PRE-DECISIONAL

SOUTH TEXAS

I. HISTORY

South Texas (STP) was first discussed at the January 1993 Senior Management Meeting (SMM). The licensee had exhibited poor and declining performance for two systematic assessment of licensee performance (SALP) periods. In addition, repetitive hardware problems had resulted in numerous plant trips, transients, engineering safety features (ESF) actuations, and forced outages. As discussed in the Narrative Summary for the January 1993 SMM, the identified performance problems were grouped into three broad areas, including material condition and housekeeping, human performance, and organizational performance.

II. CHANGES SINCE LAST SMM

Performance at STP has continued to decline since the last SMM. The actions taken by the licensee to improve the implementation of the corrective action program, in addition to other licensee programs, have not been effective. The licensee's attempts at establishing several interdepartmental task forces to address longstanding weaknesses in material deficiencies and personnel performance have not been fully successful. Equipment concerns continue, in particular the reliability of the emergency diesel generators (EDGs), turbine-driven auxiliary feedwater pumps (TDAFWPs), safety-related motor-operated valves (MOVs), and the solid-state protection system (SSPS). Three reactor trips occurred in Unit 2 since the last SMM, resulting from balance-of-plant equipment deficiencies.

STP has made several management changes since the last SMM. The Maintenance Manager resigned and was replaced by the former Deputy Plant Manager, whose position was filled by the former Planning and Assessment Manager. [redacted] and considering the licensee's inability to reduce the large maintenance backlog and the poor reliability of a number of safety-related components. [redacted] A new Group Vice President—Nuclear was named and elected to the parent company's board of directors effective April 5, 1993. The new Group Vice President—Nuclear was previously employed by Entergy Operations, Inc., as Vice President, Operations, at the Grand Gulf Nuclear Station. The retiring Group Vice President—Nuclear has been retained in a consultant role until December 1993. In addition to these changes, effective May 3, 1993, STP added a new position, Vice President, Nuclear Support. This position has been filled by the former Vice President, Nuclear Operations, with a new Vice President, Nuclear Operations being named. The New Vice President, Nuclear Operations previously was employed by INPO.

EX 5 and 6

A number of special inspections have been conducted at STP since the last SMM. An Operational Safety Team Inspection was conducted November 30 to December 11, 1992. The team identified weaknesses in the manner that the security and radiological controls departments support operations, in the implementation of the corrective action program by all levels of STP supervision and craft workers, and in the licensee's inservice testing program.

H/1

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A special inspection conducted January 12-29, 1993, identified eight examples of a failure to perform adequate self-verification by plant operators and maintenance workers. These eight examples represented a continuation of a negative trend in personnel performance that resulted in work being performed on the wrong component, wrong train, and wrong unit. Two enforcement conferences were held on March 8, 1993. The first enforcement conference was to address issues concerning personnel performance at STP. The second enforcement conference was to address issues concerning STP failure to independently test all circuits associated with the reactor trip breaker shunt coil, the licensee's entry into Technical Specification (TS) 3.0.3 because of this deficient test, licensee management's failure to inform licensed operators of this condition, and a second TS 3.0.3 event. Civil penalties have been issued for both these violations.

An Augmented Inspection Team (AIT) was sent to STP February 4-24, 1993, to conduct an inspection of the issues surrounding the repeated overspeed trips of both units' TDAFWPs. A Confirmatory Action Letter (CAL) was issued as a result of these overspeed events and required that prior to either unit's restart, STP management brief the staff on the actions taken to correct the deficiencies that caused the overspeed trip conditions. Because of additional problems encountered in both units, a CAL Supplement letter was issued to the licensee on May 7, 1993. This supplement identifies additional topics that STP management will brief the staff prior to restart. This briefing has not yet occurred and both units remain shut down. Unit 1 continues to address a number of issues that include several EDG problems, MOV operability concerns, rod control operability problems, safety injection pump vibration problems, electrical component configuration inadequacies, and steam generator manway leakage; in addition to the required TDAFWP testing that must be completed prior to restart. Unit 2 completed the TDAFWP testing in late February and began a scheduled 85-day outage on February 27, 1993.

The followup inspection after the AIT inspection identified eight apparent violations; including one where the inappropriate voiding of a post maintenance test on a Unit 1 EDG resulted in its inoperability for 24 days and a second concerning an inadequate TDAFWP surveillance test program that resulted in the Unit 1 TDAFWP being inoperable for 33 days. In addition, the inspection identified a period of 61 hours during which a second Unit 1 EDG was inoperable. During this 61-hour period, all three of these safety-related components were determined to be inoperable concurrently. An enforcement conference was conducted April 22, 1993, and a civil penalty proposed.

A special inspection was conducted February 17-19 and 23-26, 1993, concerning numerous MOV deficiencies. One apparent violation of the TS was identified, in that one train of the Unit 1 low head safety-injection system was determined to be inoperable for approximately 18 months. Two other significant weaknesses were identified concerning the licensee's failure to take appropriate corrective action to address identified deficient conditions associated with MOVs. These weaknesses indicate that the trend of station personnel being reluctant to utilize the corrective action system to document known problems is continuing. A civil penalty was issued.

