APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

NRC Inspection Report: 50-482/92-05 Operating License No.: NPF-42

Docket: 50-482

Licensee: Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas 66839

Facility Name: Wolf Creek Generating Station (WCGS)

Inspection At: Coffey County, Burlington, Kansas

Inspection Conducted: March 8 through April 18, 1992

Inspectors: G. A. Pick, Senior Resident Inspector
L. L. Gundrum, Resident Inspector

Approved: A T Howell 5-11-92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted March 8 through April 18, 1992
(Report 50-482/92-05)

Areas Inspected: Routine, unannounced inspection including plant status, followup on a previously identified inspection followup item, operational safety verification, surveillance observations, maintenance observations, and licensee evaluations of changes to the environs.

Results:

In the area of NRC followup of identified items, the licensee's actions were good. The evaluation performed by engineering on the effects of cavity seal ring melted polyethylene was thorough (Section 3).

In the area of operational safety verification, performance was mixed. Operators demonstrated excellent response to plant transients (Section 4.10 and 4.12); however, licensed operator actions to declare the turbine-driven auxiliary feedwater pump operable appeared nonconservative (Section 5.3). The licensee's responses to a hot particle overexposure event and the failure to verify locked containment isolation valves (Sections 4.2, and 4.3) were good; however, ongoing problems with the plant computer are continuing to result in operational events (Sections 4.4 and 4.8), and the licensee has not resolved a long-standing problem with thermal barrier heat exchanger isolations (Section 4.7).

The inspector provided prompt onsite followup to an additional "noise" inside containment event that occurred on March 16, 1992 (Section 4.9). Special NRC inspection followup of this event will be documented in NRC Inspection Report 50-482/92-06. During this inspection period, the licensee presented their Management Action Plan to NRC personnel at a management meeting that was conducted in the Region IV office on April 17, 1992 (Section 4.12).

The results of the performance of surveillance activities were mixed. While all observed surveillances were satisfactorily performed, a number of problems were identified. The inspector noted past instances of instrumentation and control (I&C) technicians working around a minor procedure deficiency instead of correcting the procedure (Section 5.1). A normalization constant was miscalculated because of an error during manual data transfer (Section 5.2).

Maintenance activities, observed by the inspector, were performed well during this inspection period. The licensee performed a thorough root cause evaluation of rigging attached to main steam piping. However, this issue was indicative of weaknesses in the work control process. An inspection followup item will be used to track the increasing maintenance work request backlog (Section 6.1). Maintenance instructions were well written; however, a minor documentation deficiency of the work completed was identified (Section 6.3). The inspector noted that this condition could reduce the effectiveness of future material history reviews.

The inspector determined that the licensee has no formal program to review changes to the environs around the facility. However, the licensee's existing emergency planning and environmental organizations provided sufficient oversite to ensure changes in the surrounding area would be identified. The licensee will implement by June 30, 1992, procedural requirements to ensure that changes affecting the environs will be considered as a change affecting the Updated Safety Analysis Report (Section 7).

On March 31, 1992, Kansas Gas and Electric (KG&E) Company became a subsidiary of Kansas Power and Light (KPL) Company when their merger was completed (Section 4.13).

A list of acronyms and initialisms is provided as an attachment of this report.

DETAILS

1. Persons Contacted

B. D. Withers, President and Chief Executive Officer
J. A. Bailey, Vice President, Operations
F. T. Rhodes, Vice President, Engineering and Technical Services
T. M. Anselmi, Licensing Engineer
B. L. Bergstrom, Supervisor, Maintenance & Modifications Services
M. E. Dingler, Manager, Nuclear Plant Engineering (NPE) Systems
D. L. Fehr, Manager, Operations Training
R. B. Flannigan, Manager, Nuclear Safety Engineering
C. W. Fowler, Manager, Instrumentation and Controls (I&C)
R. W. Holloway, Manager, Maintenance and Modifications
D. M. Hooper, Licensing Engineer
W. M. Lindsay, Manager, Quality Assurance
R. L. Logsdon, Manager, Chemistry
T. S. Morrill, Manager, Radiation Protection
W. B. Norton, Manager, Technical Support
C. E. Parry, Director, Quality & Safety
A. L. Payne, Manager, Supplier/Material, & Quality
G. J. Pendergrass, Supervisor Engineer-Inservice Inspection
J. M. Pippin, Director, NPE
B. B. Smith, Manager, Modifications
C M. Sprout, Section Manager, NPE, WCGS
J. D. Weeks, Manager, Operations
M. G. Williams, Manager, Plant Support

The above licensee personnel attended the exit meeting held on April 22, 1992. In addition to the above, the inspector also held discussions with various other licensee and contractor personnel during this inspection.

2. PLANT STATUS

The plant was in Mode 5 at the beginning of the inspection period, and the licensee's investigation into the "noise" inside containment was ongoing. The licensee began a controlled heatup on March 15, 1992. On March 16, 1992, another "noise" event occurred. Additional instrumentation located on safety injection (SI) piping and reactor coolant system (RCS) crossover piping enabled the licensee to determine that the cause of the "noise" was interference at the RCS crossover piping restraint shims. The licensee corrected the problem and began a plant heatup and power increase on March 26, 1992. The licensee was in Mode 1 at the end of the inspection period.

3. FOLLOWUP ON A PREVIOUSLY IDENTIFIED INSPECTION FOLLOWUP ITEM (IFI) (92701)

(Open) IFI (482/9202-01): Permanent Cavity Seal Ring Corrective Actions

This item was initiated to review the effectiveness of the licensee's actions for reducing temperature in the area of the permanent cavity seal ring and to review the licensee's long-term corrective actions. During the forced outage, the licensee determined that boron impregnated polyethylene material flowed from the permanent cavity seal ring structure. One of the actions documented in NRC Inspection Report 50-482/92-02, Section 5.3, described the redistribution the air flow to the permanent cavity seal ring.

