APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-445/91-70 Unit 1 Operating License: NPF-87
50-446/91-70 Unit 2 Construction Permit: CPPR-127
Expiration Date: August 1, 1992

Licensee: TU Electric
Skyway Tower
400 North Olive Street
Lock Box 81
Dallas, Texas 75201

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: December 20, 1991, through February 1, 1992

Inspectors: W. D. Johnson, Senior Resident Inspector
G. E. Werner, Resident Inspector
J. I. Tapia, Senior Resident Inspector
C. E. Johnson, Project Engineer

Reviewed by: L A Yandell Feb 12 '92
L. A. Yandell, Chief, Project Section B Date
Division of Reactor Projects

Inspection Summary

Inspection conducted December 20, 1991, through February 1, 1992
(Report 50-445/91-70)

Areas Inspected: Unannounced resident safety inspection of plant status, operational safety verification. onsite followup of events, maintenance observation, surveillance observation, special report followup, and followup on previously identified items.

Results: No violations or deviations were identified. One inspection followup item and ~e special report were reviewed and closed.

Strengths were noted in the following areas:

- Communication during performance of surveillance and maintenance activities,
- Label upgrade program, and
- The equipment clearance program.

Weaknesses were noted in the following areas:

- Control of equipment within safe zones;
- Secondary plant performance, housekeeping, and minor steam leaks; and
- Control room operators' knowledge of main turbine generator auxiliary systems and associated trip setpoints.

Inspection conducted December 20, 1991, through February 1, 1992 (Report 50-446/91-70)

Areas Inspected: No inspection activities were conducted on Unit 2.

Results: Not applicable.

DETAILS

1. PERSONS CONTACTED

TU Electric

T. Bain, Operations Supervisor
L. Barnes, Technical Staff Training Manager
*M. R. Blevins, Director, Nuclear Overview
*H. D. Bruner, Senior Vice President
*W. J. Cahill, Group Vice President, Nuclear
*C. B. Corbin, Licensing Engineer
W. Dockery, Predictive Maintenance Supervisor
*J. W. Donahue, Operations Manager
R. Flores, Shift Maintenance Manager
*W. G. Guldemond, Manager, Site Licensing
B. Heise, Engineering Analyst, Senior
*J. C. Hicks, Project Manager, Regulatory Support
*T. A. Hope, Unit 2 Licensing Manager
*J. J. Kelley, Plant Manager
*D. M. McAfee, Manager, Quality Assurance
*J. M. McLemore, Mechanical Construction Manager
J. McMahon, Manager, Nuclear Training
*J. W. Muffett, Manager of Design Engineering
*S. S. Palmer, Stipulation Manager
*D. E. Pendleton, Unit 2 Regulatory Services Manager
*P. B. Stevens, Manager, Plant Engineering
*C. L. Terry, Chief Engineer
*B. W. Wieland, Maintenance Manager
*J. E. Wren, Construction Quality Assurance Manager

Citizens Association for Sound Energy

*Owen L. Thero, Consultant

*Present at the exit interview.

In addition to the above personnel, the inspectors held discussions with various operations, engineering, technical support, maintenance, and administrative members of the licensee's staff.

2. PLANT STATUS (71707)

Unit 1 reached 100 percent power on December 21, 1991, following the first refueling outage. On December 22, the unit experienced a runback to 60 percent following a main feedwater pump trip caused by a problem with a moisture separator reheater drain tank normal drain valve. The unit was returned to full power but a power reduction was required on December 26 when extraction steam to feedwater heaters was lost. A reactor trip from 100 percent power occurred on January 8, 1992, following a generator trip caused by high temperature in the main generator primary water cooling system. The reactor was restarted on January 9 and reached full power on January 13. The unit operated at power for the rest of the inspection period.

3. ACTION ON PREVIOUS INSPECTION FINDINGS (92701)

3.1 (Closed) Open Item 445/89200-10: Completion of label upgrade program

At the end of December 1991, 95 percent of the 62,645 component labels in the upgraded program had been installed and 96 percent of these had been verified by operators. All of the 25,000 system labels had been installed and verified. The licensee has declared the Unit 1 and common enhanced label program to be closed. The remaining labels were planned to be handled by the ongoing label maintenance program. The label task group has been tasked with Unit 1 label maintenance until the completion of the Unit 2 label upgrade program. At that point, plans are for label maintenance to be handled by operations support personnel.

As operations department procedures are revised, a check against the computer database is made to ensure that the component nomenclature in the procedure matches the new label nomenclature. The licensee informed the inspector that about half of the affected procedures have been revised and that all affected procedures were scheduled to be revised by the end of 1992.

