PRE-DECISIONAL

SOUTH TEXAS

I. HISTORY

South Texas Project (STP) was first discussed at the January 1993 Senior Management Meeting (SMM) because of poor and declining performance for two systematic assessment of licensee performance (SALP) periods. Repetitive hardware problems had resulted in numerous plant trips, transients, engineering safety features actuations, and forced outages. STP was subsequently discussed at the June 1993 SMM, when it was placed on the Watch List in Category 2. Both units at STP have been shut down under a Confirmatory Action Letter (CAL), as supplemented, since February 1993, as a result of many NRC- and licensee-identified problems. As discussed at the January and June 1993 SMMs, the identified problems were grouped into three broad areas, including material condition and housekeeping, human performance, and organizational performance. A Diagnostic Evaluation was conducted in March and April 1993, and the findings of that inspection were presented to the licensee in June.

II. CHANGES SINCE LAST SMM

Performance at STP has been mixed. STP has made extensive management changes. A new Group Vice President-Nuclear, Mr. William Cottle, and Vice President, Nuclear Operations, Mr. John Groth, were named in April and May, respectively, and these individuals were discussed during the June 1993 SMM. Other new senior management selections include: Mr. Theodore Cloninger, Vice President, Engineering, formerly Executive Consultant for Cygna Energy Services; Mr. James Sheppard, General Manager, Nuclear Licensing, formerly President and Chief Executive Officer of Sequoyah Fuels Corporation; and Mr. Lawrence Martin, General Manager, Nuclear Assurance, formerly Senior Program Manager for the Vice President of Completion Assurance with the Tennessee Valley Authority. In addition to these senior management changes, STP has reorganized maintenance and operations by splitting these departments between units. Previously, a single plant manager responsible for both units oversaw the maintenance and operations departments. Currently, each unit has a plant manager, with operations, work control, and maintenance managers being his direct reports. The former plant manager, Mr. Gary Parkey, has been appointed the Unit 2 plant manager; and Mr. Lew Myers, formerly Restart Plant Manager at Browns Ferry, has become the Unit 1 plant manager. The unitization of these departments and the senior management changes are viewed as a positive action; however, many of these changes are recent, and their impact on the licensee's management effectiveness and ability to identify and correct problems remains to be seen.

As discussed in the Narrative Summary for the June 1993 SMM, a CAL was issued on February 5, 1993, requiring that, prior to either unit's restart, STP management brief the staff on the actions taken to correct the deficiencies. Supplemental Letters were issued to the licensee on May 7, 1993, and October 15, 1993, identifying issues that require resolution prior to the restart of either unit. The Restart Issues encompass the key safety issues identified by both Region IV and the diagnostic evaluation team (DET). Region IV's principal efforts at STP since October 1993 have consisted of inspecting items associated with these Restart Issues.

The licensee's response to the DET inspection was submitted in two parts. The first part, which consisted of relatively short lead-time corrective actions and enhancements, was submitted in August as the STP Operational Readiness Plan.

B/1

This Plan essentially addresses the specific actions that the licensee will take prior to the resumption of power operations. The second part was submitted in October as the 1994-1998 Business Plan and describes the longer term improvements that STP plans to take to address issues identified in the DET report, other NRC inspections, and through the licensee's own corrective action program.

As a result of the length of time that both units have been shutdown, and the number and potential safety significance of the issues, NRC formed an STP Restart Panel. This panel was composed of the same members as the STP Oversight Panel. A Restart Action Plan has been developed utilizing the guidance in Manual Chapter 0350, "Staff Guidance for Restart Approval." The Panel meets bi-weekly. Management meetings with the licensee have been held approximately monthly, mostly at the site, and have been open to public observation.

A special inspection conducted in May and June identified six problems associated with main feedwater isolation bypass valve safety-related classification, solenoid aging, calibration of remote position indicators, and correction of an identified design deficiency. Several of these items remain unresolved and are Restart Issues.

Another special inspection conducted in May and June identified the licensee's failure to take prompt corrective action following the discovery of missing seismic fasteners on card cages of the Qualified Display Processing System (QDPS), a condition that rendered portions of the QDPS inoperable.

Yet another special inspection was conducted in June to review the circumstances surrounding the 13-hour loss of spent fuel pool (SFP) cooling. Operator performance weaknesses were identified when control room operators failed to detect the loss of cooling and when non-licensed operators failed to recognize the absence of significant flow noises during routine inspection rounds.

A portion of the licensee's own assessment of the effectiveness of their programs consists of independent self-assessments of performance by the licensee's Nuclear Assurance Department. These assessments are being conducted at specific milestones during the recovery of both units. NRC has begun inspections to assess both the quality and independence of these self-assessments and the thoroughness and degree of adequacy with which the licensee has addressed previously and recently identified problems. In addition to this assessment, the licensee has initiated an independent assessment from an outside party.

The NRC Operational Readiness Assessment Team completed its first week of inspection in December. The team expressed concerns with the post maintenance test program, the configuration management program, and the corrective action program. While the licensee has also identified these areas for correction, the team believed that more could have been done to date and has expressed concern about the licensee's readiness to restart in January. NRR has sent a "quick look" letter to the licensee on these topics to highlight potential restart problems.

There were two recent incidents for which plant management issued "stop work" orders at the site. Due to human performance problems, all motor operator value (MOV) maintenance and testing activities were suspended on both units. On November 23, 1993, the licensee found that a work crew consisting of both licensee and contract MOV personnel was performing repairs on a safety injection system motor-operated valve with the component energized. The work crew was supposed to be working on a containment spray system MOV which had been tagged out and de-energized. The plant manager ordered that all work on motor-operated valves cease, and ordered an investigation of the event. Several other problems with the equipment clearance program have been identified. A new procedure for equipment clearance has been prepared, and training is ongoing on the new procedure. Although it is not certain that the new equipment clearance procedure will address all the issues involved in this recent event, the new procedure is considered an improvement.

On a related matter, contract instrumentation and controls (I&C) technicians replaced the wrong temperature switch, which was identified by quality control personnel. A stop work order was issued and plant management investigated the incident. These I&C technicians were permanently relieved of duties at South Texas.

An Office of the Inspector General (OIG) inspection report that received limited distribution and was issued February 18, 1993, concluded that violations of 10 CFR 50.7 had occurred involving two former security force personnel. This issue was referred to the Department of Justice, which subsequently declined further review. A demand for information was sent to the licensee on September 29, 1993, and a response was received on November 15, 1993. The licensee strongly disagrees with OIG's conclusions.

A request submitted by Thomas J. Saporito in accordance with 10 CFR 2.206 to shut down the facility due to a variety of issues has been acknowledged and denied. The final Director's Decision is still under review. This decision has been delayed until the Department of Justice completes its review of possible criminal violations in regard to whistleblower activities. Additionally, various allegations have been made at the facility by current and former plant workers, and these are under review.

III. FUTURE ACTIVITY

The NRC has scheduled all of the inspection activities required to assess the licensee's efforts in resolving the Restart Issues. These inspection activities are planned to be completed in January 1994, with a public meeting following the completion of the inspection effort. The licensee has currently proposed January 31, 1994, as the date for the restart of Unit 1. Based on the preliminary results of the initial Restart Issues inspections, the NRC anticipates that this date will slip, with a more realistic restart date of February 1994, or later. However, fuel was loaded in November, and the licensee anticipates that the efforts toward reducing the maintenance backlog and improving material conditions will be complete in December.

The NRC will continue the Operational Readiness Assessment Team (ORAT) inspection with another 1 1/2 weeks on-site in January 1994. The purpose of this inspection is to assess the licensee's activities and their readiness to restart, and confirm the findings of previous inspections concerning the Restart Issues.

Unit 2 remains in its third refueling outage and is currently defueled. Little work has been accomplished on it because the licensee has focused its resources on Unit 1 in order to reduce the maintenance backlog and restart the unit. Unit 2 restart has been scheduled for March 22, 1994, although a delay to April would not be unexpected.

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

None (Both units have been shut down since February 1993.)

B. Significant Operator Errors

Two examples of operator performance weaknesses were identified during the [illegible]-hour loss of SFP cooling event on June 13-14, 1993: (1) an oncoming operations shift failed to conduct an adequate review of plant status prior to assuming the shift and failed to note main control board indications of the loss of cooling, and (2) a reactor plant operator failed to note that the noise level in the area of the SFP pumps and heat exchangers was significantly reduced following the isolation of component cooling water to the SFP heat exchanger.

Approximately 500 gallons of boric acid was spilled in April 1993 when a pump was started with a drain valve open after an equipment clearance order was partially released. The spill was the result of a human performance error, associated with the equipment clearance, during the review of the boundaries needed to allow for the pump run.

Operator licensing examinations conducted at STP in September 1993 identified generic performance weaknesses in the areas of (1) familiarity with low power and shutdown procedures and (2) hesitancy to secure reactor coolant pumps when abnormal conditions were noted immediately after equipment startup.

C. Procedures

A number of procedure weaknesses and examples of licensee personnel failing to follow procedures have been identified since the last SMM. These include:

- deficient maintenance procedures and personnel failing to follow procedures associated with the documentation of boric acid leaks identified on reactor coolant system components

- weak maintenance procedures that resulted in a high-head safety injection pump motor being overfilled with oil

- a procedure revision process that did not prevent a revised solid-state protection system surveillance procedure from being issued without incorporating all of the active field changes against the old procedure

- an example of weak configuration control in the installation of a replacement safety-related reverse power relay without adequate modification controls

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

	SRO	RO	TOTAL
Licensed Operators	47	38	85

B. Number and Length of Shifts

Six 12-hour shifts

C. Role of STA

One STA is shared between the two units. They are not assigned to a specific shift crew, nor do they receive training with a specific shift crew. STAs do not hold a senior operator's license. The STA's primary duty is to act as an accident prevention and mitigation advisor to the shift supervisor.

D. Requalification Program Evaluation

In February and March 1992, the NRC administered requalification examinations at South Texas Units 1 and 2. The requalification training program was determined to be effective and was assigned an overall program rating of satisfactory.

In March 1994, the NRC plans to conduct a requalification program evaluation in accordance with Temporary Instruction 2515/117, "Licensed Operator Requalification Program Evaluation."

III. PLANT-SPECIFIC AND UNIQUE DESIGN INFORMATION

A. Plant-Specific Information

Owners	Houston Lighting and Power Company City of San Antonio Central Power & Light Company City of Austin
Reactor Supplier/Type	Westinghouse/4-loop PWR
Capacity, MWe	1250
Architect/Engineer	Bechtel
Constructor	Ebasco
Commercial Operation	Unit 1: August 25, 1988 Unit 2: June 19, 1989

B. Unique Design Information

Containment: Dry, carbon steel-lined, prestressed, reinforced concrete, cylindrical structure with a hemispherical dome

Emergency Core Cooling Systems: Three high head safety injection, low head safety injection, and containment spray pumps; three safety injection accumulators; three motor-driven, 100 percent capacity auxiliary feedwater pumps and one turbine-driven, 100 percent capacity auxiliary feedwater pump per unit

AC Power: Eight 345 kV offsite sources; three 5500 kW Cooper-Bessemer emergency diesel generators per unit

DC Power: Four sets of batteries powering four independent Class 1E 125 Vdc subsystems per unit

IV. SIGNIFICANT MPAs OR PLANT-UNIQUE ISSUES

MPA X808 (Bulletin 88-08, Thermal Stresses in Pipe Connected to RCS): Currently, the licensee is not in compliance with the bulletin as a result of removing temporary instrumentation. This action by the licensee was based on analytical studies provided by Westinghouse, which were not reviewed and approved by the staff. A meeting was conducted on November 8-9, 1993, between the licensee, Westinghouse, and the staff. The licensee has submitted to the staff an interim resolution regarding this issue. This interim resolution is expected to allow the issue to be closed in January 1994.

MPA B111 (GL 88-20; Individual Plant Examination): The licensee submitted its IPE in August 1992. The staff is reviewing it.

MPA B118 (GL 88-20, Supp. 4; IPE for External Events): The licensee submitted its IPEEE in December 1991. The staff is reviewing it.

MPA B114/115 (GL 90-06; PORV Reliability & LTOP): The last remaining issue involved the licensee's proposal to maintain the ability to test the PORVs in mode 5. The licensee agreed to drop this mode 5 provision, and the licensing action was completed on October 7, 1993.

MPA X201 & MPA L208 (Bulletin 92-01 & GL 92-08; Thermo-Lag): The licensee has substantial amounts of Thermo-Lag present and has responded to the generic letter.

MPA A-22 (10 CFR 50.63; Station Blackout Rule): The licensee has completed all actions required to meet the SBO rule. The plant is an 8-hour coping plant, using an existing Class 1E standby diesel generator as an alternate AC power source.

AOT/STI TS Changes Based on PRA Analysis: Originally, this one submittal from the licensee contained 22 individual changes regarding extending the allowed outage time (AOT) and surveillance test intervals (STI) for various technical specifications based on the three-train systems at the facility. The licensee reduced the number to 16, of which 11 are PRA-based and 5 are qualitative in nature (although these 5 deal with the same type of subject matter). The reduction to 16 changes was the result of the staff's review, which determined that the increase in the core damage frequency was unacceptably high. The licensee responded to a request for additional information, and the response is currently under review by the staff and its contractor. This licensing action is 45 months old; licensing action completion is estimated for mid-January 1994.

The licensee anticipates submitting 27 technical specification changes or commitment changes during the next few months. Some of these changes would improve its technical specifications (a DET-identified issue). Some of these changes could be considered cost-beneficial licensing actions, although others are generic issues. Moreover, some of the issues will be based on the approved PRA report.

The licensee is evaluating the applicable regulatory guidance concerning the Technical Specification Improvement Program. A decision on this is not expected in the foreseeable future.

The NRC staff has eight staff follow-up actions as a result of the DET report. Resolution of these staff actions may impact South Texas and the industry in general, depending upon the generic nature of the issue. These staff actions are currently under staff review.

V. STATUS OF THE PHYSICAL PLANT

A. Problems Attributed to Aging

STP is a relatively new site, and no major aging problems have manifested themselves. Because of the length of construction, however, equipment and components are not considered new. There have been many plant events and forced outages primarily because of balance-of-plant equipment problems.

B. Other Hardware Issues

Several longstanding problems associated with the EDGs, the main feedwater system, essential chillers, and MOVs are being addressed by the licensee and are Restart Issues.

The maintenance backlog has been reduced. However, the licensee's ability to maintain the backlog within reason remains to be demonstrated following the return to power operations.

VI. PRA

A. PRA Insights

South Texas is a newer Westinghouse four loop NSSS with a 3-train ECCS design. The ECCS design is unique in that each train delivers flow to a specific RCS loop with no ECCS injection into RCS loop 4 and no cross ties to the other loops. The success criteria for a large break LOCA require one train of injection to an intact loop. For a small break LOCA, any one train of ECCS is sufficient, regardless of the location of the break.

The RHR pumps at South Texas are separate from the LPSI pumps, and the entire RHR system is inside containment. Also, the HPSI pumps can take suction directly from the sump. Therefore, the HPSI pumps are not dependent on suction from the LPSI pumps or the RHR pumps during the recirculation mode.

South Texas is equipped with 3 EDGs per unit (one for each ECCS train). The reliability of all six EDGs is above 0.975. However, the unavailability due to maintenance is higher than the industry targets.

B. PRA Profile

The South Texas Project Probabalistic Safety Assessment (PSA) was submitted to the NRC in 1989 and included analyses of internal and external events. The PSA was reviewed and approved by the staff. As a result of the PSA findings, an important modification was implemented. This modification involved the connection of the positive displacement charging pump to the technical support center DG to provide RCP seal cooling in the event of a total loss of AC power.

HL&P responded to GL 88-20 by submitting a Level 2 IPE and IPEEE in August 1992. The original PSA estimated a core damage frequency of 1.7E-4 per year. The IPE reports an estimated core damage frequency of 4.4E-5 per year for internal and external events. The IPE CDF is about a factor of 4 less than that obtained in the original PSA. The IPE has not been reviewed by RES, so it is not yet clear what has contributed to the decrease in the CDF estimate. The licensee attributes the decrease in CDF to a reduction in conservatisms. The dominant initiators contributing to core damage from the IPE are listed below:

Initiating Event Category	% of Total CDF
Loss of Offsite Power (LOOP)	35.3%
Loss of Electrical Auxiliary Building HVAC (resulting in an internally induced SBO)	20.1%
Small LOCA	5.4%
Reactor Trip	5.1%
Transient induced LOOP	5.0%
Steam Generator Tube Rupture	4.8%
Turbine Trip	3.2%
Medium LOCA	2.8%
Loss of Essential Cooling Water	2.6%
Loss of Control Room HVAC	2.3%
All Others	13.2%

It should be noted that, while full treatment of external events and internal plant hazards such as fires and floods was included in the IPE submittal, such events contributed less than 4% to the total core damage frequency. This contribution to total CDF from external events is a significantly smaller percentage than any other recently published PRA for a PWR plant has estimated. HL&P attributes this small contribution to two principal reasons. First, the site has a very low seismicity in relation to the design basis earthquake. Second, there is ample redundancy and physical separation in the ECCS trains, which would reduce the likelihood that internal fires and floods and other spatial interactions could result in a serious accident.

The licensee found no significant accident sequence outliers as a result of performing the IPE.

C. Core Damage Precursor Events

On the basis of the precursors identified by ORNL for 1991 (NUREG/CR-4674, vols. 15 and 16) and the preliminary precursors for 1992, SPSB did not identify any precursor events for the site that have a conditional core damage probability of 1E-5 per year or greater.

SPSB notes the following event that has been classified as a "Significant Event" for the Performance Indicator Program:

South Texas Unit 1 experienced overspeed trips of their turbine-driven auxiliary feedwater (TDAFW) pump during surveillance tests on December 27, 1992, and January 28, 1993. Also, on February 3, 1993, the Unit 2 TDAFW pump tripped on overspeed during an actual demand after a plant trip. The licensee performed an analysis of the Unit 1 condition with the assumption that the TDAFW pump was inoperable for 33 days. The CDF increased from 4.4E-5 (as reported in the IPE) to 4.5E-5 per year. This analysis has not yet been reviewed by the staff.

During the same time period (Dec. 29, 1992 thru Jan. 22, 1993), Unit 1 DG-13 was inoperable due to paint drips on the fuel metering rod ports. Furthermore, Unit 2 DG-12 was out of service for a 61 hour planned maintenance period while DG-13 was inoperable.

When the DG event and the TDAFW pump trip event are analyzed as separate events, the risk does not appear to be significant. However, since the DG-13 and the TDAFW pump were inoperable during the same period, SPSB performed a preliminary ASP assessment that estimated a Conditional Core Damage Probability of 1E-5/year. SPSB has suggested to AEOD that the overall situation should be reviewed for potential precursor significance.