The licensee implemented a temporary modification to install thermocouples in each quadrant of the permanent cavity seal ring. One of the quadrants had an average measured temperature of 234°F. Licensee calculations of temperatures around the cavity seal ring determined that average temperatures near the polyethylene insulation would range from 190°F to 209°F. The calculations were based upon measurements made at various locations. Hot spots were expected to range from 243°F to 260°F. The licensee determined this would not cause significant melting of the polyethylene. If the polyethylene continues to melt, it will remain inside the permanent cavity seal ring, except at three seams. However, the seams limit the amount of polyethylene that could flow from the permanent cavity seal ring. No concerns exist if additional polyethylene is lost since the licensee bounded the effects of irradiation on components and the licensee took steps to prevent the polyethylene from contacting the RCS piping.

In addition, the licensee concluded that it was unlikely that melted polyethylene could be transported to the containment sump. From review of the physical obstacles and the mesh size of the protective screens around the containment sumps, the inspector determined the licensee's analysis to be appropriate. Any material of sufficient size to damage a safety-related component would be too large to pass through the protective sump screens. This item remains open in order for the inspector to verify long-term corrective actions.

Conclusions

The inspector determined that engineering personnel conducted a thorough evaluation of the effects of melted polyethylene on component operability. Management continued to provide oversight into the resolution of this issue.

4. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements, and that the licensee's management control systems were effectively discharging the licensee's responsibilities for continued safe operation. The inspector monitored licensee activities related to: potential compromise of safeguards information (SGI), hot particle exposure, failure to verify containment valves locked closed, axial flux difference (AFD) measurements, SI Pump A failure to start, rod control cabinet relay failure, thermal barrier heat exchanger isolations, plant computer problems, "noise" event summary, feedwater transient, turbine power fluctuations, inadequate protection on an electrical penetration branch line, management action plan (MAP) meeting summary, and the merger of KPL and KG&E. The methods used to perform this inspection included direct observation of activities and equipment, control room observations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety-system status and limiting conditions for operation (LCO), corrective actions, and review of facility records.

4.1 Potential Compromise of SGI

On March 5, 1992, the licensee discovered that a cabinet containing SGI, located inside the locked administration building, was unlocked and unattended. The licensee promptly reported the event in accordance with 10 CFR Part 73.71(b) because of the potential compromise of SGI. The licensee's investigation determined that a safeguards custodian failed to lock the cabinet the previous evening. The cabinet was unlocked and unattended for approximately 12.5 hours. The licensee reviewed security "daily activity" logs and determined that the door to the administration building was not opened or found unlocked during the 12.5-hour period. The licensee identified no evidence of tampering, and no documents in the cabinet were missing. The licensee's review of the SGI cabinet contents determined that no documents were misfiled.

The licensee counseled the person who left the cabinet unlocked. The details of the event will be included in required reading for safeguards custodians. To prevent recurrence, the licensee implemented a manual log that requires documenting that the SGI cabinet is verified locked at the end of each workday. Additionally, the licensee attached a magnetic "open/closed" sign to the front of the SGI cabinet.

The inspector reviewed the licensee's response to the event and planned corrective actions. No problems were identified with the corrective actions for the affected department. After the inspector determined that SGI was not controlled by a single department, the inspector questioned the licensee as to whether the performance improvement request (PIR) addressed the applicability to other departments. After inspector questioning, the licensee expanded the scope of the PIR to address the controls for SGI implemented by other departments. This event will be reviewed further during the inspection followup of Security Licensee Event Report 92-S01.

4.2 Hot Particle Exposure

On March 26, 1992, the licensee identified a hot particle (greater than 22,000 counts per minute/square centimeter) on the left cheek of an individual's face. The individual identified the particle at the frisking station upon exiting containment. The individual was in containment measuring the final gaps between the RCS crossover leg restraint shims and the saddle block. The inspection activities required kneeling or sitting near the saddle blocks where welding and grinding had been conducted. The licensee reported the skin overexposure in accordance with 10 CFR Part 20.403. The exposure was estimated to be 99.7 radiation absorbed dose using an NRC approved calculation. The licensee estimated that the individual was inside the containment for 4.5 hours on the basis of entry and exit times from the radiologically controlled area. The hot particle was determined by a multichannel analyzer to be Cobalt-60.

The licensee used an ion chamber and estimated the activity of the hot particle at 5.37 microcuries (uCi). The licensee initially calculated the individual's skin exposure to be 24.16 uCi-hours. NRC specified in Information Notice 90-48, "Enforcement Policy for Hot Particle Exposures," that no violation will be issued for exposures less than 75 uCi-hours if proper notifications were made. The inspector determined that the licensee met the guidance specified in the Information Notice. The licensee will report this event in Licensee Event Report (LER) 92-007. During the individual's decontamination, the licensee determined from nasal and ear smears that there was no other contamination.

The licensee contracted with a test laboratory to analyze the hot particle. A preliminary report of the analysis determined the activity to be 5.49 uCi. The hot particle dimensions were 80 micrometers (um) by 60 um and 30 um thick, and the chemical composition was typical of stellite. The licensee will perform revised hot particle exposure calculations upon receipt of the test laboratory's final report.

The licensee initiated an investigation to identify the root cause. The scope of the investigation was to determine the method of contamination, actual time the individual was exposed, procedure adherence, the individual's radiation worker training qualifications, and the source of the particle. The investigation reviewed survey records, the radiation protection program and procedures, the radiation work permit, the individual's training history, radiologically controlled area work experience, regulatory requirements, and industry information. The investigation team interviewed numerous individuals.

The licensee determined that the feeler gauge used to measure the clearances between the crossover leg saddle blocks and the shims came apart. Several individual gauges fell into a floor indentation around the shim supports. The individual reassembled the feeler gauge and continued his work activities on that support. The team concluded that the hot particle was transferred from the individual's glove to his face when he used the gaitronics headphone.

The team developed a time line that demonstrated that the actual time the particle resided on the individual's face was 1.25 hours. Because the hot particle had a high activity, the team concluded that it originated inside the RCS. No problems were identified with the individual's training. The individual had been inside the radiologically controlled area for 20 hours in 1991 and 1992. The team determined that the contributors to the contamination were breaches of the RCS, which potentially contaminated the area, and inadequate control over the use of gaitonrics inside contaminated areas.

The licensee intends to define a policy for use of communication equipment in contaminated areas and to develop additional guidance for breaching the RCS in order to prevent the spread of contamination. Other actions being considered include evaluating and redefining the minimum activity levels for a hot particle and the method used to post areas. Presently, the licensee's definition of a hot particle is greater than a factor of 10 above industry recommendations.

