UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

August 10, 2006

James J. Sheppard, President and
Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, Texas 77483

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000498/2006003 AND 05000499/2006003

Dear Mr. Sheppard:

On July 7, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings which were discussed on July 13, 2006, with you and members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one self-revealing finding of very low safety significance (Green). Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because you entered it into your corrective action program, the NRC is treating this violation as a non-cited violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest this noncited violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at South Texas Project Electric Generating Station, Units 1 and 2, facility.

In accordance with 10 CFR 2.390 of the NRC's “Rules of Practice,” a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection

in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Claude E. Johnson, Chief
Project Branch A
Division of Reactor Projects

Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2006003 and 05000499/2006003
w/Attachment: Supplemental Information and Significant Determination Process Phase 3 on Cold Overpressure Mitigation System

cc w/Enclosure:
E. D. Halpin
Site Vice President/
Plant General Manager
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, TX 77483

S. M. Head, Manager, Licensing
STP Nuclear Operating Company
P.O. Box 289, Mail Code: N5014
Wadsworth, TX 77483

C. Kirksey/C. M. Canady
City of Austin
Electric Utility Department
721 Barton Springs Road
Austin, TX 78704

J. J. Nesrsta/R. K. Temple
City Public Service Board
P.O. Box 1771
San Antonio, TX 78296

Jack A. Fusco/Michael A. Reed
Texas Genco, LP
12301 Kurland Drive
Houston, TX 77034

Jon C. Wood
Cox Smith Matthews
112 E. Pecan, Suite 1800
San Antonio, TX 78205

A. H. Gutterman, Esq.
Morgan, Lewis & Bockius
1111 Pennsylvania Avenue NW
Washington, DC 20004

Institute of Nuclear Power Operations (INPO)
Records Center
700 Galleria Parkway SE, Suite 100
Atlanta, GA 30339

Director, Division of Compliance & Inspection
Bureau of Radiation Control
Texas Department of State Health Services
1100 West 49th Street
Austin, TX 78756

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, TX 78701-3326

Environmental and Natural
Resources Policy Director
P.O. Box 12428
Austin, TX 78711-3189

Judge, Matagorda County
Matagorda County Courthouse
1700 Seventh Street
Bay City, TX 77414

Terry Parks, Chief Inspector
Texas Department of Licensing
and Regulation
Boiler Program
P.O. Box 12157
Austin, TX 78711

Susan M. Jablonski
Office of Permitting, Remediation and Registration
Texas Commission on Environmental Quality
MC-122, P.O. Box 13087
Austin, TX 78711-3087

Ted Enos
4200 South Hulen
Suite 630
Fort Worth, TX 76109

Chairperson
Denton Field Office
Chemical and Nuclear Preparedness and Protection Division
Office of Infrastructure Protection
Preparedness Directorate
Dept. of Homeland Security
800 North Loop 288
Federal Regional Center
Denton, TX 76201-3698

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(RJC1)**
Senior Resident Inspector **(JLD5)**
Branch Chief, DRP/A **(CEJ1)**
Senior Project Engineer, DRP/A **(TRF)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**
DRS STA **(DAP)**
J. Lamb, OEDO RIV Coordinator **(JGL1)**
ROPreports
STP Site Secretary **(Vacant)**
Regional State Liaison Officer **(WAM)**
NSIR/DPR/EPD **(REK)**

SUNSI Review Completed: _CEJ_ ADAMS: Yes ☐ No Initials: __CEJ____
Publicly Available ☐ Non-Publicly Available ☐ Sensitive Non-Sensitive

R:_REACTORS_STP\2006\ST2006003RP-JLD.wpd

RIV:RI:DRP/A	SRI:DRP/A	PE:DRP/A	SPE:DRP/A	C:DRS/PSB	C:DRS/EB1
JLTaylor	JLDixon	MABrown	TRFarnholtz	MPShannon	JAClark
E-MJSpivey	***E-MJSpivey***	***/RA/***	***/RA/***	***/RA/***	***/RA/***
08/2/06	08/2/06	08/04/06	08/02/06	08/01/06	07/28/06

C:DRS/OB	C:DRS/PEB2	C:DRP/A			
ATGody	LJSmith	CEJohnson			
/RA/	***NFO'Keefe for***	***/RA/***			
07/31/06	07/24/06	08/10/06			

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-498, 50-499
Licenses:	NPF-76, NPF-80
Report:	05000498/2006003 and 05000499/2006003
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM 521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Dates:	April 8 through July 7, 2006
Inspectors:	T. Brown, Project Engineer K. Clayton, Operations Engineer J. Dixon, Senior Resident Inspector P. Elkmann, Emergency Preparedness Inspector J. Taylor, Resident Inspector G. Werner, Senior Project Engineer, PBD
Approved By:	Claude E. Johnson, Chief Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000498/2006003, 05000499/2006003; 04/08/06 - 07/07/06; South Texas Project Electric Generating Station, Units 1 & 2; Integrated Resident and Regional Report, Event Follow-up

The report covered a 3-month period of inspection by resident inspectors, project engineers and announced inspections by regional inspectors. Two Green findings, one of which was a licensee-identified noncited violation, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified for the failure to provide an adequate procedure, which resulted in an unexpected initiation of a "Generator U/F (Under-Frequency) Loss of Field Voltage" alarm. This alarm would have caused a generator/turbine/reactor trip in 30 seconds. Prompt action by the operators to terminate the test prevented the trip. The licensee performed a thorough root cause of the event to determine the short and long term corrective actions.

  This finding was greater than minor because it was associated with the procedure quality attribute affecting the Initiating Event Cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. This finding was determined to be a finding of very low safety significance because, although the likelihood of a reactor trip increased, the likelihood that mitigating systems would not be available did not increase and no transient actually occurred (Section 4OA3).