VII. ENFORCEMENT HISTORY

12/91 CIVIL PENALTY — The action was based on the licensee's failure to keep complete and accurate records of preventative maintenance activities for safety-related valves in the safety injection system and the reactor coolant purification system. A civil penalty was issued to emphasize the importance of ensuring that records kept of the conduct of licensed activities be complete and accurate and that licensed activities are conducted in strict compliance with regulatory requirements. Mitigation of the civil penalty was appropriate for licensee identification and corrective action, but was offset by the escalation for multiple occurrences. ($50,000)

4/93 CIVIL PENALTY — The action was based on a number of violations of established procedures which resulted in the failure to inform NRC-licensed operators in the control room of potentially significant conditions that could have affected the operation of the plant. Because the failures to follow established procedures involved plant management personnel, these violations were classified as a Severity Level III problem. A civil penalty was issued to emphasize the need for managers, when necessary, to promptly and properly interface with the NRC-licensed personnel in the control room and the importance of plant management personnel following or properly modifying established procedures. Mitigation of the civil penalty was appropriate for the licensee's corrective actions, but it was offset by the escalation for NRC identification and the licensee's prior opportunity to identify one of the violations. ($75,000)

4/93 CIVIL PENALTY — The action was based on numerous examples of failures to adhere to procedural requirements regarding self-verification that primarily involved the failure to verify the correct unit, correct train, or correct device before conducting testing or maintenance activities. Although none of the errors resulted in adverse safety consequences, collectively they represented a significant regulatory concern and were classified as a Severity Level III problem. A civil penalty was issued to emphasize the importance of attention to detail and the need for the licensee to be aggressive in implementing corrective actions of a lasting nature. The civil penalty was partially mitigated based on the licensee's corrective actions. ($25,000)

4/93 CIVIL PENALTY — The action was based on the licensee's failure to take corrective actions for a failed motor on a motor operated valve in the Unit 2 Low Head Safety Injection System. The violations involved in this action were classified as a Severity Level III problem because (1) a safety-related valve went unrepaired for 18 months despite multiple opportunities to recognize the significance of the problem, and (2) operations personnel did not recognize the technical specification implications of operating the reactor with the valve inoperable. A civil penalty was issued to emphasize the importance of ensuring that identified problems that have the potential to affect the operability of safety systems are resolved in a timely manner and are resolved commensurate with their relevance to ensuring compliance with plant Technical Specifications. Mitigation of the civil penalty was appropriate for the licensee's aggressive identification of the root causes of the self-identifying event, but was offset by the escalation for the duration of the inoperable valve and the licensee's inadequate corrective actions. ($75,000)

5/93 ENFORCEMENT CONFERENCE — The staff exercised discretion and did not cite a violation involving a design control issue (undersizing of fuses) that was subsequently determined to have minor safety significance.

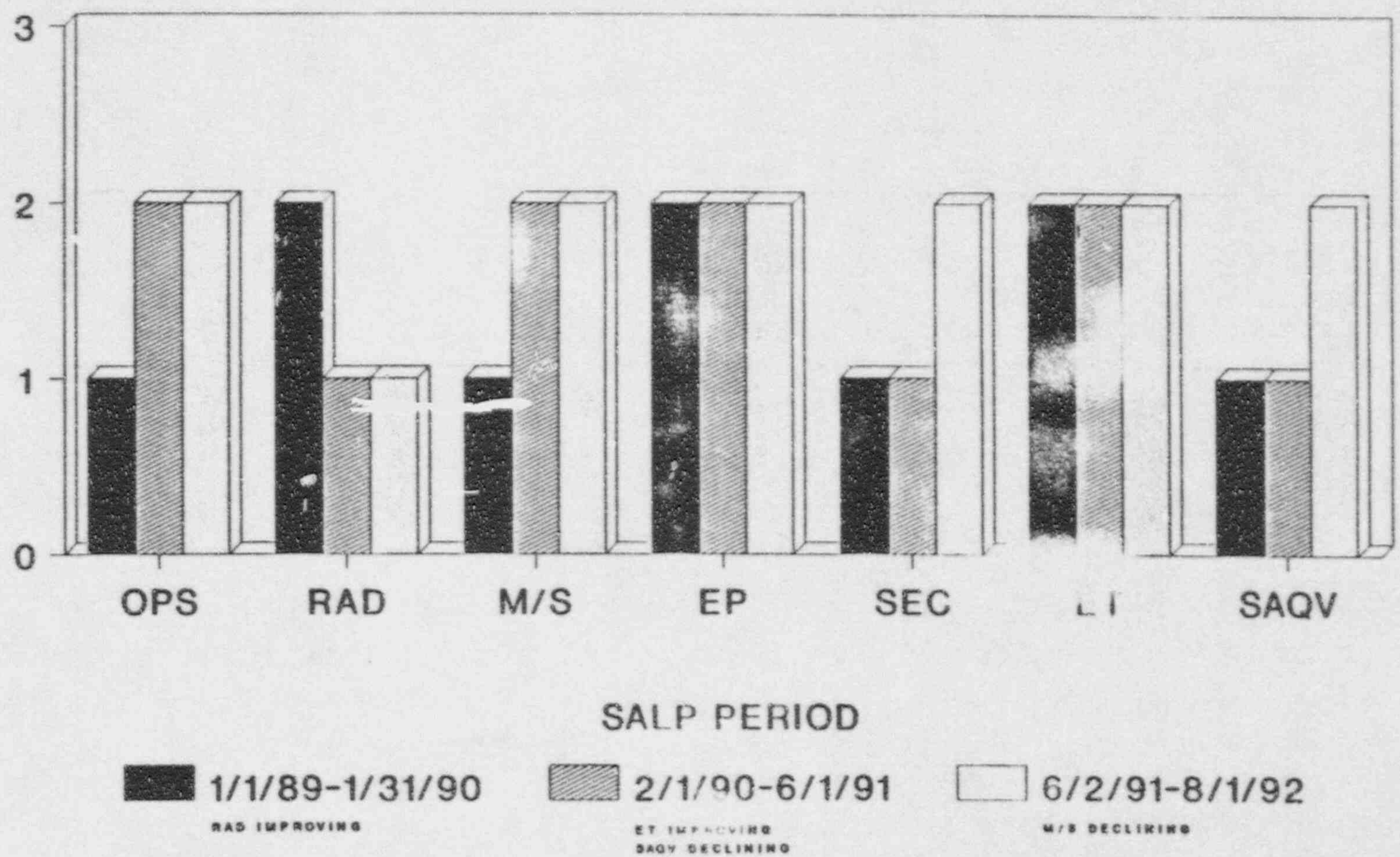
5/93 CIVIL PENALTIES — The action was based on two Severity Level III problems. The first consisted of (1) the Unit 1 TDAFW pump remaining in an inoperable condition for a period in excess of that permitted by the plant Technical Specifications; (2) a failure to perform adequate TDAFW pump surveillance testing to ensure that the pumps would operate when called upon to do so (both units) in light of the recurring overspeed trips; (3) a failure to provide adequate instructions for conducting preventative maintenance on the Unit 1 TDAFW pump governor valve; (4) a failure to follow procedures regarding the positioning of a steam trap valve associated with the Unit 2 TDAFW pump; and (5) the performance of maintenance on the Unit 2 TDAFW pump throttle valve linkage by an unauthorized individual. The second Severity Level III problem consisted of (1) EDG 13 remaining in an inoperable condition for a period in excess of that permitted by the plant Technical Specifications; (2) a failure the ensure that maintenance activities that could affect safety-related equipment were carried out in accordance with procedures appropriate to the circumstances resulting in a failure to test ED 13 following painting to ensure its operability; (3) EDGs 13 and 12 remaining in an inoperable condition for a period of 61 hours, when the Technical Specifications permit such a condition to exist for only two hours. Civil penalties were issued to emphasize the importance of ensuring the operability of safety-related equipment through proper maintenance, adequate testing and the correction of recurring problems. The civil penalty associated with the first Severity Level III problem was escalated for NRC identification of program inadequacies, multiple opportunities to correct the deficiencies, and for the duration of the inoperable Unit 1 TDAFW pump ($175,000). The civil penalty associated with the second Severity Level III problem was escalated for specific prior notice given with regard to EDG problems caused by painting and for the duration of the inoperable EDG 13 ($150,000). (Total: $325,000)

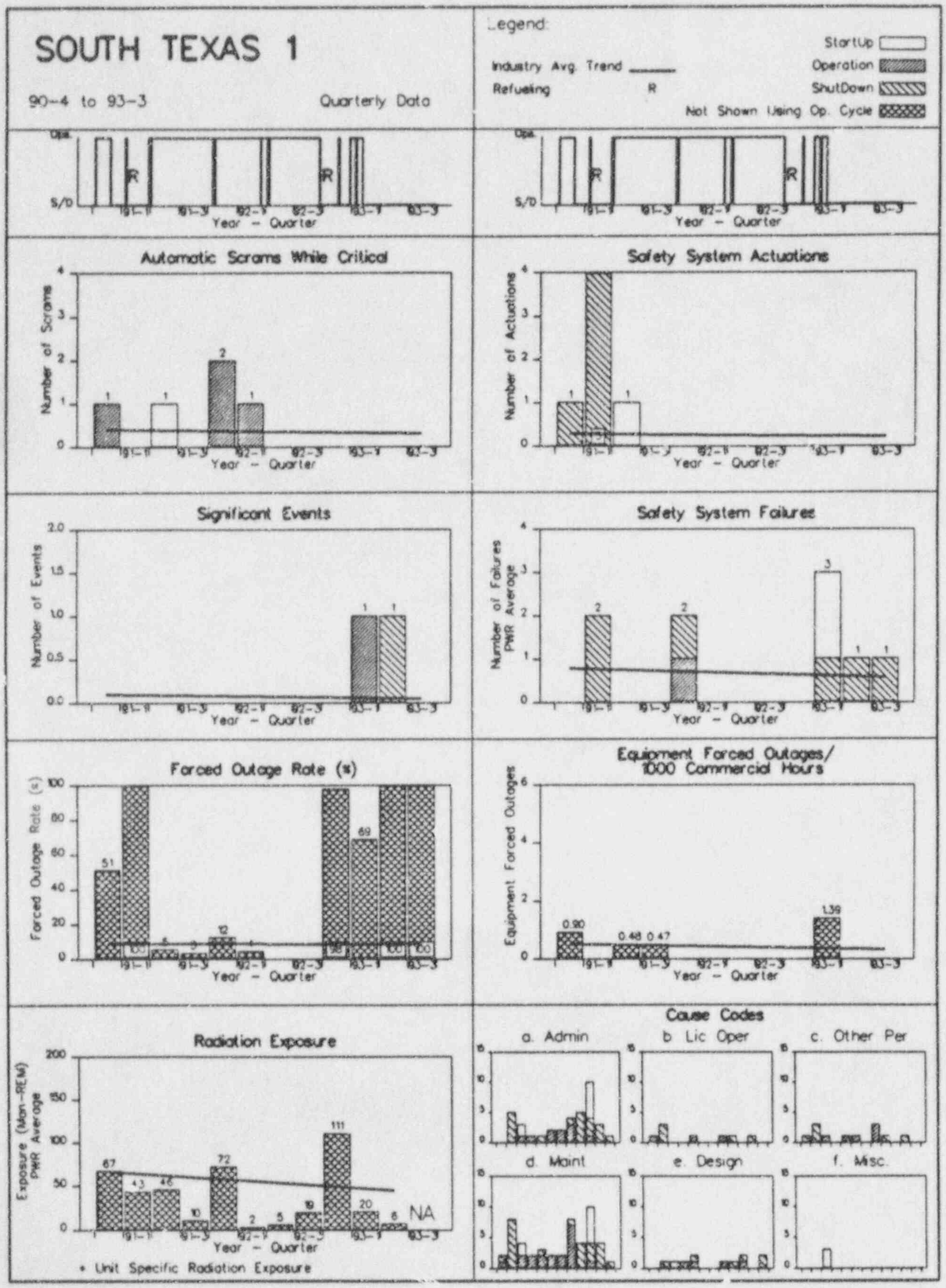
6/93 ENFORCEMENT CONFERENCE — Severity Level IV violation for inoperable steam generator power-operated relief valves and the reactor coolant system subcooled margin monitor due to deficiencies identified in the seismic qualifications of the qualified display processing system.

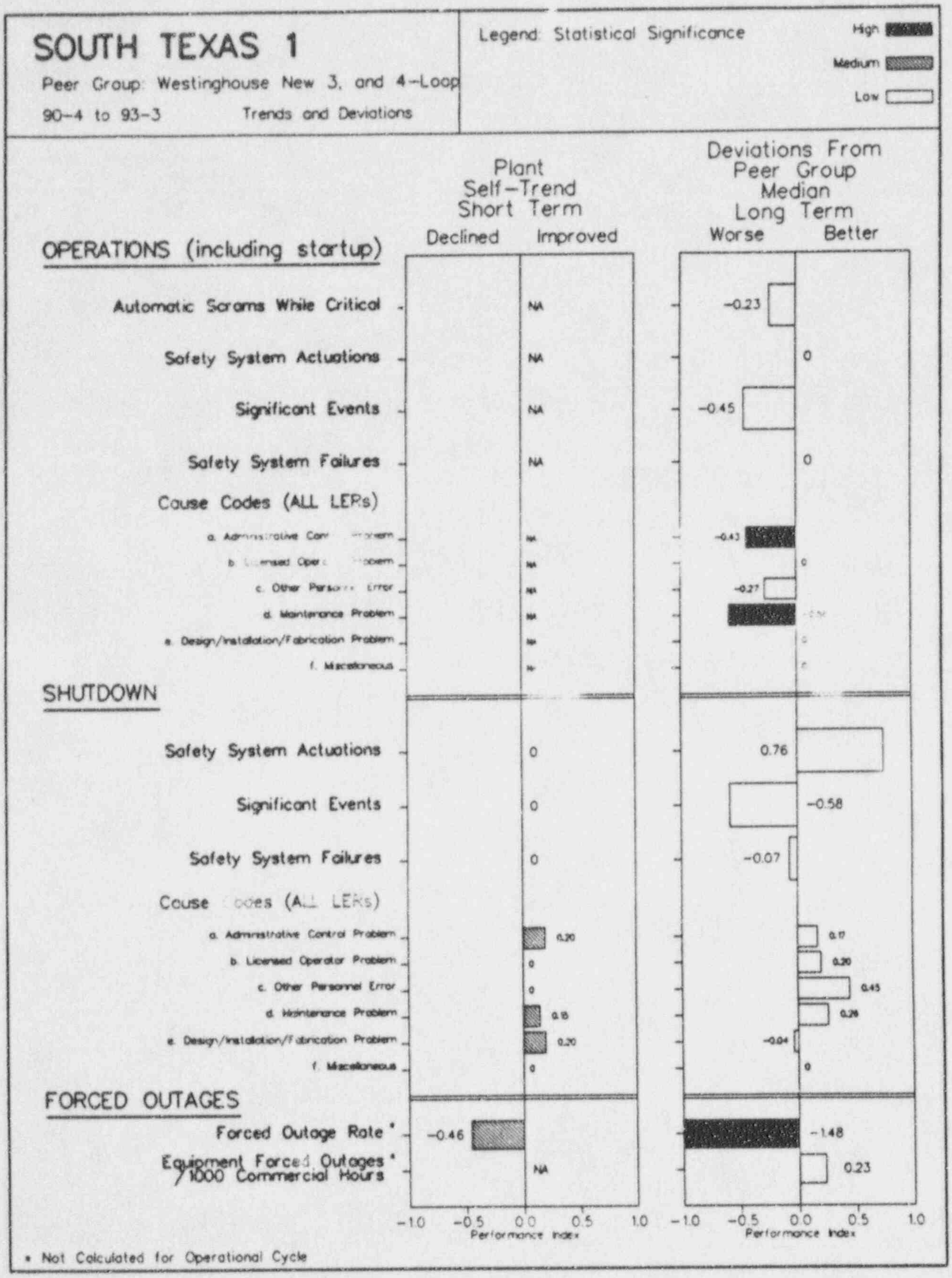
9/93 DEMAND FOR INFORMATION — The staff issued a Demand For Information related to apparent discrimination against security force members.

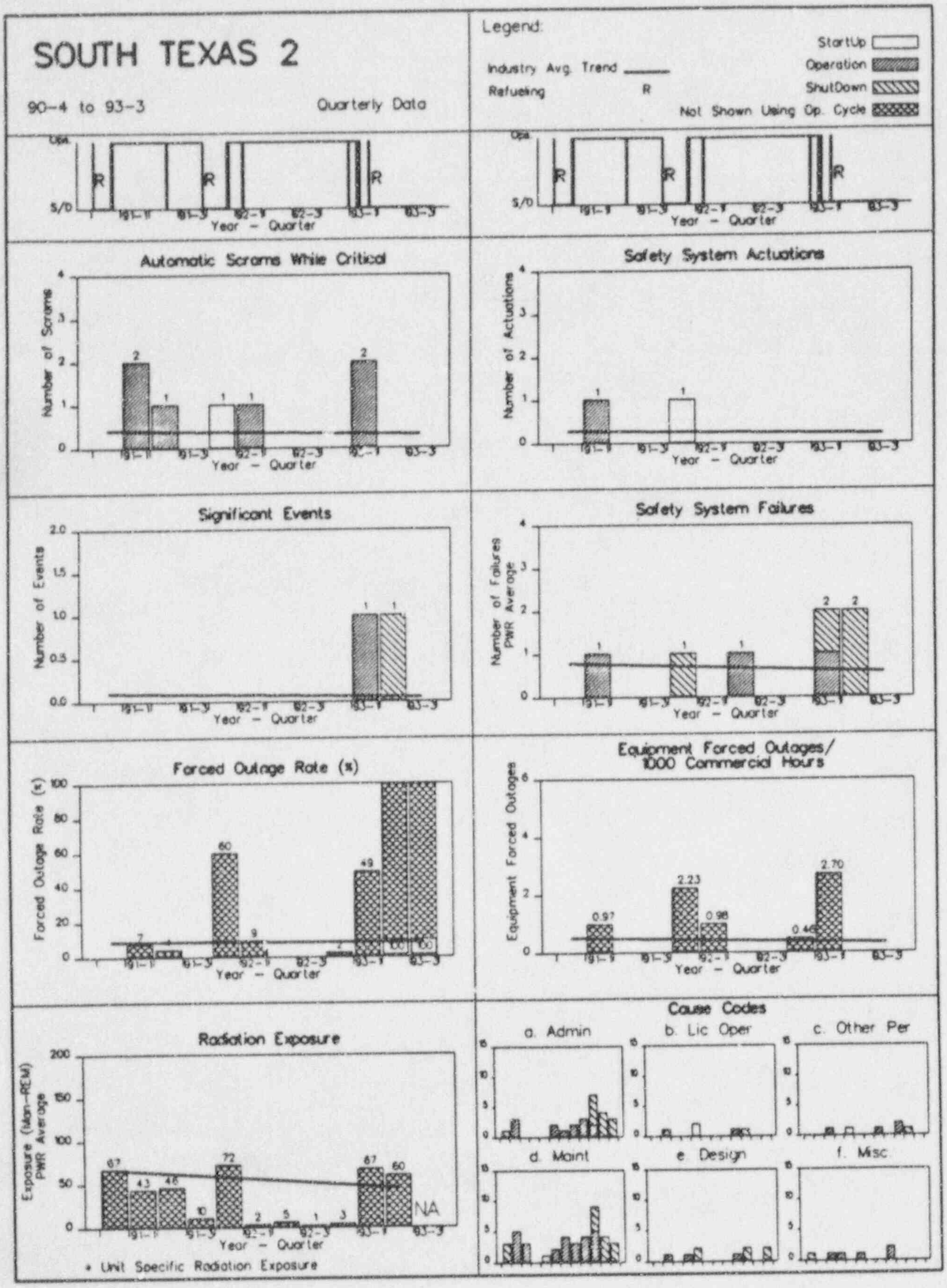
PENDING — Based on an Office of Inspection Report dated March 16, 1993, the staff is considering enforcement action for apparent harassment and intimidation of a contract I&C technician.