The inspector's review of the investigation determined that the team's activities were thorough. The inspector determined that the licensee had taken all reasonable precautions to identify hot particles while conducting the shim repairs.

4.3 Failure to Verify Containment Valves Locked Closed

During the review of Industry Technical Information Program (ITIP) 01812, "Callaway LER 91-008," the licensee determined that WCGS could be similarly affected. The Callaway LER described a condition in which the residual heat removal suction header vent valve was not included in a listing of locked containment isolation valves.

In response to information in ITIP 01812, the licensee researched historical information for vent, drain, and test valves that should be locked to assure containment isolation integrity. As described in the ITIP investigation, the licensee added a large group of safety-related vent and drain valves to Procedure STS GP-007, "Containment Penetration Isolation Verification," in March 1986. The licensee also compared Procedure ADM 02-102, "Control of Locked Component Status," to Procedure STS GP-007. From the review, the licensee determined numerous locked manual containment isolation valves that were listed in Procedure ADM 02-102 and were not listed in Procedure STS GP-007. Also, the licensee compared their list of valves to the valves specified in the Updated Safety Analysis Report (USAR). Valves EJ V187 and 189 that were listed in the USAR were not listed in either procedure.

The initial corrective action included issuing a procedure change to add all the manual containment isolation valves to Procedure STS GP-007 and completing the surveillance procedure for the added valves prior to entering Mode 4. Adding the valves to Procedure STS GP-007 ensured that the licensee complied with Technical Specification (TS) 4.6.1.1.a, which requires manual valves located inside containment to be verified secured in the closed position every 92 days. Subsequently, the licensee concluded that controlling manual vent, drain, and test valves with a locked valve administrative procedure ensured proper positioning in accordance with TS 4.6.1.1.a and the design requirements listed in USAR Section 6.2.4.4. The USAR and TS requirements address valves located within the isolation valve envelope. Valves EJ V187 and -V189 were added to Procedure STS GP-007 to ensure that they are verified closed because they are located in the residual heat removal valve encapsulation and are not inside the isolation valve envelope. The licensee issued LER 92-005 on March 30, 1992, for the failure to include Valves EJ V187 and -V189 in either ADM 02-102 or Procedure STS GP-007. This event will be reviewed in further detail during future inspection followup of LER 92-005.

4.4 AFD Measurements

On March 29, 1992, a control room operator noticed that the AFD readings were not being monitored every 30 minutes as required by TS 4.2.1.1.b. Whenever the reactor exceeds 15 percent of rated thermal power and the AFD monitor alarm is inoperable, operators are required to log AFD each hour for the first 24 hours and every 30 minutes thereafter. Procedure STS SF-002, Revision 3, "Core Axial Flux Difference," was commenced at 11:10 p.m. on March 27, 1992, because Annunciator 79D, "Delta Flux Out of Band," was out of service. The licensee should have begun logging AFD on 30-minute intervals at 11 p.m. on March 28, 1992. The operators initiated 30-minute log readings at 5:37 p.m. on March 29, 1992. The licensee determined this event was reportable in accordance with 10 CFR Part 50.73(a)(2)(i)(B) and will describe this event in LER 92-008. The licensee initiated PIR OP 92-0295.

This event was somewhat similar to the event described in LER 91-12 and NRC Inspection Report 50-482/91-18 since both were associated with the loss of the plant computer. However, the root causes were different. During the 1991 event, a miscommunication between I&C and operations resulted in the failure to log control rod positions every 4 hours as required by TS 4.1.3.1.1 when the control rod deviation alarm is inoperable. During this occurrence, licensed operators failed to increase the frequency of logging AFD from 1 hour to 30 minutes as specified in TS 4.2.1.1.b when the AFD monitor alarm is inoperable greater than 24 hours. The inspector noted that ongoing problems with the plant computer are continuing to challenge plant operators. This event will be reviewed further during inspection followup of LER 92-008.

4.5 SI Pump A Failure to Start

On March 12, 1992, operators attempted to start SI Pump A in order to fill SI Accumulator C. After the SI pump failed to start on the first attempt, the operators requested that electrical maintenance review the condition of the breaker. Electrical maintenance personnel determined that no "flags" changed state on the breaker and asked the operators to start the pump while they observed the breaker. The breaker closed and all indications were normal. The Director of Plant Operations directed maintenance personnel to inspect the breaker internals to determine whether there were any deficiencies. No problems were identified during the inspection. The licensee postulated that the handswitch had not been held in position long enough by the operator during the first attempt to start SI Pump A. The licensee also operated SI Pump B to assure themselves no problem existed on the other train.

4.6 <u>Rod Control Cabinet Relay Failure</u>

On March 26, 1992, as an operator withdrew Shutdown Bank B rods in order to position the shutdown rods for a plant startup, the Shutdown Bank B Group 1 rods stepped out but Shutdown Bank B Group 2 rods did not. The operator noticed that Control Bank D Group 2 rods stepped out instead.

The inspector determined that the control panel step counters indicated that Shutdown Bank B Groups 1 and 2 had stepped out to 10 and 9 steps, respectively. The step counters indicate the demanded position. The digital rod position indicator (DRPI) indicated that Shutdown Bank B Group 1 rods were at 12 steps, Shutdown Bank B Group 2 rods at 0 steps, and Control Bank D Group 2 rods at 6 steps. The DRPI lights indicate rod positions for every six steps of movement on the control panel step counter. After noticing the DRPI error, the operator inserted the Shutdown Bank B and Shutdown Bank A rods.

The operators contacted I&C personnel who suspected that the multiplexing relay in Cabinet 2BD was the problem. No alarms were received because the correct logic in the system was maintained. Control room annunciators would have been received had Shutdown Bank B Group [illegible] rods differed by 12 steps or more from the step counter demand position. The licensee entered TS 3.1.3.1.c that states the licensee must restore the inoperable rods because of an electrical problem to an OPERABLE status within 72 hours or be in Mode 3 within 6 hours. Since the licensee was in Mode 3, the shift supervisor made this rep[illegible] a Mode 2 restraint. The multiplexing relay, when functioning properly, sends signals to the control rods and the DRPI panel equivalent to the demand step counter. I&C technicians determined that the relay was deenergized instead of energized as required. However, the relay contacts remained closed. This configuration created the logic signal for withdrawing Control Bank D Group 2 rods instead of Shutdown Bank B Group 2 rods. The multiplexing relay was replaced, and the licensee cycled the control and shutdown rods to verify that the rods functioned properly.