B. Licensee-Identified Violations

- A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially 100 percent rated thermal power throughout the inspection period.

Unit 2 operated at essentially 100 percent rated thermal power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

Readiness for Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving hurricanes. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report (USAR), and Technical Specifications (TSs) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the one system listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, temporary chillers, etc. . .) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

C June 1, 2006, Units 1 and 2: Hurricane supply storage room inventory and general site cleanliness

Documents reviewed by the inspectors included:

Operating Procedure 0PGP03-ZV-0001, “Severe Weather Plan,” Revision 13
Operating Procedure 0PGP03-ZV-0002, “Hurricane Plan,” Revision 0

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

Partial Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the three below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's CAP to ensure problems were being identified and corrected.

- April 19, 2006, Unit 1: The inspectors verified the alignment of essential cooling water (ECW) Train A during and following a Train B outage. The inspectors verified the valve, control panel, local switch, and electrical lineups in accordance with Operating Procedure 0POP02-EW-0001, "Essential Cooling Water Operations," Revision 37.

- May 9, 2006, Unit 1: The inspectors verified the alignment and condition of auxiliary feedwater Train B while Train A was out of service. The inspectors verified that the auxiliary feedwater system equipment and control board were aligned in accordance with Operating Procedure 0POP02-AF-0001, "Auxiliary Feedwater," Revision 22.

- June 6, 2006, Unit 1: The inspectors verified the alignment and condition of residual heat removal (RHR) Train B during maintenance activities removing Train A from service. The inspectors verified that the system equipment and control board were aligned in accordance with Operating Procedure 0POP02-RH-0001, "Residual Heat Removal System Operation," Revision 44.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Quarterly Inspection

a. Inspection Scope

The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire

suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the CAP to determine if the licensee identified and corrected fire protection problems.

- April 10, 2006, Units 1 and 2: ECW intake structure (Fire Zones Z600-605)
- April 13, 2006, Unit 1: Safety injection cubicles (Fire Zones Z305-307)
- April 13, 2006, Unit 2: Isolation valves cubicles (Fire Zones Z401-405)
- May 2, 2006, Unit 1: Control room heating, ventilation, and air conditioning Train A equipment room, corridor, auxiliary shutdown and qualified display processing system train rooms and electrical chases (Fire Zones Z005, 016, 017, 071-073)
- June 5, 2006, Unit 1: Refueling and reactor makeup water storage tank rooms (Fire Zones Z103,104)
- June 13, 2006, Unit 2: Reactor containment building (Fire Zones Z207-214)

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators on June 20, 2006, to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a plant cooldown from Mode 3 to Mode 4 with a failure of the cold overpressure mitigation system (COMS).

Documents reviewed by the inspectors included:

Operating Procedure 0POP03-ZG-0007, “Plant Cooldown,” Revision 46
Operating Procedure 0POP04-RP-0005, “COMS Actuation or Failure,” Revision 11

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the two below listed maintenance activities to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR Part 50, Appendix B, and the TSs.

- April 17-19, 2006, Unit 1: Preventative Maintenance Work Order PM MV-1-90001551 (WAN 290741), "Containment Emergency Sump 1B to Safety Injection Train B Pumps Suction Isolation MOV Operator (ORC)," for Valve SI-0016B inspection, lubrication, and static diagnostic test

- June 19-23, 2006, Units 1 and 2: ECW system health report, plan of action to address emergent maintenance, all ECW condition reports (CRs) from June 1, 2005, through June 23, 2006, and risk management review for CR 06-4982

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the six below listed assessment activities to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- April 27, 2006, Unit 2: Evaluation of risk for Train B equipment outage which included the 5 year standby diesel generator maintenance outage (Evaluation 1355)

- May 2, 2006, Unit 2: Evaluation of risk assessment process during loss of plant Radiological Assessment System for Consequence Analysis capability during Standby Diesel Generator 22 maintenance with Lane-Bay City Temporary 138kV line outage (one of two lines to the emergency transformer)

- May 11, 2006, Units 1 and 2: Evaluation of risk for both units during planned equipment outages and concurrent main switchyard modifications

- June 9, 2006, Unit 1: Evaluation of risk for the week during planned equipment outages on Train A with emergent issues associated with emergency response facility data acquisition and display system (ERFDADS) inverter and digital rod position indication power supply

- June 16, 2006, Unit 2: Evaluation of risk for the week during planned equipment outages on Train A

- June 30, 2006, Units 1 and 2: Evaluation of risk for the week during Unit 1 personnel air lock seal replacement concurrent with planned maintenance and Unit 2 freeze seal on pressurizer liquid sample line with planned maintenance

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Nonroutine Evolutions and Events (71111.14)

a. Inspection Scope

For the two nonroutine events described below, the inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts to evaluate operator performance in coping with nonroutine events and transients; (2) verified that the operator actions were in accordance with the response required by plant procedures and training; and (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- June 2, 2006, Unit 2: Control room operator response to an unplanned grid voltage reduction, and recovery, due to main generator reactive power capability testing (See Section 4OA3 for additional information)

- June 6, 2006, Unit 2: Control room operator response to a fire in the ERFDADS inverter in the 4160 Volt Train B safety-related switchgear room

The inspectors completed two samples.

b. Findings

The inspectors reviewed the licensee's response to a fire in a nonvital inverter in vital switchgear room Train B. The first indication of an inverter problem was several control board alarms associated with ERFDADS, part of the integrated computer system. All control board alarms cleared immediately. Several minutes later a smoke alarm was received and a control room operator was dispatched to investigate. Within the next minute a second smoke alarm was received. The operator reported to the control room that the fire was located in the vicinity of the Transformer T1 associated with the ERFDADS uninterruptible power supply (UPS) inverter.