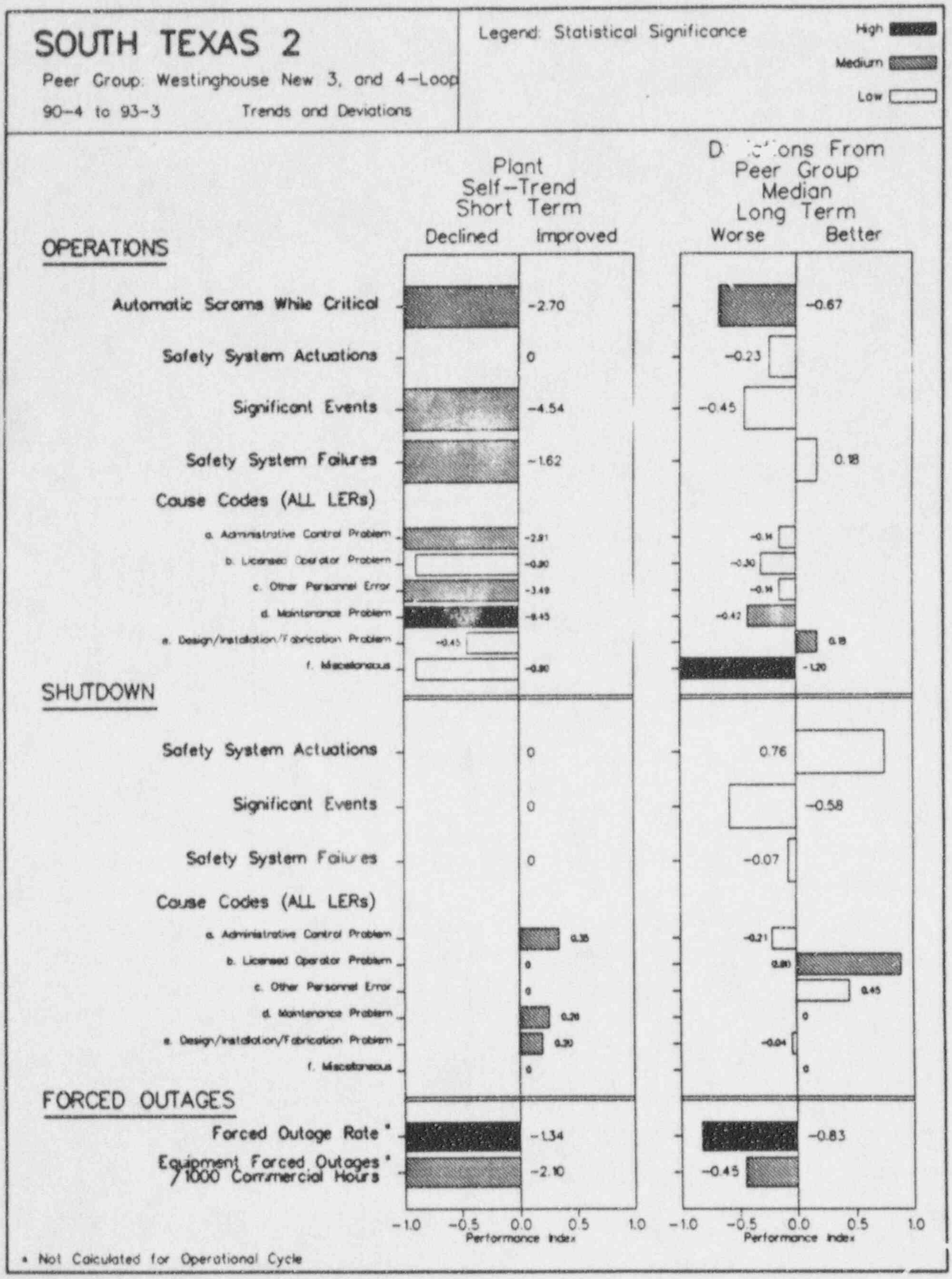
SOUTH TEXAS
MOST RECENT SALP RATINGS



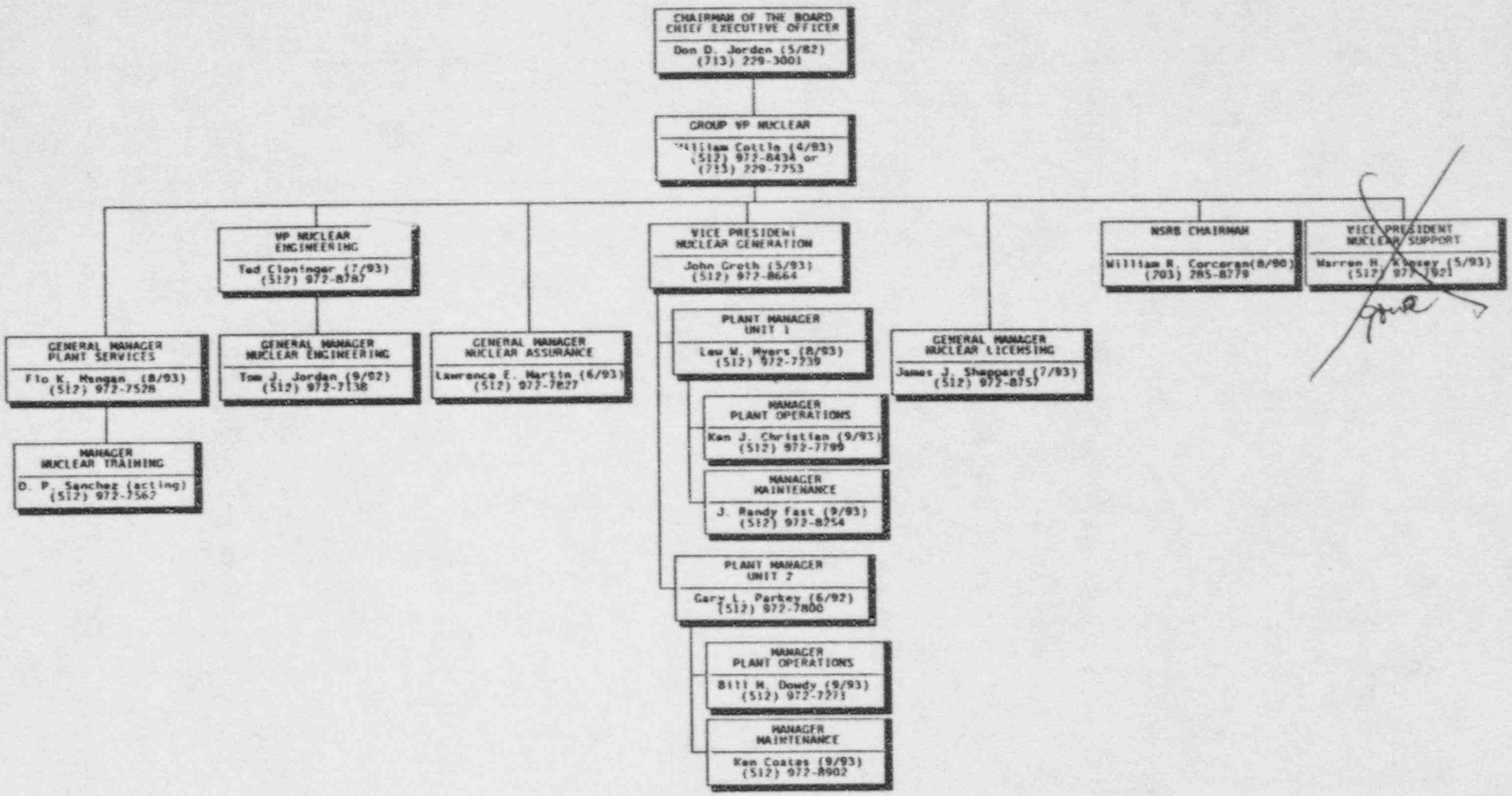

SOUTH TEXAS 1
90-4 to 93-3
Quarterly Data
Legend:
Industry Avg. Trend
Refueling R
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
Ops.
S/D
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
Number of Events
Safety System Failures
Number of Failures
PWR Average
Forced Outage Rate (%)
Forced Outage Rate (%)
Equipment Forced Outages/
1000 Commercial Hours
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM)
PWR Average
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc.


SOUTH TEXAS 1
Peer Group: Westinghouse New 3, and 4-Loop
90-4 to 93-3
Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Deviations From Peer Group Median Long Term
Worse
Better
OPERATIONS (including startup)
Automatic Scrams While Critical
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
NA
-0.23
0
-0.45
-0.43
-0.27
SHUTDOWN
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
0
0.20
0.15
0.76
-0.58
-0.07
0.17
0.45
0.26
-0.04
FORCED OUTAGES
Forced Outage Rate *
Equipment Forced Outages * /1000 Commercial Hours
-0.46
NA
-1.48
0.23
-1.0
-0.5
0.0
0.5
1.0
Performance Index
* Not Calculated for Operational Cycle


SOUTH TEXAS 2
90-4 to 93-3
Quarterly Data
Legend:
Industry Avg. Trend
Refueling R
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
Number of Events
Safety System Failures
Number of Failures PWR Average
Forced Outage Rate (%)
Forced Outage Rate (%)
Equipment Forced Outages/ 1000 Commercial Hours
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM) PWR Average
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc


SOUTH TEXAS 2
Peer Group: Westinghouse New 3, and 4-Loop
90-4 to 93-3
Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Peer Group Median Long Term
Worse
Better
OPERATIONS
Automatic Scrams While Critical
-2.70
-0.67
Safety System Actuations
0
-0.23
Significant Events
-4.54
-0.45
Safety System Failures
-1.62
0.18
Cause Codes (ALL LERs)
a. Administrative Control Problem
-2.91
-0.14
b. Licensed Operator Problem
-0.30
c. Other Personnel Error
-3.49
d. Maintenance Problem
-0.42
e. Design/Installation/Fabrication Problem
-0.45
f. Miscellaneous
-1.20
SHUTDOWN
Safety System Actuations
0
0.76
Significant Events
0
-0.58
Safety System Failures
0
-0.07
Cause Codes (ALL LERs)
a. Administrative Control Problem
-0.21
b. Licensed Operator Problem
0
c. Other Personnel Error
0
0.45
d. Maintenance Problem
0
e. Design/Installation/Fabrication Problem
-0.04
f. Miscellaneous
0
0
FORCED OUTAGES
Forced Outage Rate *
-1.34
-0.83
Equipment Forced Outages * /1000 Commercial Hours
-2.10
-0.45
-1.0 -0.5 0.0 0.5 1.0
Performance Index
* Not Calculated for Operational Cycle

HOUSTON LIGHTING & POWER COMPANY
SOUTH TEXAS PROJECT



12/93

PRE-DECISIONAL

SOUTH TEXAS

I. HISTORY

South Texas Project (STP) was first discussed at the January 1993, Senior Management Meeting (SMM), initially because of poor and declining performance for two systematic assessment of licensee performance periods. Repetitive hardware problems had resulted in numerous plant trips, transients, engineering safety features actuation, and forced outages. STP was subsequently discussed at the June 1993 SMM, when it was placed on the Watch List. Both units at STP were shutdown under a Confirmatory Action Letter (CAL) which was issued in February 1993. The problems were grouped into three broad areas; material condition and housekeeping, human performance, and organizational performance. A Diagnostic Evaluation was conducted in April 1993, and the findings of that inspection were presented to the licensee on June 3, 1993.

The CAL for Unit 1 was lifted on February 15, 1994, and the unit subsequently entered Modes 2 and 1. The unit attained 28 percent power before a manual reactor trip was initiated because a feedwater regulating valve failed closed. The unit restart was delayed because of a steam generator tube plug leak. The unit was restarted on March 21 and full power operation was attained on April 7. Unit 2 completed reloading the reactor vessel on April [illegible], 1994, entered Mode 5 on April 8, Mode 4 on May 11, and is currently scheduled to startup on May 17, 1994.

II. CHANGES SINCE LAST SMM

Based on the results of the Operational Readiness Assessment Team and Region IV's inspections at STP since October 1993, all restart issues were found to have been adequately addressed and the CAL was lifted on February 15, 1994, for Unit 1. The staff provided 24 hour coverage of plant activities during the startup and power ascension of Unit 1.

The STP Restart Panel (Panel) developed a Restart Action Plan, following the guidance in Manual Chapter 0350, "Staff Guidance for Restart Approval," The Panel used this plan to ensure coordination of NRC resources associated with the restart of Unit 1. A similar approach has been initiated for Unit 2. Management meetings with the licensee have been held approximately monthly, and most of these meetings have been held at the site. All of the management meetings have been open to public observation.

The licensee has conducted independent assessments utilizing an outside party. These assessments identified areas for improvement which included the size of the station problem report backlog. These improvement items were discussed by the licensee during April 8, and May 4, 1994, Public Management Meetings.

The Region IV staff conducted an assessment of licensee performance as Unit 1 approached 90% power in February and March, 1994. The results of this assessment indicated that generally plant operators were performing acceptably, with a few exceptions noted in the areas of oversight and control of plant tests and surveillances.

The licensee has experienced several problems with Cooper-Bessemer emergency diesel generators. These problems consist of a relay problem with the field flash circuit of Emergency Diesel Generator 11, that rendered the machine inoperable from February 3 to March 11, 1994; inadvertent starts of Emergency Diesel Generator 21; and a broken piston and other signs of significant degradation of Emergency Diesel Generator 22. A Public Management Meeting was conducted with the licensee on March 16, 1994, to discuss these recently identified emergency diesel generator problems and the actions the licensee has taken, or plans to take, to resolve them. These issues were also discussed in a Public Management Meeting at the site on May 4, 1994. The Region IV and NRR staff are continuing to follow up on the potential emergency diesel generator operational concerns.

The Operational Readiness Assessment Team completed its inspection activities in January 1994. The team identified some continuing weaknesses with configuration management and the corrective action program, but the findings were generally positive and supportive of Unit 1 restart.

A special inspection was performed in January 1994 on the reactor containment building sump issues and a violation was cited. Specifically, the as-found condition of the emergency containment sump enclosures did not meet the design basis because openings in the sump screen were too wide and debris could enter the sump during the recirculation phase of the design basis accident.

On March 10, 1994, while in mid-loop operation in support of the leaking steam generator tube repair, Unit 1 lost shutdown cooling for approximately five minutes. This event occurred during the performance of a solid state protection system surveillance when licensed operators failed to inform the control room of procedure adherence problems encountered during the performance of the activity. A Public Management Meeting was conducted with the licensee on March 16, 1994. During that meeting the licensee informed the staff that no hardware problems had been identified with the solid state protection system. This event was significant because the lack of management controls allowed a test to be performed that had the potential to cause a loss of decay heat removal while the reactor was in mid-loop operations. Additionally, the reactor operators failed to verify that they were performing the test in the correct protection cabinet and that, once they identified the error, they failed to inform the shift supervisor prior to proceeding with recovery actions. Also, prior to the actuation, the shift supervisor had indications that reactor operators were not properly controlling the testing evolution but did not ensure the evolution was being properly conducted and that the operators' questions had been resolved.

A request on May 5, 1993, by Mr. Thomas J. Saporito in accordance with 10 CFR 2.206 to shut down the facility has been acknowledged and denied. The final Director's Decision is still under review.

The decision was delayed until the Department of Justice completed its grand jury investigation of possible criminal violations in regard to whistleblower activities. On April 8, 1994, the Department of Justice notified the licensee that it was no longer a target of the investigation. The Director's Decision is expected to be completed in June 1994. Additionally, various allegations have been made at the facility by current and former plant workers, and these are under review.

III. FUTURE ACTIVITY

Region IV has scheduled the inspection activities required to assess the licensee's efforts to restart Unit 2. A public meeting following the completion of the inspection effort will be held to ascertain whether the Unit 2 restart CAL should be lifted. The licensee has scheduled May 17, 1994, as the date for the restart of Unit 2. The licensee has shifted resources to Unit 2 to facilitate completion of restart work activities. Based on the preliminary results of the inspections conducted to date and an assessment of the licensee's restart plan, Region IV anticipates that this date is achievable. The largest potential impact to the schedule was resolution of diesel generator problems, but all emergency diesel generators were declared operable on May 11, 1994.

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

Unit 1

On February 28, 1994, the unit was manually tripped from 28 percent thermal power because of a failed closed feedwater regulating valve. An automatic reactor trip would have occurred because of decreasing steam generator level.

Unit 2

None

B. Significant Operator Errors

On March 10, 1994, with Unit 1 in Mode 5 an unexpected safety injection actuation occurred on all three trains during restoration from a solid state protection system logic functional test. The reactor operators transitioned from Train S to Train R which resulted in the safety injection actuation signal, a loss of shutdown cooling and a gravity feed path from the refueling water storage tank to the reactor coolant system. It was determined that the operators had conducted the surveillance test on the incorrect train and that inadequate management oversight had been provided in permitting the activity to performed with the plant in mid-loop operation.

C. Procedures

A number of procedure weaknesses and examples of licensee personnel failing to follow procedures have been identified since the last SMM. These include:

- the reactor startup procedure did not provide clear guidance on linearly extrapolating the critical boron concentration,
- two temperature switches were replaced in a emergency diesel generator room without first conducting a pre-job briefing,
- valve maintenance technicians failed to verify the station component valve identifications matched resulting in work being conducted on the incorrect valve,
- operators performed a surveillance on the incorrect train resulting in a safety injection actuation signal and loss of shutdown cooling.

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

	SRO	RO	Total
Licensed Operators	51	37	88

B. Number and Length of Shifts

Six, 12-hour shifts

C. Role of STA

One STA is shared between the two units. They are not assigned to a specific shift crew, nor do they receive training with a specific shift crew. STAs do not hold a senior operator's license. The STA's primary duty is to act as an accident prevention and mitigation advisor to the shift supervisor.

D. Requalification Program Evaluation

A requalification program inspection was conducted during the month of January 1993, in accordance with Temporary Instruction 2515/117, "Licensed Operator Requalification Program Evaluation." There was one violation: (1) failure to follow an approved procedure of the Nuclear Training department, NTP-230, which required review and approval of the current biennial training plan by the Technical Advisory Council. The inspectors noted that operators' performance as well as facility evaluators during the operating examinations was good.

Region IV will conduct an inspection in accordance with IP-71001, "Licensed Operator Requalification Program Evaluation," during the month of November 1994.

III. PLANT-SPECIFIC AND UNIQUE DESIGN INFORMATION

A. Plant-Specific Information

Owners:	Houston Lighting and Power Company City of San Antonio Central Power & Light Company City of Austin
Reactor Supplier/Type:	Westinghouse/4-loop PWR
Capacity, MWT:	3800 MWT
Architect/Engineer:	Bechtel
Constructor:	Ebasco
Commercial Operation:	Unit 1: August 25, 1988 Unit 2: June 19, 1989

B. Unique Design Information

Containment: Dry, carbon steel lined, prestressed, reinforced concrete, cylindrical structure with a hemispherical dome

Emergency Core Cooling Systems: Three high head safety injection, low head safety injection, and containment spray pumps; three safety injection accumulators; three motor-driven, 50 percent capacity, auxiliary feedwater pumps, one turbine-driven, 50 percent capacity auxiliary feedwater pump per unit

AC Power: Eight 345 kV offsite sources; three 5500 kW Cooper-Bessemer emergency diesel generators per unit

DC Power: Four sets of batteries powering four independent Class 1E 125-VDC subsystems per unit

IV. SIGNIFICANT MPAS OR PLANT-UNIQUE ISSUES

A. Generic Licensing Items

MPA B111, Generic Letter 88-20, Individual Plant Examination (IPE)

The licensee submitted its IPE on August 28, 1992. The staff is reviewing the licensee's submittal.