The inspector determined from discussions with licensee personnel that a similar occurrence occurred on August 12, 1991. The personnel that conducted troubleshooting at that time could not repeat the problem. The inspector determined that these circuit boards are tested each refueling outage and that the cabinets are cleaned and terminations checked to ensure good connection. The circuit board failure identified in August 1991 was the first failure of these multiplexing relays. The licensee had assurance that the remainder of the rod banks functioned properly because monthly Procedure STS SF-001, Revision 8, "Control and Shutdown Rod Operability Verification," which verifies that the control rods function, was completed successfully on April 13, 1992.

4.7 <u>Thermal Barrier Heat Exchanger Isolations</u>

On April 1, 1992, the component cooling water (CCW) from reactor coolant pumps (RCPs) B and C isolated on two occasions. Upon receipt of the alarms, the operators verified that flows, temperatures, and levels were stable. No activities were ongoing that should have caused flow changes. Control room operators determined that CCW flow to the RCS components was at a slightly higher flow than normal. Subsequently, the control room operators requested the radwaste operator to increase CCW flow to an idle evaporator in order to decrease flow to the RCP thermal barrier heat exchangers.

The inspector determined that isolations of RCP thermal barrier heat exchangers have been occurring periodically. The RCP thermal barrier heat exchanger isolations occur following small CCW system flow fluctuations because the flow through the flow switches is close to the high flow trip point.

On April 12, 1992, CCW flow to the RCP C thermal barrier heat exchanger isolated. The inspector determined that the temperature control valve for the CCW heat exchanger had opened slightly. The valve movement increased system flow and caused the flow to exceed the thermal barrier heat exchanger high flow trip point.

On April 18, 1992, during performance of CCW valve stroking in accordance with Procedure STS EG-205, Revision 8, "Component Cooling Water System Inservice," the licensee received several thermal barrier heat exchanger isolations because of system flow perturbations during valve cycling.

The inspector noted that this was a long-standing problem. However, the licensee has moved the implementation date for a modification to the system from Refuel VII to Refuel VI. The inspector determined that the licensee has contracted with an engineering firm to review, by May 1992, the system and propose modifications to stop the unnecessary isolations. Some actions being considered in the review included: (1) performance of an evaluation of the current system design including physical arrangement; (2) determination of system lineups during different isolation occurrences; (3) evaluation of intersystem loss of cooling accidents; and (4) evaluatation of the basis for the flow switch setpoints.

4.8 Plant Computer Problems

As discussed in NRC Inspection Report 50-482/92-02, Section 5.10, there were problems with both Annunciator 79C, "RPD Dev or PR Tilt," and Annunciator 79D, "Delta Flux Out of Band." The licensee determined that the printed circuit card had a hardware fault. After repairing the printed circuit card, the licensee determined that the software for Annunciator 79C was working improperly. To test the software changes that corrected the fault in the computer logic for Annunciator 79C, the control and shutdown rods needed to be withdrawn.

On April 1, 1992, reactor engineers performed a test to determine the operability of Annunciator 79D. The test was performed by inputting false numbers into computer points RJK 0551, -0552, -0553, and -0554. The computer points are constants used when calculating the incore/excore AFD. While restoring the AFD constants after the completion of the test, reactor engineers noticed that the constants did not agree with the values listed in the Cycle 6 Curves and Tables Reference Manual. The licensee determined that on January 21, 1992, the new AFD constants were placed in the curve book and were entered in the computer using the "update constants" option. However, licensee personnel failed to initialize the new values of the AFD constants, when the computer was initialized between January 21 and April 1, 1992. As a result, the old values remained in the data base. The licensee determined the error occurred because the transfer of data had been conducted informally between reactor engineering and I&C personnel. The licensee initiated a procedure change to require documentation that the data was transferred from reactor engineering to I&C for initialization. The affected constants were updated, and the operators declared Annunciator 79D operable after verifying that the alarm actuated as designed. The licensee initiated PIR 92 TS-0324 to ensure that other reactor engineering procedures that require processing of information by the computer group are similarly revised.

The inspector reviewed the effects of using the Cycle 5 AFD constants on the determination of the AFD required by TS 3.2.1. The TS requires that the AFD shall be maintained within a target band of plus or minus 5 percent. The largest difference in the constants was 3.5 percent that caused, under worst case conditions, a 0.15 percent change in AFD, which was negligible. The inspector considered the failure to update the constants to be a weakness; however, the safety significance of this issue was minimal.

4.9 Noise Event Summary (71707, 93702)

At the beginning of this inspection period, the licensee's investigation into the "noise" inside containment was ongoing (see also NRC Inspection Report 50-482/92-02). On March 8, 1992, the licensee had begun a controlled heatup in accordance with Test Procedure TP-TS-73, "Thermal Expansion Monitoring Procedure." The monitoring procedure specified temperature plateaus for monitoring the thermal growth of the RCS. This information was compared to the initial startup data. The licensee held the RCS temperature steady throughout the data gathering. Data gathering took 4 hours at each plateau and began after 1 hour of temperature stabilization.

The licensee added additional instruments to increase their monitoring capability. The licensee placed instruments to monitor temperature and pressure between the first and second check valves in SI system piping that connects to the RCS. The licensee obtained this data to provide better information for evaluating thermal hydraulic conditions in the pipes. A channel recorder was installed to monitor all 12 loose parts monitor channels. The licensee installed lanyard potentiometers on each of the steam generator (SG) crossover saddles and one on the RCP B motor. The lanyards measured the displacement of the RCS piping as the heatup progressed.

