APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report Nos. 50-498/92-01
50-499/92-01

Operating License Nos. NPF-76
NPF-80

Licensee: Houston Lighting and Power Company (HL&P)

Facility Name: South Texas Project Electric Generating Station (STP), Units 1 and 2

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: January 27-31, 1992

Inspectors: D. R. Hunter, Senior Reactor Inspector, Operational Programs Section, Division of Reactor Safety

J. E. Bess, Reactor Inspector, Operational Programs Section Division of Reactor Safety

Approved: T. F. Stetka, Chief, Operational Programs Section Division of Reactor Safety — 2/24/92 Date

Inspection Summary

Inspection Conducted January 27-31, 1992 (Report Nos. 50-498/92-01; 50-499/92-01)

Areas Inspected: Routine, announced inspection of the licensee's self-assessment and corrective action processes and the followup of previously identified inspection findings.

Results: Within the two areas inspected, no violations or deviations were identified.

The licensee's self-assessment and corrective-action processes were functioning and effective in most all instances. The licensee actions associated with the reactor trip, which occurred on October 14, 1991, did not promptly address all of the adverse conditions which occurred during the trip transient.

The inspectors noted that the licensee classified and processed some adverse conditions as Severity Level 2 (not significant) station problem reports, when, in fact, the items appeared to be potentially significant and required additional specific and generic reviews. Additionally, the nuclear safety review board had not developed adequate criteria to ensure the committee reviewed all recognized adverse conditions which could effect nuclear safety.

DETAILS

1. PERSONS CONTACTED

STP

*D. Hall, Group Vice President
*S. Rosen, Vice President, Nuclear Engineering
*W. Kinsey, Vice President, Nuclear Generation
*M. Chalravorty, Executive Director, NSRB
*R. Chewing, Vice President, Nuclear Support
*M. Wisenburg, Plant Manger
T. Jordan, General Manager, Nuclear Assurance
*J. Johnson, Supervisor, Engineering Assurance
*D. Lazar, Manager, Plant Engineering
*J. Sharpe, Manager, Maintenance
*R. Hernadez, Manager, Design Engineering
*G. Midhiff, Manager, Plant Operations
*D. Denver, Manager, Nuclear Engineering
W. Jump, Manager, Nuclear Licensing
*R. Balcom, Manager, Nuclear Security
*T. Underwood, Manager, ISEG
*B. McLaughlin, Operations Engineer (CPL)
*R. Rehkughr, Senior Consultant, Quality Assurance
*G. Parkey, Manager, Planning and Assessment
*C. Ayala, Supervising Engineer, Licensing
*R. Dally, Engineering Specialist, Licensing
*U. Tran, Engineer, Licensing
*A. McIntyre, Director, Plant Projects
*W. Humble, Acting Programs Manager, Plant Engineering
*H. Berzendahl, Manager, Technical Services
*P. Appleby, Manager, Training

NRC

*D. Hunter, Senior Reactor Inspector
*J. Bess, Reactor Inspector
*J. Tapia, Senior Resident Inspector
*T. Stetka, Chief, Operational Programs Section

Other licensee technical and administrative personnel were contacted during the inspection.

*Denotes the individuals attending the exit interview conducted on January 31, 1992.

2. ACTIONS ON PREVIOUSLY IDENTIFIED INSPECTION FINDINGS (92701)

2.1 (Closed) Open Item (498/8907-02): Modifications to Unit 1 Essential Cooling Water (ECW) Flow Control Valves on Essential Chillers 11(A), (B), and (C) and 12 (A), (B), and (C).

This item addressed the licensee's planned actions to maintain Unit 1 essential chillers operations during winter periods. To ensure that the essential chillers were operable during winter months, the licensee implemented temporary modifications which placed the chiller condenser outlet valves in the locked-open position. The manually operated chiller inlet valves were changed from the locked-open position to the locked-in-place position. These valves (inlet) will be used to manually control ECW flow through the essential chillers when the ECW pond temperature decreased to 54°F. With this temporary modification, operator action will be required to maintain chiller condenser pressure by manually adjusting the inlet ECW valve when the ECW pond temperature decreased below 54°F.

