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SUBJECT: Entergy services final readiness audit report

ACTION: Information

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From: "Richard Schneider" <Richard.Schneider@nerc.net>
To: <jcase@entergy.com>
Date: Wed, Jul 21, 2004 2:41 PM
Subject: Entergy Services Final Readiness Audit Report

To: Mr. James Case

Dear Mr. Case:

Please find attached a letter and report regarding the final Entergy Services control area readiness audit. Contact

me if you have any questions.

Sincerely,
Richard Schneider
Compliance Assessment Engineer
North American Electric Reliability Council
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Mark E. Fidrych, OC Chair

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Jim Dodge, Audit Team Member

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

July 21, 2004

Mr. James Case
Entergy Services Inc.
5201 West Barraque Street
Pine Bluff, Arkansas 71602

Dear Mr. Case:

Entergy Services Final Readiness Audit Report

Enclosed please find a copy of the audit team's final report for the Entergy Services Control Area readiness audit completed on May 13, 2004. In that report are the findings and recommendations that were developed as a result of the audit. This report will be posted on the NERC website, http://www.nerc.com/~rap/audits.html, in accordance with the Certification and Compliance Committee (CCC) procedure.

That procedure states:

> *The final audit report will be posted to the NERC website. Should there be a disagreement regarding the findings and recommendations, the control area may provide a statement in writing to be posted in conjunction with final audit report.*
>
> *Should the control area seek adjudication of the dispute through the dispute resolution process, they shall notify NERC within thirty days from the time the audit is posted and transmitted to the control area.*

The audit report includes several recommendations from the audit team. The final procedures for tracking the implementation of these recommendations is being developed by the CCC, however, it is expected that the regions, working with NERC will monitor the implementation.

Once again I would like to thank you and your staff for all of your support during this audit and would welcome any suggestions you may have to improve the audit process.

Sincerely,

David W. Hilt

David W. Hilt
Vice President–Compliance

Attachment

cc: Robert K. Harbour, CCC Chair
Mark E. Fidrych, OC Chair
William F. Reinke, SERC Regional Manager
Dick Worthen, SERC Regional Compliance Manager
Wayne Leonard, Entergy Chief Executive Office
Jim Dodge, Audit Team Member
Larry Akens, Audit Team Member
Nathan Brown, Audit Team Member
Kim York, Audit Team Member
Bill Comish, Audit Team Member
Richard Mabry, Audit Team Member
Frank Macedo, Audit Team Member

Control Area Readiness Audit Report

Entergy
May 12–13, 2004
Pine Bluff, Arkansas

North American Electric Reliability Council

Table of Contents

Introduction and Audit Process 3
Entergy Participants 4
Auditors 4
Preface 5
Executive Summary 5
Positive Observations 6
Areas for Improvement 6
On-site Review Notes 8
1. Criteria and Compliance 9
   1.1. Agreements 9
   1.2. Staff Certification 9
   1.3. Security 9
   1.4. Training 10
2. Authority 12
3. Responsibilities in the Planning Time Frame 12
4. Real Time Monitoring 14
   4.1. General 14
   4.2. Alarms 15
   4.3. Plans for the loss of Control Facilities 15
   4.4. Monitoring Responsibilities 16
   4.5. Frequency Monitoring 16
   4.6. Voltage Monitoring 17
   4.7. Reactive Reserve 18
   4.8. Critical Facility Monitoring 18
   4.9. Transmission System Congestion 18
   4.10. Load Generation Balance 19
   4.11. Contingency Reserves 20
   4.12. Special Protection Systems 20
5. System Restoration 20
6. Delegation of Reliability Authority Functions 21
7. Outage Coordination 21
8. Transmission and Generation Relaying 21
9. Capacity and Energy Emergency Plan 22
10. Operating Policy/Procedure Changes 23
11. Vegetation Management (Line Clearances) 24
12. Nuclear Power Plant Requirements 24
Conclusions 25

Introduction and Audit Process

In response to the August 14, 2003, blackout, on February 10, 2004, the NERC Board of Trustees committed to take immediate actions to strengthen the reliability of the North American bulk electric system. Specifically, the board adopted the recommendations of the NERC Steering Group that investigated the August 14, 2003, blackout. These recommendations included:

- A list of specific actions to correct the deficiencies that led to the August 14 blackout;
- Near-term strategic initiatives by NERC and its regional reliability councils to strengthen compliance with existing standards and to formally track completion of recommended actions from August 14 and other significant power system events; and
- Longer-term technical initiatives to prevent or mitigate the impacts of future cascading blackouts.

NERC tasked the readiness audit team with assessing the degree to which the control area meets its responsibilities that are defined as:

> "The control area authority is responsible for the safe and reliable operation of their portion of the bulk electric system in cooperation with neighboring control areas and their reliability coordinator."

The audit process includes:

- A self-assessment questionnaire for the control area being audited
- Questionnaires for neighboring control areas
- A questionnaire to the reliability coordinator
- A two-day on-site audit by a selected audit team

Pre-audit information (responses to the self-assessment questionnaire, a set of questions and guidelines to assist the audit team in the on-site audit, and copies of some of the documentation provided by the control area being audited) was sent to the audit team to assist them in their readiness evaluation. The team met prior to the on-site visit to complete necessary preparations for the audit. This preparation included discussing and reviewing interview assignments, the audit process, interview questions, and questionnaire responses.

Entergy Participants

Manager, Transmission System Security
Manager, Transmission Business Operations
Manager, Reliability Coordination
Manager, Operations Support
Manager, Entergy Management Operations
Manager, Transmission Operational Planning
Supervisor, Transmission Operational Planning
Supervisor, Transmission Planning & Compliance
Supervisor, Transmission System Security
Supervisor, EMS Hardware
Policy Consultant, Transmission Policy
Senior Analyst
Engineer II, Operational Planning
Senior System Operator
Senior System Operator

Auditors

James Dodge, J. M. Dodge Consulting, Inc. (NERC Co-lead)
Larry Akens, Manager Operations Analysis, Tennessee Valley Authority (SERC Co-lead)
Richard Mabry, FERC
Frank Macedo, FERC
Nathan Brown, Director Transmission Planning, South Mississippi Electric Power Association (SERC)
Kim York, Lead System Coordinator, Duke Energy (SERC)
William Reinke, SERC-Executive Director (non-voting participant from SERC)
Bill Comish, Western Electricity Coordinating Council (WECC)

Preface

The North American Electric Reliability Council (NERC) has prepared this report. The report represents a review of the readiness of Entergy to meet its responsibilities as a control area and contains recommendations for follow-up action. It is the responsibility of Entergy to address these areas for improvement and to operate its system in a reliable manner.

