design engineer. I returned to System Planning in 1988. From May 1991 until June 1997, I was a Manager within the Transmission Planning and Policy Departments for ESI. In June 1997, I accepted my present position, Director of Transmission Operations, and I am responsible for transmission planning and operations.

In the course of my career, I have been involved in various aspects of the engineering processes relating to the Transmission functions, and I am familiar with the standards and practices of the transmission operations of utilities.

I am a registered professional engineer in the state of Louisiana. I am a member of the Institute of Electrical and Electronics Engineers ("IEEE") and the Louisiana Engineering Society.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF TRANSMISSION OPERATIONS?

A. I am responsible for the supervision of Transmission System Planning, Transmission System Security, Transmission System Security Coordination, and Local Dispatching.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I will describe the planning process Transco, the independent transmission company, will use to meet its load requirements, the criteria to be used in determining transmission system upgrades, and how these criteria were developed and will be applied. I will also address the criteria Entergy proposes to use to determine the physical and functional separation of its generation, transmission, and distribution assets, how these criteria were developed, and how they will be applied.

Q. DO YOU ADDRESS THE SEPARATION OF GENERATION, TRANSMISSION, AND DISTRIBUTION ASSETS FROM AN ACCOUNTING PERSPECTIVE IN YOUR DIRECT TESTIMONY?

A. No. The separation of the transmission assets from an accounting perspective will be addressed by Company witness Nathan E. Langston.

III. TRANSCO'S PLANNING PROCESS

Q. WHAT IS THE OBJECTIVE OF THE TRANSCO PLANNING PROCESS?

A. The Transco Planning Process is intended to address system reliability issues in order to ensure the security and adequacy of Transco's interconnected transmission system.

Security refers to the ability of the interconnected transmission system to withstand the impacts of dynamic system disturbances. When a transmission element fails, security dictates that the system must be able to isolate that element and ride through the disturbance without the threat of cascading outages or equipment damage. Adequacy relates to the ability of a transmission system to transfer energy from the generating sources to the load. Additionally, following the loss of a transmission element, adequacy dictates that the facilities that remain in service must be capable of transferring the required energy to the load without any resulting overloads or voltage level violations.

Q. WHAT ARE THE CIRCUMSTANCES THAT COULD LEAD TO SECURITY PROBLEMS ON THE INTERCONNECTED TRANSMISSION SYSTEM?

A. Modifications to the transmission grid or any of the interconnected generation can cause changes in the dynamic characteristic of the system, and all modifications must be analyzed for their effects on system security. An example of such a condition is the interconnection of a new generator that injects additional fault current into the system during system disturbances. The additional fault current will impact existing equipment, thereby affecting the integrity of the system, the proper operation of the equipment, and the safety of the general public.

Q. WHAT ARE THE CIRCUMSTANCES THAT COULD LEAD TO ADEQUACY PROBLEMS ON THE INTERCONNECTED TRANSMISSION SYSTEM?

A. Some of the circumstances that can negatively affect the adequacy of the interconnected transmission system are congestion, which limits transfers across the system, and planned and unplanned transmission facility outages, which could result in violation of voltage and thermal limits on system elements.

Q. WHAT FACTORS LEAD TO TRANSMISSION CONGESTION?

A. Factors leading to transmission congestion include loop flows and parallel flows, changes in generation commitment or dispatch, and changes in transmission service requests. Each of these occurrences is dynamic in nature and must be managed on a real time basis in the normal course of operating the transmission grid. Lately, system operations have been complicated by the fact that transmission congestion is increasing across the entire Eastern Interconnection. The increasing numbers of Transmission Loading Relief (TLR) measures having to be implemented by the Security Coordinators evidences this fact. TLRs result in the disruption of transaction schedules. Mr. Schnitzer's testimony discusses how TLRs are becoming more and more problematic and are impeding the development of bulk power markets.

Q. ARE THERE INDICATIONS OF CONGESTION ON THE ENTERGY SYSTEM?

A. Yes. The level of congestion is evidenced by the nature of the flowgates on the Entergy system. A flowgate is a specific transmission line or transformer recognized by the NERC as presenting a limit to the flow of energy across the transmission network. It is across flowgates that the Security Coordinators implement TLRs. Entergy has identified 45 flowgates on our system for the implementation of TLR procedures. Of these 45, we have complete historical data for 37, at least 32 of which have been at or near their operating limit during the past year. And, because the factors leading to congestion are dynamic in nature, the number and location of flowgates is dynamic. Over the past 6 months, Entergy has revised its list of NERC flowgates no less than 15 times.

Q. WHAT FACTORS ARE ACTING TO INCREASE THE CONGESTION IN THE ENTERGY REGION?

A. The congestion is exacerbated by the increasing amount of energy being scheduled across the interconnected system, adding to the problems of loop flow and parallel flow. The number of transactions on the Entergy system alone has increased from 3,500 in 1997 to more than 80,000 projected to occur this year. The number of transactions and amount of energy being scheduled across Entergy is expected to continue to increase with the new generation that is being added in the region.

The Entergy region has access to significant natural gas fuel supplies. As a result of this and other factors, Entergy has seen the request for the interconnection of merchant generation grow at an unprecedented rate. At this time, the Entergy region has approximately 8,000 megawatts of merchant generation under construction, an additional 7,000 megawatts that have executed interconnection agreements, and over 60,000 megawatts in the queue for interconnection studies. As this new generation comes on-line, it will significantly impact generation dispatch and energy flows across the region, thereby impacting system performance and congestion. For example, a new

800 megawatt merchant plant slated for Texas threatened the contingency limit on adjacent transmission lines, necessitating the designation of a new flowgate to the Entergy system. I would expect similar effects from other new generators. As Mr. Schnitzer explains, because generation and transmission facility additions are no longer planned as part of an integrated process, the adoption of a congestion management regime that provides for the proper signals and incentives for the construction of transmission and generation is critical for this region of the country.

Q. HOW IS SYSTEM ADEQUACY ANALYZED CURRENTLY BY THE INDUSTRY?

A. Planners within each North American Electric Reliability Council ("NERC") Reliability Region create base case load flow models which allow them to evaluate system reliability and test the effectiveness of any proposed facility upgrades and expansions prior to their going into service. Inputs to the model include transmission system parameters, regional loads and generation, and transactions with interconnected utilities.

Q. HOW IS THE LOAD FLOW MODEL USED IN EVALUATION OF SYSTEM RELIABILITY?

A. Contingency analysis is performed by using the model to test the transmission system response to a prescribed set of contingencies. Contingencies are identified that reflect expected system conditions, and a series of computer runs are made after suitably modifying the load flow model for each contingency. Computer output yields the system's response for each perturbation. This response is measured against industry standards to ensure that the transmission system will exhibit acceptable reliability performance under expected system conditions.