The operators used four CO_2 extinguishers to control/extinguish the fire, and the control room instructed the operators to open the breakers associated with the transformer. A continuous fire watch was posted and the fire brigade reported to the scene to evaluate the fire being out. The total time from identification to extinguishing the fire was approximately 8 minutes. Since the fire lasted less than 15 minutes, the licensee was not required to declare an unusual event.

This fire occurred in the same component on Unit 1 on March 23, 2006, (for additional information on this event see NRC Inspection Report 05000498/2006002 and 05000499/2006002, Section 4OA3) and consequently the Unit 2 transformer was scheduled to be replaced within the next several months. The inspectors reviewed the licensee's corrective actions from the first fire, to determine if appropriate corrective actions had been completed, and determined that appropriate measures had been implemented to address the concern. The inspectors did not identify any issues or concerns with the licensee's response or timeliness of corrective actions.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the USAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TSs; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- June 8, 2006, Unit 1: Engineering evaluation of grease fitting found in compensator housing of containment isolation motor-operated Valve 1SIMOV0004C (CR 06-6802)

- June 8, 2006, Units 1 and 2: Engineering evaluation of loose emergency core cooling systems pump shaft sleeve retaining ring setscrews (CR 06-7459 and -7494)

- June 14, 2006, Unit 1: Engineering evaluation of ECW Train A self-cleaning strainer leak (CR 06-7085)

- July 5, 2006, Unit 2: Evaluation of vital Battery E2D11 computer indications (CR 06-8407)

- July 6, 2006, Unit 2: Engineering evaluation of main steam isolation valve bypass valve actuator volume booster leak (CR 06-8160)

The inspectors completed five samples.

b. <u>Findings</u>

No findings of significance were identified.

1R19 <u>Postmaintenance Testing (71111.19)</u>

a. <u>Inspection Scope</u>

The inspectors selected the six below listed postmaintenance test activities of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the USAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- April 14, 2006, Unit 1: Centrifugal charging Pump 1B air handling Unit 11B

- June 6-7, 2006, Unit 1: Preventative Maintenance Work Order PM:MMI-1-01000411, “RHR Heat Exchanger 1A Outlet Valve,” Revision 3, and RHR system Design Change Package 03-9384-88, “Replace I/P Transducer for A1RHHCV-0864"

- June 5-6, 2006, Unit 1: ECW Train A self-cleaning strainer gasket replacement and system drain and refill

- June 12-13, 2006, Unit 2: Essential chilled water expansion tank pressure relief valve replacement per Design Change Package 05-4753-2

- June 13, 2006, Unit 2: Preventative Maintenance Work Order PM:MV-2-90001483, “Hi Head Safety Injection Pump 2A Discharge to Loop 2A Hot Leg Isolation MOV Operator,” Revision 3

- June 26-28, 2006, Unit 1: Personnel air lock reactor containment building side inner door seal and air supply tee fitting replacement

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the USAR, procedure requirements, and TSs to ensure that the six below listed surveillance activities demonstrated that the SSC’s tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator (PI) data; (13) engineering evaluations, root causes, and bases for returning tested SSC’s not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- April 14, 2006, Unit 1: Operating Procedure 0PSP03-SP-0010B, “Train B ESF Load Sequencer Manual Local Test,” Revision 16

- April 24, 2006, Unit 1: Operating Procedures 0PSP03-RS-0001, “Monthly Control Rod Operability,” Revision 20 and 0PEP02-RS-0001, “Control Rod Axial Repositioning,” Revision 4

- April 26, 2006, Unit 1: Operating Procedure 0PSP03-DG-0003, “Monthly Standby Diesel 13(23) Operability Test,” Revision 30

- April 27, 2006, Unit 2: Operating Procedure 0PEP07-ZE-0008, “Non-Intrusive Check Valve Testing,” Revision 5

- June 13, 2006, Unit 2: Operating Procedure 0PSP03-CC-0007, “Component Cooling Water System Train 1A(2A) Valve Operability Test,” Revision 13, for inside containment isolation Valves MOV-0068 and -0049

- June 15, 2006, Unit 2: Operating Procedure 0PSP03-RC-0006, “Reactor Coolant Inventory,” Revision 1

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the USAR, plant drawings, procedure requirements, and TSs to ensure that the one below listed temporary modification was properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the postinstallation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC’s were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- April 13, 2006, Unit 1: Temporary Modification T1 06-0195-1, removal of Panel DPL 434 temporary power installed during load center 1N outage (CR 06-0195-3)

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2006 biennial emergency plan exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario simulated a fire in a vital area lasting more than

15 minutes, mechanical damage to the core from loose parts, a reactor coolant leak which progressed to a loss of coolant accident, progressive core damage and a radiological release to the environment from a recirculation line leak in the fuel handling building.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of event classification, offsite notification, recognition of offsite dose consequences, and development of protective action recommendations, in the simulator control room and the following dedicated emergency response facilities:

- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed recognition of and response to abnormal and emergency plant conditions, the transfer of decision making authority and emergency function responsibilities between facilities, onsite and offsite communications, protection of emergency workers, emergency repair evaluation and capability, and the overall implementation of the emergency plan to protect public health and safety and the environment. The inspectors reviewed the current revision of the facility emergency plan and emergency plan implementing procedures associated with operation of the above facilities and performance of the associated emergency functions. These procedures are listed in the attachment to this report.

The inspectors compared the observed exercise performance with the requirements in the facility emergency plan; 10 CFR 50.47(b); 10 CFR Part 50, Appendix E; and with the guidance in the emergency plan implementing procedures and other federal guidance.

The inspectors attended the postexercise critiques in each of the above facilities to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended a subsequent formal presentation of critique items to plant management.

The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the one below listed drill and simulator-based training evolution contributing to drill/exercise performance and emergency response organization, PIs, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and

(3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2, acceptance criteria.