Executive Summary

Entergy is comprised of five operating companies that serve customer load in central and eastern Arkansas, western Mississippi, north and south Louisiana and southeast Texas.

The Entergy System Operations Center (SOC) is located in Pine Bluff, Arkansas and the Energy Management Organization (EMO) operating facility is located in Woodlands, Texas. There are five Entergy Transmission Operating Centers (TOCs).

Entergy is a member of the Southeastern Electric Reliability Council (SERC) region of NERC.

Entergy is the reliability coordinator for its reliability area, which includes the Entergy control area. Entergy does have sufficient NERC-certified system operators. The SOC's operating shift is comprised of six to seven NERC-certified system operators and the EMO's operating shift is comprised of two NERC-certified system operators. The system operators do have the authority to shed load.

Both the Entergy SOC and EMO primary and backup facilities have secured access systems. The Entergy EMO has a Cyber Security Policy. Entergy does have a fully documented Cyber Security Policy, although not all areas of the policy have been implemented. Both the SOC and EMO have policies and practices in place to address both physical security and data security.

Both the Entergy SOC and EMO utilize on-the-job-training (OJT) to train new hires. A check-off list is utilized to monitor training progress. In addition, two computer based training programs are also utilized for system operator training. Entergy does provide additional training to its system operators in the areas of system restoration, backup facility startup and operations.

Entergy's planning time frame includes long-term, short-term and day-ahead. Entergy utilizes the following tools for its planning processes: Power Technology, Inc. (PTI) Power System Simulator for Engineers (PSS/E), PTI Managing and Utilizing System Transmission (MUST), Power World (load flow simulations) software and System Data Exchange (SDX). The planners also indicated that they use internal outage coordination software: Transmission Automatic Outage Request System (TAORS) to coordinate transmission outages and Station (SWMS) and Line (LWMS) Work Management Systems for maintenance tracking. The Transmission Operational Planning (TOP) group provides operational planning data to the SOC operations duty chiefs. Entergy SOC operates specific load centers to be able to withstand N-2 contingencies (simultaneous loss of largest generator and most heavily loaded transmission facility within the load center).

The Entergy SOC does have redundant computer/servers and power supplies, an uninterruptible power supply (UPS), a backup generator and redundant phone communications systems. The Entergy EMO has a UPS and a backup generator. Both the SOC and EMO have interim and backup facilities. Entergy uses an AREVA (ESCA) Energy Management System (EMS) for generation and load balance along with a state estimator for contingency analysis.

Entergy does have a System Restoration Plan, a Capacity and Energy Emergency Plan and a Vegetation Management Program.

Entergy's TOP conducts planning studies to demonstrate the adequacy of its transmission system for offsite power to its nuclear power plants following a unit trip and a simultaneous transmission outage. These are offsite power studies that are performed to meet Nuclear Regulatory Commission (NRC) requirements.

The audit team would like to acknowledge Entergy where it exemplifies its commitment to system reliability and the audit team would also like to recommend areas for improvement as indicated in the respective "positive observations" and "areas for improvement" sections below.

Positive Observations

The audit team commends Entergy on its system operator's work schedule that includes a dedicated training week in each six-week shift rotation.

The audit team commends Entergy for its implementation of a real-time analysis system operator shift position to assess system conditions (looking ahead) and to develop remedial plans as appropriate.

The audit team commends Entergy for implementing custom EMS displays for the reliability coordinator to monitor post contingency loading of critical facilities using Line Outage Distribution Factors (LODF).

The audit team commends Entergy for providing the system operator with contingency analysis using LODF in addition to the state estimator.

The audit team commends Entergy for providing the system operator with large monitors for wide-screen views.

The audit team commends Entergy for providing the system operators with virtual recording charts. The audit team commends Entergy for its plans to implement a real-time voltage stability analysis capability on its EMS and for its policy for maintaining dynamic reactive reserves.

The audit team commends Entergy for its proactive attention to maintenance.

The audit team commends Entergy for its utilization of N-2 criteria (loss of largest generator and simultaneous loss of most heavily loaded transmission facility) for major load centers.

Areas for Improvement

The numbered list below does not indicate priority.

1. The audit team recommends that Entergy SOC develop a backup facility EMS that is fully independent from the primary EMS.

2. The audit team recommends that Entergy ensures the system operator's authority to shed load is consistently communicated to appropriate entities within Entergy and that the EMO's authority to shed load be clarified.

3. The audit team recommends that Entergy document its procedure for the loss of communications.

4. The audit team recommends that Entergy coordinate with local and state authorities to obtain credentials for its operating personnel. This will facilitate travel to Entergy's main backup facility and the interim backup facility during emergencies that may result in road closures or roadblocks.

5. The audit team recommends that both the Entergy SOC and EMO implement more enhanced formalized training programs and processes.

6. The audit team believes that Entergy EMO could benefit from a dedicated training facility and recommends that Entergy consider establishing such a facility.

7. The audit team recommends that Entergy develop and implement a program to test the reactive capability of generating plants.

8. The audit team recommends that Entergy review its EMS alarming capabilities to ensure that failures of EMS critical elements or functions are known to the system operator.

9. The audit team recommends that Entergy ensure its primary frequency source for its ACE calculation is inside the control area.

10. The audit team recommends that training, process and procedure documentation (similar to that provided for audit review) have dates and approval signatures.

11. The audit team recommends that Entergy Generation develop and implement a generator relay maintenance and testing program for Entergy owned generators.

12. The audit team recommends that Entergy include within its real-time monitoring capabilities the ability to identify and notify the nuclear power plant operator when its transmission system voltage is not adequate to supply offsite power following a unit trip and loss of a critical transmission facility.

13. The audit team recommends that Entergy continue with its future plans:
    - Develop real-time EMS voltage stability studies
        - Increase the wide-area view — to obtain additional external data.
    - Develop a SCADA Management Platform to share telemetered data among multiple locations.
    - Complete the work in progress on the implementation of the SOC Cyber Security Policy.
    - Complete the work in progress to implement time synchronization of all its digital fault recorders (DFRs).

On-site Review Notes

The Entergy system consists of five operating companies:

- Entergy Arkansas, Inc.
- Entergy Gulf States, Inc.
- Entergy Louisiana, Inc.
- Entergy Mississippi, Inc.
- Entergy New Orleans, Inc.