The operations department performs an impact review of design modifications. This review notes any impact on plant labeling and initiates action to procure new labels when needed. As enhancements to the label maintenance program, the licensee was considering how to ensure that labels damaged or removed during maintenance or modification are replaced and how to ensure that labels made obsolete by modifications are removed.

The licensee has implemented an excellent labeling program. This item is closed.

4. ONSITE FOLLOWUP OF WRITTEN REPORTS OF NONROUTINE EVENTS (92700)

The inspectors reviewed one special report submitted by the licensee to determine whether corrective actions were adequate and whether response to the event was adequate and met regulatory requirements, license conditions, and commitments.

4.1 (Closed) Special Report No. SR 90-006: "Elevated Temperatures in Safeguards Building Normal Areas"

On May 9, 1990, during performance of the power ascension heating, ventilation, and air-conditioning temperature survey, it was discovered that the Technical Specification temperature limit for the main steam penetration area was exceeded for greater than 8 hours. For purposes of compliance with Technical Specification 3/4.7.10, these rooms are considered normal areas as specified in Technical Specification Table 3.7-3. The temperature during normal conditions was observed to be in excess of 104°F for a total of 58 hours, and the temperature reached a maximum of 119°F at the hottest measured locations within the affected rooms.

At the time the overtemperature condition was observed, only one set of 50 percent capacity main steam and feedwater area supply and exhaust fans was in operation. Operations personnel were informed of the overtemperature condition and they initiated additional ventilation by starting the second set of supply and exhaust fans. Operation with both sets of fans was only partially effective at reducing area temperatures.

The main steam and feedwater area heating, ventilation, and air conditioning system design calculations used to determine required system capacity do not normally consider the effects of thermal contributions from uninsulated valve bodies and pipe supports, small steam leaks, or convective heat transfer from the feedwater penetration area to the main steam penetration area. Another contributing factor was that the system operating procedure for the safeguards building ventilation system did not clearly specify when both sets of 50 percent capacity supply and exhaust fans were required to operate. The procedure implied that only one set of supply and exhaust fans was necessary for normal operation and that additional fans might be required if area temperatures were high. The design configuration for normal operations requires that both sets of supply and exhaust fans be in operation.

The licensee's corrective action included adding insulation to various pipe supports and valve bodies in the main steam and feedwater penetration areas to reduce heat gains into the affected rooms. The system operating procedure for the safeguards building ventilation system has also been revised to more clearly identify when both sets of supply and exhaust fans should be in operation.

The inspectors reviewed the licensee's design modifications (DM) for implementation of the proposed corrective actions. Review of DM 90-225 indicated that insulation was added to supports and valve bodies in the main steam and feedwater areas. Field observation by the inspectors verified that insulation of these components had been completed. However, this DM has not been closed out by the licensee because of a question of whether to replace Burglass 1200 insulation with Alpha Style 3259-2-SS (fiberglass cloth) insulation. DM 90-247 was initiated because insulation by itself was not sufficient to consistently reduce the temperatures in the main steam penetration areas. DM 90-247 increased the amount of chilled water supplied to the main steam and feedwater area ventilation cooling coils. A temperature element was also mounted on the exhaust ductwork to indicate the bulk average temperature of the air leaving the areas in question. The inspectors verified portions of DM 90-247 and the revised operating procedure and determined that corrective action was adequate. DM 90-247 has not been closed out by the licensee because they have not determined an appropriate setpoint for the temperature element. However, the inspectors reviewed all temperature data for the month of July 1991 and in no instances did the temperature exceed the Technical Specification limit.

Based on the inspectors' review of Special Report No. 90-006, this issue is considered closed.

5. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, to assure that selected activities of the licensee's radiological protection programs were implemented in conformance with plant policies and procedures and in compliance with regulatory requirements, and to inspect the licensee's compliance with the approved physical security plan.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. Through in-plant observations and attendance of the licensee's plan-of-the-day meetings, the inspectors maintained cognizance over plant status and Technical Specification action statements in effect.

The following paragraphs provide details of certain areas reviewed during this inspection period.

5.1 Plant Tours

The inspectors toured the plant at various times during the inspection period. Overall plant conditions and housekeeping were generally good with the exceptions noted below.

The inspectors performed a walkdown of the auxiliary building and found several valve and fitting maintenance deficiencies. A body-to-bonnet leak was identified on Valve 1FCV-121 as evidenced by boron crystals around the circumference of the seal. Also, several pipe caps on vent and drain lines had evidence of leakage past the threads (1CS-80, 1CS-82, 1CS-115, and 1SI-163). These deficiencies were discussed with operations management so work requests could be initiated.