On May 17, 2006, the inspectors observed a drill in the simulator control room. The scenario included the following:

- Failure of a low pressure turbine rotor
- Loss of offsite power with the failure of two standby diesel generators
- Main Steam Line B rupture in the turbine building
- Steam Generator B tube rupture

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 PI Verification (71151)

Cornerstone: Initiating Events

a. Inspection Scope

The inspectors sampled licensee submittals for the three PIs listed below for the period January 2004 through March 2006, for Units 1 and 2. The definitions and guidance of NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 2, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors reviewed licensee event reports (LER), monthly operating reports, and operating logs as part of the assessment. Licensee PI data was also reviewed against the requirements of Operating Procedures 0PGP05-ZN-0007, “Preparation and Submittal of NRC Performance Indicators,” Revision 1, and 0PGP05-ZV-0013, “Performance Indicator Tracking Guide,” Revision 1.

- Unplanned scrams per 7,000 critical hours
- Unplanned scrams with loss of normal heat removal
- Unplanned power changes per 7,000 critical hours

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

a. Inspection Scope

The inspectors reviewed licensee evaluations for the three emergency preparedness cornerstone PIs of drill and exercise performance, emergency response organization participation, and alert and notification system reliability for the period October 1, 2005, through March 31, 2006. The definitions and guidance of NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revisions 2 and 3, and the licensee PI Operating Procedures 0PGP05-ZN-0007, “Preparation and Submittal of NRC Performance Indicators,” Revision 2, and 0PGP05-ZV-0013, “Performance Indicator Tracking Guide,” Revision 1, were used to verify the accuracy of the licensee’s evaluations for each PI reported during the assessment period.

The inspectors reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspectors reviewed selected emergency responder qualification, training, and drill participation records. The inspectors reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspectors also reviewed other documents listed in the attachment to this report.

- Drill and exercise performance
- Emergency response organization participation
- Alert and notification system reliability

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a daily screening of items entered into the licensee’s CAP. This assessment was accomplished by reviewing work orders, CRs, etc. . . and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional

follow-up through other baseline inspection procedures. The inspectors used the licensee's Operating Procedure 0PGP03-X-002, "Condition Reporting Process," Revision 30, for understanding the threshold level for generating a CR.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the one below listed issue for a more in-depth review. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- July 7, 2006, Units 1 and 2: The inspectors completed an in-depth review of various failures associated with inverters, capacitors, and transformers. Notably, the recent failures of the Units 1 and 2 ERFDADS transformers that resulted in fires as well as failures of capacitors that have resulted in degraded inverter output.

Documents reviewed by the inspectors are listed in the attachment.

b. Findings

No findings of significance were identified.

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors completed a semi-annual trend review of repetitive or closely related issues that were documented in trend reports, problem lists, PIs, health reports, quality assurance audits, corrective action documents, etc. . . to identify trends that might indicate the existence of more safety significant issues. The inspectors review consisted of the 6-month period of January 1 through June 30, 2006. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors compared and contrasted their results with the results contained in the licensee's quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy.

b. Findings

No findings of significance were identified. However, the inspectors did make the following observations which were shared with licensee management. The licensee has captured each of these events in their CAP under various CRs.

- The inspectors observed that during several prejob briefs operating experience from the industry was not being used. The operating experience that was being discussed was limited to events that occurred at the site, even when more current experience was relevant and available. In addition, old operating experience has not been effectively implemented into plant procedures and is a potential challenge to plant operations. The most recent occurrences of this missed opportunity to effectively implement operating experience was with motor-operated valve t-drains and zerk fittings.

- Inverters, capacitors, and transformers continued to be problematic and the number of recent failures may be indicative of a negative trend that might be age related. These failures included an EFRDADS inverter fire in each unit, a couple of failed voltage regulator transformers, and a couple of failed capacitors that power various nonsafety but potentially risk significant components from control room annunciators to digital rod position indication.

.4 Annual Sample Review (Emergency Preparedness)

a. Inspection Scope

The inspectors reviewed eight drill and exercise evaluation reports for drills conducted between May 2004 and February 2006 as listed in the attachment and reviewed summaries of 166 CRs generated between July 1, 2004, and May 31, 2006. Emergency response organization performance during the June 7, 2006, biennial exercise was compared to performance deficiencies identified in previous drill and exercise evaluation reports and emergency preparedness-related CRs to identify adverse performance trends and ineffective corrective actions.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 05000499/2005003-00, “Inoperable Cold Overpressure Mitigation System”

The inspectors reviewed LER 05000499/2005003-00 to verify that the cause of the COMS inoperability for more than the TS allowed outage time was identified and that corrective actions were reasonable. The inoperability was declared for Unit 2 due to discovery of the potential for COMS inoperability while preparing to install the same

modification during the Unit 1 refueling outage. The modification was completed during the previous Unit 2 refueling outage, but the condition for inoperability was not identified at that time. The licensee documented this failure in CR 05-3071. The enforcement aspects are discussed in Section 4OA7. This LER is closed.

.2 (Closed) LER 05000499/2005001-00, "Unit 2 Shutdown Due to Reactor Coolant System Pressure Boundary Leak"

The inspectors reviewed LER 05000499/2005001-00 to verify that the cause of the RCS pressure boundary leak requiring a Unit 2 shutdown on February 9, 2005, was identified and that corrective actions were reasonable. The leak, from a 3/4-inch vent line off of the "A" cold leg safety injection line, was determined to be unisolable and Unit 2 was shutdown to MODE 5 in accordance with TS 3.4.6. The root cause of the leak was determined to be a crack propagating from a flaw in a socket weld due to high cycle fatigue. The condition resulted in no personnel injuries, no offsite radiological releases, and no damage to safety-related equipment other than the leaking weld joint. No findings of significance were identified and no violation of NRC requirements occurred. The licensee documented this failure in CRs 05-1620 and -1749. This LER is closed.