Entergy is interconnected with 15 neighboring control areas.

Entergy management presented an overview of its system operations. Entergy's control area is operated from the SOC but certain responsibilities are shared with or delegated to the five transmission operations centers (TOC) and the Energy Management Organization group (EMO). At the SOC, each operating shift has six to seven system operators in the SOC working a six-week rotation. One week of that rotation is dedicated to training. The reliability coordinator is also the shift supervisor and is responsible for assigning the on-shift operating positions of the system operators. Although Entergy has a general policy, which allows operators to rotate through and learn the different positions, the shift supervisor makes the final determination on desk assignments for his or her shift. Entergy has the following operating positions at the SOC: two Scheduling positions (to handle tagging and schedule requests), a Generation Imbalance Agreement position (to monitor independent power producers (IPPs) and qualifying facilities (QFs)), a real-time analysis (RTA) position (to look ahead and run contingency analysis), two transmission dispatcher positions and the reliability coordinator position. The SOC also has a duty chief who is responsible for next-day to next-week planning.

The TOCs receive switching orders and approvals from the SOC and the TOCs are first responders for system voltage control with oversight by the SOC. Operating orders and approval for transmission switching are given by the SOC transmission operators. The five Entergy TOCs and their areas of responsibility are:

- Gretna — New Orleans area
- Jackson — Mississippi portion of Entergy system
- Little Rock — Arkansas portion of the Entergy system
- Beaumont — the Texas portion and the southwest Louisiana portion of the Entergy system
- West Monroe — Northern Louisiana portion of the Entergy system

The Entergy EMO control center has two system operators for each shift position. Responsibilities include: load forecasting, CPS1, CPS2, DCS and operating reserve monitoring. Refer to the table on the next page for areas of responsibility for the SOC, EMO and TOC.

EMO	SOC	TOC
Generation/load balance	OASIS	Voltage
Frequency	Tagging	Switching
ACE	Security — Real-time analysis	Outage planning
CPS1, CPS2 management	Reliability Coordinator	
DCS Load forecast Reserves	Monitoring System generation, frequency and voltage Outage approval	
	Report Compliance with NERC Operating Templates for the Entergy Control Area	

1. Criteria and Compliance

1.1. Agreements

The control area must have agreements that establish their authority as a control area. The control area must have agreements that establish the reliability coordinator for its control area.

Audit Notes:
Entergy is a member of the Southeastern Electric Reliability Council (SERC). Entergy is its own reliability coordinator. The audit team reviewed the following documents: SERC Compliance Review, SERC Security Coordinator Plan with Entergy and a document related to Entergy becoming a member of SERC.

	Applicable Documents	Dated	Version
1	Document to Mr. Ponsetti and Mr. Ables re:on-site review SERC compliance review.	2-27-98	-
2	SERC document re: SERC Security Coordinator Plan with Entergy	12-10-97	-
3	Letter to SERC and Entergy Preliminary Review of Entergy Subregion Security Plan	12-23-97	-

1.2. Staff Certification

Control area operators must be NERC operator certified. The control area must have sufficient NERC operator certified staff for continuous coverage of the control area operating positions.

Audit Notes:
The Entergy SOC has 59 people that are NERC-certified system operators, 33 system operators (scheduling operators and transmission operators), eight security coordinators and three security superintendents, as well as 15 management and engineering support personnel. Entergy has one operator whose certification has expired and who is planning on becoming re-certified in May 2004. Until this operator becomes re-certified, he is working under the direct supervision of a NERC-certified operator.

The Entergy EMO has 11 system dispatchers who are NERC-certified system operators.

Entergy does not require NERC certification for its TOC operating personnel.

	Applicable Documents	Dated	Version
1	List of SOC operators with certification dates, date Certified and Expiration dates	-	-
2	EMO Copies of NERC Certification documents (11)	-	-
3	SOC personnel list with certification dates, date Certified and Expiration dates	-	-
4	Entergy SOC System Operator Schedule--three year schedule	-	-

1.3. Security

Access to the control room must be controlled for security reasons.

Audit Notes:
The Entergy SOC primary facility has a security fence installed around the building perimeter. Access to the SOC site is controlled, through an electronic gate, by a receptionist during the day and by the system operator after hours. Surveillance cameras monitor the electronic gate and other areas around the facility and are viewed by system operators located within the control room. Building access and access to locations within the facility is controlled by electronic key cards. Access to the server room is also key card controlled and is limited to authorized personnel only.

The Entergy SOC backup facility is located at one of the TOCs, and uses key/locks to secure the site. Entergy is currently in the process of installing electronic key card access.

Access to Entergy EMO's primary facility is controlled by key cards. There is controlled access to the building facility; a separate key card code is needed to access the operating floor. Access to the server room is key card controlled and limited to authorized personnel only. The EMO backup facility access is also key card controlled

The Entergy EMO has a Cyber Security Policy document. The SOC also has a physical access policy and is under the Cyber Security Policy of the Entergy Corporation. Not all aspects of Entergy's Cyber Security Policy have been implemented at this time. The audit team recommends that Entergy continue with its plan to complete the work in progress on the implementation of the SOC Cyber Security Policy (Recommendation 13).

	Applicable Documents	Dated	Version
1	Entergy, EMO IT Security Management	8-28-2003	1.0

1.4. Training

The control area operators must be adequately and effectively trained to perform their roles and responsibilities. The control area must have documents that outline the training plans for the control area operators. The control area must have training records and individual staff training records available for review.

Audit Notes:
Entergy demonstrated that it is committed to system operator training by implementing a work schedule that includes a dedicated training week in each six-week shift rotation. This schedule allows for up to eight training weeks per year for each system operator. The audit team commends Entergy on its system operator's work schedule that includes a dedicated training week in each six-week shift rotation.

Entergy management stated that the initial SOC system operator training program consists primarily of OJT under an assigned NERC-certified system operator. The EMO is revamping its training program. New operator's training will start with the next-day planning group; migrate to the real-time operations (marketing); gas and/or operations planning and then finally to the hourly marketing desk. A NERC-certified system operator supervises the new operator on those desks where NERC certification is required. The EMO also uses a Computer Based Training (CBT) program for system dispatcher training. This program consists of training modules related to power systems operations and includes a test at the end of each module. The EMO uses a Training Application Program (TAP) to record training records. The SOC plans to implement a CBT program this summer.

Entergy stated that both the SOC and EMO use a check-off list and observation to determine when a system operator is sufficiently trained to take over an independent position. At the SOC, a trainer/shift performs the observation. At the EMO, a senior operator signs off on the check-off list. The EMO referred to its check-off list as a qualification guide.