The inspectors performed a walkdown of the safeguards building and found the following housekeeping discrepancies:

- An extension ladder was being supported by ventilation chilled water piping in Room 104.
- Two step ladders were unsecured and outside of safe zones in Room 104.
- Tornado Door S1-37X has been found open several times. Markings on the door direct that this door be kept closed.
- Unsecured carts (wheels not locked) were found in safe zones (48, 141, and 151) in electrical equipment Room 96.

- Radiation protection was informed of water and trash on the floor inside a contaminated area in Room 77B. The technician later informed the inspectors that the catch funnels would be reworked to attempt to stop the leakage.
- Contaminated Valve 1-8119 had boron crystals on the outside of the protective covering and boric acid dust had apparently been blown on adjacent piping and pipe supports. A radiation protection technician took several swipe surveys and found no contamination; however, he stated that the protective covering would be reworked to contain the boron crystals.

General housekeeping in the turbine building deteriorated slightly during this inspection period and the number of minor steam leaks increased after the reactor trip recovery.

5.2 Equipment Clearance Program

A review was conducted of the licensee's administrative controls which manage changes that deviate from the configurations established by normal operating procedures. These controls are delineated in Procedure STA-605, Revision 10, "Clearance and Safety Tagging." This procedure is intended to provide a safe and uniform method of component, subsystem, or system isolation in order to protect personnel and equipment. The inspectors' review included a technical evaluation of the adequacy of the procedural requirements as well as conducting interviews with personnel responsible for implementing the procedure and providing oversight for its correct implementation.

The inspectors found that the licensee's controls for preventing component or system operation when the operation of the component or system might cause personnel injury or equipment damage were extensive and contained sufficient direction and independent verification.

The inspectors noted one technical issue which, although not observed to be a problem, warrants additional consideration by the licensee. The program lacks a prohibition against using throttle valves as isolation boundaries. Throttle valve designs are not conducive to use as pressure retaining isolation valves due to their propensity for leaking by. The inspectors considered the concern over lack of prohibition to be further enforced when consideration was given to the licensee's criteria for using double valve isolation for clearance boundaries. The use of double valve isolation is not required unless the fluid pressure is greater than 500 psig. This value is relatively high if single valve isolation is provided by anything other than valves designed to be used as pressure retaining boundaries. In addition, the licensee's requirements do not automatically call for double valve isolation on systems containing radioactive fluids.

Oversight of the implementation of the procedural requirements of the clearance procedure is provided by Operations Department Work Instruction OWI-203, Revision 5, "Operations Department Management Periodic Reviews." This procedure requires a monthly field walkdown of at least 10 percent of the total active clearances. The inspectors verified that this activity was being performed at the required frequency. A review of the completed periodic review packages for the last 6 months disclosed that the completed reports had not been signed as being reviewed by the shift operations manager. This signature is intended to document management's review of the results of the clearance program monthly reviews.

The inspectors reviewed training records in the safety clearance and tagging area for the years 1990 and 1991. A total of 1028 persons were recorded as having received training during this period in this area. The training sessions varied in length from 1 to 4 hours. Groups receiving training in this area included maintenance department personnel, licensed operators, auxiliary operators, performance and test engineers and technicians, work control center personnel, construction and operations support group personnel, radioactive waste operators, nuclear overview personnel, and contractors. In addition, the protective tagging program and requirements is covered in general employee training for new personnel and in the annual general employee requalification training.

The inspectors reviewed the following lesson plans:

- MD01A01XD1, "STA-605 and STA-606 Change Review"
- A011A0FE01, "Auxiliary Operator Fundamentals, Clearance and Safety Tagging"
- L041B92XA1, "Licensed Operator Requalification Training, Clearance and Safety Tagging"

These lesson plans were used for most of the 1990 and 1991 training sessions mentioned above. These lesson plans also covered the clearance process in the appropriate level of detail needed by the various groups being trained. The inspectors reviewed the training and qualification records for the two instructors who conducted most of the safety and clearance tagging training in 1990 and 1991 at Comanche Peak. Both of these persons had previously been qualified as auxiliary operators and one held a senior reactor operator certification. One had attended 6 hours of instruction in this area and the other had attended 9 hours of safety and clearance tagging instruction. The inspectors viewed videotapes of safety and clearance tagging lectures given by both of these two instructors. The inspectors considered the qualifications of the instructors and the quality of the videotaped lectures to be appropriate.

5.3 Summary of Findings

The equipment clearance program was reviewed in detail with one technical issue noted. This program was seen as well developed and implemented.

Several housekeeping discrepancies were noted in the storage and use of ladders. In addition, some carts within safe zones were not properly secured.

air operator was replaced using an identical operator from Unit 2. No discrepancies were observed. All appropriate documentation along with authorizations to perform the work were completed.