Q. HOW DOES THE LOAD FLOW MODEL REFLECT THE RESPONSE TO A CHANGE IN THE SYSTEM?

A. A system planner will make changes, such as system upgrades and expansions, to the base case model, thereby building a change case suitable for inspection. Contingency analysis is performed, and the system response is again measured against industry standards to ensure that the system with the changes will continue to exhibit acceptable reliability performance under expected system conditions.

Q. HOW WILL TRANSCO DEVELOP A BASE CASE LOAD FLOW MODEL?

A. It is intended that Transco will derive a base case load flow model from those that are currently in use by Entergy and any additional Transco participants.

Q. WHAT BASE CASE LOAD FLOW MODEL DOES ENTERGY CURRENTLY USE?

A. Because Entergy is on the boundary between the Southwest Power Pool ("SPP") and the Southeastern Electric Reliability Council ("SERC"), it builds its base case load flow models by combining those created by the two Reliability Regions. The aggregate model contains the level of detail needed to accurately reflect the Entergy system's response to changes in model parameters for measurement of compliance with prescribed guidelines.

Q. WHAT GUIDELINES WILL THE TRANSCO PLANNING DEPARTMENT USE TO DETERMINE THE ACCEPTABLE LEVEL OF RELIABILITY ON THE INTERCONNECTED TRANSMISSION SYSTEM?

A. It is anticipated that the Transco planning department will use the guidelines currently in use by Entergy, as well the Reliability Criteria of the SPP Partnership RTO and the guidelines of any other Transco participants as criteria to determine the security and adequacy of the integrated transmission system.

Q. WHAT GUIDELINES ARE CURRENTLY UTILIZED BY ENTERGY?

A. Entergy currently follows the planning standards of the NERC, the supplemental planning standards of the SERC, and the Entergy Transmission Planning Guidelines, attached at Exhibit GRB-1

Q. WHAT DO THESE PLANNING GUIDELINES PROVIDE FOR?

A. The NERC Planning Standards address the requisite system response to both more probable and less probable system contingencies of the interconnected electrical grids. Systems must be able to withstand more probable contingencies without loss of load, and to be able to handle less probable contingencies with controlled loss of load. The purpose of the NERC standards is to ensure the reliability of each of the three interconnected electrical grids of North America. The supplemental planning standards of the NERC Reliability Regions define the methodology for implementing the NERC Planning Standards. These supplemental standards vary between the ten Reliability Regions to accommodate the different system operating characteristics between the regions. The Entergy Transmission Planning Guidelines address the application of both the standards and supplements and the philosophy of serving interconnected generation and load on the Entergy transmission system.

Q. HOW WILL TRANSCO ACHIEVE ADEQUATE TRANSMISSION SYSTEM RELIABILITY AS INDICATED BY THESE PROPOSED GUIDELINES?

A. Adequate transmission system reliability will be achieved through transmission facility upgrades or expansion and through the implementation of Operating Guides.

Q. WHAT ARE OPERATING GUIDES?

A. Operating Guides consist of a prescribed set of actions to be taken by the system operators in response to events likely to occur on the transmission system. Such actions include generation redispatch, transmission system reconfiguration, and the utilization of active system control elements.

Q. WILL THE PLANNING GUIDELINES BE USED TO DETERMINE FACILITY UPGRADES AND EXPANSIONS?

A. Yes, it is intended that Transco will apply these guidelines to determine transmission facility upgrades and expansions on the Transco transmission system.

Q. HOW WILL REGIONAL FACILITY UPGRADES AND EXPANSIONS BE DETERMINED?

A. Regional facility upgrades and expansions will be determined by guidelines developed by the SPP Partnership RTO. The SPP Partnership RTO relationship is described in the direct testimony of witness Steve Owens.

Q. HOW WILL THE TRANSCO PLANNING PROCESS APPLY THE GUIDELINES TO ITS TRANSMISSION SYSTEM EXPANSION AND FACILITY UPGRADES?

A. Transco's planning department will apply industry guidelines through contingency analysis to develop projected system requirements as part of the

Transco Annual Planning Process. Transco will determine the ability of its interconnected system to maintain adequacy and security while accommodating the system's projected load requirements, network resources, transmission service requests, and transactions with neighboring systems.

Q. HOW WILL THE TRANSCO PLANNING PROCESS DEVELOP THESE PROJECTED SYSTEM REQUIREMENTS?

A. As part of the annual planning process, Transco will post on the SPP Partnership RTO Open Access Same Time Information System ("OASIS") a request for data concerning expected transmission system usage, proposed new interconnections, generation additions, and proposed transmission system upgrades for the next planning season.

All users of the Transco-controlled grid will submit to Transco all requests for service from proposed facilities and requests for studies pursuant to the SPP Partnership RTO's Transmission Tariff. Load serving entities shall also submit their 10-year forecast of network load, network resources, and other firm load and resources connected to the Transco transmission system.

Using customer input and requests, the Transco planning department will then perform planning studies to include: (1) an identification of existing and projected electric system limitations using contingency analysis, (2) an evaluation and analysis of potential facility upgrades and expansions, including alternatives thereto, needed to mitigate such limitations, and (3) a determination of the effectiveness and compliance (with reliability criteria) of recommended facility upgrades and expansions.

Q. HOW WILL THE RESULTS OF THE PLANNING STUDIES BE USED?

A. The potential facility upgrades and expansions will be incorporated into a proposed Transco expansion plan ("Proposed Expansion Plan"), which will be submitted to customers for review and comments during the Transco annual planning process.

Q. WHAT TYPES OF PROJECTS WILL BE INCORPORATED INTO THE PROPOSED EXPANSION PLAN?

A. The four types of projects that will be incorporated into the Proposed Expansion Plan are mandatory, reliability, infrastructure, and customer-initiated projects.

<u>Mandatory projects</u> include those that are either government-mandated or required because of safety, contractual, or regulatory requirements. An example of a mandatory project is the relocation of transmission lines to accommodate highway construction.

<u>Reliability projects</u> are needed to meet customer load (including load growth) requirements. These projects are determined through the studies performed by the Transco planning department using customer load projections and anticipated system changes. System changes that are investigated will

include the addition of network resources and construction of regional transmission facilities.

Infrastructure projects are those required to maintain the continued integrity of the existing transmission assets. Examples of such projects include pole replacement and changeout of obsolete equipment.

Customer-initiated projects are required to transfer energy through the Transco transmission system. Such projects are normally associated with generation interconnection or transmission service requests, and generally increase the transfer capability of the transmission system.