Entergy stated that all operating shifts undergo training for the SOC backup facility twice per year. The training simulates an evacuation from the primary facility at Pine Bluff but not loss of primary EMS capability. Training for the EMO is done once per quarter each for both the interim and the main backup facility.

Entergy's SOC trains its system operators on system restoration. The system restoration training consists of a blackstart drill scenario that the SOC and TOC system operators practice. The drill includes communications that would take place during an actual blackstart event. Entergy's EMO training for system restoration is a self-study computer based training program.

Entergy utilizes several web-based training programs to train its system operators for low voltage conditions. Entergy's Transmission Operations Planning (TOP) group provides training to the SOC system operators and is also developing a Dispatcher Training Simulator (DTS) that will include voltage scenarios.

Entergy management stated that both the SOC and EMO will meet the NERC board recommendation No.6 for the required five training days (40 hours for each certified operator) for emergency operation.

The audit team recommends that that both the Entergy SOC and EMO implement more enhanced formalized training programs and processes (Recommendation 5). The audit team believes that Entergy EMO could benefit from a dedicated training facility and recommends that Entergy consider establishing such a facility (Recommendation 6).

The audit team viewed various training documents and reviewed the capabilities of the computer based training program developed by System Operations Success, Intl.

The audit team recommends that training, process and procedure documentation, (similar to that provided for audit review) have dates and approval signatures (Recommendation 10).

	Applicable Documents	Dated	Version
1	SOC, Black start training for LPLN, GSU, with Signatures by the individuals receiving the training, with dates.	-	-
2	SOC, Auto load shed programs, with signatures by the individuals receiving the training with dates.	-	-
3	SOC, NERC/DOE Reporting, with signatures by the individuals receiving the training, with dates.	-	-
4	SOC and EMO, Spreadsheet summarizing the training hours with applicable topics that will meet the 40hour requirement for operators	-	-
5	Flow chart process to test knowledge of appropriate procedures to use for loss of critical facilities	-	-
6	EMO, System CPS2 Planning Guide 1.3	2-27-04	-
7	EMO, Qualification Guides for Hourly Marketer, Generation Dispatcher	-	-
8	EMO, Emergency Evacuation Procedure 2.7	10-3-03	-

2. Authority

The control area is responsible for establishing and authorizing the control area operator position that will have the on-shift responsibility for the safe and reliable operation of their portion of the bulk electric system in cooperation with neighboring control areas and its reliability coordinator.

Audit Notes:
Entergy indicated that its SOC system operators and transmission system operators do have the authority to shed load. This authority is included in transmission system operator job description. There is also a letter of authority to the system operators, signed by the vice-president of transmission, giving authority to shed load. It was determined by the audit team that this letter is not distributed to Entergy's TOCs. The Entergy EMO system dispatcher job description includes the authority to shed load but there is no letter from Entergy upper management to support this.

All orders for load shedding are directed by the SOC system operators to the TOCs, who direct the various distribution companies accordingly. The audit team recommends that Entergy ensures the system operator's authority to shed load is consistently communicated to appropriate entities within Entergy and that the EMO's authority to shed load be clarified (Recommendation 2).

	Applicable Documents	Dated	Version
1	SOC, Transmission System Operator Job Description	4-23-04	-
2	Letter of authority to System Operators, signed by John Zemanek, Vice President Transmission	4-20-04	-
3	EMO System Dispatcher Job Description	-	-

3. Responsibilities in the Planning Time Frame

The control area must have a process for day-ahead planning, as well as a process for longer-term planning, such as week-ahead, year-ahead etc. for the operation and outage scheduling of transmission facilities and generation and reactive resources.

The control area must have agreements with its reliability coordinator to ensure that day-ahead and longer term plans for the operation and outage scheduling of transmission facilities, generation and reactive resources, will not result in unacceptable bulk electrical system reliability.

Audit Notes:
The following time frames constitute Entergy's planning operating time frame:

- Long-term planning is 21 days to 18 months.
- Short-term planning is seven to 21 days. The planning process builds six weeks of outage data on a rolling basis for zero to 21 days. Near emergency or emergency outages within zero to seven days are accommodated according to the following criteria: P1, within 24 hours and P2 is within seven days. (P1 and P2 are names given to the planning studies.)
- Day-ahead planning is covered in the zero to seven day, short-term time frame.

Entergy's planners use the following tools for their planning process: PTI PSS/E and MUST, Power World (graphical-based load flow simulation) software and SDX. The planners also use internal outage coordination software, Transmission Automated Outage Request System (TAORS) to coordinate transmission outages and Station (SWMS) and Line (LWMS) Work Management Systems for maintenance tracking. The system encourages and accommodates requestor's early outage requests up to 18 months in advance.

Entergy stated that its TOP group provides the operational plans to the SOC duty chiefs. The duty chiefs review and follow the plans but can cancel outages if necessary. Entergy indicated that the TOP group starts with the five year schedule of nuclear unit refueling dates and works backwards from there to develop the operational plans. The SOC works with the EMO for day-ahead planning and up to 18 months ahead for generation planning.

The TOP group and the RTA desk perform reliability analysis studies. Operating security limits are established by the engineering analysis of thermal, stability and voltage limits.

Entergy stated that its control area voltage is established by internal guidelines that set a minimum voltage level. Entergy TOP group also carries out voltage stability studies to determine critical voltages and minimum reactive reserve margins. Entergy has historically operated with 1.0 per unit for off-peak load seasons and 1.02 per unit for on peak load seasons. Entergy's generator interconnection agreement includes voltage schedules.

Entergy's planning and operating requirements for reactive reserves are determined by the TOP group and are based on meeting the N-2 criteria in major load centers. Must-run generation criteria and distribution of operating reserves in the major load centers are two direct results of Entergy's N-2 planning requirement in these areas. Entergy stated that the EMO in conjunction with the SPP Reserve Sharing Group develops operating reserve requirements and is responsible for the distribution of operating reserves. Almost all of Entergy's operating reserves are spinning and Entergy stated that it does have some purchase agreements that can provide secondary reserves, if necessary. The audit team commends Entergy for its utilization of N-2 criteria (loss of largest generator and simultaneous loss of most heavily loaded transmission facility) for major load centers.

Entergy's planners described the Substation Work Management System (SWMS) and Line Work Management System (LWMS) that provide maintenance tracking for asset preservation. They also described the use of the EMS information storage and retrieval system to highlight the need for preventive maintenance (e.g., identifying breakers that have not been cycled within a specified period of time). The audit team commends Entergy for its proactive attention to maintenance.