.3 Main Generator Reactance Testing

a. Inspection Scope

The inspectors reviewed CR 06-7272 identifying that a Unit 2 reactive and power capability test was terminated due to receipt of an unexpected "Generator U/F (Under-Frequency) Loss of Field Voltage" alarm. The inspectors also reviewed completed Operating Procedure 0POP07-GM-0001, "Reactive and Power Capability Test," Revision 2, and earlier revisions, and discussed the test with licensee personnel.

b. Findings

Introduction. A Green self-revealing finding was identified for the failure to provide an adequate procedure, which resulted in an unexpected initiation of a "Generator U/F (Under-Frequency) Loss of Field Voltage" alarm condition which would have opened the main generator breakers in 30 seconds.

Description. On June 3, 2006, the licensee was performing a main generator reactive power capability test to meet Electric Reliability Council of Texas requirements. Unit 2 LEAD reactive power was being increased from 0 to 420 megavoltamps reactive (MVAR) when a "95% Generator Output Voltage" computer point alarm was received. The test was temporarily halted and the alarm evaluated against the generator capability curves, but protective relaying effects and how the lower generator voltage affected them were not considered. The test was resumed and continued to approximately 390 MVAR when the "Generator U/F (Under-Frequency) Loss of Field Voltage" alarm was received. This alarm coincided with initiation of a protective relaying 30-second

timer to open the main generator breakers. Prompt action by the operators and test director to stop the test and raise generator voltage back above the alarm setpoint (approximately 17 seconds) averted a generator and, therefore, a turbine and reactor trip.

The licensee's initial investigation determined that Operating Procedure 0POP07-GM-0001, "Reactive and Power Capability Test," Revision 2, was inadequate, in that, test technical review was based on the generator capability without an adequate understanding of the effects on protective relaying on the required voltage reduction to create the test conditions. The procedure had cautions and notes for high voltage limits but nothing on low voltage limits. The situation was compounded by the fact that the remote location of the plant requires the main transformer output voltage to be approximately 362 kV, rather than the nominal 345 kV design. The licensee also determined that it missed an opportunity to halt the test and gain a better understanding when the 95 percent alarm was received. The procedure was revised extensively for the LEAD portion in Revision 1, dated May 31, 2006, and the procedure weakness was not recognized at the time since none of the design documents or calculations gave any indications that picking up reactive load would result in any adverse conditions. The situation did not become evident during Unit 1 testing because the Unit 1 LEAD MVAR limit had been set at zero.

<u>Analysis</u>. The performance deficiency associated with this event is a failure to develop an adequate procedure in accordance with the provisions of Procedure 0PAP01-ZA-0102, "Plant Procedures," Revision 9. This resulted in the subsequent development and implementation of an inadequate Procedure 0POP07-GM-0001, which led to the unexpected receipt of a "Generator U/F (Under-Frequency) Loss of Field Voltage" alarm and initiation of a main generator trip timing relay. This event had an actual impact of initiating a relay operation that would have led to a reactor trip if it had not been immediately corrected by operator response. This finding was greater than minor because it was associated with the procedure quality attribute affecting the Initiating Event Cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. This finding was determined to be a finding of very low safety significance (Green) because, although the likelihood of a reactor trip increased, the likelihood that mitigating systems would not be available did not increase and no transient actually occurred.

<u>Enforcement</u>. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on nonsafety-related equipment. Licensee personnel entered this issue into the CAP as CR 06-7272. This issue is being treated as a finding: FIN 05000499/2006003-01, "Inadequate Main Generator Reactive Power Test Procedure."

4OA5 Other

Implementation of Temporary Instruction (TI) 2515/165 - Operational Readiness of Offsite Power and Impact on Plant Risk

TI 2515/165, "Operational Readiness of Offsite Power and Impact on Plant Risk," was performed on March 6-17, 2006. For additional information and documentation see NRC Inspection Report 05000498/2006002 and 05000499/2006002, Section 4OA5, including the Errata to NRC Inspection Report 05000498/2006002 and 05000499/2006002.

4OA6 Meetings, Including Exit

On June 9, 2006, the inspectors conducted an on-site debrief meeting to discuss preliminary inspection results with Mr. E. Halpin, Site Vice President/Plant General Manager, and other members of his staff. On June 20, 2006, the inspectors conducted a telephonic exit meeting with Mr. P. Serra, Manager, Plant Protection, and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The results of the resident inspection were presented to Mr. James J. Sheppard, President and Chief Executive Officer, and other members of licensee management on July 13, 2006. Mr. Claude E. Johnson, Chief, Project Branch A, Division of Reactor Projects was also present at this exit meeting.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- TS 3.9.4.3 requires, in part, that with both PORVs unavailable, the RCS must be depressurized and vented through at least a 2-square inch vent within 8 hours. Contrary to the above, in March 2004 during Refueling Outage 2RE10 a modification was made which de-energized both solid state protection system trains, which made COMS inoperable. This condition was identified in Unit 2 during a review process that resulted from identifying a similar condition that would have existed during Refueling Outage 1RE12. Refueling Outage 1RE12 work was rearranged such that COMS operability was not a concern, but the condition was determined to have existed for approximately 39 hours 53 minutes without the required actions being completed in Unit 2 during Refueling Outage 2RE10. The licensee entered this failure into their CAP as CR 05-3071. Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," requires that any finding associated with low temperature overpressure protection be evaluated using a significance determination process Phase 3 analysis. The Phase 3 analysis determined that the issue was of very low safety significance, the entire Phase 3 analysis can be found in Attachment 2.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Bowman, Manager, Operations
W. Bullard, Manager, Health Physics
J. Calvert, Manager, Operations Training
K. Coates, Manager, Maintenance
J. Crenshaw, General Manager Oversight
T. Frawley, Manager Performance Improvement
R. Gangluff, Manager, Chemistry
R. Grantum, Manager, PRA
E. Halpin, Site Vice President/Plant General Manager
W. Harrison, Senior Engineer, Quality and Licensing
S. Head, Manager, Licensing
B. Jenewel, Supervisor, Engineering
T. Jordan, Assistant to CEO
J. Jump, Manager, Process Improvement Leadership Team
S. Kasper, Shift Supervisor
M. Kistler, Specialist, Licensing
M. McBurnett, Manager, Nuclear Safety Assurance
L. Meier, Acting Supervisor, Emergency Preparedness
M. Meier, General Manager, Station Support
W. Mookhoek, Senior Engineer, Licensing
A. Morgan, Supervisor, Emergency Response
G. Powell, Manager, System Engineering
D. Rencurrel, Manager, Plant Engineering
M. Ruvalcaba, Supervisor, Systems Engineering
R. Savage, Staff Specialist, Licensing
C. Sayko, Co-Owner Liaison
P. Serra, Manager, Plant Protection
J. Sheppard, President and CEO
D. Stillwell, Supervisor, Configuration Control and Analysis
K. Taplett, Senior Engineer, Licensing