Another special inspection (February 13 to March 17, 1993) addressed the operability of the SSPS. This inspection identified a condition that had existed since initial startup where under a steam line break accident scenario, the SSPS might not have been capable of initiating an ESF signal necessary to mitigate the consequence of the accident. An enforcement conference was conducted May 6, 1993, with enforcement action currently pending.

A diagnostic evaluation team (DET) inspection commenced on March 29, 1993. This inspection completed the onsite period on April 30, 1993. As a result of the interviews conducted by the DET, a significant number of allegations have been received and forwarded to Region IV for resolution. The allegations, in addition to other preliminary DET findings do not appear to have a central theme; however, they are indicative of a work force with low morale and a management style at STP that is less than receptive to addressing workers' concerns of plant material conditions and adequate procedural guidance.

As a result of the number of issues and their potential safety significance, Region IV established an STP Oversight Panel composed of managers from Region IV and NRR. The purposes of this panel are to: 1) assure a consistent agency approach to the issues being identified; 2) assure proper coordination of followup on significant safety issues; 3) schedule significant meetings and inspections; 4) assure that the views and concerns of different NRC offices are properly addressed; and 5) assure proper coordination of the followup of issues identified by the DET inspection. This Panel meets weekly, and has decided, after consultation with senior management, to invoke Manual Chapter 0350, "Staff Guidance for Restart Approval."

During the last SALP assessment period, which ended on August 1, 1992, there were several plant events, near misses, and transients that were caused by equipment failures and problems. Although the frequency of these events had decreased from the first half of that assessment period, recent events (since the last SMM) are indicative of a return to the previous negative trend of performance. The last SALP recognized that the licensee had made significant efforts to improve station reliability and the material condition of the plant; however, recent events indicate that the reliability of a number of safety-related components has decreased.

The Diagnostic Evaluation Team will formally exit in a public meeting with the licensee on June 3, 1993, at the STP facility.

III. FUTURE ACTIVITY

As a result of the CAL issued to the licensee on February 5, 1993, following the repeated overspeed trips of both TDAFWPs on February 3-4 1993, a public meeting to discuss the licensee's actions to resolve the deficiencies that caused the overspeed conditions will be scheduled. In addition to these issues, the STP Oversight Panel has developed a number of other topics for resolution prior to startup of either unit. These additional issues were included in the CAL Supplement that was issued to the licensee.

Unit 2 entered its third refueling outage on February 27, 1993. The outage is planned for 85 days. Activities planned for completion during the outage include:

- 18 month reactor coolant pump motor inspections
- Sludge lancing of all steam generators
- Main turbine low pressure gland repair
- 98 MOV operation tests
- Low Pressure Turbine No. 21 rotor replacement
- Emergency Diesel Generator No. 21 5-year maintenance
- Emergency Diesel Generators No. 22 and 23 18 month inspection
- Implementation of 53 major modifications
- Replacement of the main feedwater control system with solid-state equipment

Due to Unit 1 being in a forced outage because of the TDAFWP problems, little outage work has been accomplished on Unit 2, and the restart date has slipped significantly. No firm restart date has been announced by the licensee.

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

Unit 1

None

Unit 2

12/27/92 Manual reactor trip from 100 percent power when a steam generator feedwater regulating valve failed closed and could not be reopened from the control room. The root cause was a failed component in the feedwater regulating control system.

1/23/93 Automatic reactor trip from 100 percent power following a turbine trip when a main turbine and steam generator feedwater pump turbine electrohydraulic control (EHC) system pipe, which was common to both turbines, failed. The root cause was a deficient component in the feedwater pump control circuitry that resulted in excessive vibration and subsequent fatigue failure of the EHC piping.

2/3/93 Automatic reactor trip from 100 percent power following the loss of a steam generator feedwater pump and the failure of the startup feedwater pump to automatically start and maintain feedwater flow to the steam generators. The root cause of the loss of the steam generator feedwater pump was a high bearing temperature. The root cause of the failure of the startup feedwater pump to start was water intrusion into the pump's lubricating oil system, a condition that had caused the pump to trip previously.

B. Significant Operator Errors

On January 9, 1993, an instrumentation and controls (I & C) technician failed to practice adequate self and independent verification when setting the reactor protection over-power trip setpoints. This resulted in a non-conservative reactor trip setpoint being inserted into the SSPS. This action, in addition to seven other previous examples of improper self-verification were the subject of a special inspection that was conducted January 12-29, 1993, a subsequent severity level III violation and civil penalty were issued.

On January 25, 1993, a licensed senior reactor operator failed to follow procedures when he performed an unauthorized adjustment of the Unit 2 TDAFWP trip and throttle valve linkage.

On February 14, 1993, both licensed senior reactor operators were absent from the Unit 2 control room for a period of approximately 45 seconds while the unit was in Mode 4. This error, which was due to operator error, resulted in a violation of the TS required staffing requirements.

On March 18, 1993, a nonlicensed operator performed an inadequate self-verification that resulted in de-energizing the plant computer. The event was attributable to fatigue-induced mental lapse as a result of eight consecutive mid-shifts, several were of 12-hour duration.