Q. HOW WILL THE FOUR DIFFERENT TYPES OF PROJECTS BE IDENTIFIED?

A. Mandatory projects will be identified through either internal studies or requests from customers whose projects will impact the Transmission facilities.

Reliability projects will be identified by using the Transco Planning Guidelines. The Transco planning department will perform studies to determine the adequacy and security of the interconnected transmission system in order to meet the existing and future load requirements of the load-serving customers. The planning department will identify transmission constraints that limit the load-serving customers' ability to serve the load as well as projects to relieve those constraints.

Infrastructure projects will be identified through Transco's internal maintenance programs such as an annual pole and line inspection.

Customer-initiated projects will be identified through either interconnection requests and subsequent studies or system impact studies performed by the Transco planning department. Interconnection studies will determine the system constraints due to the connection of a generator to the Transco transmission system. System impact studies will determine the system constraints due to the transfer of energy from a generator to a specific customer-requested delivery point (Transmission Service Request). The projects that are proposed to relieve constraints resulting from generation interconnection or transmission service requests are referred to as customer-initiated projects since that they are not required to meet the Transco's customer load requirements.

Q. CAN YOU ELABORATE ON CUSTOMER-INITIATED PROJECTS THAT MAY BE IDENTIFIED THROUGH AN INTERCONNECTION OR SYSTEM IMPACT STUDY?

A. Yes. These projects may include (1) direct interconnection facilities necessary to physically connect new generation to the transmission system, (2) projects to ensure the stability of the interconnected transmission system due to the interconnection of generation, or (3) direct interconnection of independent transmission projects such as a direct current transmission line tie between transmission systems.

They may also include transmission upgrades that are necessary to fulfill a transmission service request. These projects will generally be funded by the entity requesting transmission service or other market participants willing to fund such a transmission system expansion.

Q. HOW ARE INTERCONNECTION STUDIES OR SYSTEM IMPACT STUDIES INITIATED?

A. Interconnection studies or system impact studies are requested by a market participant to the SPP Partnership RTO. If the study request is within the Transco service area, it will be assigned to the Transco planning department by the RTO for evaluation. Transco and the SPP Partnership RTO will develop and utilize a mutually agreed upon process to evaluate such projects.

Q. AT WHAT POINT ARE FACILITY UPGRADES AND EXPANSION PROJECTS INCORPORATED INTO THE PROPOSED EXPANSION PLAN?

A. If the Transco Planning and Engineering departments determine that a project must be initiated within a two-year cycle in order to reliably serve the projected load, then Transco planning department personnel will initiate these projects by placing them into the Proposed Expansion Plan. This plan will cover a two-year horizon and will be incorporated into a two-year rolling budget cycle.

The Transco planning department will place projects that are identified either through the interconnection or system impact studies in Transco's Proposed Expansion Plan upon receipt of a commitment from the IPP or market participant.

Q. WILL THERE BE PROJECTS THAT ARE IDENTIFIED BUT WILL NOT BE INCLUDED IN THE PROPOSED EXPANSION PLAN?

A. Yes. Projects that are not required to be initiated within the two-year planning cycle are incorporated into the year three to year seven contingency plan ("Contingency Plan") but not the Proposed Expansion Plan. An example of this type of project is a facility upgrade whose in-service date is projected to be six years out in the future but whose project cycle time is only three years. Such a project will not have any budget commitment (*i.e.*, reasonable certainty that funds will be approved for construction) until it is rolled into the Proposed Expansion Plan three years before its proposed in-service date.

Q. WHY DON'T ALL PROJECTS IN THE CONTINGENCY PLAN HAVE REASONABLE CERTAINTY THAT FUNDS WILL BE APPROVED FOR CONSTRUCTION (BUDGET COMMITMENT)?

A. Various factors such as load growth, location of merchant plants, designation of generation resources to transmission customers, and area interchange (*i.e.*, power transfers between areas or regions) affect the need for transmission projects. The time frame associated with several of these factors is often less than the time frame of the Proposed Expansion Plan. For example the time to build new generation is often less than the time required to plan, design, and construct a transmission project. Additionally, transmission customers can re-designate new or different generation resources which impact flows on the transmission system. Within the time that it takes to certify the need for a transmission line, a generation project could be initiated, installed, and placed in service, which could negate the need for a transmission facility upgrade or expansion.

Q. HOW WILL CUSTOMERS PROVIDE FEEDBACK AND ALTERNATIVES ON THE PROPOSED EXPANSION PLAN?

A. Transco will post the Proposed Expansion Plan on its OASIS, inviting comments from all interested parties. Transco will then conduct a Planning Summit for all parties interested in the Proposed Expansion Plan. All interested parties will be invited to attend to express their needs and concerns. Transco will review all new facility plans based on the Planning Summit and all comments to its Proposed Expansion Plan, and it will then finalize its plans and submit the Proposed Transco Expansion Plan to the SPP Partnership RTO for inclusion in the RTO planning process.

IV. REGIONAL PLANNING PROCESS

Q. WHAT IS THE OBJECTIVE OF THE SPP RTO REGIONAL PLANNING PROCESS?

A. The SPP Regional Planning Process is intended to incorporate the transmission owners' expansion plans, while addressing regional transmission issues, seams issues with adjoining RTO's, and stakeholder issues.

Q. WHO WILL ADMINISTER THE REGIONAL PLANNING PROCESS?

A. The SPP Partnership RTO will administer the Regional Planning Process.

Q. HOW WILL THE TRANSCO EXPANSION PLAN DISCUSSED EARLIER BE INCORPORATED INTO THE REGIONAL PLANNING PROCESS?

A. The Transco planning department will submit the Proposed Expansion Plan to the Partnership RTO Transmission Assessment Working Group ("TAWG") for inclusion in its Regional Planning Process. The TAWG will review all customer-initiated projects for reliability considerations, and they will review all other projects (*i.e.*, mandatory, reliability, and infrastructure) for reliability considerations and appropriateness. The Transco Contingency Plan will also be provided to the RTO for informational purposes.

Q. WHAT ARE THE RESULTS OF THE RTO REGIONAL PLANNING PROCESS?

A. The SPP Partnership RTO Expansion Plan will be developed by incorporating the Transco expansion plan, the Regional Transmission Owners' expansion plans, and alternative solutions proposed by the Partnership RTO TAWG for regional issues.

Q. WHO HAS RESPONSIBILITY FOR DEVELOPING THE NEED FOR REGIONAL SYSTEM FACILITY UPGRADES AND EXPANSIONS?

A. Regional system upgrades will be determined by the Partnership RTO TAWG using the regional planning guidelines. The TAWG has responsibility for assessing the transmission needs of the region and developing the Partnership RTO Expansion Plan.