On March 16, 1992, the senior resident inspector was onsite when another "noise" event occurred. After being notified, the inspector went to the control room to perform prompt onsite event followup. The operating basis earthquake-exceeded alarm had been received but was reset. Since the loose parts monitor was in service in Mode 3 instead of Mode 2 (which is the mode that it is usually placed in service), control room log entries indicated that alarms were received approximately every 5 minutes during the heatup because of thermal expansion of the RCS. The personnel who were in containment reported that the noise sounded like metal contacting metal and that they could feel vibrations. The RCS was at 2235 pounds per square inch (psi) and 551.7°F.

The licensee conducted immediate inspections to identify offnormal conditions prior to cooling down. After conducting a plant cooldown to 440°F, the licensee conducted numerous walkdowns and evaluated the data. The licensee removed the horizontal shims on both the SG and RCP saddle block restraints and removed the vertical shims for the RCPs. The licensee determined that the most probable cause of the noise was cold pressure welding of the saddle blocks to the shims. The Nuclear Steam Supply System vendor determined the stress on the RCS piping, evaluated the possibility of conducting a plant heatup to 557°F with the shims removed, and provided an evaluation for setting the gaps at 1/16 inch plus or minus 1/32 inch. Following receipt of the gap specifications and heatup evaluations, the licensee machined the shims and began a reactor heatup.

A new test procedure was developed that added 10 additional lanyard potentiometers. The additional potentiometers were installed as follows: two on the RCS Loop D hot leg, two on the RCS Loop A cold leg, two on the permanent cavity seal ring, and four on the pressurizer surge line. The shims were reinstalled but not welded; however, as the RCS temperature increased, 11 out of 12 shims were removed prior to making hard contact. During the second heatup no "noise" occurred.

On March 24, 1992, the licensee presented their technical conclusions to NRC personnel at NRC headquarters in Rockville, Maryland. On March 26, 1992, at the WCGS training center, the licensee presented in a management meeting, open to public observation, a summary of activities conducted to determine the root cause of the "noise". Following the meeting, NRC management provided the licensee with information that stated NRC concurrence with their conclusions and corrective actions taken. The public meeting fulfilled the licensee's commitment as specified in a licensee Confirmation of Action letter dated February 28, 1992, to confer with NRC prior to restarting the plant. The details of the NRC special inspection of the "noise" event will be documented in NRC Inspection Report 50-482/92-06. In addition, the licensee will submit voluntary LER 92-006.

4.10 <u>Feedwater Transients</u>

On April 14, 1992, control room operators noted that steam flow to feedwater flow signal mismatch alarms were received and immediately cleared for three of four channels. The balance of plant operator noticed that the turbine speed for both main feedwater pumps (MFP) was increasing. The operator immediately took manual control of the controller and reduced the MFP turbine speed. The operator then noticed that the steam line pressure indicator, AB PI507, for the steam flow to the MFP turbines had failed high and indicated 1200 psi instead of the normal pressure of 1000 psi. The failure of the pressure transmitter associated with AB PI507 resulted in an increased demand signal to the master controller, which resulted in increased main feedwater flow.

The inspector reviewed the event with the operating crew involved. The chart recorders indicated that the level in the SGs increased from 50 to 53 percent and feedwater flow increased from 3.75 to 4.4 million pounds-mass per hour. The level deviation alarm of plus or minus 5 percent was not received. The high level trip occurs at 78 percent SG level.

I&C technicians replaced the pressure transmitter with a spare from the warehouse and calibrated the pressure transmitter following installation. The licensee performed a visual inspection on the failed pressure transmitter to look for loose leads or bad solder joints. The licensee performed a bench calibration in accordance with Procedure ICN-C-1003, Revision 4, "Calibration of the Pressure Transmitter." The zero and span adjusted as required; however, the linearity could not be adjusted within specifications. When pressurized to 1000 psi, the transmitter drifted slightly; however, the technicians did not observe a pressure change that was of a similar magnitude that was observed by the control room operators (i.e., 200 psi). The licensee will conduct further investigation of the pressure transmitter in an attempt to identify a root cause. The operator response to this transient was good.

4.11 Turbine Power Fluctuations

On April 14, 1992, during performance of turbine control valve testing in accordance with Procedure STS AC-002, Revision 5, "Main Turbine Valve Cycle Test," the turbine experienced a rapid load decrease of approximately 110 megawatts-electric (MWe).

The inspector reviewed the transient with the operating crew involved. The operators gradually lowered the load set controller until the load limiting light extinguished and the load decrease limit of 5 percent per minute light illuminated. The operator immediately slowed the rate of decrease to 1/2 percent per minute. Actual load dropped slightly but remained constant and the "at set load" light illuminated. The turbine remained in this condition for approximately 5 minutes, then rapidly decreased 110 MWe. The operator noticed the load drop because Annunciator 65E, "TREF/TAUCT Lo," alarmed. The operator immediately depressed the increase load pushbutton. After halting the power decrease, the operator initiated a 1 percent per minute load increase. Power increased slowly for approximately 1.5 minutes, then increased rapidly from 1090 MWe to 1170 MWe. The operator stopped the power increase by depressing the decrease load pushbutton. Power was stabilized at 1180 MWe.

Because of the sudden decrease in turbine load, the RCS temperature increased and Tave reached 594°F. The operators entered TS 3.2.5 that specified Tave to be less than or equal to 592.5°F. When temperature or pressure exceeds the specified limits, the parameter must be restored within 2 hours or reduce rated thermal power by 5 percent within the next 4 hours.

Temperature was restored in 5 minutes. The rapid power increase caused RCS pressure to decrease to 2219 psi. The operator entered TS 3.2.5 since the pressure was less than the TS limit of 2220 psi. Pressure was restored in 3 minutes. The operators terminated the surveillance until I&C technicians on dayshift could investigate the problem.

The surveillance was performed on April 15, 1992, while I&C technicians monitored the circuitry; however, no problems were noted. The licensee will have I&C coverage during future surveillances in order to identify any problems.

The inspector compared this event to a turbine load rejection that occurred in February 1991. The events were not similar. In 1991, the test was conducted using the "stage pressure feedback" circuit. The turbine load rejection occurred while restoring the control system to normal. On April 14, 1992, the event occurred prior to cycling the control valves. The "stage pressure feedback" circuits are no longer used during the test. The operator's response to this event was superior. The transient was stabilized immediately. The proper corrective action documents were issued and operators properly entered the applicable TS.