The licensee stated that procedures for maintaining chiller pressures had been implemented and made a part of the control room operators log. Also, plant log sheets for Modes 1-4 and 5-6 had been revised.

Permanent modifications were scheduled for implementation in 1994.

On the basis of the review of the temporary modification and the implementation of procedures, this item is considered closed.

2.2 (Closed) Inspector Followup Item (498/9101-01; 499/9101-01): Annunciator Procedures Associated with the Feedwater Isolation Valve Hydraulic Operating Units.

This issue concerned apparent weaknesses noted in the annunciator procedures for the valve hydraulic operating units.

The inspector reviewed the licensee's corrective actions regarding the matter, including changes to the annunciator procedures for both Units 1 and 2, which addressed the specific hydraulic operating units.

The inspector had no further questions regarding this matter and the item is considered closed.

2.3 (Closed) Inspector Followup Item (498/9101-02; 499/9101-02): Operational Trouble-Shooting Activities.

This item concerned the administrative guidance regarding the control of quality and safety-related operational trouble-shooting activities.

The inspector reviewed the licensee's corrective actions regarding this issue, including training, to familiarize the operators with the trouble-shooting

activities, and the requirements for a separate technical review of operational trouble-shooting activities.

The inspector had no further questions regarding this matter and this item is considered closed.

2.4 (Closed) Inspector Followup Item (498/9101-03; 499/9101-03): Operator Training Associated with the Feedwater Isolation Valve Hydraulic Operating Unit.

This item concerned the provision of training lesson plans regarding the hydraulic operating units.

The licensee evaluated the training regarding the hydraulic operating units and provided enhanced lesson plans to improve the overall operations knowledge level of the units.

The inspector had no further questions regarding this matter and this item is considered closed.

3. EVALUATION OF LICENSEE SELF-ASSESSMENT AND CORRECTIVE ACTION CAPABILITIES (40500 AND 92720)

The objective of this inspection effort was to determine the effectiveness of the licensee's self-assessment capabilities and actions associated with identified problems. The inspectors reviewed selected problems or issues, which had been identified and dispositioned by the licensee, in order to evaluate the process for assessing the plant problems that could have an impact on plant safety. The problems or issues selected included licensee event reports (LERs), station problem reports (SPRs), and request for action reports (RFAs). The inspectors also reviewed other information (recent reactor/plant trip reports, oversight group reports and meeting minutes, QA audit reports, temporary modifications, plant trend reports, and various activity status reports).

Each of the problems or issues was evaluated against the following criteria:

(1) Identification: The identification of the problem was at an appropriate organizational level.

(2) Evaluations: The evaluations of the problem included determinations of plant safety, operability, generic implications, causal linkage, and reportability. The evaluation also included a root-cause analysis, if appropriate.

(3) Actions Taken: The corrective actions taken were timely, had been verified, and had been tested. The problem and its correction was trended by cause, timeliness, and area of responsibility; and the problem was reported to management for their actions and oversight.

(4) Oversight: The oversight function for each type of problem included the appropriate tracking through closure, periodic review by management, and periodic audit of the process.

(5) Expectations: The responsibilities of employees at all levels had been defined for the corrective action process, and the appropriate training had been provided.

The problem reports, controlling procedures, QA audits, and other documents reviewed are listed in the Attachment to this report.

3.1 Licensee Event Reports (LERs) and Station Problem Reports (SPRs)

The inspectors reviewed selected LERs and SPRs to determine that the adverse conditions had been appropriately classified, the root cause and corrective actions to prevent recurrence were appropriate, and the event documentation was adequate.