On March 21, 1993, a nonlicensed operator performed an inadequate self-verification that resulted in positioning an incorrect valve associated with an essential cooling water (ECW) heat exchanger. The control room received an alarm for low ECW pump discharge pressure and informed the operator that he had positioned the wrong train's valve. The licensee determined that the individual did not utilize the self-verification process following a distraction. Contributing causes included communications deficiencies, inadequate staffing for the implementation of this particular surveillance procedure, and the event occurred during the mid-shift.

On April 1, 1993, I & C technicians failed to perform an adequate self-verification that resulted in erroneously positioning a SSPS bistable switch to test. No safety systems were actuated. The licensee determined that the repetitive nature of the surveillance contributed to this event.

C. <u>Procedures</u>

A number of procedure weaknesses have been identified since the last SMM. These include: deficient maintenance procedures, weak radiological procedures, inadequate surveillance testing procedures, poor procedural development and review of 20 I & C calibration procedures, and an example of weak implementation of temporary modification procedure.

Several examples of licensee personnel failing to follow procedures have been identified. These include:

- three examples of fire protection weaknesses due to personnel not following procedures

- unauthorized maintenance activities being conducted on safety-related equipment without a procedure and by unqualified personnel
- valve line-ups being altered that result in overspeed trips of the Unit 2 TDAFWP
- a system engineer voiding a post maintenance test following the painting of EDG 13 which resulted in masking the EDG's inoperability

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

	SRO	RO	Total
Licensed Operators	47	38	85

B. Number and Length of Shifts

5 shifts, 3 operating (8-hour shifts), 1-training. 1-off

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. STA's 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 evaluation was conducted in January 1993 in accordance with Temporary Instruction for Licensed Operator Requalification Program Evaluation. The program was evaluated as satisfactory. The next NRC requalification examination is scheduled for January 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

MPA X808: Bulletin 88-08 Thermal Stresses in Piping Connected to the RCS: Licensee has removed temperature sensors from lines identified as possibly susceptible to thermal stratification. Licensee arguments are based on Westinghouse analyses which conclude that fatigue failures are not a concern for the lines. EMEB has questioned the licensee's justification and is in the process of hiring a contractor to complete a detailed review.

MPA B111: GL 88-20 (IPE): Licensee submitted its IPE August 28, 1992. The staff is reviewing the submittal.

MPA B114/115: GL 90-06 PORV Reliability and LTOP: Last remaining issue was licensee's proposal to maintain ability to test PORVs in Mode 5. Licensee has agreed to drop the Mode 5 provision and licensing actions are expected to be completed in the near future.

MPA X201: Bulletin 92-01 Thermolag: The licensee has substantial amounts of thermolag present and has recently responded to the generic letter.

MPA: Station Blackout: The licensee has completed all actions required to meet the SBO rule. The plant is an 8-hour coping plant, using an existing class IE standby diesel generator as an alternate AC power source.

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 ECW system (dealloying), the EDGs, the main feedwater system, essential chillers, and MOVs have not been fully resolved.

The maintenance backlog has remained high, with approximately 5700 open items on the backlog. The licensee has been unsuccessful in reducing this backlog, which has reached a size that is challenging STP management of maintenance activities.

VI. PRA

A. PRA Insights

STP 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 between the other three 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 STP 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.

STP 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 goals.

B. PRA Profile

The STP PSA was submitted to the NRC in 1989 and included analyses of internal and external events. 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 EDG 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:

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%

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 for its potential safety significance. [redacted] Ex5 STP Unit 1 experienced overspeed trips of their 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 (December 29, 1992, thru January 22, 1993), Unit 1 DG-13 was inoperable due to paint drips on the fuel metering rod ports. Furthermore, Unit 1 EDG-12 was out of service for a 61 hour planned maintenance period while EDG-13 was inoperable.

When the EDG event and the TDAFW pump trip event are analyzed as separate events, the risk does not appear to be significant. However, since the EDG-13 and the TDAFW pump were inoperable during the same period, SPSB is planning a request for AEOD to analyze the overall situation as a potential precursor.

VII. ENFORCEMENT HISTORY

SIGNIFICANT ENFORCEMENT HISTORY (Since April 1991)

REACTOR OPERATIONS - SUPPLEMENT I

JULY 1991 (EA 91-74)	CIVIL PENALTY - The action was based on three violations associated with the plant's ATWS system that were classified in the aggregate as a Severity Level III problem. A civil penalty was issued to emphasize the importance of ensuring the reliability and operability of equipment required to serve an important safety function. Partial mitigation of the civil penalty was appropriate for the licensee's corrective actions, but was offset by the escalation for NRC identification and duration. ($75,000)
APRIL 1993 (EA 92-175)	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)
APRIL 1993 (EA 93-23)	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)

APRIL 1993 (EA 93-47)

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)

SAFEGUARDS - SUPPLEMENT III

JULY 1991 (EA 91-068)

SEVERITY LEVEL III VIOLATION - The action was based on physical security violations including one STP employee bringing a firearm into the protected area. The civil penalty was fully mitigated based on licensee identification and prompt corrective action.