MPA B118, Generic Letter 88-20, IPE-External Events (IPEEE)

The licensee submitted its IPEEE with the STP PSA report on December 23, 1991. External events contribute about 3 percent to the core damage frequency. Since this arrived well in advance of the requested date, this item is "artificially" aged, as shown by the early application date. The staff is reviewing the licensee's submittal.

MPA X201 & MPA L208, Bulletin 92-01 & GL 92-08, Thermo-Lag

The licensee has substantial amounts of Thermo-Lag present and has responded to NRR's request for additional information by letter dated February 10, 1994. The licensee has taken a different approach in its response than the staff anticipated. The licensee will utilize the PRA as a basis to show that upgrading the existing Thermo-Lag is not required in order to provide an adequate level of fire protection since there is a high degree of separation of the three independent safety trains, and fires outside of the control room contribute less than 1% to the overall CDF. The staff is reviewing the licensee's submittal.

B. Plant-Unique Licensing Issues

The licensing organization has dedicated resources to evaluate the TS Improvement Program for use at South Texas. The decision to change the TS is expected by mid-1994.

V. STATUS OF THE PHYSICAL PLANT

PLANT EQUIPMENT: STP is a relatively new site and no major problems have manifested themselves. Because of the length of construction, however, equipment and components are not considered new. There have been many plant events and forced outages primarily because of balance-of-plant equipment problems.

Several longstanding problems associated with the EDGs, the main feedwater system, essential chillers, and MOVs were addressed prior to the Unit 1 startup. Continuing concerns with the adequacy of corrective actions to resolve emergency diesel generator fuel injector pump (jerk pump) bolt failures are being addressed by the licensee.

VI. PRA

A. PRA Insights

South Texas is a newer Westinghouse four loop NSSS with a 3 train ECCS design. The ECCS design is unique in that each train delivers flow to a specific RCS loop with no ECCS injection into RCS loop 4 and no cross ties to the other loops. The success criteria for a large break LOCA require one train of injection to an intact loop. For a small break LOCA, any one train of ECCS is sufficient, regardless of the location of the break.

The RHR pumps at South Texas are separate from the LPSI pumps and the entire RHR system is inside containment. Also, the HPSI pumps can take suction directly from the sump. Therefore, the HPSI pumps are not dependent on suction from the LPSI pumps or the RHR pumps during the recirculation mode.

South Texas is equipped with 3 EDGs per unit (one for each ECCS train). The reliability of all six EDGs is above 0.975. However, the unavailability due to maintenance is higher than the industry targets.

B. PRA Profile

The South Texas Project Probabilistic Safety Assessment (PSA) was submitted to the NRC in 1989 and included analyses of internal and external events. The PSA was reviewed and approved by the staff. As a result of the PSA findings, an important modification was implemented. This modification involved the connection of the positive displacement charging pump to the technical support center DG to provide RCP seal cooling in the event of a total loss of AC power.

HL&P responded to GL 88-20 by submitting a Level 2 IPE and IPEEE in August, 1992. The original PSA estimated a core damage frequency of 1.7E-4 per year. The IPE reports an estimated core damage frequency of 4.4E-5 per year for internal and external events. The IPE CDF is about a factor of 4 less than that obtained in the original PSA. The IPE has not been reviewed by RES, so it is not yet clear what has contributed to the decrease in the CDF estimate. The licensee attributes the decrease in CDF to a reduction in conservatism. The dominant initiators contributing to core damage from the IPE are listed below:

Initiating Event Category	% of Total CDF
Loss of Offsite Power (LOOP)	35.3%
Loss of Electrical Auxiliary Building HVAC (resulting in an internally induced SBO)	20.1%
Small LOCA	5.4%
Reactor Trip	5.1%
Transient induced LOOP	5.0%
Steam Generator Tube Rupture	4.8%
Turbine Trip	3.2%
Medium LOCA	2.8%
Loss of Essential Cooling Water	2.6%
Loss of Control Room HVAC	2.3%
All Others	13.2%

It should be noted that while full treatment of external events and internal plant hazards such as fires and floods was included in the IPE submittal, such events contributed less than 4% to the total core damage frequency. This contribution to total CDF from external events is a significantly smaller percentage than any other recently published PRA for a PWR plant has estimated. HL&P attributes this small contribution to two principal reasons. First, the site has a very low seismicity in relation to the design basis earthquake. Second, there is ample redundancy and physical separation in the ECCS trains, which would reduce the likelihood that internal fires and floods and other spatial interactions could result in a serious accident.

The licensee found no significant accident sequence outliers as a result of performing the IPE.

C. Core Damage Precursor Events

On the basis of the precursors identified by ORNL for 1991 and 1992 (NUREG/CR-4674, vols. 15 through 18), SPSB did not identify any precursor events for the site that have a conditional core damage probability of 1E-5 per year or greater.

SPSB notes the following event that has been classified as a "Significant Event" for the Performance Indicator Problem. South Texas unit 1 experienced overspeed trips of their Turbine Driven Auxiliary Feedwater (TDAFW) pump during surveillance tests on Dec. 27, 1992 and Jan. 28, 1993. Also, on Feb. 3, 1993, the unit 2 TDAFW pump tripped on overspeed during an actual demand after a plant trip. The licensee performed an analysis of the unit 1 condition with the assumption that the TDAFW pump was inoperable for 33 days. The CDF increased from 4.4E-5 (as reported in the IPE) to 4.5E-5 per year.

During the same time period (Dec. 29, 1992 thru Jan. 22, 1993), unit 1 DG-13 was inoperable due to paint drips on the fuel metering rod ports. Furthermore, unit 1 DG-12 was out of service for a 61 hour planned maintenance period while DG-13 was inoperable.

When the DG event and the TDAFW pump trip event are analyzed as separate events, the risk does not appear to be significant. However, since the DG-13 and the TDAFW pump were inoperable during the same period, SPSB performed a preliminary ASP assessment which estimated a Conditional Core Damage Probability of 1E-5/year. SPSB has suggested to AEOD that the overall situation should be reviewed for potential precursor significance.

VII. ENFORCEMENT HISTORY (Since June 1992)

4/93 CIVIL PENALTY - The action was based on a number of violations of established procedures which resulted in the failure to inform NRC licensed operators in the control room of potentially significant conditions that could have affected the operation of the plant. Because the failures to follow established procedures involved plant management personnel, these violations were classified as a Severity Level III problem. A civil penalty was issued to emphasize the need for managers, when necessary, to promptly and properly interface with the NRC-licensed personnel in the control room and the importance of plant management personnel following or properly modifying established procedures. Mitigation of the civil penalty was appropriate for the licensee's corrective actions, but it was offset by the escalation for NRC identification and the licensee's prior opportunity to identify one of the violations. ($75,000)

4/93 CIVIL PENALTY - The action was based on numerous examples of failures to adhere to procedural requirements regarding self-verification that primarily involved the failure to verify the correct unit, correct train, or correct device before conducting testing or maintenance activities. Although none of the errors resulted in adverse safety consequences, collectively they represented a significant regulatory concern and were classified as a Severity Level III problem. A civil penalty was issued to emphasize the importance of attention to detail and the need for the licensee to be aggressive in implementing corrective actions of a lasting nature. The civil penalty was partially mitigated based on the licensee's corrective actions. ($25,000)

4/93 CIVIL PENALTY - The action was based on the licensee's failure to take corrective actions for a failed motor on a motor operated valve in the Unit 2 Low Head Safety Injection System. The violations involved in this action were classified as a Severity Level III. A civil penalty was issued to emphasize the importance of ensuring that identified problems that have the potential to affect the operability of safety systems are resolved in a timely manner and are resolved commensurate with their relevance to ensuring compliance with plant Technical Specifications. Mitigation of the civil penalty was appropriate for the licensee's aggressive identification of the root causes of the self-identifying event, but was offset by the escalation for the duration of the inoperable valve and the licensee's inadequate corrective actions. ($75,000)

5/93 ENFORCEMENT CONFERENCE - The staff exercised discretion and did not cite a violation involving a design control issue (undersizing of fuses) that was subsequently determined to have minor safety significance.

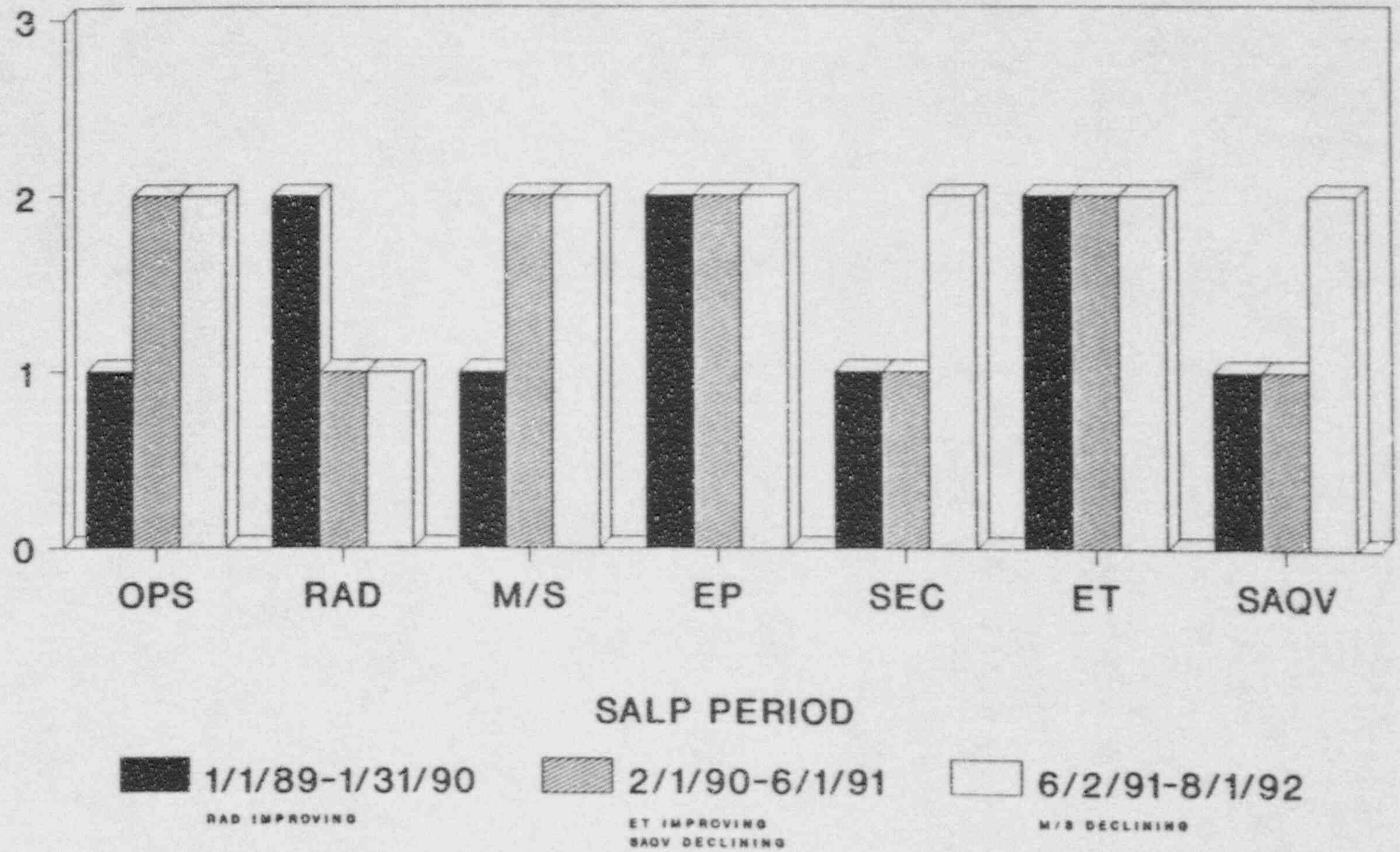
5/93 CIVIL PENALTIES - The action was based on two Severity Level III violations. The first violation involved the TDAFW system. Specifically; (1) inadequate surveillance testing; (2) inadequate instructions; (3) failure to follow procedures; (4) unauthorized maintenance; and (5) inoperable equipment longer than permitted by the plant Technical Specifications. The second violation involved the EDGs for having the equipment inoperable longer than permitted by the plant Technical Specifications and failure to follow procedures. Civil penalties were issued to emphasize the importance of ensuring the operability of safety related equipment through proper maintenance, adequate testing and the correction of recurring problems. The civil penalty associated with the first violation was escalated for NRC identification of program inadequacies, multiple opportunities to correct the deficiencies, and for the duration of the inoperable Unit 1 TDAFW pump ($175,000). The civil penalty associated with the second violation was escalated for specific prior notice given with regard to EDG problems caused by painting and for the duration of the inoperable EDG 13 ($150,000). ($325,000)

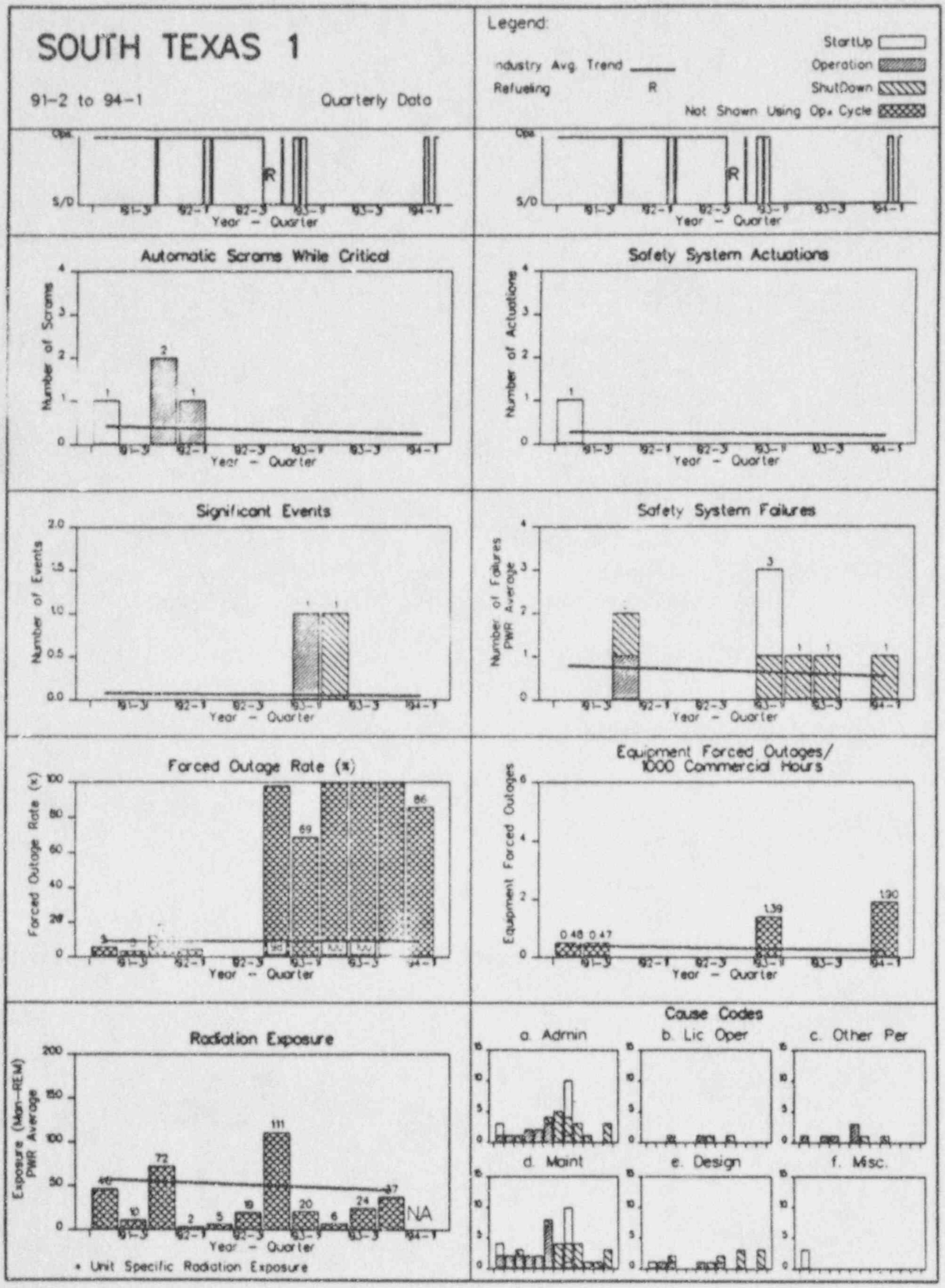
6/93 ENFORCEMENT CONFERENCE - Severity Level IV violation for inoperable steam generator power operated relief valves and the reactor coolant system subcooled margin monitor due to deficiencies identified in the seismic qualifications of the qualified display processing system.

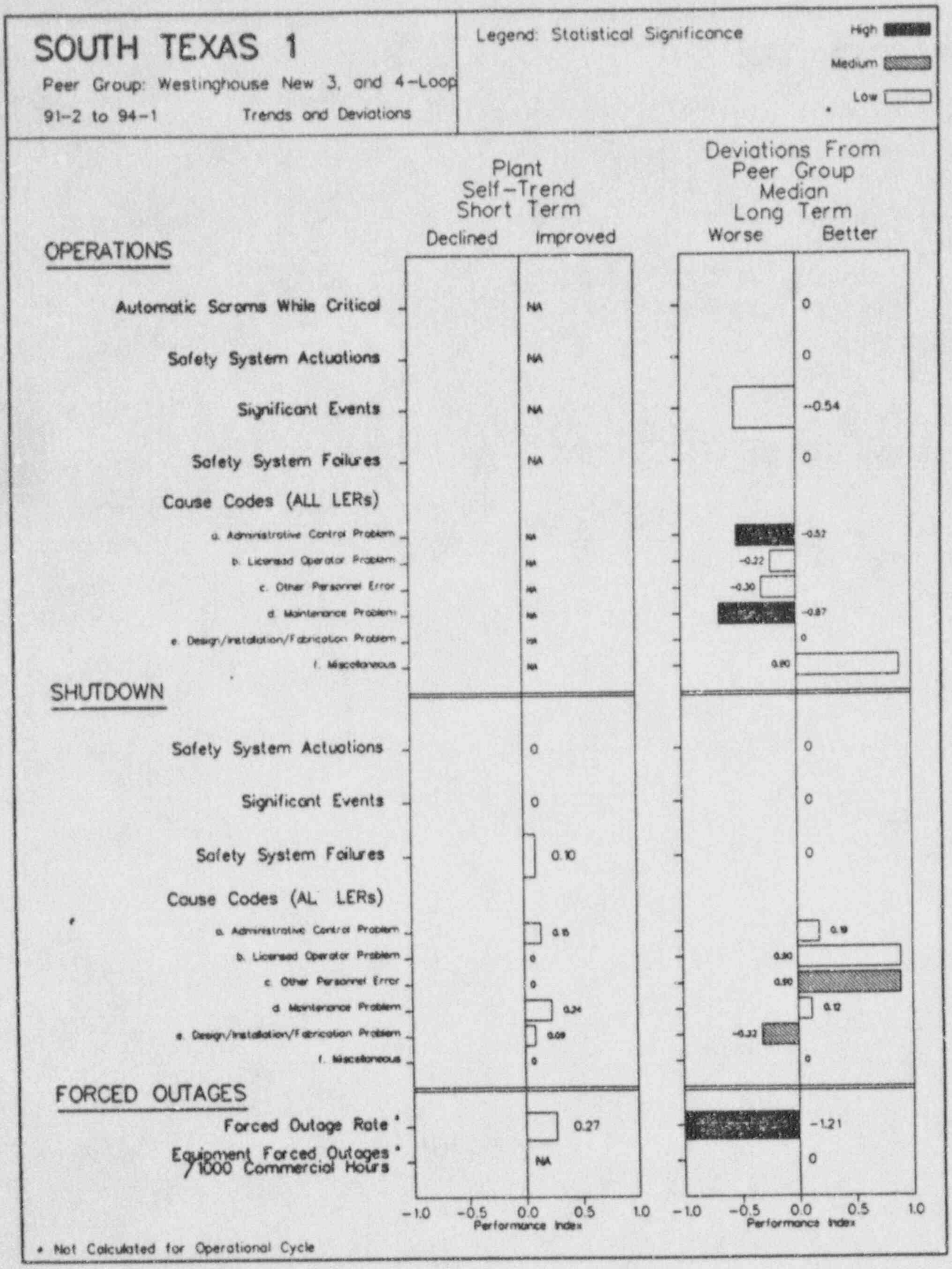
9/93 DEMAND FOR INFORMATION - The staff issued a Demand For Information related to apparent discrimination against security force members. Following the licensee's response, the staff decided to await the DOL ALJ decision before deciding on the need for enforcement action.