Entergy's EMO handles the generation outage plan, which is provided by EMO to the TOP group. This plan is evaluated to verify adequate reactive reserves in load centers. Each year, the EMO conducts two outage-planning workshops with generation and transmission participants to coordinate outage plans for the next 18-month period. The TOP group identifies remedial plans, including must-run generation, and communicates them to the Entergy SOC.

Entergy indicated that the following criterion is used as a basis for its system studies; perform N-1 analysis adhering to 100% ratings of facilities. In off-peak times, Entergy will consider higher ratings based on ambient conditions. The Entergy system voltage is monitored based on a minimum post contingency voltage of 0.92 per unit of nominal. Entergy also monitors specific load centers on an N-2 contingency basis.

Entergy validates its studies using real-time system analysis to compare the TOP group model results to the state estimator results. The RTA desk carries out next-hour assessments and approves/denies outages, as appropriate. The audit team commends Entergy for its implementation of a real-time analysis system operator shift position to assess system conditions (looking ahead) and to develop remedial plans as appropriate.

Planning study information is disseminated, as needed, through verbal communications with the SOC duty chief. Also, operators and the TOP group have daily meetings to inform operators of the next-day outages and to provide reports of outages requested for the next week.

Entergy stated that it has notified asset preservation (AP) of the need to perform inspections prior to the summer season to ensure that all critical facilities are made available for peak load periods.

Entergy provided the following documentation for audit team review: transmission operation planning, process documentation.

	Applicable Documents	Dated	Version
1	Available Flowgate Capability (AFC)	4-22-04	0.0
2	Daily Model Development	-	-
3	Daily Import/Export/Line Outage Distribution Factor (LODF) Calculation and Posting process	-	-
4	Daily and Monthly Base Case Development Process	-	-
5	Development of Operating Guides	-	-
6	Dynamic Line Rating Documentation	-	-
7	Internal and External Outage Coordination	-	-
8	Long Term Outage Coordination	-	-
9	Next Day System Studies	-	-
10	SDX Outage Data from Neighboring Control Areas	-	-
11	Short Term outage Coordination	-	-
12	Voltage Stability Study Process	-	-
13	VST/VAST (VACAR, AEP, Southern and TVA Entergy) Study Group Coordination (VACAR, Southern, TVA and Entergy)	-	-
14	Transmission Automated Outage Request System (TAORS)	-	-
15	FERC 715 Form	3-30-04	-
16	Capital Budget 2004 Presentation document	4-21-04	-
17	Entergy Facility Connection Requirements	1-13-02	-

4. Real Time Monitoring

4.1. General

The control area must provide the control area operators with effective, reliable computer and communication facilities for data and status monitoring, and voice communication at both the primary and the backup control facilities.

Audit Notes:

Entergy indicated that the SOC has dual distribution feeds into the primary facility and the servers are fed by different electrical feeds. The primary facility does have a UPS and a backup generator. Entergy EMO also indicated that the EMO facility has a UPS and a backup generator. Entergy indicated that its TOCs have backup generators.

Entergy indicated both the SOC and EMO facilities have redundant computers/servers and communication circuits. Phone systems are both digital and analog. Entergy utilizes a help request management (HRM) process for maintenance call-out procedures in the event of a communications problem. Training has been provided to the system operators for a loss of communications systems; however, there is no documented procedure for use by the system operator. The audit team recommends that Entergy document its procedure for the loss of communications (Recommendation 3).

Management indicated that most of the SOC telemetered data comes from the TOCs and not directly from the RTUs. Therefore, if a TOC goes down, the SOC will lose some data. Entergy indicated that it is currently developing a SCADA management platform (SMP) that will allow telemetered data to be shared among all TOCs, so the TOCs and SOC will not lose data during a communications failure. The project is scheduled to be completed by the end of 2005. The audit team recommends that Entergy follow-up with the timely completion of its SCADA management platform development to share telemetered data among multiple locations (Recommendation 13).

4.2. Alarms

The control area operator must have effective and reliable alarming capability. This should be supported in the control area's Energy Management System (EMS) and/or Supervisory Control And Data Acquisition (SCADA) system by alarm priority.

Audit Notes:
Entergy indicated that the SOC, EMO and TOCs EMSs have alarm systems with prioritized alarms. It was determined by the audit team that the system operator would benefit by having an alarm to indicate the failure of EMS critical elements or functions (e.g., AGC profile stops updating). The audit team recommends that Entergy review its EMS alarming capabilities to ensure that failures of EMS critical elements or functions are known to the system operator (Recommendation 8).

4.3. Plans for the loss of Control Facilities

The control area must have a workable plan to continue to perform the control area functions that are required to maintain a reliable bulk electrical system following the sudden catastrophic loss of its primary control facility.

The control area must have a workable plan to continue to perform the control area functions that are required to maintain a reliable bulk electrical system following the partial or full failure of its computer facilities or monitoring tools at the primary control facility.

Audit Notes:
Entergy indicated that both the SOC and EMO have separate interim facilities and backup facilities in case either primary facility is lost. The SOC backup facilities are fully functional, provided that the SOC primary facility EMS and other application servers are operational. If the SOC EMS and application servers are unavailable then operations performed at the SOC backup facility will be severely limited. The audit team recommends that Entergy SOC develop a backup facility EMS that is fully independent from the primary EMS (Recommendation 1). Except for the SPP reserve sharing function, the EMO backup facility will be fully functional if the EMO Generation Management System (GMS) is lost.

While the Entergy reliability coordinator is traveling to the SOC main backup facility, the Entergy reliability coordinator functions can be transferred to the Southern Company reliability coordinator. The Entergy SOC would transfer system control to the individual TOCs until the system operators arrive at the SOC backup facility, located two and a half hours away. The audit team recommends that Entergy coordinate with local and state authorities to obtain credentials for its operating personnel. This will facilitate travel to Entergy's main backup facility and the interim backup facility during emergencies that may result in road closures or road-blocks (Recommendation 4).