MISCELLANEOUS MATTERS - SUPPLEMENT VII

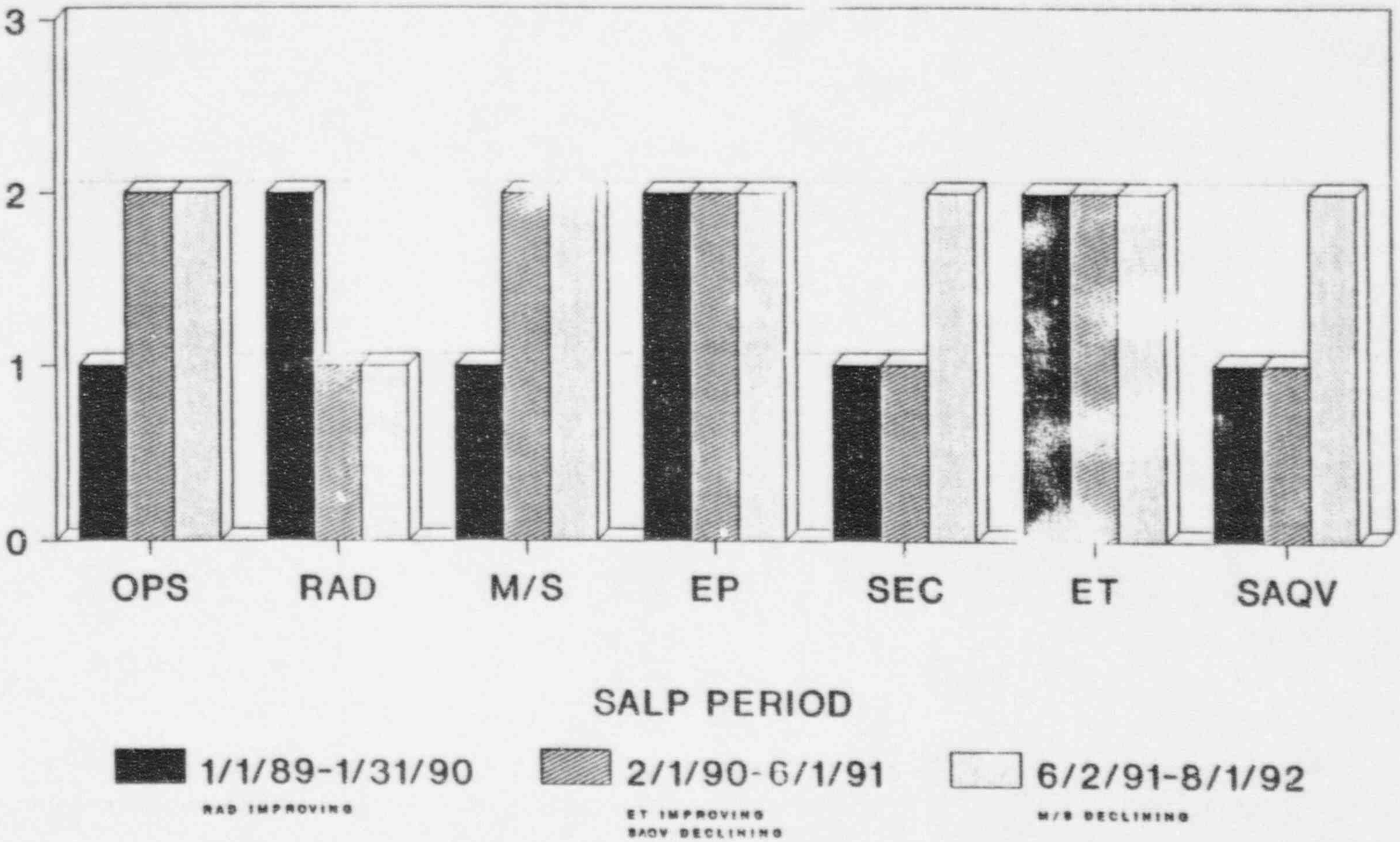
DECEMBER 1991 (EA 91-055)