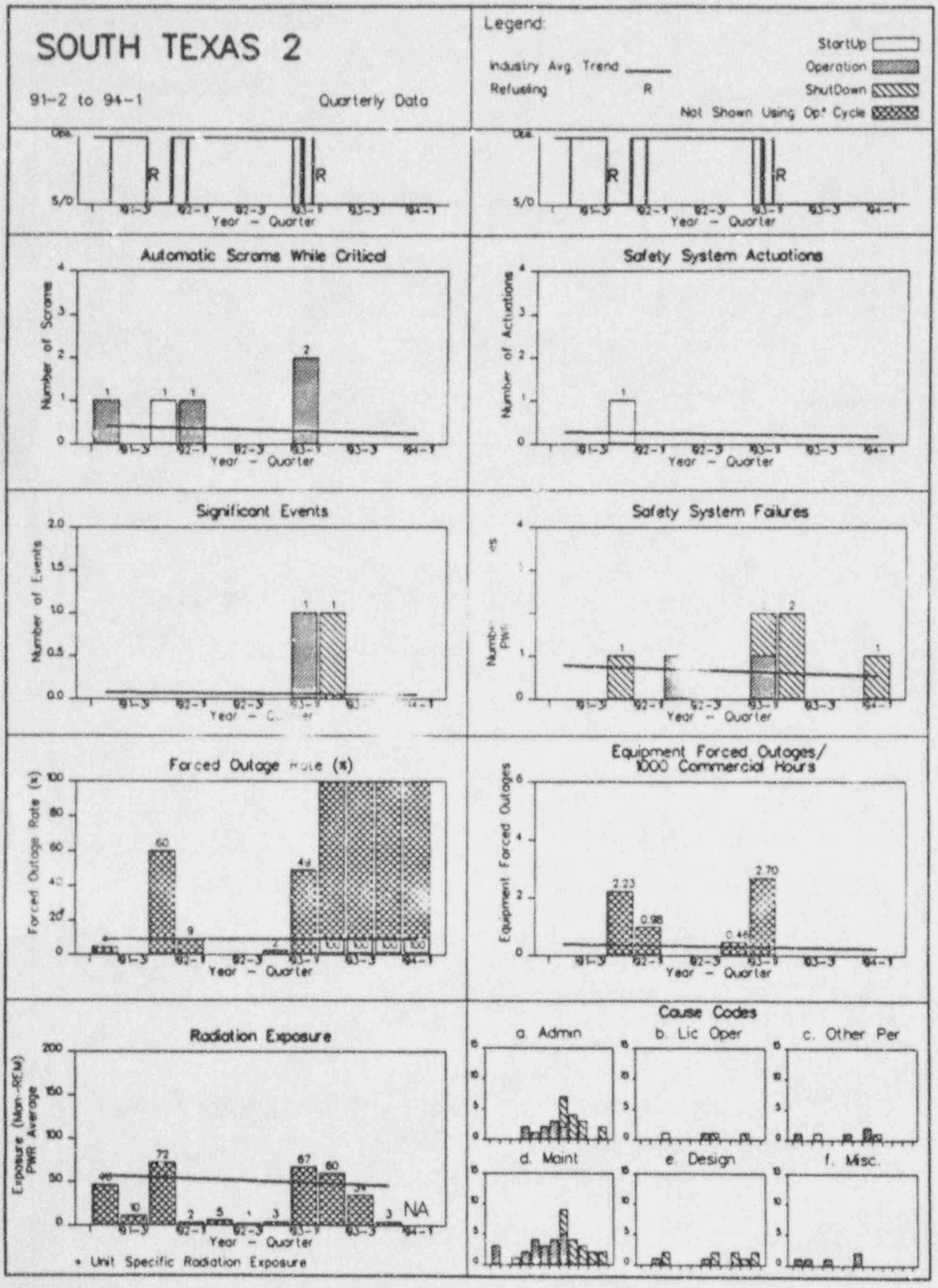
PENDING - Based on an Office of Investigations Report dated March 16, 1993, the staff is considering enforcement action for apparent harassment and intimidation of a contract I&C technician.

SOUTH TEXAS
MOST RECENT SALP RATINGS




SOUTH TEXAS 1
91-2 to 94-1
Quarterly Data
Legend:
Industry Avg. Trend
Refueling R
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
Ops
S/D
R
Year – Quarter
Automatic Scrams While Critical
Number of Scrams
1
2
1
Safety System Actuations
Number of Actuations
1
Significant Events
Number of Events
1
1
Safety System Failures
Number of Failures
PWR Average
3
1
1
1
Forced Outage Rate (%)
Forced Outage Rate (%)
69
86
Equipment Forced Outages/
1000 Commercial Hours
Equipment Forced Outages
0.48
0.47
1.39
1.90
Radiation Exposure
Exposure (Man-REM)
PWR Average
72
10
2
5
19
111
20
6
24
37
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc.


SOUTH TEXAS 1
Peer Group: Westinghouse New 3, and 4-Loop
91-2 to 94-1 Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Deviations From Peer Group Median Long Term
Worse
Better
OPERATIONS
Automatic Scrams While Critical
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
NA
0
-0.54
-0.22
-0.30
-0.87
0.90
SHUTDOWN
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
0.10
0.24
0.90
0.12
-0.32
FORCED OUTAGES
Forced Outage Rate *
Equipment Forced Outages * /1000 Commercial Hours
0.27
-1.21
-1.0 -0.5 0.0 0.5 1.0
Performance Index
* Not Calculated for Operational Cycle


SOUTH TEXAS 2
91-2 to 94-1
Quarterly Data
Legend:
StartUp
Industry Avg. Trend
Operation
Refueling R
ShutDown
Not Shown Using Op' Cycle
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
Number of Events
Safety System Failures
Forced Outage Rate (%)
Forced Outage Rate (%)
Equipment Forced Outages/
1000 Commercial Hours
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM)
PWR Average
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
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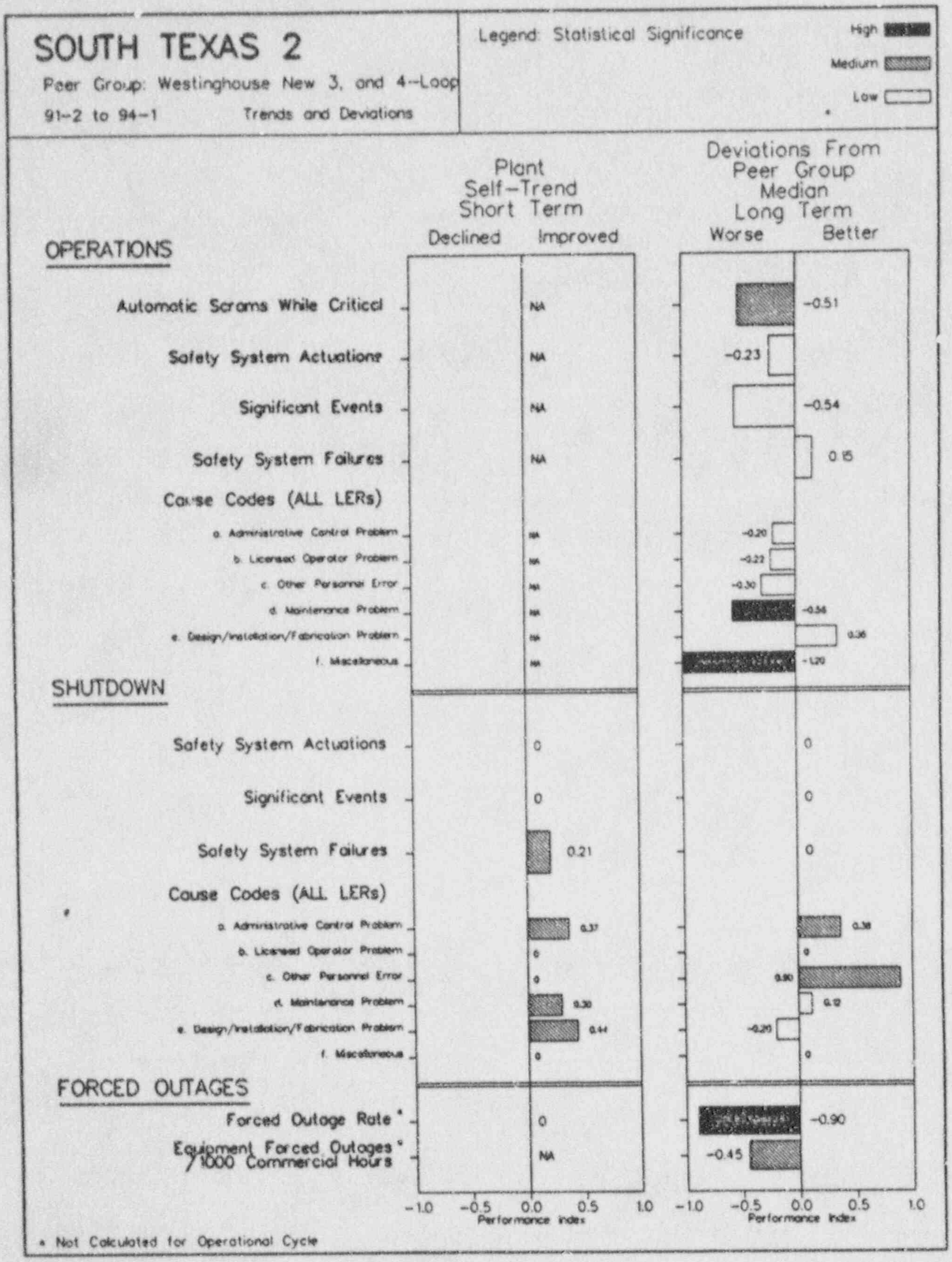
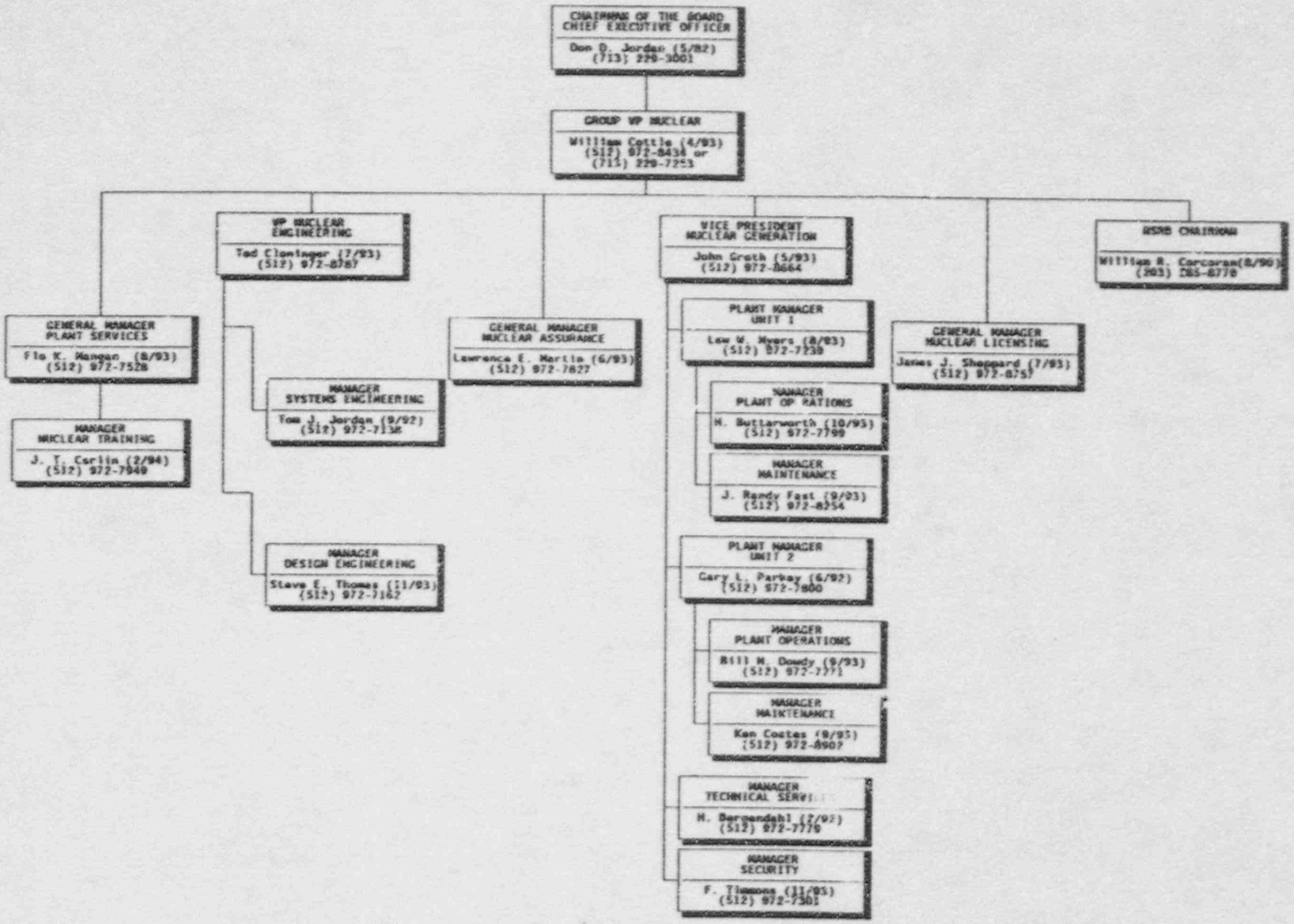
e. Design
f. Misc.


SOUTH TEXAS 2
Peer Group: Westinghouse New 3, and 4-Loop
91-2 to 94-1
Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Deviations From Peer Group Median Long Term
Worse
Better
OPERATIONS
Automatic Scrams While Critical
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
NA
-0.51
-0.23
-0.54
0.15
-0.20
-0.22
-0.30
-0.56
0.36
-1.20
SHUTDOWN
Safety System Actuations
Significant Events
Safety System Failures
Cause Codes (ALL LERs)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
0
0.21
0.37
0.30
0.44
0.38
0.90
0.12
-0.20
FORCED OUTAGES
Forced Outage Rate *
Equipment Forced Outages * /1000 Commercial Hours
0
NA
-0.90
-0.45
-1.0
-0.5
0.0
0.5
1.0
Performance Index
* Not Calculated for Operational Cycle

HOUSTON LIGHTING & POWER COMPANY
SOUTH TEXAS PROJECT



3/94

1/95

PRE-DECISIONAL

SOUTH TEXAS

I. HISTORY

South Texas Project (STP) was first discussed at the January 1993, Senior Management Meeting (SMM), initially because of poor and declining performance for two Systematic Assessment of Licensee Performance (SALP) periods. Repetitive hardware problems had resulted in numerous plant trips, transients, engineering safety features actuation, and forced outages. STP was subsequently discussed at the June 1993 SMM, when it was placed on the Watch List. Both units at STP were shut down under a Confirmatory Action Letter (CAL) which was issued in February 1993. The problems were grouped into three broad areas: material condition and housekeeping, human performance, and organizational performance. A Diagnostic Evaluation was conducted in April 1993.

Unit 1 restarted on February 18, 1994, after its CAL was closed. The unit was at 28 percent power on February 28 when a manual reactor trip was initiated because a feedwater regulating valve failed closed. The unit restart was delayed because of a steam generator tube plug leak. The unit was restarted on March 21. The unit operated at power until September 20 when loss of a main feedwater pump resulted in a trip. The unit restarted on September 21 and has operated at power since then. Unit 2 restarted on May 22, 1994, after its CAL was lifted. On June 25, a main transformer lockout resulted in a trip. The unit was restarted on June 29 and has operated at power since then.

II. CHANGES SINCE LAST SMM

All restart issues were found to have been adequately addressed and the Unit 2 CAL was closed on May 17, 1994. The staff provided 24 hour coverage of plant activities during the startup and power ascension. The licensee continued to implement its Business Plan and was revising the Business Plan and preparing the supporting budget in November 1994. In October 1994, the licensee revised its corrective action program. The revised program uses one initiating document (Condition Report) and focuses on individual ownership of issues and effectiveness of corrective actions. The NRC staff has not yet evaluated the effectiveness of the revised program.

In August 1994, a 10-member team, with little or no prior experience with the South Texas Project, performed a pilot Customized Inspection Planning Process (CIPP) team inspection at the site. Overall, the team found that performance at South Texas Project had improved in virtually all functional areas. The licensee had been effective in identifying and resolving problems. Almost without exception, performance problems were identified and entered into the corrective action system for evaluation and resolution. Quality assurance had an active role in identifying performance issues and in assessing the effectiveness of corrective actions. Significant improvements had been made in management involvement, communications and team work. An atmosphere had been established that encouraged the identification of problems, and the management commitment and support to resolve these problems was evident. The team noted extensive management presence in the problem review group that met to review the problems that had been identified and to review proposed corrective actions. The team

B/3

observed that the group was critical and challenged root causes, corrective actions, and station problem report classification. A copy of the South Texas Final Performance/Inspection Planning Tree is included on page 3a.

In November 1994, the NRC evaluated the licensee's annual Emergency Preparedness exercise. No weaknesses were identified and overall performance during the exercise was excellent. The licensee emergency response staff demonstrated effective implementation of the emergency plan. All previously identified weaknesses were closed. This represented a significant improvement over prior graded exercises.

In September 1994, Mr. R. E. Masse and Mr. G. L. Parkey exchanged positions, with Mr. Masse becoming Unit 2 Plant Manager and Mr. Parkey becoming the General Manager of Generation Support. Also in October, the Technical Services Department was broken up, with Chemical Operations reporting to Plant Operations and Chemistry and Health Physics reporting to Generation Support. Another major organizational change was the merger of the Nuclear Assurance and Nuclear Licensing into one organization under L. E. Martin, the former General Manager of Nuclear Assurance. This merger started in September 1994 and will be complete by the end of 1994.