NRC

J. Dixon, Senior Resident Inspector
G. Apger, Operations Engineer
R. Patterson, Physical Security Inspector

Other

J. Mitchell, Sheriff, Matagorda County
J. Nortan, Mayor, City of Palacios
G. Westmoreland, County Judge, Matagorda County
R. Watts, Emergency Management Coordinator, Matagorda County

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000499/2006003-01	FIN	Inadequate Main Generator Reactive Power Test Procedure (Section 4OA3)

Closed

05000499/2005-001	LER	Unit 2 Shutdown Due to RCS Pressure Boundary Leak (Section 4OA3)
05000499/2005-003	LER	Inoperable Cold Overpressure Mitigation System (Section 4OA3)

Discussed

None

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R19: Postmaintenance Testing

CRs

05-4753	06-7351	06-7658	06-8114
06-7085	06-7643	06-8094	06-8115

Drawing

4056-01027ZU

Operating Procedures

0PSP11-XC-0008, “LLRT Penetration M-90 Personnel Airlock Door Seals,” Revision 13

Work Authorizations

298192	318986
309427	320280

Work Order

456401

Section 1EP1: Exercise Evaluation

Procedures

NUMBER	TITLE	REVISION
0ERP-01-ZV-EF01	EOF Director	12
0ERP-01-ZV-IN02	Notifications to Offsite Agencies	18
0ERP-01-ZV-IN03	Emergency Response Organization Notification	12
0ERP-01-ZV-IN07	Offsite Protective Action Recommendations	10
0ERP-01-ZV-SH01	Shift Supervisor	20
0ERP-01-ZV-TS01	TSC Manager	11

Section 4OA1: PI Verification

Operating Procedures

NUMBER	TITLE	REVISION
0PGP05-ZV-0001	Emergency Response Drills and Exercises	7
0PGP05-ZV-0006	Emergency Notification and Response System	3
0PGP-5-ZV-0007	Prompt Notification System	6

Section 4OA2: Problem Identification and Resolution

CRs

04-9969	06-4128	06-7299	06-7412
05-16523	06-4130	06-7349	

Drawings

00009E0VCAB#1	Single Line Diagram 120VAC Regulated Power Distribution Panels DP003, DO004
00009E0VCAC#1	Single Line Diagram 120VAC UPS Plant Computer Distribution Panel CU001
00009E0VCAG#1	Single Line Diagram ERF Computer 120 AC Dist Panels DP0200 & DP0300
20-110014	Schematic Prototype 10 KVA Inverter 125VDC 125 VAC 1φ 60HZ

Evaluation Reports for Drills

May 5, 2004	January 5, 2005
August 10, 2004	February 22, 2006
August 31, 2004	June 8, 2005
October 28, 2004	July 25, 2005

Procedures

NUMBER	TITLE	REVISION
0ERP01-ZV-IN01	Emergency Classification	7
0PGP03-ZO-0042	Reactivity Management Program,	8
0POP04-AN-0001	Loss of Control Room Annunciator Alarms	13
0POP04-ZO-0008	Fire/Explosion	12
	South Texas Project Emergency Plan	20-3

LIST OF ACRONYMS

CAP	corrective action program
CCP	centrifugal charging pump
CDF	core damage frequency
COMS	cold overpressure mitigation system
CR	condition report
ECW	essential cooling water
LER	licensee event report
MVAR	megavoltamps reactive
NCV	noncited violation
PI	performance indicator
PORV	power operated relief valve
PRT	primary relief tank
RCS	reactor coolant system
RHR	residual heat removal
SSC	structure, system, and component
SSPS	solid state protection system
TS	Technical specification
USAR	Updated Safety Analysis Report

ATTACHMENT 2

FINAL SIGNIFICANCE DETERMINATION
South Texas Project Electric Generating Station, Unit 2
COMS Disablement

I. Performance Deficiency

In March 2004, while Unit 2 was shutdown and during installation of a modification, a tagout of the SSPS resulted in disabling the COMS during a period that was required by TSs to be operable.

II. Conclusion

The performance deficiency had very low risk significance (GREEN).

III. Background

The COMS uses a lowered setpoint of the primary PORVs to ensure that a high-pressure, low temperature condition, conducive to brittle fracture of the reactor vessel, is avoided during shutdown operations. During the event under review starting on March 31, 2004, both PORVs were inadvertently made inoperable for approximately 40 hours, though the RCS was vented 8 hours prior to the restoration of COMS, meaning that the exposure consequential to risk was 32 hours. The TSs requires that a 2-inch vent be established within 8 hours of PORV inoperability, but this action was not taken because plant operators were unaware of the situation.