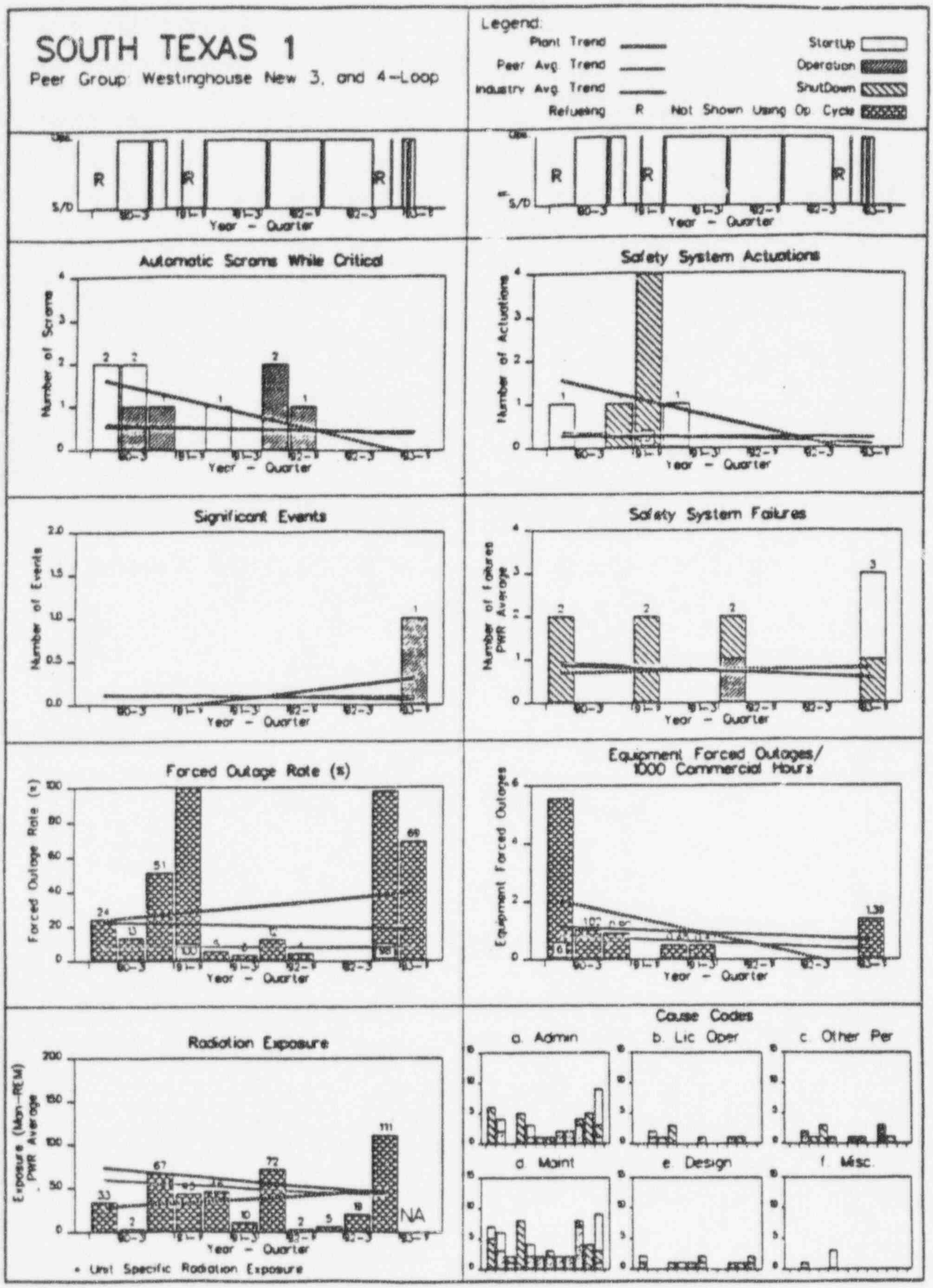
CIVIL PENALTY - The action was based on the licensee's failure to keep complete and accurate records of preventative maintenance activities for safety-related valves in the safety injection system and the reactor coolant purification system. A civil penalty was issued to emphasize the importance of ensuring 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)

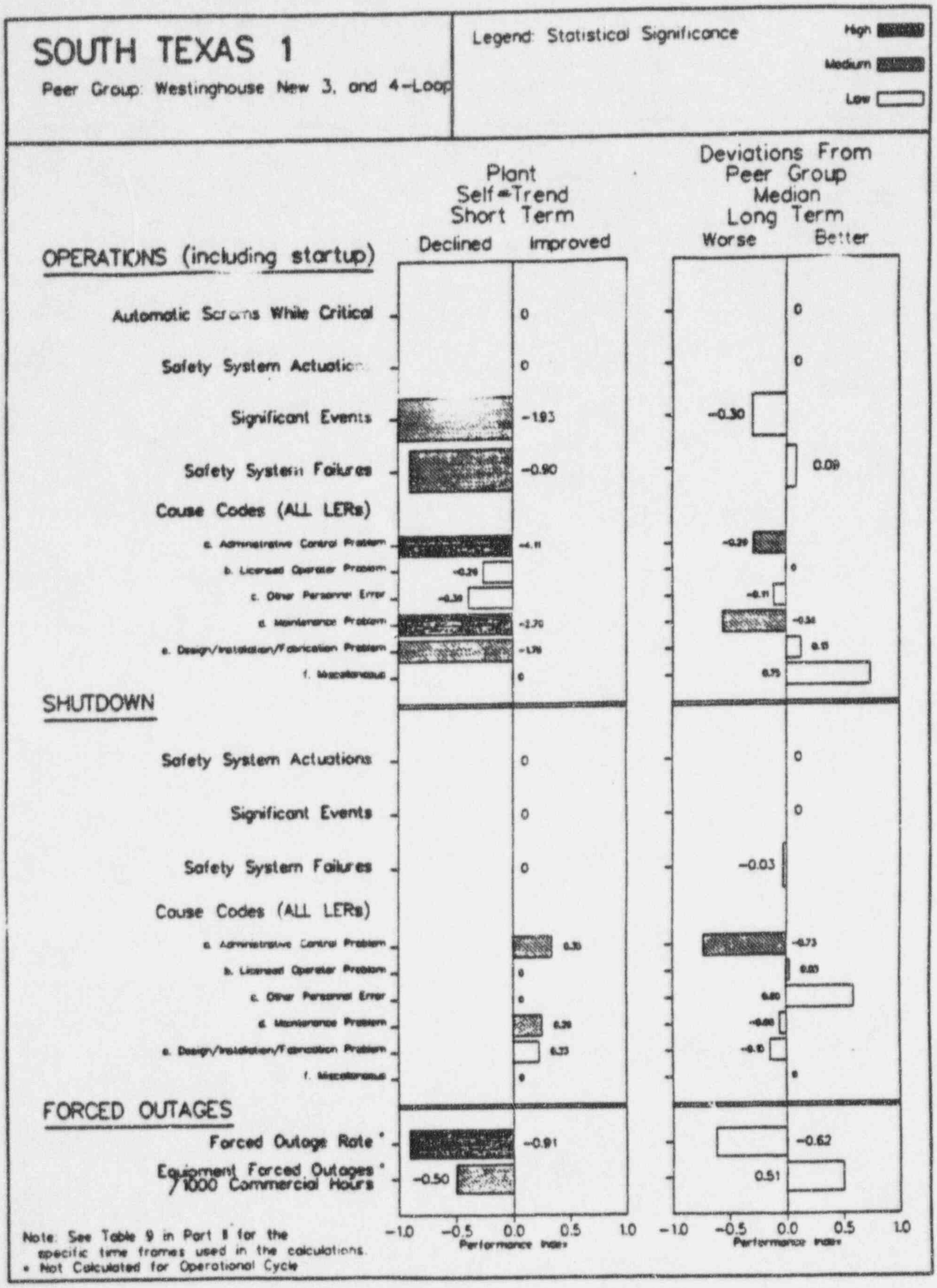
PENDING (EA 93-43)	The staff is considering enforcement action for potential discrimination against security force members.
PENDING (EA 93-56)	The staff is considering enforcement action for apparent harassment and intimidation of a contract I&C technician.
PENDING (EA 93-57)	The staff is considering enforcement action for potential Technical Specification violations involving emergency diesel generators and auxiliary feedwater pumps.
PENDING (EA 93-66)	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.