The NRC SALP report for the period of August 2, 1992, through September 24, 1994, was issued on October 21, 1994. The extended assessment period was a result of suspending the normal SALP process during the plant shutdown. The assessment focused on the last six months of facility performance which included activities in support of restart and recent operational performance of STP Units 1 and 2. Overall the level of safety performance at the South Texas Project facility improved. Significant changes occurred in site management and organizational structure. Management's efforts resulted in a renewed focus on safety standards, program definition, and enhanced oversight and control of plant activities. The active role of management and increased corporate support resulted in significantly improved material condition of the plant and contributed to the successful restart and subsequent operating history of Units 1 and 2. Performance in all functional areas was evaluated as good (Category 2). The board noted that the licensee had several continuing challenges. These include further improvement in the work control process; providing for improvements in procedure quality and procedure compliance; providing for oversight and evaluation of proposed changes in the site-wide corrective action program; providing emphasis on configuration control and design change processes; and follow through on proposed upgrades to the security program and emergency preparedness initiatives. Line management programs and monthly independent assessments were effective in identifying and tracking areas with weak performance. The self-assessment activities to assure readiness for restart of the units were noteworthy.

Overall safety performance at STP has dramatically improved since the site was placed on the Watch List in June 1993. Most senior managers were replaced with outside hires in 1993. Operations and maintenance have been unitized. Other organizational structure changes have been and are being made to increase efficiency and effectiveness. The current management team has demonstrated significantly improved involvement in plant activities and responsiveness to issues and their proper resolution. The Business Plan has several action plans to improve and monitor management and supervisory performance. There is room for optimism concerning continued improvements in safety performance.

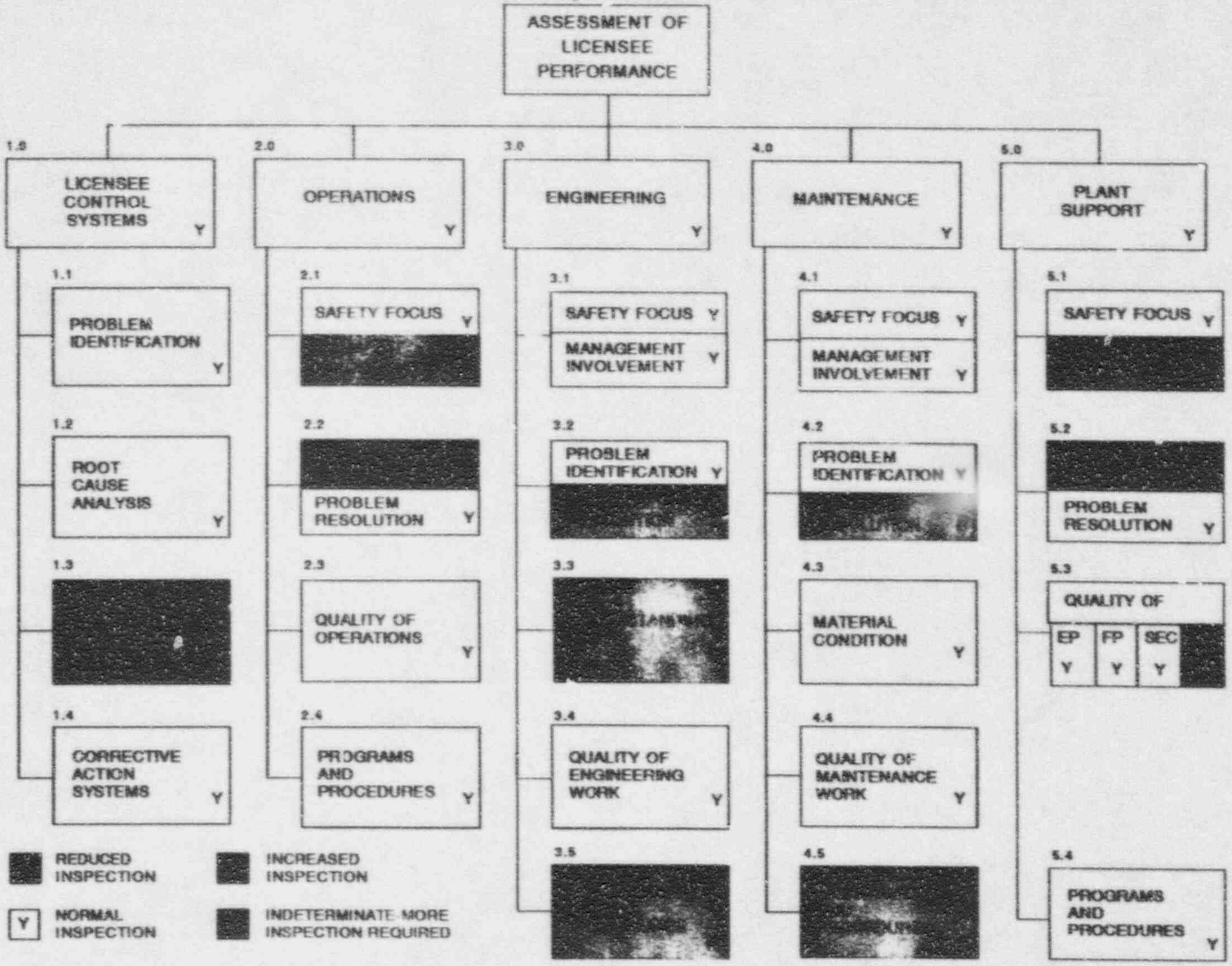
III. FUTURE ACTIVITY

In accordance with the Master Inspection Plan, the RIV staff will perform regional initiative inspections in the areas of procedures and maintenance program implementation. In addition NRR will lead a followup inspection of the employee concerns program. The core engineering inspection will be performed early in the SALP cycle to evaluate progress in identified weak areas. The MIP will likely be revised later to include an integrated assessment team inspection late in the SALP cycle.

Refueling outages are scheduled for spring and fall of 1995 for Unit 1 and Unit 2, respectively.

The licensing organization has dedicated resources and is actively pursuing upgrading its Technical Specifications (TS) as a result of its own findings and the DET's observations. Short-term and long-term TS improvements are being considered. Additional information on the upgrade is included in the Data Summary section of this paper.

SOUTH TEXAS PROJECT - FINAL
PERFORMANCE ASSESSMENT/INSPECTION PLANNING TREE



8/94

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

Unit 1

2/28/94 The unit was manually tripped from 28 percent thermal power because of a failed closed feedwater regulating valve.

9/20/94 The unit tripped from near full power following loss of a main feedwater pump.

Unit 2

6/25/94 The unit tripped from full power following a main transformer lockout.

B. Significant Operator Errors

Crew communications weaknesses, focusing on expected plant conditions rather than actual plant conditions, a weak abnormal operating procedure, and training weaknesses contributed to a Unit 1 plant trip on September 20, 1994, following loss of a main feedwater pump.

C. Procedures

A number of procedure weaknesses have been identified since the last SMM. Surveillance test procedure weaknesses were identified in the areas of instrumentation channel checks, boric acid flow path verification, periodic verification of valve positions (danger tags being used as administrative locks), failure to test diesel generator starting air compressor check valves, control room envelope positive pressure test, and time response testing of the control room and fuel handling building HVAC and containment fan coolers. Abnormal operating procedure weaknesses delayed recovery of lost electrical buses on Unit 2 and contributed to the Unit 1 reactor trip following loss of a main feedwater pump.

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

SRO	RO	LSRO	TOTAL
38	51	0	89

B. Number and Length of Shifts

Six, 12-hour shifts

C. Role of STA

One STA is assigned to each unit. There are currently 11 qualified STAs plus a supervisor. They work and train with a specific shift crew about 90% of the time. No current STAs are licensed but 6 prospective STAs are enrolled in a license class. The STA's primary duty is to act as an accident prevention and mitigation advisor to the shift supervisor.

D. Requalification Program Evaluation

A requalification program evaluation conducted in January 1993 resulted in a satisfactory rating for the program. The NRC will conduct a requalification program evaluation in December 1994.

III. PLANT-SPECIFIC INFORMATION

A. Plant-Specific Information

Owners	Houston Lighting and Power Company City of San Antonio Central Power & Light Company City of Austin
Reactor Supplier/Type	Westinghouse/4-loop PWR
Capacity, MWe	1251
Architect/Engineer	Bechtel
Constructor	Ebasco
Commercial Operation:	Unit 1: August 25, 1988 Unit 2: June 19, 1989

B. Unique Design Information

Containment: Dry, carbon steel lined, prestressed, reinforced concrete, cylindrical structure with a hemispherical dome

Emergency Core Cooling Systems: Three high head safety injection, low head safety injection, and containment spray pumps; three safety injection accumulators; three motor-driven, 50 percent capacity, auxiliary feedwater pumps, one turbine-driven, 50 percent capacity auxiliary feedwater pump per unit

AC Power: Eight 345 kV offsite sources; three 5500 kW Cooper-Bessemer emergency diesel generators per unit

DC Power: Four sets of batteries powering four independent Class 1E 125-VDC subsystems per unit

IV. SIGNIFICANT MPAs OR PLANT-UNIQUE ISSUES

MPA B111 Individual Plant Examination (IPE): This is a staff initiative and the licensee submitted its IPE on August 28, 1992. The results of the IPE show a core damage frequency (CDF) of 4.4E-5. No single accident sequence was found to dominate the CDF. The top ranking sequence is a loss of electrical auxiliary building HVAC resulting in an internally induced station blackout and failure of the positive displacement pumps (8.6% of CDF). The largest contribution of specific initiating events is the loss of offsite power (35%) followed by the loss of HVAC in the electrical-auxiliary building (20%). A request for additional information was issued on September 19, 1994.

MPA B118 IPE-External Events (IPEEE): The licensee submitted its IPEEE with the STP PRA report on December 23, 1991. External events contribute about 3 percent to the CDF. Since this arrived well in advance of the requested date, this item is "artificially" aged. At the time the South Texas IPEEE was submitted, the staff did not have the resources to perform the review. The staff is now reviewing the licensee's submittal.

MPA X201 & MPA L208 Thermo-Lag: The licensee has substantial amounts of Thermo-Lag present. The licensee desires to use PRA to show that upgrading the existing Thermo-Lag is not required to provide an adequate level of fire protection since there is a high degree of separation of the three independent safety trains, and fires outside of the control room contribute less than 1% to the overall CDF.

By letter dated September 19, 1994, the staff stated that consistent with the Staff Requirements Memorandum of June 27, 1994, the staff will not accept a performance-based approach to resolve the Thermo-Lag issue, and requested that the licensee revise their response.

Station Blackout (SBO) Rule (10 CFR 50.63): This item was previously closed. On August 4, 1994, the licensee discovered that their 8-hour SBO coping strategy, to power either the "A" or "C" train battery charger from the "B" standby diesel generator (SDG) (the SBO Alternate AC Source) by backfeeding through the Auxiliary ESF Transformers, is invalidated because the transformers are located outside and are not protected from likely weather-related events. The licensee's JCO changes the shutdown criteria for hurricanes from 120 mph to 73 mph and changes the coping duration from 8 hours to 4 hours. NRR is reviewing the JCO and additional information submitted on October 31, 1994. The staff has no immediate safety concerns.

Technical Specification Improvement Program: The licensing organization has dedicated resources and is actively pursuing upgrading its Technical Specifications (TS) as a result of its own findings and the DET's observations. Short-term and long-term TS improvements are being considered. The primary short-term proposal will focus on reducing the number of required operable SDGs (per unit) in Modes 5 and 6 from two (out of three) to one. The staff had shutdown risk safety concerns with the licensee's initial proposal, particularly when having only one SDG when in mid-loop early in the shutdown with high decay heat loads. On November 7, 1994, the licensee submitted a TS change that it claims is consistent with the proposed rule on shutdown risk by adding an additional onsite AC source during refueling outages.

The licensee's long-term proposal will focus on converting their TS to the Improved Standard Technical Specifications (ISTS). This will involve modifying the two-train ISTS to incorporate STP's site-specific three-ESF-train design. The staff suggested that the licensee submit specific license amendment requests for those areas involving high safety significance and changes to the licensing basis, before submitting the amendment request for the conversion. In this way, the hard spots will have already been addressed and the conversion will be more administrative in nature.

10 CFR 2.206 Request: A request by Mr. T. Saporito in accordance with 10 CFR 2.206 to shut down the facility has been acknowledged and denied. The final Director's Decision was previously on hold due to the related enforcement action. Now that NRC has issued the licensee a Notice of Violation and Proposed Imposition of Civil Penalty in the amount of $100,000 for a violation of 10 CFR 50.7, the Director's Decision under 10 CFR 2.206 is being prepared.

Due to recent congressional interest, two teams have been formed in regard to South Texas Project activities and oversight. The first team combines NRR and OI together to obtain allegations from past and present employees, and refer them to the appropriate technical branches. The second team is exclusively NRR personnel to determine inspection program effectiveness at South Texas Project.

Congressman John Dingell's Subcommittee on Oversight and Investigations on the Committee on Energy and Commerce has expressed strong interest in NRC handling of whistleblowers and allegations management, using South Texas Project as one example. Hearings may occur in the Spring of 1995.

The General Accounting Office (GAO) is investigating NRC inspection program effectiveness using South Texas Project and other facilities as examples.

In February 1994, the City of Austin filed suit against HL&P. In May 1994, the City of San Antonio intervened in the Austin litigation against HL&P. The suit alleges that the STP outages were due to HL&P's failure to perform its obligations under the Participation Agreement among the four co-owners of the South Texas Project and that the outages resulted in increased costs to the cities.

The City of Austin placed advertisements in several newspapers in October 1994 seeking proposals from parties interested in acquiring its 400 megawatt share of STP.

The Texas Public Utility Commission has initiated an inquiry into the prudence of HL&P's operation of STP, the results of which will be considered in determining whether the additional fuel expenses during the 1993–1994 STP outages were unreasonable and whether there has been mismanagement of STP by HL&P which should be taken into account in considering the appropriate rate of return.

V. STATUS OF THE PHYSICAL PLANT

A. Problems Attributed to Aging

None.

B. Other Hardware Issues

PLANT EQUIPMENT: STP is a relatively new site and no major problems have manifested themselves. Because of the length of construction, however, equipment and components are not considered new. There have been many plant events and forced outages primarily because of balance-of-plant equipment problems. Overall plant condition, including balance-of-plant equipment condition, improved during the extended outages of 1993. In late 1994, overall condition was very good to excellent.

EMERGENCY DIESEL GENERATORS (EDG): Several longstanding problems associated with the EDGs, the main feedwater system, essential chillers, and MOVs were addressed prior to the Unit 1 startup. Continuing inadvertent test mode starts of emergency diesel generators are being addressed by the licensee.

VI. PRA

A. PRA Insights

South Texas is a newer Westinghouse four loop NSSS with a 3 train ECCS design. The ECCS design is unique in that each train delivers flow to a specific RCS loop with no ECCS injection into RCS loop 4 and no cross ties to the other loops. The success criteria for a large break LOCA require one train of injection to an intact loop. For a small break LOCA, any one train of ECCS is sufficient, regardless of the location of the break.

The RHR pumps at South Texas are separate from the LPSI pumps and the entire RHR system is inside containment. Also, the HPSI pumps can take suction directly from the sump. Therefore, the HPSI pumps are not dependent on suction from the LPSI pumps or the RHR pumps during the recirculation mode.

South Texas is equipped with 3 EDGs per unit (one for each ECCS train). The reliability of all EDGs, except for Unit 1 #11 EDG, is above 97.5% and shows an improving trend. The #11 EDG reliability is 95.7% with a declining trend.

B. PRA Profile

The South Texas Project Probabilistic Risk Assessment (PSA) was submitted to the NRC in 1989 and included analyses of internal and external events. The PSA was reviewed and approved by the staff. As a result of the PSA findings, an important modification was implemented. This modification involved the connection of the positive displacement charging pump to the technical support center DG to provide RCP seal cooling in the event of a total loss of AC power.

HL&P responded to GL 88-20 by submitting a Level 2 IPE and IPEEE in August, 1992. The original PSA estimated a core damage frequency of 1.7E-4 per year. The IPE reports an estimated core damage frequency of 4.4E-5 per year for internal and external events. The IPE CDF is about a factor of 4 less than that obtained in the original PSA. The licensee attributes the decrease in CDF to a reduction in conservatisms. This claim has not been validated since the NRC has not completed its review of the IPE. The staff expects to complete its review by January of 1995. The dominant initiators contributing to core damage from the IPE are listed below:

Initiating Events	CDF per Year	% of Total CDF
Loss of Offsite Power (LOOP)	1.6E-05	35.3%
Loss of Electrical Aux. Bldg. HVAC (resulting in an internally induced SBO)	8.8E-06	20.1%
Small LOCA	2.4E-06	5.4%
Reactor Trip	2.2E-06	5.1%
Transient induced LOOP	2.2E-06	5.0%
Steam Generator Tube Rupture	2.1E-06	4.8%
Turbine Trip	1.4E-06	3.2%
Medium LOCA	1.2E-06	2.8%
Loss of Essential Cooling Water	1.1E-06	2.6%
Loss of Control Room HVAC	1.0E-06	2.3%
All Others	5.8E-06	13.2%

It should be noted that while full treatment of external events and internal plant hazards such as fires and floods was included in the IPE submittal, such events contributed less than 4% to the total core damage frequency. This contribution to total CDF from external events is a significantly smaller percentage than any other recently published PRA for a PWR plant has estimated. HL&P attributes this small contribution to two principal reasons. First, the site has a very low seismicity in relation to the design basis earthquake. Second, there is ample redundancy and physical separation in the ECCS trains, which would reduce the likelihood that internal fires and floods and other spatial interactions could result in a serious accident.

The licensee found no significant accident sequence outliers as a result of performing the IPE.

C. Core Damage Precursor Events

On the basis of the precursors identified by ORNL for 1992 and 1993 (NUREG/CR-4674, vols. 17 through 20), the NRC identified the following precursor event that has a conditional core damage probability of 1E-5 per year or greater.

From December 29, 1992, through January 22, 1993, South Texas Unit 1 operated with one EDG and the turbine driven auxiliary feedwater (TDAFW) pump inoperable. The EDG was rendered inoperable because of binding of the fuel metering rods caused by paint drip. The TDAFW was inoperable because of water intrusion into the turbine, which would have prevented its automatic start (as indicated by failed surveillance tests on 12/27/92 and 1/28/93). During the same time period, a second EDG was removed from service for maintenance for a period of 61 hours.

The conditional core damage probability of this event was estimated at 1.2E-5.