The inspectors noted that the SPR was the licensee's principal corrective-action method to document and disposition both programmatic and hardware problems. The LERs were developed as an integral part of the SPR process. The LERs were routinely classified as Severity Level 1 SPRs (e.g., significant condition adverse to quality) in accordance with the program requirements. The Severity Level 1 SPRs and LERs were formally reviewed by the plant operating review committee (PORC), the plant manager (PM), the nuclear safety review board (NSRB), and the QA group. The SPRs could also be classified as Severity Level 2 items (e.g., condition adverse to quality) in accordance with the program requirements. The major differences between the Severity Level 1 and the Severity Level 2 SPRs were that the Severity Level 2 SPRs were not formally reviewed by the PORC, the PM, the NSRB, or the QA group. The program required the use of the system problem-solving process to provide a root cause determination for Severity Level 1 SPRs.

Interviews revealed that the licensee was presently establishing a separate corrective action management group to further enhance the effectiveness and efficiency of the corrective action process at the facility. The licensee indicated that the plan was to develop an integrated corrective-action process to improve the product. The conversion, which was planned to start in the near future, would require some time to fully implement.

The following observations were made associated with the identified events (LERs and SPRs) reviewed:

SPR 91-440/441, "RCP 2A Breaker Failure to Trip From the Control Room," November 24, 1991; and

SPR 91-0409, "Current Transformers for 50/51 Devices for 13.8kV Bus 2G Found Disconnected," November 15, 1991.

The events were classified as Severity Level 2 SPRs.

The review by the inspector of the investigation of SPR 91-440/441 conducted by the licensee determined that similar breakers had failed to open upon demand from the control room. The inspector noted that the investigation had not adequately addressed the failure of the breaker to trip if a fault current was present to protect the containment penetration (RCP 2A motor cables). The 13.8kV RCP 2A breaker was classified as nonsafety-related; however, the breaker failure to open/trip as a result of over-current conditions appeared to be a safety-affecting function.

The investigation of SPR 91-0409 by the licensee determined that the affected 50/51 devices were not the primary protection devices; however, the use of the same type procedures to calibrate other similar protection devices (generic implications) was not addressed.

The specific Severity Level 2 SPRs were not required to be reviewed by the offsite nuclear safety review board (NSRB). These events, which could affect nuclear safety [(1) 13.8kV breaker failure to open was repetitive and provided protection for the containment penetration and (2) common procedures used to calibrate other similar protection devices)], were presented to the licensee representatives as events which appeared to have safety significance and may need to be considered by the NSRB during routine independent reviews.

The licensee indicated that the NSRB reviewed some Severity Level 2 SPRs, when deemed appropriate; however, the licensee representative indicated that the need for formal criteria for NSRB review of recognized deficiencies that could affect nuclear safety would be reviewed.

3.2 Reactor Post-Trip Review Reports

The inspectors reviewed four recent post-trip review reports associated with Units 1 and 2.

The following observations were made regarding these reports and unit trips.

Post-Trip Review Report 1-018, "Reactor Trip From 100% Power Due to a Loss of a Reactor Coolant Pump - Loss of Bus Voltage" (October 10, 1991).

The report was acceptable overall; however, the report identified that the "MSIVs were closed to limit cooldown following plant trip," (Section 2.4). The closing (and apparent opening) of the main-steam isolation and bypass valves subsequent to the reactor trip were not appropriately noted in the attached control room log sheets to provide for routine reviews. This apparent discrepancy in log-keeping practices was brought to the licensee's attention.

Post-Trip Review Report 1-019, "Reactor Trip from 100% Power Due to a Turbine Trip Resulting From Less Than Adequate Testing Activities" (October 14, 1991).

The review of the report, the supporting documentation, and the associated investigation reports identified that a HEAT SINK (H) red path critical safety

function (loss of heat sink) was encountered when the auxiliary feedwater (AFW) flow was reduced to less than 576 gpm with all steam generators (S/Gs) narrow range (NR) levels less than 5 percent. The report documented that the "AFW flow <576 gpm because operators took manual control of reg. valves."