SOUTH TEXAS

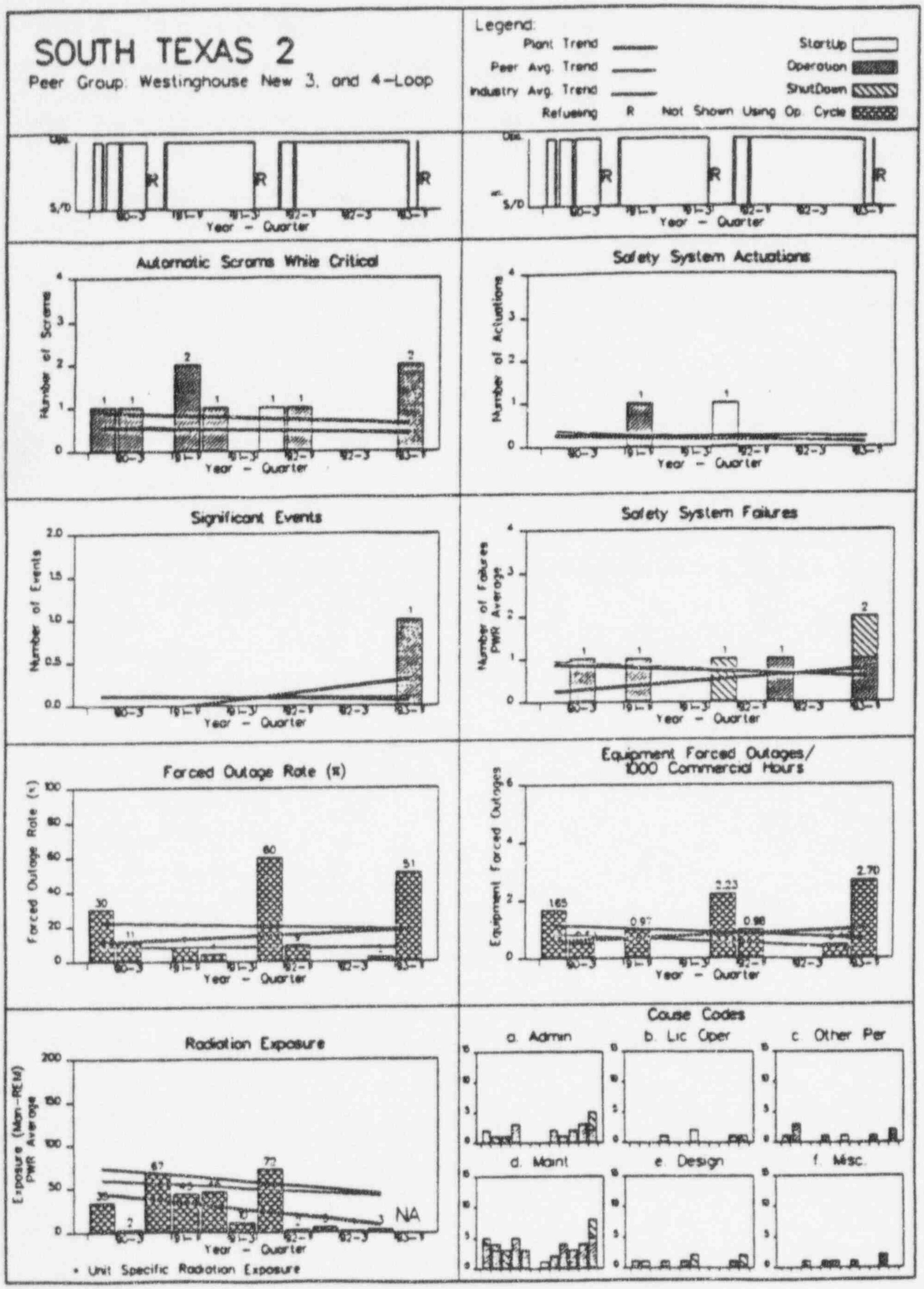
MOST RECENT SALP RATINGS



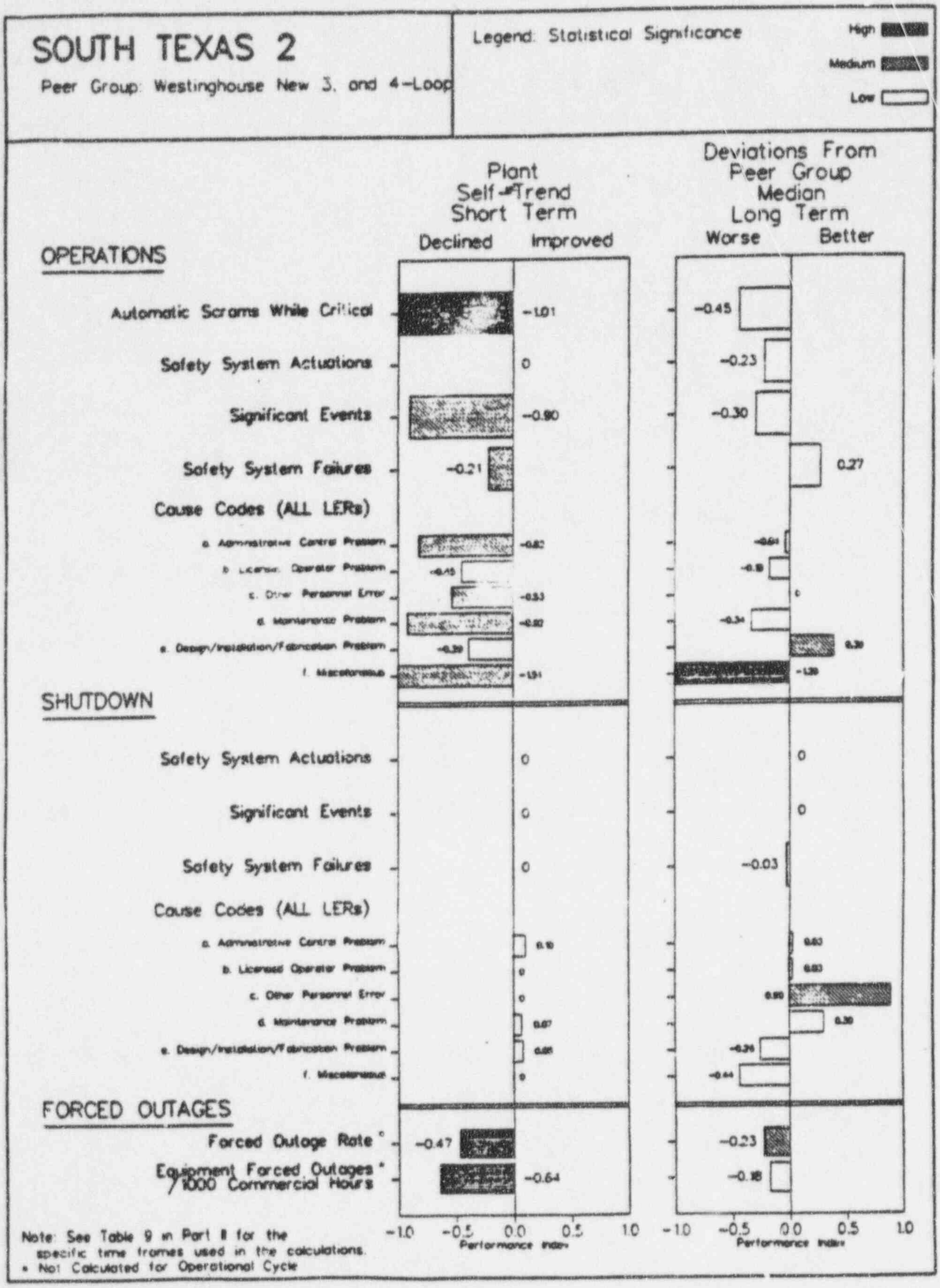

SOUTH TEXAS 1
Peer Group: Westinghouse New 3, and 4-Loop
Legend:
Plant Trend
Peer Avg. Trend
Industry Avg. Trend
Refueling R
Not Shown Using Op. Cycle
StartUp
Operation
ShutDown
Year - Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant Events
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
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)
a. Administrative Control Problem
b. Licensed Operator Problem
c. Other Personnel Error
d. Maintenance Problem
e. Design/Installation/Fabrication Problem
f. Miscellaneous
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
FORCED OUTAGES
Forced Outage Rate *
Equipment Forced Outages */1000 Commercial Hours
0
0
-1.93
-0.90
0
0
0
-0.91
-0.50
0
0
-0.30
0.09
0
0
-0.03
-0.62
0.51
-1.0 -0.5 0.0 0.5 1.0
Performance Index
-1.0 -0.5 0.0 0.5 1.0
Performance Index
Note: See Table 9 in Part II for the specific time frames used in the calculations.
* Not Calculated for Operational Cycle