4.12 <u>MAP Meeting</u>

On April 17, 1992, a management meeting, open to public observation, was conducted in the Region IV office to discuss the licensee's MAP. The licensee developed the MAP to address deficiencies identified in NRC inspections, licensee self-assessments, and third-party reviews. The MAP is a living document with nine issues initially identified. The licensee developed the MAP as a tool to focus management attention and resources on significant performance and program issues. The licensee integrated the MAP into their budget and planning processes, and the MAP will be implemented with existing programs and procedures. MAP issues will be implemented with specific action plans that have measures specified to monitor the effectiveness of actions taken. NRC will monitor the MAP's implementation effectiveness.

4.13 <u>Merger of the Owner Organization</u>

On November 19, 1991, the NRC approved Amendment 53 to Facility Operating License NPF-42 that provided consent for transfer of KG&E interest in WCGS to KPL by March 31, 1992. Because the "noise" event created uncertainty in the public and financial sectors, KG&E made a request under exigent circumstances, on March 20, 1992, to extend the "sunset date" for completion of the merger to May 31, 1992. After startup of the reactor on

March 27 1992, KPL and KG&E completed their merger on March 31, 1992.

Conclusions

The licensee's immediate corrective actions for a potential compromise of SGI were good. However, the licensee did not appear to have considered the generic implications of this event until questioned by the inspector.

The licensee's investigation into the cause of the hot particle exposure was extensive. The team provided good corrective action recommendations to help prevent future occurrences. The recently implemented root cause training appeared to have improved the quality of the investigation into the hot particle exposure.

The licensee took responsible actions by adding the list of manual isolation valves to the TS surveillance procedure prior to changing modes. However, the licensee has not resolved a long-standing issue pertaining to inadvertent thermal barrier heat exchanger isolations.

The licensee submitted an LER for failure to log AFD as required by TS. The inspector determined that a contributing cause of this event was recurring plant computer problems. In addition, the licensee failed to properly update computer constants based on Cycle 6 core physics data because of limited procedure requirements. However, the significance of this condition was minimal.

Licensee actions regarding the failure of SI Pump A to start on the first attempt were prudent. The directive to review the operation of the SI pump breaker by the Director of Plant Operations demonstrated management involvement in day-to-day operations.

The inspector determined that the licensed operators' actions to declare the turbine-driven auxiliary feedwater (TDAFW) pump operable were nonconservative. On the other hand, the prompt operator responses to a feedwater flow transient and a turbine runback were superior.

5. SURVEILLANCE OBSERVATIONS (61726)

The purpose of this inspection was to ascertain whether surveillance of safety-significant systems and components was being conducted in accordance with TS. Methods used to perform this inspection included direct observation of licensee activities and review of records.

5.1 7300 Process Instruments Analog Channel Operational Test

On March 24, 1992, the inspector observed I&C technicians perform a functional test of Protection Set II process instrumentation in accordance with Procedure STS IC-202, Revision 12, "Analog Channel Operational Test 7300 Process Instrumentation Protection Set II (White)." The inspector determined that the I&C technicians had implemented a procedure change to correct Step 5.3.89, which required inserting an input voltage above the low pressurizer pressure trip voltage setpoint. The voltage setpoints in the data tables were previously changed to reflect a modification to the low pressurizer pressure trip; however, personnel failed to change Step 5.3.89 during previous completions of this ACOT. The procedure error was minor and self-disc ing in that the following steps required decreasing the voltage until the circuit trips. At the specified voltage (as specified in Step 5.3.89 prior to its correction), the circuit was already tripped.

The inspector determined that the procedure change to the data tables was implemented in November 1991. The surveillance was performed each month between November 1991 and March 1992, but the error was not corrected. One exception occurred in January 1992. I&C technicians identified and corrected the input voltage value for Protection Channel III while conducting a postmaintenance calibration. The other protection channels were not similarly modified. The failure to implement the procedure change subsequent to November 1991 was indicative of I&C technician willingness to work around known procedure problems rather than using the procedure change process as intended. The inspector considered this to be a weakness; however, a review of the licensee's MAP revealed that one of the identified subissues was increased procedural compliance, particularly in the area of the procedure revision process. The inspector will monitor the implementation effectiveness of the MAP during future inspections. Subsequently, the licensee initiated PIR TS 92-0301.

5.2 Precision Primary Calorimetric

On April 2, 1992, the inspector observed licensee personnel performing Procedure STS RE-011, Revision 5, "RCS Total Flow Rate Measurement." The procedure measured the RCS total flow rates as required by TS. Additional parameters obtained during the test included RCS loop temperature differences and steam flow loop normalization constants. The inspector reviewed the completed procedure. Personnel performing the test were knowledgeable of the test. The RCS was maintained at constant pressure and temperature conditions as specified in the prerequisites. The test instruments were within calibration.

Following completion of the precision calorimetric, the licensee determined that an error was made when calculating the SG Loop A flow normalization constant. The steam flow normalization constants are used during the performance of the steam flow calorimetric. The feedwater calorimetric uses "as measured" feedwater flows. Therefore, the SG Loop A flow normalization constant error had no effect on the validity of the feedwater flow calorimetric.

As a result of a PIR that was issued for the above noted problem, the licensee determined, after a review of actual feedwater flows, steam flows, loop calibrations, and recently completed procedures, that the average feedwater flow value which is used in determining the steam flow normalization constants, was miscalculated while implementing Procedure STS RE-011. The inspector determined that personnel made an error when manually inputting feedwater flow values into a spreadsheet program. The licensee personnel input approximately 2350 values into the spreadsheet. Although this value was incorrect, other incorrect values were identified and corrected during the independent verification performed while implementing Procedure STS RE-011. The licensee was investigating the feasibility of transferring the required data onto a floppy disc that would then be accessed by the spreadsheet. This would reduce the likelihood of human error and save time. The licensee initiated a PIR to assure that proper corrective actions would be taken.