Document reviews and personnel interviews revealed that the reduction of AFW flow following a routine reactor trip was a normal operator response to limit the AFW contribution to the cool down of the secondary and primary systems. The operators reduced the AFW flow from about 2400 gpm to about 576 gpm, as indicated on the main control board. Additionally, the operators also routinely closed the main steam isolation valves and/or manually isolated selected secondary system steam loads to limit the reactor cool down transient. The operators apparently did not realize that the AFW flow had been reduced below 576 gpm total and that the HEAT SINK (H) red path was present. The condition was sustained for about 4 minutes while the AFW flow was less than 576 gpm [indicated 530 gpm total on the safety parameter display system (SPDS)]. The operators restored the AFW flow to greater than 576 gpm total flow about 6 minutes after the plant trip.

The existence of the degraded condition was not identified during the reactor post-trip review. The post-trip review required the identification of any "SPDS Alarr Indication (Include all alarms immediately following trip)" (step 2.B. 10), and "For each alarm explain the behavior of the analog parameter involved in the logic branch causing the alarm; a'so, give the time of each alarm." The inspector noted that the HEAT SINK (H) red path alarm caused by AFW flow less than 576 gpm total and all S/G NR levels less than 5 percent was identified; however, the actual parameter values and time were not specifically noted in the report. The adverse condition was not recognized by operations personnel and the condition was not identified and dispositioned promptly; therefore, any immediate corrective actions, as appropriate, were not determined and implemented prior to the plant restart authorization provided by the Plant Manager on October 16, 1991.

Interviews revealed that following licensee discussions during the period of October 18 and November 1, 1991, an SPR (91-0402) was initiated to identify and disposition the "Inadequate AFW Flow After Reactor Trip" as an adverse condition. The inspector reviewed the licensee investigation report concerning the situation. Document reviews and personnel interviews indicated that the operators "did not intentionally enter the requisite conditions for the red path," and the review of the post-trip data by the inspector confirmed that the minimum, sustained total AFW flow was about 530 gpm. The licensee determined the root cause of the event to be the repetitive plant response/cooldown following a reactor trip, placing "an undue amount of response effort on the operator." It was also noted that contributing factors included reducing AFW flows "to a point too close to a safety limit," the failure to adequately monitor the SPDS indications, and an apparent weakness in the simulator modeling of the trip-transient and the related operator training. Further, the licensee identified that the plant response/cooldown following a reactor trip was "unnecessary and would be a major distraction if the plant ever did have an actual safety challenge during (or causing) the

trip" and could mask the indications which would alert the operator to an actual accident such as a LOCA or an apparent steamline break.

The licensee had not addressed the minimum total AFW flow encountered during the reactor trip transient. Document review and personnel interviews revealed that the licensee had determined that following the unit trip the reactor plant parameters were stabilized, with the average reactor coolant system temperature at 563°F, during the period the AFW flow was at 530 gpm and the S/G narrow range levels were less than 5 percent. However, the licensee had not determined whether the AFW flow of 530 gpm was acceptable with regards to the assumed conditions in the plant safety analysis. The licensee reviewed the concern during the inspection and provided an evaluation to the inspector on January 30, 1992, which indicated that a minimum of 500 gpm AFW flow was acceptable, based on the latest analysis.

The inspector discussed the need to fully evaluate this condition and any other adverse conditions identified during the post-trip reviews to ensure that the causes and needed immediate corrective actions were fully developed and implemented prior to authorizing plant restart. Such actions might include issuing a memorandum promptly to caution all licensed operators, as appropriate, to monitor all plant safety instrumentation (e.g. critical safety functions) more closely during plant trips. The inspector reviewed a recently issued "Plant Operations Department, Information Bulletin," dated January 15, 1992, issued to all licensed operators, discussing the reduction of the AFW flow to 530 gpm for a short period and cautioning the operators "to not reduce AFW flow too close to the safe limit of 576 gpm."

Additionally, regarding the continuing secondary steam demand issue, the licensee presented the inspector some preliminary information noting that design engineering (Design Change Request 91-Z-1075) was in the process of reviewing "the problem of excessive cooldown to determine if any design changes are appropriate." The licensee had determined the sources of the continuing steam flow following a reactor trip to be substantial and included flows to the moisture separator-reheater, main steam drains, auxiliary steam system, and the main feed pumps.