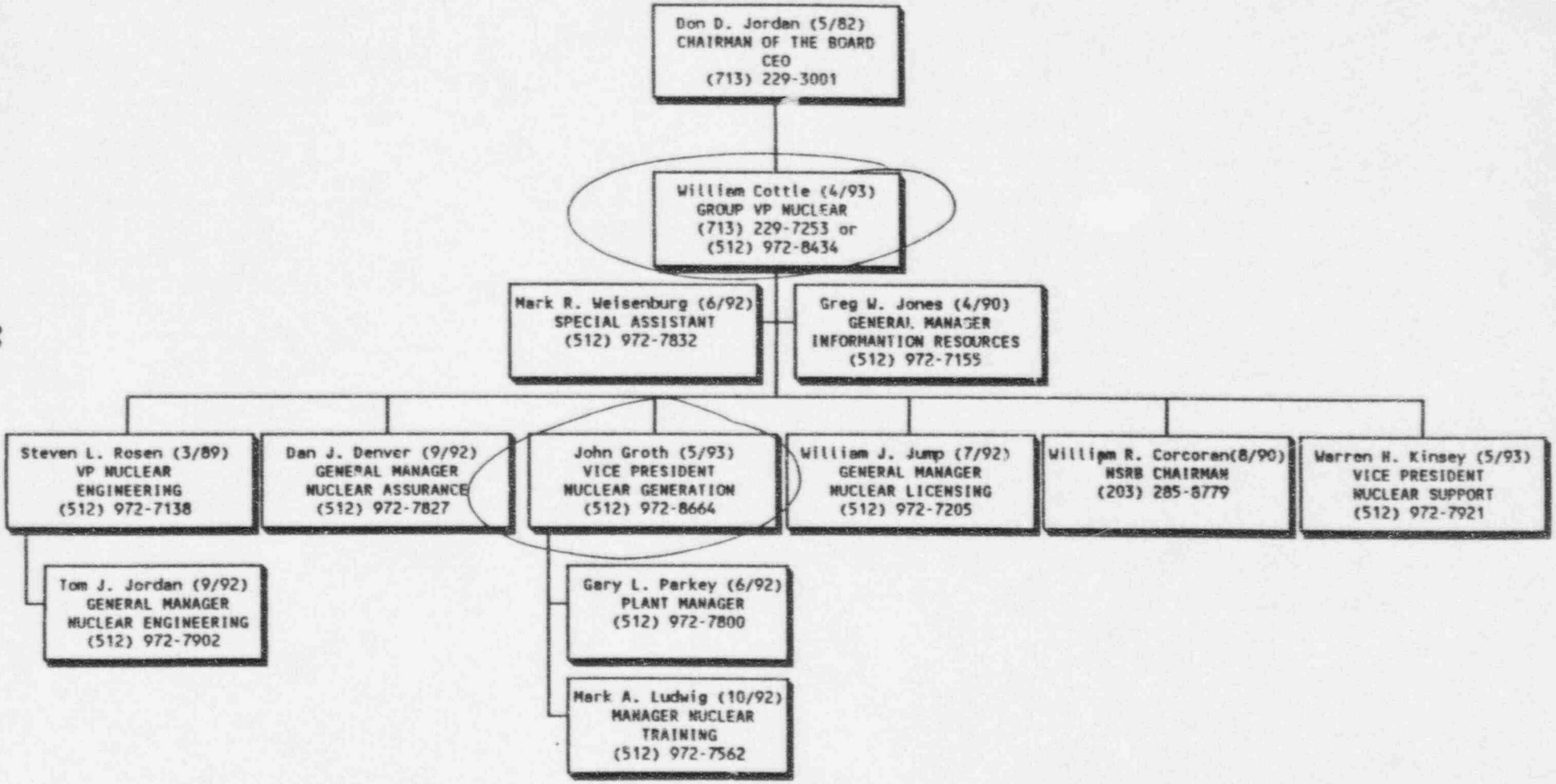


SOUTH TEXAS 2
Peer Group: Westinghouse New 3, and 4-Loop
Legend:
Plant Trend
Peer Avg. Trend
Industry Avg. Trend
Refueling R
StartUp
Operation
ShutDown
Not Shown Using Op. Cycle
S/D
Year – Quarter
Automatic Scrams While Critical
Number of Scrams
Safety System Actuations
Number of Actuations
Significant 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
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
-1.01
-0.45
Safety System Actuations
0
-0.23
Significant Events
-0.90
-0.30
Safety System Failures
-0.21
0.27
Cause Codes (ALL LERs)
SHUTDOWN
Safety System Actuations
0
0
Significant Events
0
0
Safety System Failures
0
-0.03
Cause Codes (ALL LERs)
FORCED OUTAGES
Forced Outage Rate *
-0.47
-0.23
Equipment Forced Outages * /1000 Commercial Hours
-0.64
-0.18
-1.0
-0.5
0.0
0.5
1.0
Performance Index
Note: See Table 9 in Part II for the specific time frames used in the calculations.
* Not Calculated for Operational Cycle

HOUSTON LIGHTING & POWER COMPANY
SOUTH TEXAS PROJECT



6/93