During the 32-hour event, the RCS was solid for all but approximately 3 hours. The RCS temperature was 180EF. One centrifugal charging pump (CCP) was running and the other was tagged out. The inservice CCP was injecting to one cold leg and to seal injection. The charging flow control valve was in manual. All three of the high head injection pumps were tagged out. The letdown flow rate was controlled by the position of the Letdown Backpressure Control Valve PCV-0135 in automatic control. Letdown Backpressure Control Valve PCV-0135 was set to maintain pressure at approximately 380 psig in the RCS to support reactor coolant pump operation.

IV. Safety Impact

This event was determined to be of very low risk significance based on the change in delta-CDF documented in Section V.

V. Characterization of Risk

Minor Determination:

The significance of this performance deficiency was greater than minor because it resulted in the loss of safety system for longer than allowed byTSs.

Manual Chapter 0609, Appendix G, Screening

In accordance with Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," issues associated with low temperature overpressure protection are evaluated under the SDP Phase 3 process.

Phase 3 Evaluation

Internal Events

Assumptions

1. The disablement of COMS in Unit 2 was discovered well after the fact (a year later) while performing an identical modification in Unit 1. It is assumed that the performance deficiency would result in one event as observed, but not more than one event per year for any given unit. Therefore, this evaluation was focused on determining the ICCDP of the event and using that figure as an upper bound of the delta-CDF. For this evaluation, over-pressurization of the RCS is assumed to result in core damage.

2. For a period of 32 hours, neither PORV would have opened to mitigate a pressure transient in the RCS. During this time, the RCS was solid with one charging pump running, the other tagged out. The high-head safety injection pumps were tagged out. RCS pressure was being maintained by the Letdown Back Pressure Control Valve PCV-0135 in automatic control.

3. All three RHR discharge relief valves were available to mitigate a pressure transient. This included two running loops of RHR and one idle loop. In all cases, an overpressure of the RCS would relieve through any one of the RHR relief valves. The capacity of each RHR relief valve, individually, is sufficient to relieve RCS pressure caused by one charging pump discharging fully to the RCS (relief capacity approximately 600 gpm). The successful actuation of one RHR relief valve is sufficient to prevent damage to the RHR system and, with RCS temperature at 180EF, is also sufficient to protect the RCS pressure boundary components (in discussion with licensee engineers, it was understood that at lower RCS temperatures, a single RHR relief may not be sufficient to protect the RCS because of greater pressure sensitivity to brittle fracture events).

4. Given the configuration that existed, the analyst assumed that the only likely event that would cause an overpressure challenge (such that the RHR discharge relief valves would need to open to avoid a high pressure condition) would be for Valve PCV-0135 to fail closed. As long as this valve was operating properly, any other effects on pressure, such as a loss of shutdown cooling or the presence of an external heating source, would be alleviated by its modulating action. A possible exception would be the unauthorized untagging and starting of the idle CCP or high head pumps, but the probability of this occurring was considered

too remote to assess. Likewise, the probability of a simultaneous loss of shutdown cooling and a failure of Valve PCV-0135 was considered negligible.

The analyst discussed the function and capability of Valve PCV-0135 to successfully mitigate a loss of RHR event. The licensee stated that the valve was fast-acting and had sufficient capacity to relieve pressure caused by the RCS temperature rise from a loss of shutdown cooling. This included consideration of the capacity of the letdown relief orifices that were in service. The licensee stated that boiling would occur in the RCS approximately 25 minutes after the loss of cooling, but stated that operators would have acted within this time to start low pressure injection and thus maintain temperature below the boiling point.

5. Valve PCV-0135 is an air-operated valve. The valve is designed to fail open on loss of power or air. The valve control consists of a pressure transmitter (PT0135), a pressure controller (PK0135), and an I/P converter (PY0135).

   From the licensee's PRA, general air-operated valve failure rates are as follows:

   Valve mechanically transferring closed
   ZTVAOT 2.45E-07 per hour

   Pressure transmitter failure (which includes the control loop)
   ZTTRP1 1.24E-05 per hour

   The probability of the valve failing closed would be approximately the sum of the valve and transmitter failure rates or 1.26E-5 per hour. Therefore, the probability of the valve failing in the closed position sometime during the 32-hour exposure period is 1.26E-5/hr (32 hours) = 4.0E-4.

6. Using the STP SPAR model, Revision 3.21, the probability of a safety-relief valve failing to open on a high-pressure demand is 1.2E-3. In this analysis, it is assumed that an RHR relief valve would have similar reliability. Using the STP, SPAR model, Revision 3.21, a standard common cause factor for a group of three valves is 0.0176. Therefore, an estimate of the probability that all of the three available RHR relief valves fail to open on demand is 1.2E-3 (0.0176) = 2.1E-5.

7. It is recognized that some risk exists for an RHR relief valve to open in response to a pressure transient and then fail to close. The probability in SPAR for a safety-relief valve to fail to close is 3.0E-3 (this figure includes consideration of several demands on the valve before pressure stabilizes below the relief setpoint, which is similar to the expected response of the RHR relief valves). Given three valves and assuming that all three open to mitigate the pressure transient, the probability that at least one of the three fail to close can be estimated as 3.0E-3 (3) = 9.0E-3. The RHR relief valves discharge to the primary relief tank (PRT) which is located within containment, therefore, a

containment bypass situation would not exist (the containment hatch was open, but requirements were met for an intact containment hatch able to be closed quickly). A stuck open relief valve would be diagnosed by control room operators as a lowering level in the pressurizer and an increasing level in the PRT. If pressurizer level fell to a low level, operators are procedurally required to start the low pressure injection system. With containment open and workers present in the area, it would not be difficult to determine which relief was stuck open. From the control room, operators could isolate the leak by closing two motor-operated valves. If the stuck open relief valve was not isolated, the operators would eventually need to transfer suction of the low pressure injection pumps to the containment sump, which would be filled after the rupture discs in the PRT fail from overpressure in the tank.