3.3 Independent Safety Engineering Group (ISEG)

The inspectors reviewed ISEG activities to assess the group's review practices and the handling of findings. ISEG had effectively implemented a program of oversight at STP and had demonstrated a proactive approach to give management insight into the operation of the facility.

The inspectors noted that ISEG response to a NRC noncited violation, pertaining to a lack of timely corrective action on an ISEG identified deficiency, was prompt. ISEG responded to this violation by issuing an internal directive requiring personnel to issue appropriate corrective action documents on discrepancies observed in the field.

In response to an NRC comment, relative to "followup" on ISEG recommendations, ISEG completed a self-assessment on corrective action effectiveness. The results of the self-assessment showed a high degree of responsiveness by the line organization; however, timeliness in responding to recommendations and in meeting action commitments dates were less consistent. The self-assessment also resulted in several recommendations and suggestions and if completed, should make ISEG even more effective in implementing a program of oversight at STP.

3.4 Conclusion

The LER program and the root causes and corrective actions associated with the LERs appeared to be acceptable.

Overall, the SPR program and the root causes and corrective actions associated with the identified events appeared to be acceptable. However, concerns were noted regarding the classification of some SPRs, in that, a nonsafety-related component may perform a safety affecting function, warranting an increased level of significance placed on the associated adverse condition. Similarly, the same calibration procedures may be utilized on a safety-related, as well as a nonsafety-related, component indicating potential generic implications for an adverse condition associated with the nonsafety-related component calibration procedure. Additionally, the offsite nuclear safety review committee (NSRB) had not developed criteria to cause the review of the Severity Level 2 SPRs, which identified conditions that could affect nuclear safety.

The inspector's review of the post-trip review reports revealed that record and log-keeping practices could be enhanced in order to provide comprehensive information for subsequent staff reviews.

The inspector reviewed the report regarding the reactor trip on October 14, 1991. The licensee identified that the operators unknowingly entered the HEAT SINK (H) red path and the on-shift supervisors and the shift technical advisor were not immediately aware of the situation. The inspector noted that the situation was not identified promptly as an adverse condition (not included in, or referenced by, the reactor trip SPR) and the minimum AFW flow rate of 530 gpm had not been appropriately evaluated. The licensee was able to adequately address the potential safety issues during the inspection.

The unintentional entry into the HEAT SINK (H) red path was likely caused by the operators reacting to the continuing secondary plant steam demand following the reactor trip. This was noted to be a problem common to both the units and the licensee's engineering group was evaluating the situation to determine corrective actions.

The licensee actions associated with this specific reactor trip transient were not as prompt and conservative as expected.

The Independent Safety Engineering Group (ISEG) had responded to NRC concerns in a timely manner. A self-assessment was performed to check the effectiveness of tracking and implementing actions for ISEG recommendations. The assessment indicated that line management was responsive to ISEG recommendations. The ISEG appeared to be functioning effectively and headed in a positive direction.

4. EXIT INTERVIEW

The inspectors met with the licensee representatives denoted in paragraph 1 on January 31, 1992, and summarized the scope and findings of this inspection. The licensee did not identify, as proprietary, any of the material provided to, or reviewed by, the inspectors during this inspection.

ATTACHMENT

Documents Reviewed

Licensee Event Reports (LERs)

LER 1-91-018 (SPR 91-0263), "Inability of Condenser Air Removal Vent Radiation Monitors to Operate Under Low Flow Condition"

LER 1-91-017 (SPR 91-0214), "Control Room Ventilation Actuation of Recirculation Mode Due to a Spurious Signal From a Topic Gas Analyzer"

LER 2-91-008 (SPR 91-0478), "Containment Ventilation Isolation Actuation Due to A Failure in the Radiation Monitoring System"

LER 1-91-019 (SPR 91-0322), "RCS Leak Rate Greater Than TS Limit"