4.4. Monitoring Responsibilities

The control area operators must monitor operating data and status in real-time operation, including:

- Multiple frequency monitoring
- Multiple voltage monitoring
- Facility monitoring
- Transmission system congestion
- Load generation balance
- Contingency reserves
- Special protection systems
- Load tap changing (LTC) settings
- Status of rotating and static reactive resources

Audit Notes:
Entergy utilizes an ESCA EMS system and a dynamic overview map board. Entergy's state estimator observes about 3400 buses (including 1400 external to its system), runs every five minutes, and runs about 1800 contingencies every 90 seconds. Entergy also provides operators with post contingency loading on critical facilities that is updated every two seconds using line outage distribution factors (LODF). Currently the LODFs are calculated daily or as needed to reflect changes in system topology, but Entergy states that work is underway to automate the process to allow more frequent updates. Entergy SOC has provided its system operators with large monitors for wide-screen views and virtual recording charts for trend recording. The audit team commends Entergy for providing the system operator with contingency analysis using LODF in addition to the state estimator, large monitors for wide screen views and virtual recording charts.

Entergy monitors the status of neighboring control areas that will have an effect on Entergy's system. Entergy is evaluating whether to expand its state estimator visibility by obtaining more external data than what it has currently two buses out. The audit team recommends that Entergy follow-up with its future plan to increase the wide-area view to obtain additional external data (Recommendation 13).

4.5. Frequency Monitoring

The control area operator must monitor frequency and direct actions to resolve significant frequency errors, and correct real-time trends that are indicative of potentially developing problems. Frequency monitoring points should be of sufficient number and from several locations with sufficient area coverage to allow the control area operator to effectively monitor the control area, and be able to determine possible islands.

Audit Notes:
Entergy provides its System operators with multiple frequency points to monitor its control area footprint. Currently there are four frequency monitors and Entergy indicated that it is in the process of installing ten new, self-calibrating frequency meters at well-chosen sites. Entergy has an automatic underfrequency load shedding program that is triggered at 59.3, 59.0 and 58.7 Hz. There is a 10% load reduction per each step for a total of 30%. It was determined by the audit team that the Entergy system operators are aware of the automatic underfrequency load shedding points and the frequency set points at which loads and generating units would trip.

Entergy management indicated that it uses a frequency signal provided by MISO in its ACE calculation. During the system operator interview, the system operators indicated the frequency is obtained from the Woodward bus at the SOC. The audit team recommends that Entergy ensure its primary frequency source for its ACE calculation is inside the control area (Recommendation 9).

4.6. Voltage Monitoring

The control area operator must monitor voltage levels, and take appropriate actions to support the bulk electric system voltage if real-time trends are indicative of potentially developing problems. Voltage measuring points must be of sufficient number and from several locations and voltage levels to allow the control area operator to effectively monitor the voltage profile of their control area.

Audit Notes:
Entergy indicated that it does provide its system operators with multiple points to monitor its control area footprint voltage levels. Entergy monitors all generating station and transmission equipment (115 kV and above) voltages and Entergy indicated that the SOC is ultimately responsible for monitoring system voltage; however, the TOCs are the first responders. Entergy controls its system voltage levels to 1.02 per unit from May to October for all hours (on peak) and to 1.0 per unit November to April for all hours (off-peak). Operators receive alarms for voltage violations. Alarming is set at +/-5% for 115 kV–230 kV and 7% (high-side) and 1% (low-side) for 500 kV. It was determined that Entergy has two undervoltage load shedding schemes. The system operators will receive a high priority EMS alarm when the undervoltage scheme is armed or operates.

Entergy indicated that it is developing a real-time, EMS voltage stability analysis program. The audit team recommends that Entergy follow up with its plan to develop real-time EMS voltage stability studies (Recommendation 13).

In accordance with Entergy's Operations Interconnection Agreement, Entergy requires IPPs within the Entergy control area to operate running units in automatic voltage regulator (AVR) mode to a planned voltage schedule. Entergy does not receive real-time operational status of the IPPs AVR. In addition, Entergy requires the IPPs to have power system stabilizers (PSS); however, Entergy does not monitor the IPPs PSSs. The majority of the interconnection and operating agreements between Entergy and the IPPs require the IPPs to follow NERC and SERC requirements. However, not all IPPs are SERC members and membership is voluntary. Currently there is no mechanism to ensure compliance with these requirements. Entergy relies upon the contractual obligation of the IPPs to ensure that the IPPs meet these requirements.

4.7. Reactive Reserve

The control area must ensure that reactive reserves are available and properly located to satisfy the most severe single contingency.

Audit Notes:
To provide dynamic reactive support, Entergy first uses static reactive devices and then synchronous reactive generation. Entergy provided its system operators with an EMS generation display that shows each generator's reactive capability and output. Entergy is working on a scheme to monitor dynamic reactive reserves in local areas. Entergy's enforcement of its N-2 criteria in load centers ensures reactive reserves are adequate to prevent voltage collapse following contingencies. The audit team commends Entergy for its policy of maintaining dynamic reactive reserves.

It was determined that Entergy does not have a testing program to verify the reactive reserve capability of its generators. Entergy is currently determining when the last tests were run and when tests should be done again. Some generating plants have said that they have done the testing but do not have the documentation so Entergy is looking for documentation and data. The Entergy control area will ensure that the results of the generator reactive testing are incorporated into the SOC's models of the system. The audit team recommends that Entergy implement a program to test the reactive capability of generating plants (Recommendation 7).

4.8. Critical Facility Monitoring

Monitoring of facilities that are critical to the reliability of the bulk electrical system is a joint responsibility of the control area operators and reliability coordinators.

There must be an established process to determine which facilities will be considered critical to the reliability of the bulk electrical system, and real-time operating information (data and status). Operating limits for the critical facilities must be provided to the control area operators and the reliability coordinators.

Audit Notes:
Entergy indicated that all facilities rated 115 kV and above are critical facilities and are monitored by the system operator. Entergy also monitors facilities two buses out in other control areas and is planning to extend coverage to other facilities that have a significant effect on Entergy. Entergy utilizes the VACAR Southern TVA Entergy (VST) modeling process and the Seams update process to ensure its neighboring control areas use the same ratings Entergy uses for its critical facilities. The Seams efforts is based on a Memorandum of Understanding (MOU) between Entergy, Southern and TVA to improve coordination between the utilities. The coordination effort targets major operational and planning issues which include monthly model development, short term operating guides, dynamic ratings on facilities etc. The coordination effort has been expanded to include other utilities in the region.

4.9. Transmission System Congestion

The control area must monitor transmission flowgates and be prepared to take actions to alleviate congestion in conjunction with and as directed by its reliability coordinator.