Analysis

From the information provided above, the estimated probability that during the 32-hour exposure period Valve PCV-0135 fails to a closed position, and the relief valves in the two active RHR loops fail to open to relieve the pressure transient is:

4.0E-4 (1.2E-4) = 4.8E-8

The estimated probability that Valve PCV-0135 fails to a closed position, one of the three available RHR relief valves opens and then fails to reclose is:

4.0E-4 (9.0E-3) = 3.6E-6

Given this occurrence, it is assumed that timely action taken by plant staff to identify the source of the blowdown and to isolate the failed relief valve will avert core damage. The failure probability for these actions can be taken as the nominal diagnosis and action failure probability assigned in the SPAR-H Human Reliability Analysis Method (NUREG/CR-6883), which is 1.0E-2 (diagnosis)+ 1.0E-3 (action) = 1.1E-2. Considering high stress, the failure probability is increased by a factor of 2, giving a final estimate of 2.2E-2. Neglecting recovery using the low pressure injection system, this would yield an estimated core damage probability from a failed open RHR relief valve of:

3.6E-6 (2.2E-2) = 7.9E-8

The base case failure of a PORV to re-close was not considered in the analysis; but, if included, it would subtract from the risk shown above, because with the valves failed, they could not have stuck open in the evaluation case.

Based on the above, the analyst concluded that the risk significance of the performance deficiency from internal events was very low. A combination of the ICCDP of the two scenarios, as explained above, also equates to the delta-CDF, is 1.3E-7.

External Events

The plant-specific SDP worksheets do not currently include initiating events related to fire, flooding, severe weather, seismic, or other external initiating events. In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.5, “Screen for the Potential Risk Contribution Due to External Initiating Events,” experience with using the Site Specific Risk-Informed Inspection Notebooks has indicated that accounting for external initiators could result in increasing the risk significance attributed to an inspection finding by as much as one order of magnitude. The analyst determined that an evaluation of external risk was required because the result of the Phase 3 indicated that the risk was greater than 1×10^{-7}.

The analyst determined that external events would only negligibly increase the risk significance of the deficiency. This is because, during the short 32-hour exposure period, the probability of an external event occurring is very low and, additionally, most external events would not lead to an overpressure condition in the RCS. One possible exception to the former assertion would be a fire in an area that heats the RCS piping or one that causes Valve PCV-0135 to fail in a closed position. As explained above, a gradual heating of RCS piping would not likely cause a pressure transient because of the pressure-controlling capability of Valve PCV-0135. A fire-induced circuit failure of Valve PCV-0135 during a 32-hour period is also of very low probability, especially considering that all non-hot-short failures of the valve would cause it to fail in an open position.

Large Early Release Frequency

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.6, “Screen for the Potential Risk Contribution Due to Large Early Release Frequency (LERF),” the analyst determined that the finding required consideration of large early release, because the risk from internal and external initiators exceeded a delta-CDF of 1.0E-7/yr.

In accordance with Table 5.4 of Manual Chapter 0609, Appendix H, the finding can be screened for large early release for a large, dry containment with an intact containment. The containment hatch was capable of being closed in a time less than that needed to cause severe core damage. This assumption is also valid in the event of a loss of offsite power.

Conclusion

The change in risk caused by the performance deficiency was very low (Green).

Evaluation of the Licensee's Analysis

The licensee PRA staff calculated an ICCDP of 1.4E-8 for the condition. This analysis did not include consideration of a stuck-open RHR relief valve, but was otherwise generally consistent with the analysis provided above.

VI. References

LER 05000499/2005003-00

Licensee PRA analysis PRA-05-006, Revision 0

Operator logs for March 31 through April 2, 2004

VII. Peer Review Comments (Marie Pohida, SPSB)

The result of this analysis was accepted based on the following points and discussion:

1. The licensee was water solid for 32 hours when low temperature overpressure was disabled.

2. No challenges to the COMS system occurred.

3. All three RHR discharge relief valves were available to mitigate a pressure transient. The capacity of one relief valve is sufficient to relief RCS pressure caused by one charging pump discharging fully to the RCS (relief capacity approximately 600 gpm). Also, there is one discharge relief valve per RHR loop. There were two running loops of RHR and one idle loop. Thus, a stuck open RHR relief valve can be isolated without isolating the RHR function.

4. The high head safety injection pumps were tagged out. One centrifugal charging pump was running, and the other was tagged out.

5. According to Revision 7 of the STPEGS USAR Table 5.3-7, the STPEGS Unit 1 Reactor Vessel Values for Analysis of Potential Pressurized Thermal Shock Events (Table 5.3-7), the End-of-Life RT (PTS) values for each material was well under 100EF. Therefore, the vessel fracture probability per overpressurization event as reported in Figure 6.1 of NUREG/CR-5186, "Value/Impact Analysis of Generic Issue 94, Additional Low Temperature Overpressure Protection for Light Water Reactors," is very low (approximately 1E-4).

6. The licensee had a large dry intact containment during the event.

It is important to note that the licensee credited Pressure Control Valve PCV-0135 as being able to mitigate an overpressure challenge. Based on discussions, with the Division of Safety Systems, the staff cannot give credit for this valve (which is not credited in TS for COMS mitigation) without supporting analysis. Therefore, the likelihood of having a pressure transient from a (1) mass addition by maximizing charging or (2) an energy addition following a loss or interruption of the RHR function was considered in APOB's screening assessment. The unauthorized untagging and starting of the idle CCP or high head pumps were considered small in comparison to a loss/interruption of the RHR function or an inadvertent increase of charging (which was assessed a screening value of .1).