Q. HOW WILL THE REGIONAL AND TRANSCO PLANNING ACTIVITIES BE COORDINATED?

A To the extent that a facility identified in the Regional Planning Process impacts Transco or the TAWG makes a recommendation to modify a facility in the

Transco Proposed Expansion Plan, the SPP and Transco will work together to perform joint studies when appropriate.

Q. WHY COULD THERE BE MODIFICATIONS TO THE PROPOSED TRANSCO EXPANSION PLAN THAT COULD REQUIRE JOINT STUDIES?

A. While the Transco Proposed Expansion Plan is meant to address "local" concerns on the Transco system, it is recognized that some of those projects may have regional impacts. Therefore, the Partnership RTO TAWG, which studies the regional concerns, may discover that a project proposed by the Transco to solve a local area problem impacts the operation of the regional grid.

Q. WHAT ARE THE POSSIBLE OUTCOMES OF THESE JOINT STUDIES?

A. There are three possible outcomes. The SPP Partnership RTO TAWG could accept the Proposed Transco Expansion Plan as is. The TAWG could propose that Transco exclude or modify some of its projects. There may be a project that the TAWG has deemed beneficial to the region and it is within the Transco's territory. Therefore, the TAWG would include that project in the Partnership RTO Expansion Plan.

Q. WHAT WILL HAPPEN TO THE TRANSCO EXPANSION PLAN IF THE PARTNERSHIP RTO TAWG ACCEPTS IT AS IS?

A. Transco will submit the Expansion Plan to the Board of Directors of Managing Member for approval.

Q. WHAT WILL TRANSCO DO IF THE PARTNERSHIP RTO TAWG PROPOSES TO MODIFY A PROJECT IN THE PROPOSED TRANSCO EXPANSION PLAN?

A. Transco will perform joint studies with the RTO to determine whether such a modification to its Proposed Expansion Plan is appropriate.

Q. HOW WILL TRANSCO REVISE ITS PROPOSED EXPANSION PLAN SHOULD THE PARTNERSHIP RTO TAWG ADD A PROJECT TO THE SUBMITTED TRANSCO EXPANSION PLAN?

A. Transco will submit the project to the Transco Board of Directors for approval or submit the project for bids to interested third parties.

Q. HOW WILL THE PARTNERSHIP RTO EXPANSION PLAN BE IMPLEMENTED?

A. The SPP Partnership RTO Expansion Plan will be implemented by the RTO's transmission owners including the Transco.

Q. HAS THE PLANNING PROCESS OUTLINED IN YOUR TESTIMONY BEEN FINALIZED WITH THE SPP?

A. No. Entergy will work with the SPP to finalize the planning process. Therefore, some of the process details stated in my testimony may change. However, the spirit of the planning process, such as obtaining and incorporating customer input to create an expansion plan that meets the Transco Planning Guidelines, will not change.

V. TRANSMISSION/DISTRIBUTION SPLIT

Q. WHAT FACILITIES CONSTITUTE ENTERGY'S TRANSMISSION AND DISTRIBUTION SYSTEM?

A. The facilities that comprise the Entergy transmission and distribution system include transmission lines, distribution lines, switching stations, and substations.

Q. PLEASE DESCRIBE EACH OF THESE FACILITIES IN MORE DETAIL.

A. A transmission line transports energy from remote generation to local area loads by delivery to substations. Entergy has determined to transfer to the Transco those lines that operate at or above 69 kilovolts ("kV"). Such lines, historically, have been booked to transmission.

A distribution line moves energy from the substation to the load, and Entergy has determined to assign to distribution those lines that operate below

69 kV. Such lines, historically, have been booked to distribution.

A switching station is a facility containing breakers and/or switches used for interconnecting elements of the system, establishing protective zones, directing the flow of energy, or metering.

A substation is a facility, which in addition to switchyard elements, would also contain voltage transformation or voltage regulation equipment.

Q. CAN ANY OF THESE FACILITIES BE DEFINED SOLELY AS TRANSMISSION OR DISTRIBUTION ASSETS?

A. Yes. Transmission assets include equipment and devices that operate at 69kV or higher and function as part of an integrated transmission system to deliver bulk power to transmission customers. Therefore, transmission lines, and the switching stations and substations which serve to interconnect only transmission lines, are transmission facilities.

Similarly, distribution assets include equipment and devices that operate below 69kV or function as part of the distribution delivery system. Therefore, distribution lines, and the switching stations and substations which serve to interconnect only distribution lines, are distribution facilities.

Q. DO FACILITIES EXIST THAT CONTAIN BOTH TRANSMISSION AND DISTRIBUTION ELEMENTS?

A. Yes. Dual-function substations contain transmission elements, (*i.e.*, facilities that operate at or above 69 kV) and also distribution elements (*i.e.*, facilities that operate below 69 kV). Such substations may also contain common-use facilities that support both the transmission and distribution facilities within the station.

Q. WHAT IS THE DIVIDING LINE BETWEEN DISTRIBUTION AND TRANSMISSION SUBSTATION ASSETS IN A DUAL-FUNCTION SUBSTATION?

A. The dividing line between Distribution and Transmission in dual-function substations is defined to be the transmission side of the high-voltage disconnecting device of the distribution transformer.

Q. WHAT IS A COMMON-USE ASSET WITHIN A DUAL-FUNCTION SUBSTATION?

A. Common-use assets within a dual-function substation include land, structures, and equipment used to support both transmission and distribution functions within the substations. Examples of common-use assets include the property, control house, battery set, and ground grid.

Q. WHAT IS THE CRITERION USED IN ASSIGNING COMMON-USE ASSETS IN DUAL-FUNCTION SUBSTATIONS TO A TRANSMISSION OR DISTRIBUTION CLASS OF ASSETS?

A. The major service provided by the substation, as indicated by the number of transmission lines that connect to it, is the criterion used to assign common-use assets.

Q. HOW IS THIS CRITERION APPLIED?

A. Dual-function substations that are connected to three or more transmission lines are considered to be critical to the reliability and control of the interconnected transmission grid. Therefore, common-use assets at these substations are classified as transmission. Dual-function substations connected to only one or two transmission lines serve primarily a distribution function. Therefore, the common-use assets at these substations are classified as distribution.

Q. DO THESE DEFINITIONS AND CRITERIA MEET THE FERC'S REQUIREMENTS FOR SEPARATING TRANSMISSION AND DISTRIBUTION ASSETS FOR RATEMAKING AND ACCOUNTING PURPOSES?

A. Yes.

VI. TRANSMISSION/GENERATION SPLIT

Q. HOW ARE GENERATION AND TRANSMISSION SYSTEMS CONNECTED?

A. Generation and transmission systems are connected via generator leads, generator step-up transformers, and some form of disconnecting device which ties the high-voltage side of the generator step-up transformer to the transmission bus.