VII. ENFORCEMENT HISTORY

4/93 CIVIL PENALTY — The action was based on a number of violations of established procedures which resulted in the failure to inform NRC licensed operators in the control room of potentially significant conditions that could have affected the operation of the plant. Because the failures to follow established procedures involved plant management personnel, these violations were classified as a Severity Level III problem. A civil penalty was issued to emphasize the need for managers, when necessary, to promptly and properly interface with the NRC-licensed personnel in the control room and the importance of plant management personnel following or properly modifying established procedures. Mitigation of the civil penalty was appropriate for the licensee's corrective actions, but it was offset by the escalation for NRC identification and the licensee's prior opportunity to identify one of the violations. ($75,000)

4/93 CIVIL PENALTY — The action was based on numerous examples of failures to adhere to procedural requirements regarding self-verification that primarily involved the failure to verify the correct unit, correct train, or correct device before conducting testing or maintenance activities. Although none of the errors resulted in adverse safety consequences, collectively they represented a significant regulatory concern and were classified as a Severity Level III problem. A civil penalty was issued to emphasize the importance of attention to detail and the need for the licensee to be aggressive in implementing corrective actions of a lasting nature. The civil penalty was partially mitigated based on the licensee's corrective actions. ($25,000)

4/93 CIVIL PENALTY — The action was based on the licensee's failure to take corrective actions for a failed motor on a motor operated valve in the Unit 2 Low Head Safety Injection System. The violations involved in this action were classified as a Severity Level III. A civil penalty was issued to emphasize the importance of ensuring that identified problems that have the potential to affect the operability of safety systems are resolved in a timely manner and are resolved commersurate with their relevance to ensuring compliance with plant Technical Specifications. Mitigation of the civil penalty was appropriate for the licensee's aggressive identification of the root causes of the self-identifying event, but was offset by the escalation for the duration of the inoperable valve and the licensee's inadequate corrective actions. ($75,000)

5/93 ENFORCEMENT CONFERENCE — The staff exercised discretion and did not cite a violation involving a design control issue (undersizing of fuses) that was subsequently determined to have minor safety significance.

5/93 CIVIL PENALTIES — The action was based on two Severity Level III violations. The first violation involved the TDAFW system. Specifically: (1) inadequate surveillance testing; (2) inadequate instructions; (3) failure to follow procedures; (4) unauthorized maintenance; and (5) inoperable equipment longer than permitted by the plant Technical Specifications. The second violation involved the EDGs for having the equipment inoperable longer than permitted by the plant Technical Specifications and failure to follow procedures. Civil penalties were issued to emphasize the importance of ensuring the operability of safety related equipment through proper maintenance, adequate testing and the correction of recurring problems. The civil penalty associated with the first violation was escalated for NRC identification of program inadequacies, multiple opportunities to correct the deficiencies, and for the duration of the inoperable Unit 1 TDAFW pump ($175,000). The civil penalty associated with the second violation was escalated for specific prior notice given with regard to EDG problems caused by painting and for the duration of the inoperable EDG 13 ($150,000). ($325,000)

6/93 ENFORCEMENT CONFERENCE — Severity Level IV violation for inoperable steam generator power operated relief valves and the reactor coolant system subcooled margin monitor due to deficiencies identified in the seismic qualifications of the qualified display processing system.

9/93 DEMAND FOR INFORMATION — The staff issued a Demand For Information related to apparent discrimination against security force members. Following the licensee's response, the staff decided to await the Department of Labor (DOL) administrative Law Judge (ALJ) decision before deciding on the need for enforcement action.

10/94 PROPOSED CIVIL PENALTY — Based on an Office of Investigations Report dated March 16, 1993, the staff issued a NOV and Proposed Implementation of Civil Penalty to the licensee for apparent harassment and intimidation of a contract I&C technician. In addition, Demands for Information were issued to the licensee and two involved employees. Response to the NOV and payment of the CP are not required until 30 days after the decision of the DOL ALJ. ($100,000)

PRE-DECISIONAL

SOUTH TEXAS PROJECT
EVALUATION FACTORS FOR REMOVAL OF PLANTS FROM THE PROBLEM PLANT LIST

Evaluation Factors	Response	Comments
I. Root Cause Identified and Corrected		
Weak performance areas are thoroughly assessed.	Yes	Startup issues were adequately addressed prior to startup of the units. Longer term improvement items are addressed in the Business Plan. Improvement has been noted in all functional areas.
Comprehensive and clearly defined corrective action program has been developed.	Yes	The Business Plan includes comprehensive improvement programs.
Corrective actions include sufficient measures to prevent recurrence of problems.	Yes	The corrective action program, self-assessments by departments, and independent assessments by oversight groups are intended to prevent recurrence of problems. These measures, implemented under new management, appear to be effective. For the specific problems with the turbine driven auxiliary feedwater pumps, additional training, enhanced surveillance testing procedures, and improved management oversight have prevented recurrence of the overspeed problems.
Management has allocated sufficient resources to carry out long-range corrective action programs.	Yes	The licensee's budget process is a part of the Business Plan process, so resources are budgeted for planned initiatives. The licensee has announced a reorganization process which will reduce overall staff size at the site from about 2350 at the end of 1994 to about 1750 by the end

Evaluation Factors	Response	Comments
		of 1997. About 450 of the displaced personnel are expected to be HL&P employees and about 150 contractors. The licensee's stated goal is to improve cost performance and efficiency without adversely impacting safety or reliability.
NRC is satisfied that corrective action program is sufficiently implemented.	Yes	The Business Plan is comprehensive and its implementation has been monitored by management. Restart inspections, including an ORAT, concluded that the corrective action program was sufficiently implemented. Since restart, improvement has been noted in all functional areas.
Sustained, successful plant performance has been demonstrated.	Yes	Unit 1 restarted on February 18, 1994, after its CAL was closed. The unit was at 28 percent power on February 28 when a manual reactor trip was initiated because a feedwater regulating valve failed closed. The unit restart was delayed because of a steam generator tube plug leak. The unit was restarted on March 21. The unit operated at power until September 20 when loss of a main feedwater pump resulted in a trip. The unit restarted on September 21 and has operated at power since then. Unit 2 restarted on May 22 after its CAL was closed. On June 25, a main transformer lockout resulted in a trip. The unit was restarted on June 29 and has operated at power since then. Dual unit performance has been very good, with reduced maintenance backlog and improved plant conditions in both units.

Evaluation Factors	Response	Comments
II. <u>Improved Self-Assessment and Problem Resolution Evident</u>		
Program elements that monitor and evaluate effectiveness of corrective actions have been instituted.	Yes	Department self-assessment capability has improved and self-assessment is becoming a part of the culture. Independent assessment by oversight groups has been effective. The corrective action program was recently revised to simplify the process, increase ownership of issues, and monitor the effectiveness of corrective actions.
Safety issues are being identified to appropriate management level and corrected in a timely manner.	Yes	The Problem Review Group, recently renamed the Condition Review Group, meets frequently to review all newly identified significant issues. Membership includes managers at the plant manager level. Management has shown a capability to apply the necessary resources and to resolve issues in a timely manner.
Quality assurance and safety oversight groups provide timely and effective self-assessments of performance to site and corporate management.	Yes	Assessments by oversight groups have been effective in identifying areas for improvement. Their monthly summary assessment is published in the monthly performance indicator report. This has provided useful feedback to line management. The corrective action group has improved its capability to identify adverse trends and to bring these to management's attention. Management's response to identified problems has been timely and comprehensive.

Evaluation Factors	Response	Comments
III. <u>Licensee Management Organization and Oversight Improved</u>		
Corporate and plant management teams are fully committed to achieving improved performance.	Yes	The recent SALP report noted improved management support in all functional areas.
Licensee has effective corporate management oversight and involvement in plant operations and problem resolution.	Yes	Corporate management with day-to-day plant oversight is the Group Vice President, Nuclear. He maintains an office on site and spends significant time on site. He has met with many groups of employees to hear their concerns and to discuss his philosophy and expectations. The Vice Presidents for Operations and Engineering are at the site full time and have been heavily involved in plant oversight and problem resolution.
Management team provides strong direction and fosters a nuclear safety work ethic that is understood at all levels in the organization.	Yes	The NRC has observed significant improvement in management oversight, involvement, and support. The new management team brought with them higher performance expectations and a better nuclear safety work ethic. There have been extensive efforts to communicate management expectations to the work force. The Group Vice President, Nuclear, holds regular 2 Cs (compliments and concerns) meetings with groups of employees. The Vice President for Operations' management style includes frequent tours of the plant and communications with plant staff. Other types of meetings with employee groups are common and newsletters have been heavily used to communicate philosophy and expectations.

Evaluation Factors	Response	Comments
IV. NRC Assessment Complete		
Senior NRC management no longer considers the plant as having weaknesses that warrant increased NRC-wide attention.	Yes	The major issues identified prior to and during the 1993-1994 outages were resolved by the licensee and reviewed by the NRC staff prior to the closing of the CALs and restart of Unit 1 in February 1994 and Unit 2 in May 1994. The NRC activities associated with approval of restart of the units were coordinated in accordance with Manual Chapter 0350. The NRC STP Restart Panel included regional and NRR membership and coordinated with other NRC offices and senior NRC management.
Significant NRC inspection and licensing activities are complete and findings properly resolved or understood.	Yes	The major hardware concerns involving the auxiliary feedwater pumps have been resolved. The staff will continue monitoring the licensee's actions related to standby diesel generators. All restart issues were satisfactorily resolved and inspected prior to restart of the units. The pilot Customized Inspection Planning Process (CIPP) team inspection in August 1994 noted improvement in all areas.
V. Additional Considerations		
Most recent set of Performance Indicators reflect overall improving performance.	Yes	Each unit has had one automatic scram since restart. Performance indicator trends are improving except for Unit 1 safety system failure which reflects two recent failures of toxic gas analyzers.

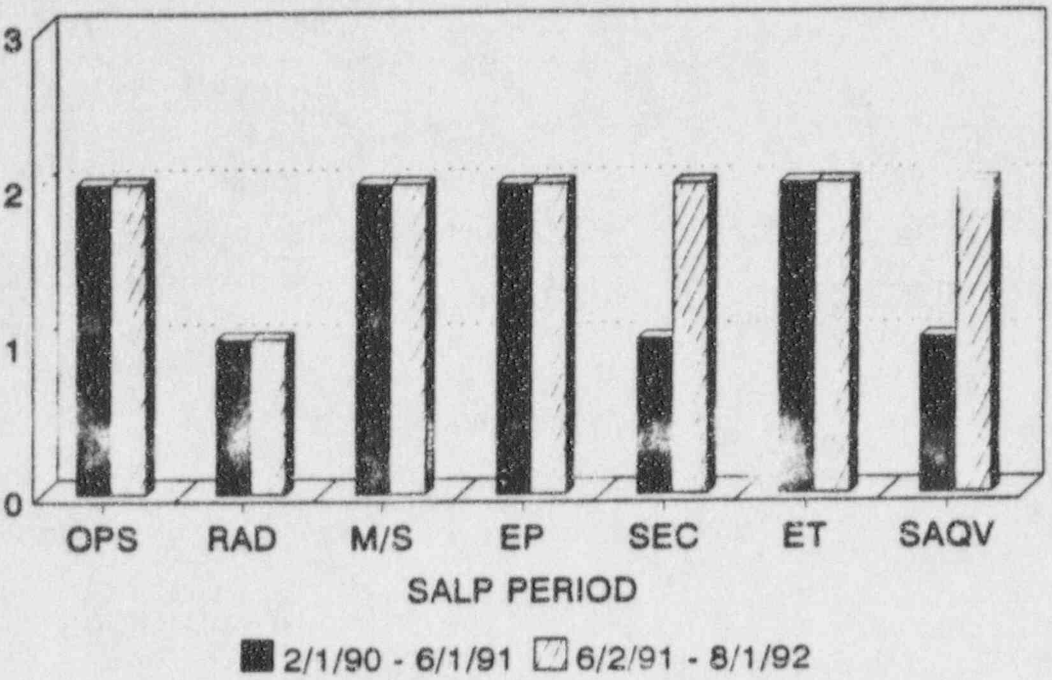
Evaluation Factors	Response	Comments
Overall performance has improved as reflected in the most recent SALP ratings.	Yes	The SALP ratings for the period ending September 24, 1994, were all 2s. The SALP focused on the period since restart. Overall improvement in performance was noted.
Enforcement history has indicated an improving trend.	Yes	Enforcement history has an improving trend. There were several escalated enforcement cases in the first half of 1993 related to poor corrective actions, poor personnel performance, and events which led up to the extended outages. Since then the two escalated cases deal with harassment and intimidation which occurred in 1992 or before.
Performance has improved as demonstrated by a lack of operational problems.	Yes	Operational performance since restart has been good. Each unit has had one automatic trip. The maintenance backlog has been steadily reduced during two-unit operations.
Performance has improved as demonstrated by a lack of significant operator errors.	Yes	Operator performance has generally been good since restart. One significant operator error resulted in an inadvertent safety injection actuation signal and loss of decay heat removal flow while shutdown. This was caused by operators performing testing in the wrong train.
Procedure adherence problems are not evident.	Yes	In general procedure adherence has been good. Several exceptions have been identified. Most had minor safety significance. The quality of procedures is a long-term improvement item at STP.

Evaluation Factors	Response	Comments
Simulator is operational.	Yes	The simulator has been used recently for operator training, operator licensing exams, and for an emergency preparedness exercise. Some fidelity problems have been identified. The licensee plans a major simulator upgrade.
All identified aging problems have been addressed to the NRC's satisfaction.	Yes	STP is a relatively new site and no major aging problems have manifested themselves. Because of the length of construction, however, equipment and components are not considered new and some electronic equipment could be considered obsolete. Overall plant condition, including balance-of-plant equipment condition, improved during the extended outages. In late 1994, overall material condition was very good to excellent.
Licensee has improved its management organization.	Yes	Most senior managers were replaced with outside hires in 1993. Operations and maintenance have been unitized. Other organizational structure changes have been and are being made to increase efficiency and effectiveness. The current management team has demonstrated significantly improved involvement in plant activities and responsiveness to issues and their proper resolution. The Business Plan has several action plans to improve and monitor management and supervisory performance.
Licensee procedures are considered adequate overall.	See comment	Improvement is needed in maintenance procedures, which rely heavily on skill-of-the-craft. Abnormal operating procedures have weaknesses which were noted by the NRC during transient

Evaluation Factors	Response	Comments
		response. An inspection in this area is being scheduled for Spring 1995. Several surveillance test procedures have been found to be inadequate. The licensee has a Business Plan action plan to review and improve surveillance procedures, but it may be necessary to increase management attention on surveillance procedures.
Licensee has an effective root cause analysis program.	Yes	The root cause analysis program has been much improved and training of numerous site personnel has been completed or scheduled. The overall corrective action program has become much more effective, with emphasis being placed on review of all significant issues by a management committee, solving problems at the lowest practical level, ownership of issues, and verification of the effectiveness of corrective actions. A major revision to the licensee's corrective action program was implemented in October 1994.
PRA has been performed.	Yes	The 4/14/89 PSA submittal was reviewed by the NRC staff. The 8/28/92 IPE submittal is still under staff review.
PRA has been used.	Yes	The PSA was used to support 10 Technical Specification changes in February 1994. The licensee is using it to evaluate on line maintenance risk.