5.3 TDAFW Pump Testing

On April 8, 1992, operators conducted the monthly TS operability test of the TDAFW pump in accordance with Procedure STS AL-103, Revision 14, "Turbine Driven Aux FW Pump Inservice Pump Test." During performance of Procedure STS AL-103, the turbine speed was determined to be 3825 revolutions per minute (rpm), which failed to meet the minimum required speed of 3900 (+0, -50) rpm specified in the procedure. A strobe light tachometer determined the actual turbine speed to be 3802 rpm.

I&C personnel adjusted the TDAFW pump speed setpoint controller card in accordance with Procedure STN IC-241, Revision 2, "Channel Calibration Aux Feedwater Pump Turbine Speed Control and Indication." After completion of TDAFW pump speed controller calibration, the licensee conducted a partial operability test in accordance with Procedure STS AL-103. The supervising operator declared TDAFW pump operable because all acceptance criteria were met. The turbine speed did not fall below the setpoint as measured by a strobe light tachometer; however, the operator conducting the test noticed that the speed indicator drifted slightly. The operators determined that the speed controller logic card may need to be replaced. The control room and shift supervisor logs contained entries that indicated the operating crews concern over the turbine speed indicator drift. In spite of this concern, however, the TDAFW pump was restored to operable status. Subsequently, the licensee performed further troubleshooting during the dayshift. The card was replaced and the test was reperformed. The operators noted that the speed indicators remained steady at 3860 rpm.

The licensee determined that the control signal for the upper limit maximum setpoint was set at 3850 rpm by Procedure STN IC-241; however, the control room operators must establish a speed of 3850 rpm in accordance with the governing procedure. This control logic conflict caused the pronounced drift over a period of time. The licensee determined from review of startup test data that the TDAFW pump is operable with turbine speeds between 3773 and 3927 rpm. Therefore, the licensee will modify the test procedure to raise the upper limit maximum value above the demand setpoint of 3850 rpm to eliminate control logic conflict.

After reviewing diagrams and discussing the control circuit with I&C personnel, the inspector determined that had the card failed low instead of drifting, the TDAFW turbine governor valve would have closed, resulting in the inoperability of the TDAFW pump. The decision to declare the TDAFW pump operable, even though there were suspected problems with the speed setpoint controller card, was nonconservative and indicative of continuing problems in this area. No TS violation occurred because the allowed outage time was not exceeded.

5.4 Positive Displacement Pump (PDP) Testing

On April 14, 1992, the inspector observed operators perform special Test Procedure TP-OP-255, Revision 0, "PDP Discharge Pressure Observation." The procedure was developed to instrument the PDP discharge line in order to determine whether the relief valve, BG V8118, lifts during the shift from the PDP to a centrifugal charging pump. The operators shifted from operating the PDP to operating a centrifugal charging pump in accordance with Procedure SYS BG-201, Revision 13, "Shifting Between Positive Displacement and Centrifugal Charging Pumps." The discharge pressure did not exceed the relief valve lift pressure. The licensee determined, however, that the telltail drain for BG V8118 indicated that the valve was leaking, and that water flowed from the volume control tank through the relief valve bellows to the floor drains. The licensee had previously determined that the relief valve lifted when its setpoint was exceeded and that the pressure stressed the bellows. No problems occurred during performance of the test and good coordination among work groups occurred during the test. The licensee's review was ongoing at the end of the inspection period.

Conclusion

The inspector determined that I&C technicians failed to use the procedure change process to modify a minor error in a test procedure. Several opportunities presented themselves; however, the personnel worked around the error. This issue is addressed by the licensee's MAP. The licensee determined that their method of transferring data during the conduct of a surveillance was cumbersome and subject to errors. The inspector determined that the licensed operators' actions were nonconservative when they restored the TDAFW pump to operable status even though they suspected problems with the speed setpoint controller card. The licensee discovered that incorrect data was used to develop normalization constants; however, this error did not affect the primary calorimetric.

6. MAINTENANCE OBSERVATIONS (62703)

The purpose of inspections in this area was to ascertain that maintenance activities on safety-related systems and components were conducted in accordance with approved procedures and TS. Methods used in this inspection included direct observation, personnel interviews, and records review. Portions of selected maintenance activities regarding the work requests (WRs) were observed. The WRs and related documents reviewed by the inspectors are listed below:

6.1 Rigging Apparatus Not Removed as Required

On March 9, 1992, the licensee determined that rigging used during disassembly of the SG B atmospheric relief valve (ARV) was not removed following completion of maintenance activities in January 1992. The rigging apparatus consisted of two vertical members clamped to piping on either side of the valve and one horizontal cross member with a chainfall attached; however, the rigging did not interfere with operation of the valve. The licensee wrote PIR MA 92-0247 to document the issue and ensure identification of a root cause. Engineering evaluated the additional load placed on the piping by the rigging apparatus and conducted a Class II/I review. No problems were identified.

The inspector determined from discussions with personnel performing the root cause evaluation that several causes contributed to the failure to remove the rigging upon work completion. The WR that controlled the rigging installation was signed as complete on January 6, 1992. The rigging should have been removed at this time; however, another WR was initiated on January 6, 1992, for repair of a pinhole leak in the valve actuator yoke. The licensee determined that the personnel involved did not remove the rigging because they believed the valve would be reworked soon after the previous work activity.

The licensee's long-term corrective action will be the creation of a mechanical coordinator position. These individuals will be responsible for assuring that all necessary resources are available to perform the work activity and, upon work completion, the areas are restored to original configuration. The mechanical coordinator will ensure that scaffolding is built, the clearance order is available, health physics personnel can provide job coverage, parts are available, and the elimination of interferences. The coordinator will be responsible for resolving any difficulties that arise during implementation of the work. The licensee intends to implement the new positions in the third quarter of 1992.

As a result of this issue, the inspector also noted that the licensee's backlog of WRs has increased significantly over the past several months. The mechanical maintenance department work request backlog is increasing, for example, primarily because of delays in work package preparation and development. The licensee believes that the mechanical coordinator position will eliminate this condition. However, the inspector noted that many other factors in addition to work process control affect the size of the work request backlog, including availability and allocation of resources, productivity, rework rate, training, and availabity of spare parts. The inspector will track, by IFI 482/9205-01, the licensee's efforts to reduce the WR backlog.