Audit Notes:
Entergy indicated that the Entergy Transmission desk, RTA desk and the reliability coordinator monitor real-time operations for transmission system congestion management. The RTA desk also performs real-time analysis for the next hour and monitors known critical transmission facilities that are known to exceed their thermal capabilities. For contingencies that are identified, the RTA operator verifies the analysis results and works with transmission operations planning engineers and the shift supervisors to develop a solution, which is provided to the transmission desk and the reliability coordinator. If a mitigation plan cannot be implemented post-contingency, then the reliability coordinator will implement a transmission loading relief (TLR), redispatch generation or shed load, as necessary. Analysis determines if the congestion is due to a local area or an interconnection problem. If the congestion is a local area problem, redispatch of generation may be implemented. TLRs are implemented at 90% of line loading limits or on N-1 contingency basis.

Entergy provides its reliability coordinator with custom EMS displays to monitor the post contingency loading of critical facilities using line outage distribution factors (LODFs). The audit team commends Entergy for implementing custom EMS displays for the reliability coordinator to monitor post contingency loading of critical facilities using LODF.

With the exception of those transactions called on for reserve sharing, Entergy tags all interchange transactions. It was determined by the audit team that Entergy does perform hourly net scheduled interchange checks with its neighboring control areas that have such capability (not all are willing to perform these checks) and uses webScheduler for the others.

4.10. Load Generation Balance

The control area operator must monitor the balance of load, generation and net schedule interchange in their control area. The control area operator must take actions to mitigate unacceptable load, generation and net scheduled interchange imbalance.

Audit Notes:
Entergy indicated the EMO is responsible for load generation balance, with oversight by the SOC. The EMO is also responsible for CPS1, CPS2 and DCS performance and for ensuring that it has the ramping capability to meet schedule changes. EMO stated that it provides its System operators with a Generation Management System (GMS), which includes a display that projects load for the upcoming hour and the amount of generation available. The GMS also calculates regulation capability of the on-line generating units.

The Entergy SOC EMS sends the Entergy ACE signal to the EMO facility's GMS. The SOC is responsible for checking that IPPs and QFs are meeting their schedules and for correcting any tie-line data problems with its neighboring control areas.

Entergy management indicated that its control area contains a large number of IPPs and QFs with a combined capacity in excess of 15,500 MW, and that the IPPs and QFs can create ramping problems on their system. Entergy has created a Generation Imbalance Agreement position at the SOC to enforce scheduling requirements related to IPPs and QFs.

4.11. Contingency Reserves

The control area operator must monitor the required reserves, and the actual operating reserves in real-time, and must take action to restore acceptable reserve levels when reserve shortages are identified.

Audit Notes:
Entergy is a member of the Southwest Power Pool (SPP) Reserve Sharing Group (RSG). The EMO is responsible for distributing and monitoring reserves with oversight by the SOC. The SPP RSG calculates Entergy's regulation margin and operating reserve requirements. Entergy indicated that its regulation and operating reserves are dispersed across its system to allow for coverage of N-2 events in load centers.

There was no EMO system operator present during the operator interview portion for this section; however, the SOC system operator did provide some information to the audit team. Entergy has in the past interrupted load for a generation shortage and a voltage problem and if Entergy has a shortage of operating reserves, the reliability coordinator would assist in contacting neighbors to obtain emergency power.

	Applicable Documents	Dated	Version
1	Entergy Reserve Planning Guide	10/18/02	-

4.12. Special Protection Systems

The control area operator and the reliability coordinator must be aware of the operational condition of special protection systems (SPS) that may have an effect on the operation of the bulk electrical system.

Audit Notes:
Entergy stated that it does not have any SPS. Entergy stated that it does have two undervoltage, load-shed schemes, which are not considered to be SPSs by the NERC planning standards. These schemes are coordinated with generation protection and controls, as warranted, to ensure that the load is shed before over excitation limiters run back the generating units.

5. System Restoration

The control area operator must have a documented system restoration plan and must be provided to the reliability coordinator.

The control area operator must be prepared to restore their control area following a partial or total collapse of the system and coordinate system restoration with their neighboring control areas and with the reliability coordinators.

Audit Notes:
Entergy indicated that they have a system restoration plan and blackstart restoration plan. Each TOC has its own blackstart restoration plan, which is coordinated through the TOP group. Entergy stated that it also participates in the annual SERC Emergency Coordination Seminar. The Entergy reliability coordinator coordinates system restoration efforts with the EMO, TOCs and generating plants. Entergy does have the required phone numbers for emergency contacts.

	Applicable Documents	Dated	Version
1	Entergy Blackstart Restoration Plan	2003	-

6. Delegation of Reliability Authority Functions

Any reliability coordinator functions that have been delegated to a control area operator must be clearly documented. The documentation must recognize that the reliability coordinator continues to be responsible for that function.

Audit Notes:
Entergy stated that the Entergy reliability coordinator has delegated the generation reserve monitoring function to Entergy's EMO for the Entergy control area.

	Applicable Documents	Dated	Version
1	Letter from G.Bartlett to J. Hurstell subject: Delegation Of Control Area and Reliability Coordinator Functions	5-10-04	-

7. Outage Coordination

Planned control area transmission facilities and generating unit outages must be coordinated with the reliability coordinator to ensure that conflicting outages do not jeopardize the reliability of the bulk electrical system.

Information relative to forced transmission facilities and generating unit outages that may jeopardize the reliability of the bulk electrical system must be shared with affected transmission operators and the control area's reliability coordinator as expeditiously as possible.

Audit Notes:
Entergy indicated that the TOP group prepares a weekly outage report for the reliability coordinator and that the reliability coordinator meets with TOP every afternoon to discus the next day's outage plan and any remedial actions that may be required.

Transmission and generating outages, planned and forced, are communicated to other control areas and reliability coordinators by conference call every Tuesday, the use of OASIS, the reliability coordinator information system (RCIS), the interchange distribution calculator (IDC) and SDX. Entergy also indicated that the TOCs will communicate with neighboring control areas and that notification by neighboring control areas of forced outages is communicated to the Entergy TOP group.

	Applicable Documents	Dated	Version
1	Outage Coordination Procedure	-	-

8. Transmission and Generation Relaying

Control areas must ensure that transmission and generator relay maintenance is carried out as per control area, regional, and/or NERC established requirements.

Audit Notes:
Entergy stated that it does not have a generator relay and maintenance and testing program; however, Entergy generation does have plans to develop one for Entergy owned generators. The audit team recommends that Entergy generation develop and implement a generator relay maintenance and testing program for Entergy owned generation (Recommendation 11).