LER 2-91-009 (SPR 91-0265), "ESF Actuation Caused by a Failed Light Emitting Diode (LED)"

Quality Assurance Reports

1991 Joint Utility Management Audit, 91-22 (JUMA)

1991 Nuclear Assurance Audit No. 91-010 (CA-1), "Corrective Action Program" (July 1-19, 1991)

1991 Nuclear Assurance Audit No. 91-019 (CA-1), "Corrective Action Program" (December 2-20, 1991)

Station Problem Reports (SPRs)

91-0404, "Pilot Solenoid Valve Stuck in the Open Position (MSIV)"

91-0402, "Total AFW Flow Reduced to Less Than 576 gpm"

91-0409, "Current Transformer for Overcurrent Relays for Tie Breaker for 13.8kV Bus 2G Found Disconnected"

91-0440/0441, "RCP 2A Breaker Would Not Open from Control Room"

91-0434, "Seismic Scaffolds in Seismic II/I Areas in Unit 1 and 2"

91-0437, "Injector Pump 101 Holddown Stud Failure on Standby Diesel Generator #22"

91-0299, "Improper Disposition of Work Request PL-113054"

91-0387, "Forced Outage Startup Delayed Due to Main Steam Isolation Valve Work"

91-0377, "Main Steam Isolation Valve (MSIV) Packing Material"

91-0330, "Output Breaker for DG 23 Not Racked in Properly"

91-0295, "Main Power Breaker to EAB Main Area HVAC Supply for Train B Would Not Open"

91-0288, "U2 Experienced a Loss of All Condensate Flow Due to the CP Outlet Valves Closure"

Plant Outage Reports

LER 1-91-021 (SPR 91-0362) (Post-Trip Report #1-018), "Reactor Trip Due to RCS Loop 4 Low Flow - Loss of 13.8kV Bus"

LER 1-91-022 (SPR 91-0369) (Post-Trip Report #1-019), Reactor Trip Caused by a Turbine Trip Due to Less Than Adequate Performance of Testing"

LER 2-91-007 (SPR 91-209) (Post-Trip Report #2-018) "Reactor Trip Caused by Inadvertent Actuation of Generator Breaker Emergency Trip"

LER 2-91-010 (SPR 91-0484) (Post-Trip Report #2-019) "Automatic Reactor Trip and Safety Injection Actuation Due to Low Pressurizer Pressure"

Temporary Modifications

T1-DB-91-022, Pickup Voltage Too Low for Load Sequence Relays to Energize (August 8, 1991)

T2-DJ-91-024, Jumper A11 #7, Battery E2011 (November 27, 1991)

Station Trend Reports

First Quarter 1991 (May 22, 1991)

Second Quarter 1991 (August 13, 1991)

Third Quarter 1991 (November 7, 1991)

Request for Action (RFA)

91-1730, "B2SIMOV0008B, HHSI Hot Leg Isolation Valve, Train B Open Limit Switch Setting Evaluation," (October 26, 1991)

91-1779, "Type DS-206, 480V Breaker Became Trip-Fee Investigation," (November 1, 1991)

91-1727, "A2SIMOV 0018A LHSI Discharge Isolation Valve, Train A, Open Overthrust During Testing Evaluations," (October 25, 1991)

ISEG Procedures

ISEG-01, "Independent Safety Engineering Group Organization and Responsibilities," Revision 3

ISEG-02, "Procedure Development," Revision 2

ISEG-03, "Task Administration and Report Preparation," Revision 4

ISEG-04, "Operational Event Review," Revision 6

ISEG-05, "Observation and Reviews," Revision 4

ISEG-06, "Assessments and Investigations," Revision 1

ISEG-07, "Technical Staff Training," Revision 2

ISEG-08, "Records Control," Revision 2

Independent Safety Engineering Group (ISEG) Quarterly Reports

August 26, 1991, through November 1, 1991

Independent Safety Engineering Group (ISEG) Monthly Reports

June 1991 through December 1991