6.2 480 Volt AC Breaker Maintenance

On April 2, 1992, the inspector observed electricians performing preventive maintenance (PM) on the 480 Volt AC AKR 30 breaker for the NK24 battery charger. The electricians performed the maintenance in accordance with Procedure MPE E017Q-04, Revision 9, "Circuit Breaker Test For AKR 50 and AKR 30 Electrically Operated Breakers." Prior to performance of the PM, the electricians placed a spare breaker in the cubicle because of the short duration of the TS LCO.

No problems were identified with the breaker. Quality control steps were properly verified and test equipment was within calibration. From discussions with the electricians, the inspector determined they were knowledgeable of the preventive maintenance activity.

6.3 Motor-Operated Valve (MOV) Maintenance

On April 2 and 3, 1992, the inspector observed mechanics begin repair of MOV EG HV126, "Component Cooling Water to Reactor Coolant System Bypass Isolation," in accordance with corrective WR instructions. The instructions were detailed and provided good guidance for performance of the maintenance. During performance of PM activities, mechanics determined that the manual declutch lever would not remain engaged in the declutch position without holding the handle. The MOV was designed so that the declutch handle would be engaged then released and the valve handwheel manually operated. The failure to remain engaged did not prevent the manual operation of the valve but was an inconvenience.

Initially, the mechanics believed that the gear case grease had hardened since the last valve overhaul in 1986. However, the inspector subsequently determined from discussions with personnel that two washers were found reversed on the worm shaft. The reversed washers caused wear on the tripper cams and tripper fingers and, therefore, prevented proper declutch lever operation. From review of the completed work package, the inspector verified that the parts were documented as replaced; however, no description of the reversed washers existed. The inspector considered this a weakness because it reduces the effectiveness of future material history reviews.

6.4 ARV C Limit Switch Problem

On April 6, 1992, during performance of Procedure STS AB-201, Revision 11, "Main Steam System Inservice Valve Test," licensed operators identified a dual light indication on ARV C. The surveillance procedure demonstrates the operability of main steam valves as required by TS 4.0.5, which specifies inservice testing requirements for ASME Class 1, 2, and 3 components.

I&C personnel determined that the stem appeared to be twisting, consequently, operations personnel declared ARV C inoperable. When mechanics observed the valve actuator operation, they noticed only a slight movement that caused the valve stem indicator to not come in contact with the limit switch operating lever. The mechanics determined that the locking stem nut internal to the actuator was loose. After mechanics tightened the locking stem nut by three flats, the limit switches actuated properly.

The inspector reviewed the completed work package. The work instructions were explicit and provided sufficient guidance for performance of the maintenance. Discussions with maintenance personnel determined that the work instructions would be changed to require installation of a new locking stem nut to prevent loosening in the future.

Conclusions

The licensee performed an extensive investigation into the root cause of leaving a rigging apparatus on main steam piping (which was indicative of a weakness in the work control process). The development of the mechanical coordinator position indicated that the licensee is beginning to address an increasing maintenance WR backlog, which will be tracked by an IFI. Quality control coverage was evident during performance of electrical breaker maintenance and personnel were knowledgeable. The maintenance instructions for repair of an MOV were well written. However, a deficiency in the documentation of "as found" conditions of the MOV was noted.

7. Licensee Evaluations of Changes to the Environs Around Licensed Reactor Facilities (TI 2515/112)

This inspection was conducted to evaluate the extent of licensee programs for evaluating the environs around the facility. The licensee had no formal program for evaluating changes to the environs. However, the inspector determined that the licensee had programs for determining changes to the surrounding population and use of the lands for radiological emergency response.

Personnel in the emergency planning and environmental group attend the weekly county commissioner meetings. The information obtained from the meeting includes changes within the county, such as: (1) new or different transportation routes, (2) the addition of factories, and (3) changes in the use of water sources.

The emergency preparedness group obtains monthly updates from the county on recent population changes. The licensee annually implements Procedure KI-RA211.10, Revision 2, "Population Land Use Census," for conduct of a land use survey from June to October. The information is reported to the NRC in the Annual Radiological Environmental Operating Report.

From discussions with the licensee, the inspector determined that there existed no formal programmatic controls to ensure that changes in the environs that affected the USAR would be reflected in the USAR. The licensee stated they will change Procedure KP LE-2201, "Environmental Protection Plan," by June 30, 1992, to require that changes affecting the environs will be transmitted to licensing to assure that they will be considered as a change affecting the USAR.

In 1989, a new airport became operational in Coffey County. The licensee had incorporated this change into the USAR. The licensee intends to change the purpose of an onsite building from general storage into a low-level waste storage facility. This change was documented in the 10 CFR Part 50.59 annual report to the NRC.

Conclusions

The inspector determined the licensee has no formal program to review changes to the environs around the facility. However, the licensee's existing emergency planning and environmental organization provided sufficient oversite to ensure changes in the surrounding area would be identified. The licensee will implement by June 30, 1992, procedural requirements to ensure that changes affecting the environs will be considered as a change affecting the USAR.

8. EXIT MEETING

The inspectors met with licensee personnel (denoted in paragraph 1) on April 22, 1992. The inspectors summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

Acronym List

ADM	administrative procedure
AFD	axial flux difference
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
CCW	component cooling water
DRPI	digital rod position indication
I&C	instrumentation and control
IFI	inspection followup item
ITIP	Industry Technical Information Program
KG&E	Kansas Gas and Electric Company
KPL	Kansas Power & Light Company
LCO	limiting conditions for operation
LER	licensee event report
MAP	Management Action Plan
MFP	main feedwater pump
MOV	motor-operated valve
MWe	megawatt electric
NPE	nuclear plant engineering
NRC	Nuclear Regulatory Commission
PDP	positive displacement pump
PIR	performance improvement request
PM	preventive maintenance
psi	pounds per square inch
RCP	reactor coolant pump
RCS	reactor coolant system
rpm	revolutions per minute
SG	steam generator
SGI	safeguards information
SI	safety injection
STN	surveillance nontechnical specification
STS	surveillance technical specification
TDAFW	turbine driven auxiliary feedwater
TS	Technical Specification
uCi	microcuries
um	micrometer
USAR	Updated Safety Analysis Report
WCGS	Wolf Creek Generating Station
WR	work request