Q. WHERE ARE THESE CONNECTIONS USUALLY MADE?

A. Generator step-up transformers are usually tied to the transmission system within generation switchyards.

Q. WHAT TYPES OF ASSETS ARE WITHIN THE GENERATION SWITCHYARD?

A. The three types of assets are Transmission, Generation, and Common-Use.

Q. WHICH OF THESE FACILITIES DOES ENTERGY PROPOSE TO BE INCLUDED AS GENERATION ASSETS?

A. Generation assets are equipment and devices that are integral parts of the generation facility. Notably, these include the generator leads and the generator step-up transformers.

Q. WHAT IS THE DIVIDING LINE BETWEEN GENERATION AND TRANSMISSION ASSETS IN A GENERATION SWITCHYARD?

A. The dividing line between Generation and Transmission is defined to be at the connection to the high-voltage bushing of the generator step-up transformer.

Q. WHAT IS A COMMON-USE ASSET WITHIN A GENERATION SWITCHYARD?

A. Common-use assets within a generation switchyard are equipment, devices, or property whose function is to support both transmission and generation elements. Examples of such common-use assets would include the control house within the switchyard, the battery set which supplies power to operate the circuit breakers within the switchyard to protect the generator step-up transformers, and any communications devices required to connect the switchyard to the transmission control center.

Q. WHO WILL MAINTAIN OWNERSHIP OF THE COMMON-USE ASSETS WITHIN THE GENERATION SWITCHYARD?

A. The Transco will own the common-use assets within the generation switchyard because of their effect on the reliability of the integrated transmission system.

Q. DO THESE DEFINITIONS AND CRITERIA MEET THE FERC'S REQUIREMENTS FOR SEPARATING TRANSMISSION AND GENERATION ASSETS FOR RATEMAKING AND ACCOUNTING

PURPOSES?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF LOUISIANA)
)
PARISH OF ORLEANS)

GEORGE R. BARTLETT, being duly sworn, deposes and states: that the attached are his sworn direct testimony and exhibits and that the statements contained therein are true and correct to the best of his knowledge, information and belief.

George R. Bartlett

George R. Bartlett

SWORN AND SUBSCRIBED BEFORE ME,
this 13th day of October, 2000.

Notary Public

My Commission Expires: upon my death

ENTERGY TRANSMISSION PLANNING GUIDELINES

Revision Date: 9-28-00

I. INTRODUCTION

The criteria defined below are designed to guide planners in their assessment of the staff of the Entergy transmission system and the planning of proposed improvements. The planning criteria exist to satisfy the need for continued reliable economic operation of Entergy's transmission system and to maximize the existing transmission system capacity. Adherence to the recommended criteria will ensure that Entergy's transmission system exhibits the characteristics of a well-planned bulk power system while meeting the local transmission needs of customers. This document is an informational guideline that provides an overview of the fundamental principles used by Entergy's Transmission Planning. It does not provide criteria for which final approval of transmission system improvements are made. The intent is to provide guidelines for identifying potential system problems and evaluation of alternative solutions.

The reliability and adequacy tests, as defined in these criteria, are used to evaluate the performance of the Entergy transmission system. In accordance with the criteria set forth in this document, the Entergy transmission system will be planned applying the most recently adopted reliability criteria of the Southwest Power Pool, the Southeastern Electric Reliability Council, and the North American Electric Reliability Council. Exceptions to these criteria are based on appropriate levels of risk as determined by probabilistic planning methods. Transmission system improvements will be recommended in accordance with appropriate economic evaluation and risk assessment.

II. DEFINITIONS

A. Reliability

The measure of the transmission system's ability to transmit and deliver uninterrupted electric power to customers.

B. Subsystems

There are various subsystems within the Entergy System having natural electrical boundaries. Each subsystem consists of a network of transmission and sub-transmission elements that are interconnected with and comprise a part of Entergy's transmission system. Generally, a subsystem will include a combination of residential, commercial, and industrial loads along with multiple generation sources. Each subsystem will include one or more major load centers whose load is served from several common sources.

Subsystems identified throughout the Entergy System include but are not limited to Texas Western Region, Lake Charles, Baton Rouge, Amite South, New Orleans, North LA, Jackson, North MS, South MS, Little Rock, South AR and North AR.

C. Major Load Centers

Major load centers are areas of dense load that can include large cities and/or significant industrial load. The load mix (residential, commercial, and/or industrial) within a major load center will guide the transmission planner in determining particular operating requirements to serve the load.

Major load centers identified throughout the Entergy System include but are not limited to the following areas: New Orleans, Baton Rouge, Lake Charles, Jackson, Little Rock, Beaumont / Port Arthur, Louisiana Industrial Corridor (north of Little Gypsy and Waterford), and the Woodlands (north of Houston).

D. Major Substations

A major substation is 69kV or greater and has three or more transmission sources. Sources include non-radial transmission lines, autotransformers, and generators.

E. Transmission System

The fundamental purpose of the interconnected transmission system is to move electric power from areas of generation to areas of customer demand (load). The system should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and planned outages, continuously varying customer demands), while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

III. PLANNING PROCESSES AND RESPONSIBILITIES

A. Coordinate Joint Studies

Entergy will facilitate informational meetings with its customers (network service customers, distribution providers, and retail service providers) to achieve mutually acceptable solutions to network problems. Entergy will participate in joint regional and sub-regional studies designed to evaluate the performance of the integrated transmission system.

Long Term Area Planning studies will be performed by Transmission Planning to evaluate the present and future performance of the Entergy transmission system. These include individual studies (load flow, short circuit, stability, transient analysis and transfer capability studies) of sub-systems throughout the Entergy transmission system. The purpose of these studies is to identify system constraints and/or reliability problems and to determine the most cost-effective solutions. One third of the sub-systems will be studied annually on a rotational basis. The scope of these studies includes a ten-year evaluation of the sub-system being studied and provides input for the two-year Expansion Plan and three to seven-year Contingency Plan (Expansion Plan and Contingency Plan).

Customer load/generation studies are independent studies performed in response to proposed load/generation additions. These studies determine the adequacy of an area to accommodate a new load/generation addition. Examples of these additions include a new industrial customer, existing customer expansion or the installation of new generation.

Annually, an Expansion Plan and Contingency Plan are produced as a result of Joint Studies, Long Term Area Planning studies and customer load/generation studies. The plan includes capital projects (recommended solutions) which resolve reliability, load, and generation issues. The first two years are ranked and prioritized according to the ranking process described in this document.