It was determined by the audit team that Entergy requires its relay maintenance staff to obtain approval from the system operator to work on transmission and generator relays and to notify the system operator before they begin actual work on transmission and generator relays. When the Entergy control area is subject to high load demands, Entergy will not leave an unprotected element in service and Entergy has established a policy that will allow the system operator to declare a moratorium on any work around critical transmission or generation facilities.

Entergy currently has a total of 70 digital fault recorders (DFRs) installed throughout its control area. Forty-three are currently time synchronized. Of the remaining 27 DFRs, all but seven are capable of being time synchronized. Entergy is currently in the third year of a six-year program to add time synchronization to those DFRs that are capable and to replace non-capable DFRs with newer technology units that will accept time synchronization. The audit team recommends that Entergy complete the work in progress to implement time synchronization of all its digital fault recorders (DFRs) (Recommendation 13).

	Applicable Documents	Dated	Version
1	Station Disturbance Monitoring Equipment	-	-

9. Capacity and Energy Emergency Plan

Each Control Area must have a Capacity and Energy Emergency Plan that address the following functions. (It should be noted that some of the items might not be applicable, as the responsibilities for the item may not rest with the entity being reviewed).

1. **Coordinating functions.** The functions to be coordinated with and among neighboring systems. (The plan should include references to coordination of actions among neighboring systems when the plans are implemented.)
2. **Fuel supply.** An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel, fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil, and a plan to optimize all generating sources to optimize the availability of the fuel, if fuel is in short supply.
3. **Environmental constraints.** Plans to seek removal of environmental constraints for generating units and plants.
4. **System energy use.** The reduction of the system's own energy use to a minimum.
5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. **Load management.** Implementation of load management and voltage reductions.
7. **Appeals to large customers.** Appeals to large industrial and commercial customers to reduce non-essential energy use and start any customer-owned backup generation.

8. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements and/or to conserve the fuel in short supply.
9. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
10. **Notifying IPPs.** Notification of co-generation and independent power producers to maximize output and availability.
11. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community.
12. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented
13. **Notification to control areas and reliability coordinators.** Notification should be made to other control areas and to the reliability coordinator as the steps of the emergency plan are implemented.

Audit Notes:
Entergy has a capacity and energy emergency plan called the Entergy curtailment policy and procedure plan. The Entergy plan would be triggered when Entergy realizes that it is within two contingencies of dropping firm load, either system wide or in a load center. The plan includes proactive rather than reactive action by the system operator. Entergy looks as far forward as possible (tomorrow's peak). If Entergy anticipates a system-wide shortage of energy or capacity, Entergy's plan is implemented by the EMO. The SOC would implement the plan if a load center is short of energy or capacity. Entergy stated that it does not have a voltage reduction program.

Entergy's manual load shedding is performed by the various distribution centers. Orders for load shedding are given to the TOCs by the SOC system operators. The TOCs then contact the distribution centers to provide the requested amount of relief.

	Applicable Documents	Dated	Version
1	Entergy Curtailment Policy and Procedure	4-30-04	-

10. Operating Policy/Procedure Changes

Control areas must have an established procedure to ensure that control area operators and operations staff are aware of any changes to NERC, regional and/or local policies or procedures prior to taking over control of a shift position.

Control areas must have shift change procedures for updating incoming shift personnel on the current status of the system.

Audit Notes:
Entergy stated that it notifies its system operators of NERC, regional or local policy changes through email, training and shift-change documentation. It was determined by the audit team that Entergy requires its system operators to sign and date the appropriate cover sheet on the document indicating that they are familiar with the change. If time allows, Entergy indicated that it would create a training document to cover the material or, if time is not available, a subject matter expert meets with the

shifts to explain the material. An example of an email text message was provided for audit team review.

	Applicable Documents	Dated	Version
1	Copy of email notification to system operators re: Update to Operating Procedures	-	-

11. Vegetation Management (Line Clearances)

Control areas must have a documented Vegetation Management Program.

Audit Notes:

Entergy stated that it has not made any major changes to its vegetation management program since August 14, 2003. Entergy monitors its system for vegetation and underbuild conditions twice per year by aerial patrol. It was determined by the audit team that the Entergy system operators have not experienced many line trips due to unknown causes where the system operator might expect vegetation was the cause. Entergy's statistics indicate bulk transmission system outages due to vegetation have been trending downward since year 2000. Entergy provided the audit team with its Vegetation Management Program document for review.

	Applicable Documents	Dated	Version
1	Entergy Vegetation Management Program	9-14-95	-

12. Nuclear Power Plant Requirements

Nuclear power plants have regulatory requirements for voltage and power in both normal and abnormal operating conditions (N-1 and system restoration).

Audit Notes:

Entergy is required to identify critical transmission line configurations and/or voltage conditions, which would affect the adequacy of the offsite power or the supply to any of the nuclear power plants within its control area. Entergy performs extensive studies with its nuclear plants and uses its TAORS to coordinate transmission line and system outages with equipment at the nuclear plants. Entergy stated that it has a nuclear plant in each of its TOC areas and that each TOCs number one priority is restoring offsite power adequacy to the nuclear plant following a grid disturbance or station outage.

Entergy indicated that its nuclear plants have provided information concerning voltage requirements immediately following a unit trip (while pumps are starting, and before switched capacitors and transformer taps can move) for the off-site power supply to be considered adequate. Entergy also provided to the audit team the time requirements for restoration of adequate offsite power before the nuclear plant operator will initiate generator shutdown.

Entergy informs the nuclear plant operator when power system conditions are such that the offsite power supply for a nuclear generating unit is not adequate. This notification is initiated by the system operators following receipt of a voltage alarm indicating that the bus voltage fell below a specified point.

Entergy keeps its nuclear plant operators informed of power system conditions (transmission lines out of service, other power plants in service, etc.) that can impact the adequacy of nuclear plant, post-trip, bus voltage if potential contingencies exist that could impact the plant.

Entergy indicated that it analyzes the nuclear power plant voltage limits and considers a trip of the nuclear power generator and a simultaneous loss of a critical transmission contingency on a planning basis, but not on a real-time basis. The audit team recommends that Entergy include within its real-time monitoring capabilities the ability to identify and notify the nuclear power plant operator when its transmission system voltage is not adequate to supply offsite power following a unit trip and loss of a critical transmission facility (Recommendation 12).

Conclusions

The audit team feels that Entergy is ready and has the appropriate reliability plans, procedures, processes, tools and trained personnel in place to respond to unplanned events on its system. The audit team did not find any major issues that Entergy needs to address immediately; however, the audit team does have several recommendations that are listed in the areas for improvement section.