SOUTH TEXAS

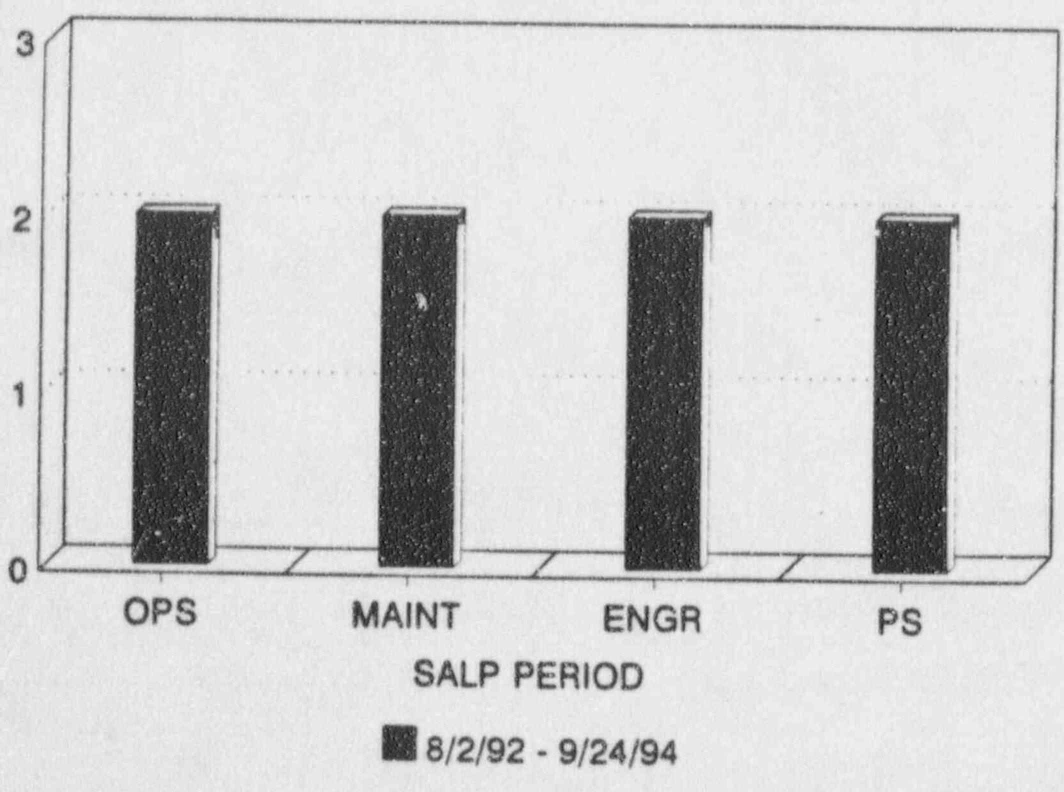
MOST RECENT SALP RATINGS

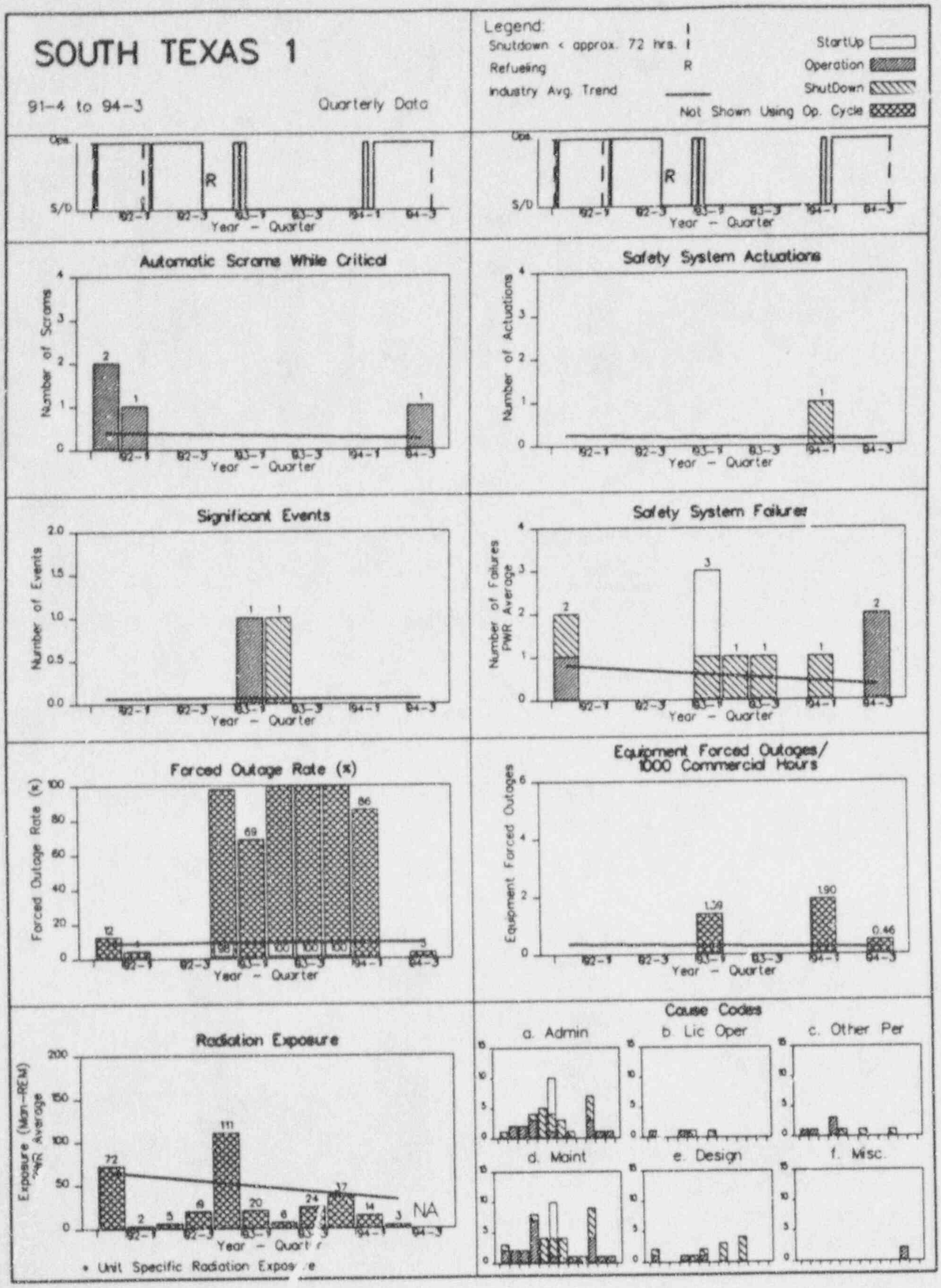


ET IMPROVING
SAQV DECLINING

M/S DECLINING

REVISED SALP PROGRAM RATINGS

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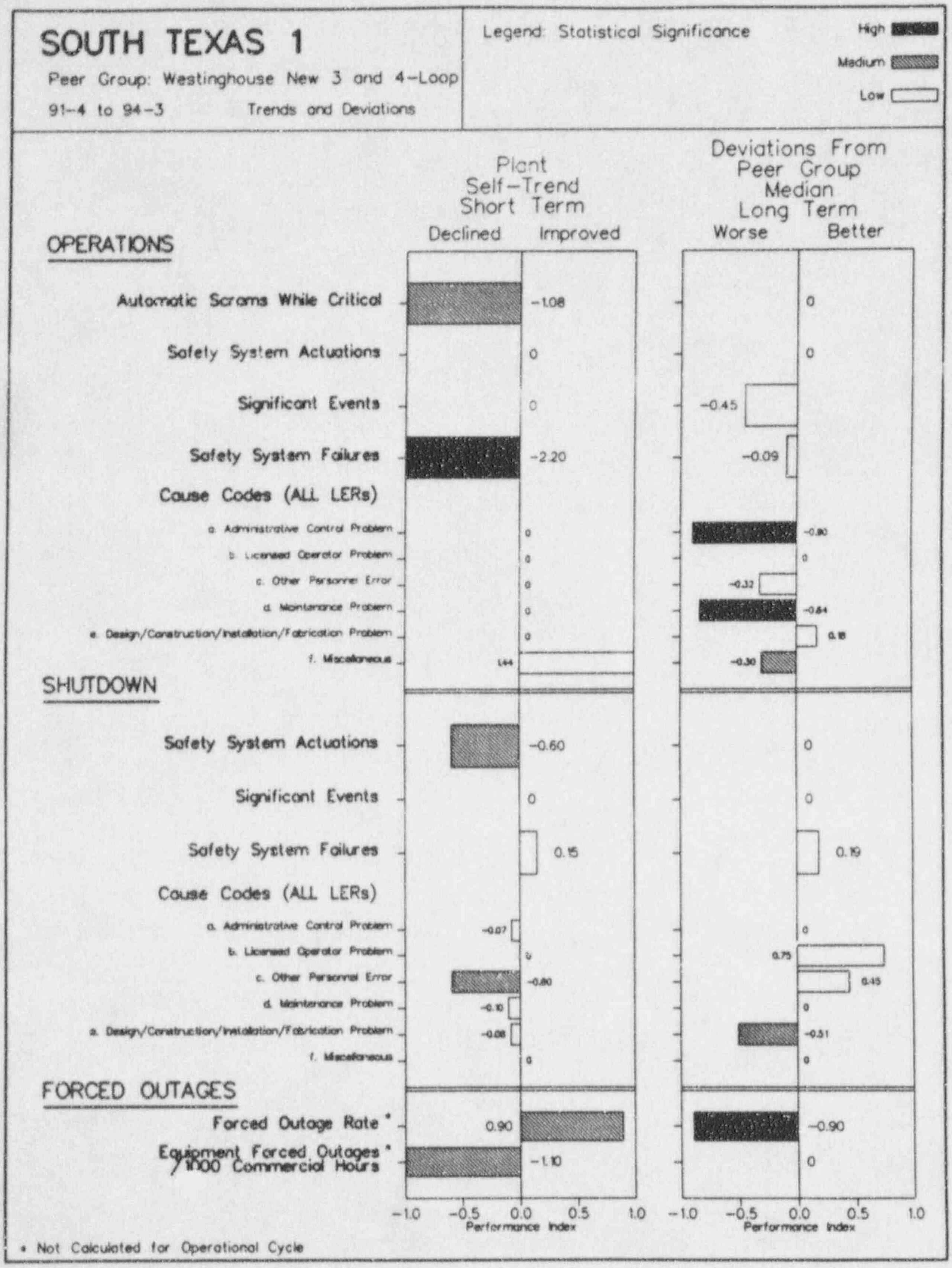
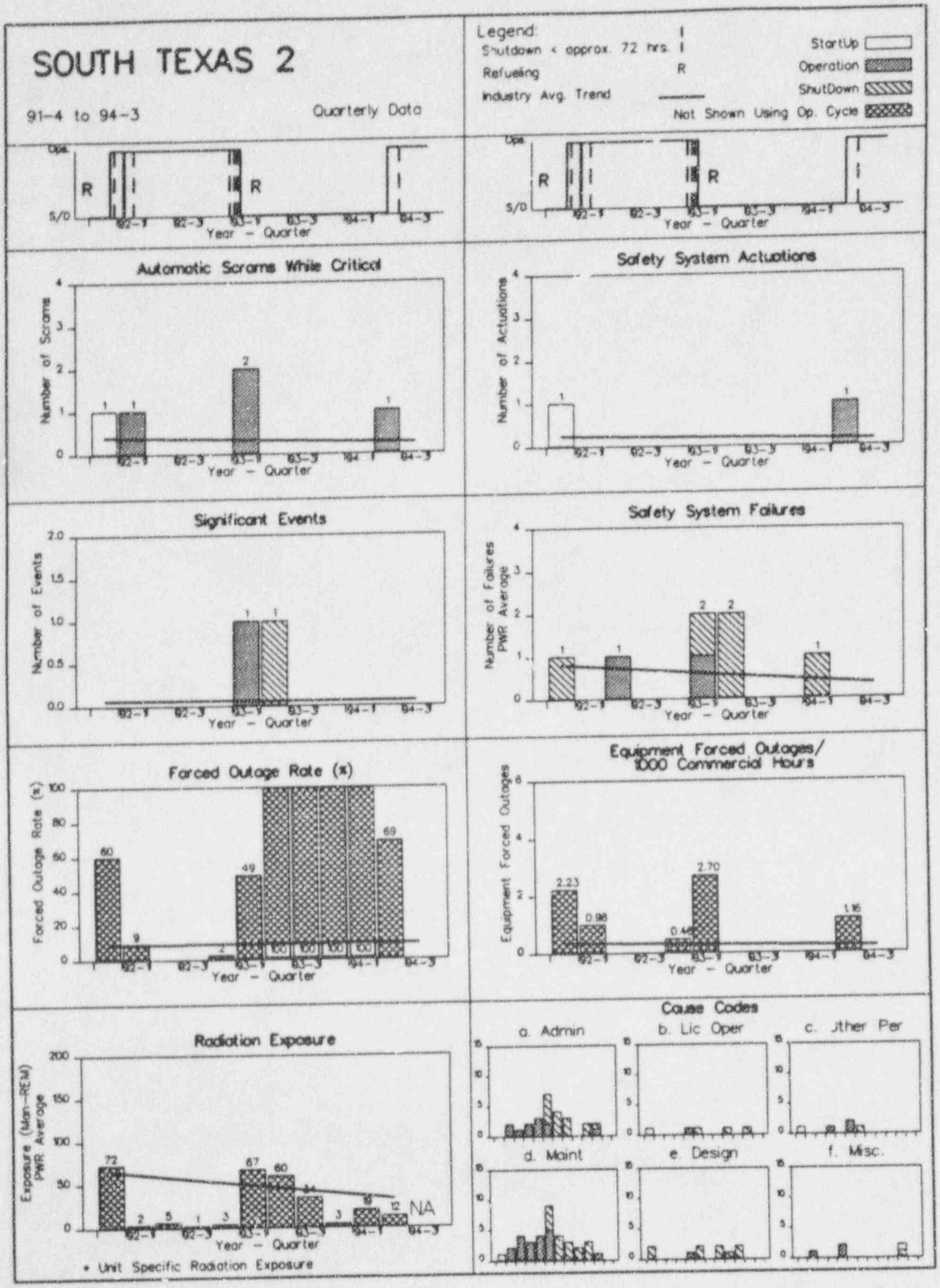
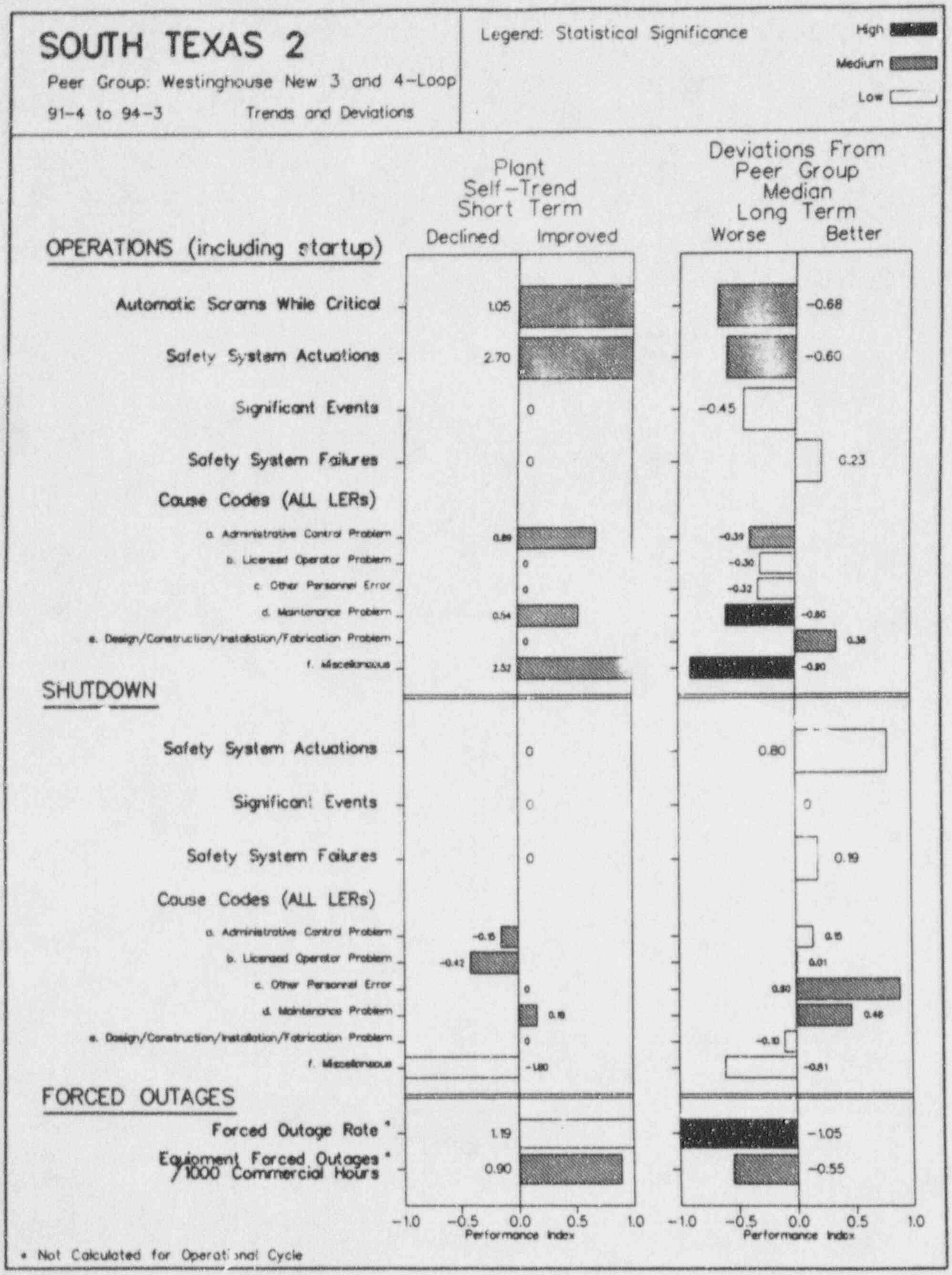
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM) PWR Average
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc.

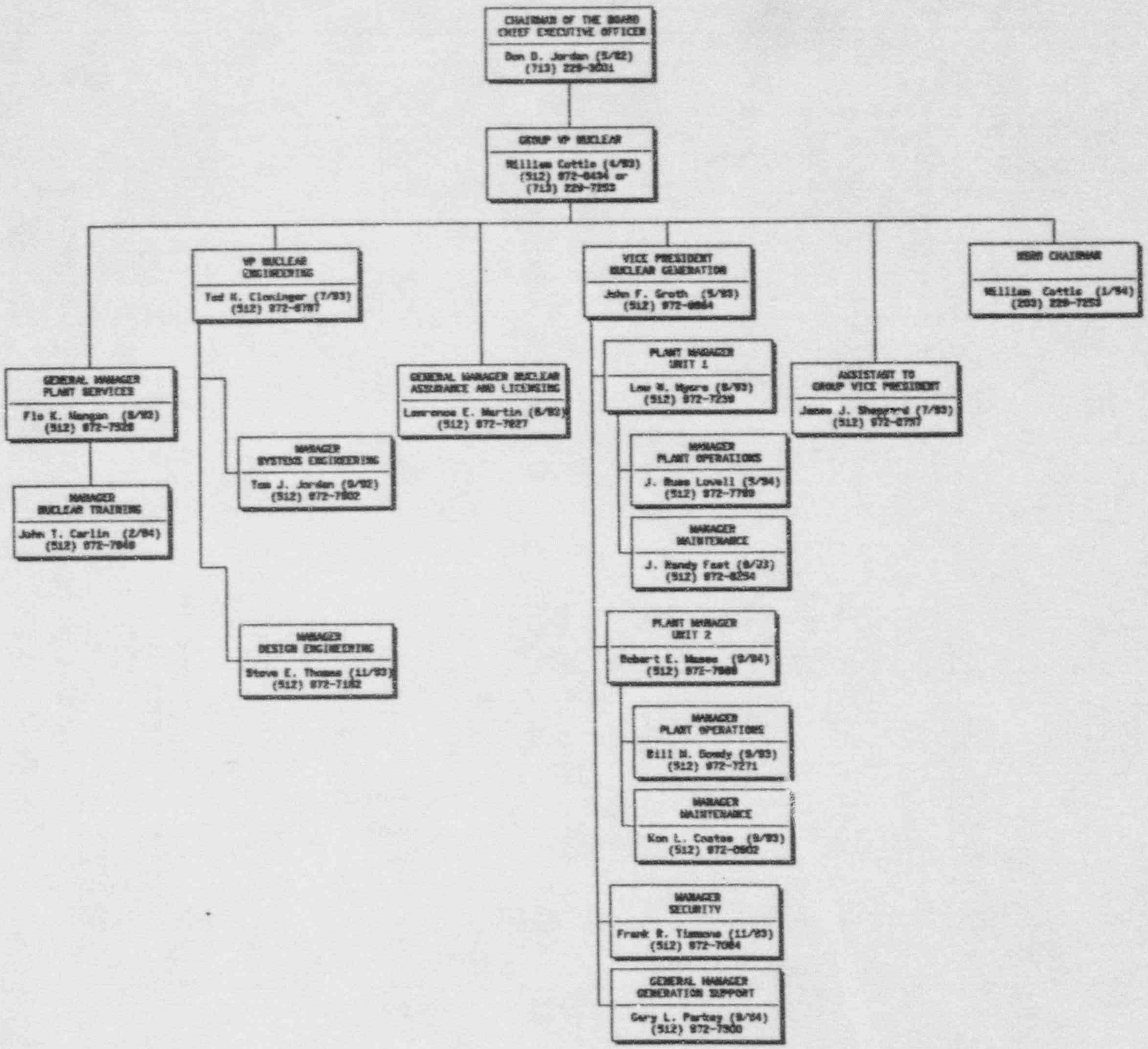
PREDECISIONAL




SOUTH TEXAS 2
91-4 to 94-3
Quarterly Data
Legend:
Shutdown < approx. 72 hrs.
Refueling
R
Industry Avg. Trend
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
Ops.
S/D
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
Number of Events
Safety System Failures
Number of Failures
PWR Average
Forced Outage Rate (%)
Forced Outage Rate (%)
Equipment Forced Outages/
1000 Commercial Hours
Equipment Forced Outages
Radiation Exposure
Exposure (Man-REM)
PWR Average
NA
* Unit Specific Radiation Exposure
Cause Codes
a. Admin
b. Lic Oper
c. Other Per
d. Maint
e. Design
f. Misc.


SOUTH TEXAS 2
Peer Group: Westinghouse New 3 and 4-Loop
91-4 to 94-3
Trends and Deviations
Legend: Statistical Significance
High
Medium
Low
Plant Self-Trend Short Term
Declined
Improved
Deviations From Peer Group Median Long Term
Worse
Better
OPERATIONS (including startup)
Automatic Scrams While Critical
1.05
-0.68
Safety System Actuations
2.70
-0.60
Significant Events
0
-0.45
Safety System Failures
0
0.23
Cause Codes (ALL LERs)
a. Administrative Control Problem
0.89
-0.39
b. Licensed Operator Problem
0
-0.30
c. Other Personnel Error
0
-0.32
d. Maintenance Problem
0.54
-0.80
e. Design/Construction/Installation/Fabrication Problem
0
0.38
f. Miscellaneous
2.52
-0.90
SHUTDOWN
Safety System Actuations
0
0.80
Significant Events
0
0
Safety System Failures
0
0.19
Cause Codes (ALL LERs)
a. Administrative Control Problem
-0.15
0.15
b. Licensed Operator Problem
-0.42
0.01
c. Other Personnel Error
0
0.90
d. Maintenance Problem
0.16
0.48
e. Design/Construction/Installation/Fabrication Problem
0
-0.10
f. Miscellaneous
-1.80
-0.81
FORCED OUTAGES
Forced Outage Rate *
1.19
-1.05
Equipment Forced Outages * /1000 Commercial Hours
0.90
-0.55
-1.0 -0.5 0.0 0.5 1.0
Performance Index
-1.0 -0.5 0.0 0.5 1.0
Performance Index
* Not Calculated for Operational Cycle

HOUSTON LIGHTING & POWER COMPANY
SOUTH TEXAS PROJECT



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