B. Model Updates

1. Load Flow

The software used for load flow analysis is Power System Simulator for Engineering (PSS/E) developed by Power Technologies, Incorporated (PTI). Load flow models will be based on the models developed annually by the VST databank update. A model will be developed for each seasonal definition prescribed by the VST. As the first step of the annual model update, Entergy will submit a list of changes to the VST. These changes are incorporated with changes from neighboring utilities and the updated models are returned to Entergy for review. This process is repeated several times to ensure model accuracy before official release and is usually completed in June.

The data required for the load flow model includes: customer load data, firm transactions, generation dispatch data from customers (network service customers, distribution providers, and retail service providers), and future system improvements from the Expansion and Contingency Plans.

2. Dynamic and Transient Analysis

The models for dynamic and transient analysis are need-based and will be developed depending on the study.

3. Availability of Files

A list of these cases will be made available on OASIS. The cases will be made available upon request for a fee of $100 per case.

VI. TRANSMISSION PLANNING AND ASSESSMENT

A. Philosophy

Entergy Transmission Planning Philosophy is to maintain the integrity of its transmission network while meeting the requirements of its customers. The Philosophy explains and provides direction for the following issues: probabilistic transmission planning, project ranking and prioritization, contingency testing, assessments and criteria.

1. Probabilistic Transmission Planning

The Transmission Planning process has evolved from strictly deterministic to more probabilistic in order to provide the required justification for system improvements while minimizing capital expenditures, accommodating more stringent customer requirements, and providing the flexibility needed to excel in an open market.

The reliability of service to individual load delivery points on the transmission system is a probabilistic measure of the effects of single and multiple outages of generation and transmission components. The effects include voltage violations, component overloads, "islanding" and loss of load. Load loss can occur directly as a result of an outage, or indirectly from load shedding necessitated by overloads and/or voltage conditions resulting from an outage.

Reliability assessment must include historical outage data, customer load information, annual and seasonal load duration curves, frequency and duration of adverse weather conditions, in addition to the actual system data normally considered when making a deterministic evaluation of transmission adequacy. Actual system event data includes: generation scheduling and reliability, transmission line maintenance scheduling, substation configuration, and seasonal ratings of transmission and generation facilities.

Probabilistic Transmission Planning is a method for evaluating the total reliability of service to individual load points on the transmission system by providing data on severity and probability of failure, rather than deterministically focusing on system violations only. The EPRI program TRELSS is a tool that can be used to evaluate transmission reliability. Three major applications of probabilistic transmission planning are:

a. To compare alternative solutions by evaluating reliability indices of the total transmission system and/or individual delivery points.

b. To identify multiple contingency conditions which cause high effect(low probability) situations that might otherwise be overlooked.

c. To perform cost/benefit analysis by computing the expected unserved energy. This is useful in scoring capital projects and determining their ranking for inclusion in the budget.

2. Project Ranking and Prioritization

The process is designed to establish a consolidated ranked list of all Entergy Operations' Transmission projects and programs. Transmission Planning uses a system of prioritization criteria (PC) and a Scoring Methodology to classify and score specific projects and programs. The PC guidelines are composed of four categories (mandatory, high, medium, and low). The Scoring Methodology is used to score all transmission reliability capital projects over $250,000. The Scoring Methodology calculates a score for each project resulting in an objective numerical ranking of the transmission projects. The Scoring Methodology includes Net Cost and MWHs saved. The probability of contingencies and probability of equipment damage are used. The probabilities are calculated from actual historical data. The final ranking is determined through meetings which include Transmission planners, Transmission managers, and the Budget Coordinator. The meetings are organized to evaluate the scores for each project and to modify the initial ranking, as necessary.

a. Capital Project Ranking Process

1. All proposed projects and conceptual needs are submitted using the Project Design and Construction Request (PDCR).

2. The conceptual needs are identified by the Transmission Planners and internal/external customers.

3. All proposed projects originated by the internal customers are to be submitted to the Budget Coordinator in the Technical System Planning group.

4. All projects originated by external customers are submitted to the Transmission Project Development group for study and verification prior to submittal to the Budget Coordinator.

5. The Budget Coordinator will verify all Specific Revenue Projects (Projects >=$250,000).

6. The Transmission Planners score each specific reliability project using the project scoring methodology.

7. The Budget Coordinator initiates a ranking meeting with the Transmission Planners and the Transmission Planning Manager to evaluate the initial scores and to finalize the ranking.

8. The Transmission Operations Director reviews and verifies the consolidated list.

9. The Vice President of the Transmission Organizations reviews and verifies the consolidated list.

10. All new projects submitted after the creation of the consolidated ranked list will follow the above process.

The Budget Coordinator will initiate the ranking meeting with the project sponsor, and the Transmission Planning manager. They will evaluate the project score and decide the ranking of the new project. They will also decide which project, blanket, or program will be delayed/reduced in order to fund the new project. This meeting is usually held quarterly in order to coordinate with the latest present value estimate for the current budget.

B. Contingency Testing

Each subsystem shall be capable of having its load supplied after the occurrence of a more probable contingency. In particular, load that is not directly outaged by the loss of the component(s) must not be affected. Examples of more probable contingencies that should be endured within subsystems without the sustained interruption of load and without any cascading of interruptions include the following:

1. Loss of any one transmission line, transformer, or generator.

2. Loss of any double-circuit transmission line.

3. Coincident but not simultaneous loss of the following pairs of components: any one transmission line and any one generator, any one transmission line and any one autotransformer, any one generator and any one auto transformer, or any two generators.

4. A line-to-ground fault at any terminal and the resultant failure of a circuit breaker to trip.

5. Any multiple contingency that can be classified as “more probable” based on the analysis of the historical outage database using probabilistic planning methodology.

Following an event such as those described above, any equipment and/or facility shall be loaded within its normal rating and all major substation bus voltage levels shall remain within +5% and -8% of the nominal voltage. Other transmission buses shall remain at voltage levels such that regulating equipment can maintain voltage to customer loads within the prescribed service standards. The system shall be capable of being adjusted within 10 minutes after the event so that all equipment and/or facilities will be operating within normal ratings. The normal operating voltage of a bus is determined by the equipment attached to the bus. The normal rating of a facility is defined in D.2.a.1& D.2.b.1 (Loading Guidelines) and/or the established MVA rating of a transmission line.

Less probable contingencies may occur resulting in the interruption of significant load but without the cascading of components that would cause further outages. Examples of these less probable contingencies are:

1. The loss of a complete substation. (all equipment of one voltage level)

2. The loss of an entire generating plant. (A plant is defined to be one or more generating units having in common such things as the same transmission substation, the same control room, the same cable room or cable trays, etc.)

3. The loss of all transmission lines on a common right-of-way.

4. The loss of a generator during abnormal conditions resulting from the previous loss of significant generating capacity.

5. A three-phase fault at any line terminal and the resultant failure of a circuit breaker to trip.

6. Any other credible contingency which might lead to system cascading.

7. Any single or multiple contingency that can be classified as “less probable” based on the analysis of the historical outage database using probabilistic planning methodology.

Stability shall be maintained in a subsystem when the loss of the second system component, as described above, is caused by a three-phase fault at the worst location and the fault is cleared by normal relay and breaker operation. If reclosing is used, it is assumed to be unsuccessful.

C. Assessment

1. Reliability

Reliability will be measured by the systems ability to maintain uninterrupted power to the customers. Energy not served, or frequency and duration of outages, will provide evidence of system reliability.

Energy not served will be assessed by determining load at risk due to voltage and overload problems as defined in this criteria using load flow analysis. Branch outage and bus load data will be used to determine tap load at risk. The sum of these two factors constitutes the total load at risk.

2. Reactive Power Requirements

The most cost-effective solution will be used to solve voltage or reactive power problems on the transmission system. Generally, distribution or transmission capacitor banks are most effective in reducing transmission VAR requirements, line losses, and low voltage. Inductive reactors may be needed in cases of high voltage. Significant VAR production by generators should be avoided under normal operation except for the use of hydro units as synchronous condensers.

Voltage Stability analysis will be used to determine the required margin of dynamic vs. mechanically switched reactive power sources for each subsystem. Area voltage problems are an indicator of a reactive power deficiency.

3. Transfer Capability

Transfer capability is the measure of the ability of 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. The electrical ability of the interconnected transmission networks to reliably transfer electric power may be limited by thermal, voltage, or stability limits.

a. 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 due to thermal expansion. Normal and emergency transmission circuit ratings are defined in the Entergy design standards.

b. Voltage Limits - System voltages must be maintained within the 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 or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent.

c. Stability Limits - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. References to stability are in the NERC Planning Criteria.

d. Contractual Requirements - Some Transmission Providers have contractual agreements regarding the power transfer available between them. These agreements have been approved by the private regulatory agencies.

4. Equipment Adequacy

a. Ampacity

As the system configuration changes, it becomes necessary to assess the ratings of previously installed equipment. Load flow analysis will be used to determine the need for equipment upgrades due to inadequate ampacity. Examples of limiting equipment are: breakers, switches, line traps, lines, bus connectors, current transformerss and terminal risers.

b. Fault Duty

Short circuit studies will be conducted to determine adequacy of equipment fault current interrupting capability. Examples of equipment that can be assessed for fault duty are breakers and circuit switches.

c. Switch Interrupting Capability

As the system configuration changes, it becomes necessary to assess the ratings of switching equipment. These devices will be assessed for their capability to interrupt loop, line charging and full load currents.

D. Criteria

1. Transmission Additions - Minimum Requirements

The operation and planning of the transmission system shall be conducted so as to preclude uncontrolled break-up and collapse of the interconnected electric system due to more probable contingencies. The criteria described below are intended to ensure that additions to the transmission system enhance system security. It is impossible to anticipate and test for all combinations of contingencies. However, application of transmission planning criteria ensures that the most probable and consequential contingencies are addressed.

Severe disturbance involving multiple contingencies may cause a subsystem to become isolated from Entergy's transmission system. Isolation due to transmission limitations may cause voltage deficiencies within the subsystem. Therefore, it is desirable to maintain a transmission system that is not readily susceptible to isolation. In addition, adequate power transfer capability between adjacent subsystems should be maintained to assure reliable, cost-effective operation of the generation and transmission system. Additions to the transmission system should be planned according to the following:

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

b. Adequate transmission capability shall be maintained to provide for intraregional, interregional and transregional power flows under normal and more probable contingency conditions.

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

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

e. Each subsystem shall maintain service continuity after the loss of the most important electric network component (either transmission or generation).

f. Sufficient reactive capacity shall be provided within the Entergy electric system at appropriate places to maintain transmission system voltages within plus 5% or minus 8% of nominal when more probable contingencies occur.

g. Stability shall be maintained between the subsystem and neighboring Utilities during more probable contingencies caused by a three-phase fault at the worst location cleared in normal clearing time according to Entergy's protective system design criteria.

h. A subregion may suffer interruption of load as a result of less probable contingencies; however, such contingencies shall not result in widespread disturbances or collapse of the Entergy electric system.

Proposed projects that meet one or more of the above criteria will be evaluated in accordance with the ranking process.

2. Reliability Improvements

A. Autotransformers

1. Loading Guidelines

Autotransformer loadings shall be allowed to exceed nameplate ratings on a case-by-case basis when analysis shows that adequate variation exists in the equipment's duty cycle. The autotransformers' gas analysis history may be reviewed if its capability is questionable. Daily peak loadings of up to 100% of nameplate rating may be allowed as normal and considered non-harmful to equipment after being confirmed by analysis of duty cycle. Brief loadings of up to 130% may be allowed under emergency conditions if equipment evaluation indicates that such action is acceptable. Thermal dynamics, gas analysis, and duty cycles of equipment may be used as appropriate, in lieu of more costly autotransformer upgrades.

2. Installations and Upgrades

Autotransformers shall normally be sized to provide sufficient capacity to satisfy expected load requirements over time, consistent with the economies of equipment relocation and replacement. Equipment mobility and site access must be considered in the installation of new facilities and upgrades.

Projects that include autotransformer additions should be evaluated to access (a) the advantages of single-phase vs. three-phase units, (b) the need for tertiary windings, no load taps, load tap changers (LTC's), (c) impedance requirements, (d) losses, and (e) voltage coordination.

B. Transmission Lines

Transmission line projects shall be planned so as to maximize transmission system utilization. Transmission additions and modifications that result in the under-utilization of portions of the existing transmission system should be avoided. The overall efficiency of the transmission system is indicated by the ability to load all transmission lines without overloading the most limiting elements. Sufficient flexibility and reliability must exist in the transmission network to maintain an acceptable level of customer service.

1. Loading Guidelines

Transmission line loading under contingency conditions are acceptable up to 100% of normal line rating. In areas known to have employed non-conservative construction techniques resulting in normal line ratings that are marginal at best, line loadings shall be maintained at or below 100% of the normal line rating. As mentioned previously, an evaluation can redefine a line's critical loading level.

2. Installations and Upgrades

Transmission line additions and upgrades shall be designed so as to provide sufficient capacity to satisfy projected transmission growth, consistent with the economic analysis associated with alternative line additions and upgrades. Transmission lines may be upgraded to a higher voltage level to solve voltage or overload problems when economically feasible and consistent with long range transmission system plans. To insure optimal utilization of existing transmission facilities and prudent application of resources, new technologies shall be evaluated as alternatives to traditional system additions and upgrades. Operational solutions to adverse transmission system conditions, such as opening overloaded transmission lines should be considered in lieu of line additions and upgrades. Such solutions must not compromise the reliability of the transmission system, nor violate Transmission Planning Criteria or operational procedures.

3. Transmission Breaker Planning Criteria

Breaker installation projects shall be evaluated for the following conditions:

a. Operations - Equipment configurations requiring complex switching procedures that compromise system protection / security will be added to three terminal stations where they will be relied on for operation of the system.

b. Ratings - Load growth causes a breaker to be underrated (interrupting capability or ampacity).

4. Voltage Control and Reactive Power Requirements

The most cost-effective solution will be used to solve voltage or reactive power problems on the transmission system. Capacitor banks are the most effective means of mitigating transmission VAR requirements, line losses, and voltage problems.

Inductive reactors may be needed in cases of high voltage problems. Significant VAR production by generators should be avoided under normal operation except for the use of hydro units as synchronous condensers. The roles of the various devices in reactive power planning are further defined below.

a. Transmission Customer Power Factor Requirements

Transmission customer shall maintain a power factor of 98% at the transmission delivery point.

b. Transmission Capacitor Banks

Transmission capacitor banks shall be utilized to reduce transmission reactive power flows by compensating for transmission line reactive power losses. A transmission capacitor bank may be utilized to alleviate distribution voltage problems or to meet distribution VAR requirements only in a situation where a distribution capacitor bank is not a viable option.

c. Shunt Inductive Reactors

Transmission shunt inductive reactors shall be utilized when applicable to alleviate high voltage problems on the transmission system either during switching or steady state conditions.

d. Static VAR Systems

A static VAR system may be utilized when appropriate and cost effective to compensate for abrupt variations in VAR requirements due to changing customer loads or other transient conditions.

e. Transmission Lines

Transmission line additions, conversion to a higher voltage, and upgrades are normally utilized to address power flow problems rather than to alleviate voltage or reactive power flow problems. Transmission line additions and modifications, such as conversion to a higher voltage, may be appropriate where the addition of either distribution or transmission capacitor banks is not an option or when capacitor banks do not significantly increase voltage support.

The opening of transmission lines that support the bulk power system is not the preferred method of controlling system voltages, but may be utilized when other voltage control measures are unavailable.

f. Generator Reactive Requirements

Alternative sources of reactive power, such as those described above, shall be installed to minimize system reliance on generators for reactive power production. This practice allows the generators to operate near unity power factor, minimizing the impact of a forced generator outage on the transmission system.

g. Generator Voltage Set Points

Generator voltage set points will be calculated for both seasonal and hourly variations of system load to provide a system voltage profile that remains within the operating guidelines as set forth in this document, under normal and emergency conditions.

h. Interconnected Utilities

Interconnected utilities, including other investor owned utilities, regional electrical cooperatives and municipalities, are expected to supply 100% of their reactive power requirements and maintain voltage control in accordance with Entergy's Transmission Planning Criteria.

5. Load Shedding and Restoration

a. Automatic Load Shedding

A major disturbance on the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage. To minimize the probability of network collapse, the transmission system shall be operated in accordance with the following requirements.

1. Operating Reserve

In the event of a major disturbance, all Entergy operating reserve shall be utilized prior to shedding firm load.

2. Voltage Regulation

During a period of declining frequency, violent swings in real and reactive power flow may occur. For this reason all generator voltage regulators shall be kept in service at all times.

3. 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. Load shedding may be implemented at sub-transmission and distribution voltage levels where the least sensitive load, and the most effective load increments, may be selected.

b. Prompt actuation of the load shedding scheme is vital to its effectiveness. Load shedding schemes shall not rely on manual implementation in response to rapidly declining frequency. Response to such conditions shall be actuated automatically by underfrequency relays, which are required to be in service at all times. Underfrequency relays should not be installed on transmission interconnections. However, it is necessary and has been mutually agreeable, that underfrequency relays installed at transmission interconnections should be non-directional.

c. Underfrequency relays shall be set in accordance with accepted industry practice to shed load in three steps, at 0.3 to 0.5 Hz intervals. Under voltage load shedding shall be implemented so as to maintain the transmission system and tie lines intact in the event of a major disturbance.

d. In the event of a major disturbance during which the frequency continues to decline, after load shedding occurs, the following operational actions may be implemented to protect generating machinery from mechanical damage: 1) open tie-lines, 2) remove generating units from service/system 3) automatic islanding with enough load left on a machine or plant to keep it in operation. These actions should be implemented if frequency declines to 58.5 Hz.

4. Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated as follows:

Frequency (Hz)	**Load Relief (%)**
59.3	**10**
59.0	**10**
58.7	**10**

b. The relays used to accomplish load shedding shall be set with no external intentional time delay devices employed. An exception to this policy would be on circuits serving considerable motor load (such as an 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. The tripping of any generating unit by under-frequency delays 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 the interconnected systems shall be protected 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.

d. 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 it should the voltage rise to intolerable levels.

b. 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.

6. Power Quality Issues

a. Voltage Flicker

Loads that could potentially contribute to voltage flicker on the transmission or distribution system (arc furnaces, some motor loads, etc.) shall be cited such that adequate fault current is available to maintain acceptable voltage flicker levels at the point of common coupling between the customer and Entergy. Voltage flicker levels are unacceptable, and constitute a violation, if either of the following conditions exist: (a) the cumulative RMS voltage flicker at the point of common coupling exceeds 0.30% for 1.0% of a representative time period, or (b) the instantaneous voltage flicker regularly exceeds 0.45% at the point of common coupling (this is approximately equal to a cumulative RMS voltage flicker of 0.45% for 0.01% of a representative time period). In circumstances where limited options exist in the citing of potentially objectionable loads, corrective equipment to alleviate voltage flicker problems must be installed with the party responsible for the drop in power quality bearing the cost of the corrective equipment.

b. Harmonic Distortion

Appropriate equipment shall be installed such that harmonic content of the voltage waveform at the point of common coupling with the utility source will be maintained in accordance with IEEE standard 519-1992. The cost of such equipment shall be borne by the owner of the source of harmonic distortion.

c. Motor Starts

Voltage regulation at the transmission delivery point during infrequent motor starts will not exceed 2.5%.

d. Voltage Variations During Switching

The magnitude of the steady-state transmission voltage during the switching of transmission lines, transformers, capacitors, or other devices shall not vary by more than 5%.

Adequate equipment shall be installed such that transient voltage variations during switching operations are maintained within equipment limits as prescribed by insulation coordination guidelines.

7. Load At Risk

Area load that must be shed to satisfy minimum planning system criteria as defined in this guide are not to exceed 100% of area load.