7.3 Thermographic Inspection

The inspectors observed thermographic inspection of a wire in a plant inverter that had been identified as a possible source of localized heating during a previous routine inspection (Panel CP1-ECIVEC-04, 118 VAC Safeguards Balance-of-Plant Inverter IV1EC4). The technician identified the hot wire by using his instrumentation since there were numerous wires within the inverter having the same labeling. Initially, the technician visually identified a different wire as the possible "hot" source and, after examining it with his equipment, could find no localized heating. The technician then scanned the inverter until he found the problem wire.

The wire showed a temperature rise of 41° Celsius from like wires located in the same area. By procedure, a temperate rise of 30° Celsius was the level which required immediate action. The technician conveyed the need for immediate replacement of the wire to electrical maintenance.

The suspect wire was changed later that evening and showed no signs of discoloration due to heating. Subsequent thermography of the newly installed wire identified no temperature difference with its surroundings.

The inspectors made two observations during the performance of this procedure. The lack of definitive wire identification and subsequent thermography of an incorrect wire could have led to failure of the faulty wire due to the mistaken identity. However, this was prevented due to the diligence of the thermographic technician. The other area of concern was in the tracking of problem components. Through interviews with the technician, the inspectors determined that informal guidance existed for tracking problem components, but was not being fully utilized.

Subsequent followup discussions with the manager of plant engineering revealed that an acceptable tracking and component identification program was in place. If the program is employed in accordance with the descriptions and expectations of the plant engineering manager, the thermographic program should develop into a useful preventive maintenance tool.

7.4 Summary of Findings

Maintenance activities were conducted using approved procedures and work orders. No discrepancies were identified.

8. MONTHLY SURVEILLANCE OBSERVATION (61726)

The inspectors observed the surveillance testing of safety-related systems and components listed below to verify that the activities were being performed in accordance with the Technical Specification. The applicable procedures were reviewed for adequacy, test instrumentation was verified to be in calibration,

6. ONSITE EVENT FOLLOWUP (93702)

6.1 Reactor Trip

Unit 1 experienced a turbine trip followed immediately by an automatic reactor trip on January 8, 1992, at 10:01 p.m. The turbine trip resulted from high turbine generator primary water temperature caused by the operator taking manual control of the primary water heat exchanger turbine plant cooling water outlet valve. The balance-of-plant operator was attempting to maintain greater than the minimum 10°F differential temperature between hydrogen and primary water temperature in accordance with a note on his log sheet. During the adjustment of turbine plant cooling water flow through the primary water heat exchanger, primary cooling water temperature exceeded the setpoint of 140°F and this initiated a turbine generator trip.

Review of computer generated graphs and sequence of events showed that all systems functioned as designed. The operators reported no abnormal equipment operations.

Review of the Operations Notification and Evaluation Form and subsequent discussions with the licensee revealed no identified equipment malfunctions. Several of the control room operators were unaware of the trip and/or trip setpoint associated with primary water high temperature. The preliminary cause of the trip was considered to be operator error.

Pending the completion of the licensee's review of this event and issuance of the licensee event report, appropriate review and immediate corrective actions have been taken to prevent a like occurrence in the future. This event will be reviewed further following receipt of Licensee Event Report 92-001.

6.2 Copes Vulcan Valve Yoke-to-Bonnet Bolts

During work on a Unit 2 Copes Vulcan Model D-100-160, 3-inch valve, the licensee found that the yoke-to-bonnet bolts (socket head cap screws) were not made of the material specified on vendor drawings (ASTM A193 B6). These bolts are not pressure boundary components covered by the ASME Code. Thirty Unit 2 valves and 15 Unit 1 valves were checked and only one valve had bolts with the specified ferromagnetic properties. Chemical analysis and hardness testing on site indicated that the bolting material was not A193 B6 but possibly B8, which was not strain hardened. Operations Notification and Evaluation Form FX 91-1663 was initiated for evaluation of the operability of the similar Copes Vulcan valves in Unit 1. The licensee determined that the specified minimum yield strength of the fasteners could be as low as 30 ksi, although physical tests on two bolts indicated a minimum yield strength of 63.8 ksi. Calculations performed by Westinghouse determined that the maximum yoke-to-bonnet stresses in Unit 1 valves were just under 30 ksi and the licensee used this as a basis for a determination that the Unit 1 valves were operable, even if the fasteners were of the wrong material. Copes Vulcan analysis of the fastener material determined that it was probably ASTM F837 XM7, an austenitic stainless steel with copper. Copes Vulcan had procured the fasteners from Fastener House, Inc. of Erie, Pennsylvania.

The licensee's review of this issue has determined it to not be reportable under 10 CFR Part 21 or 10 CFR Part 50 but a voluntary initial Part 21 notification was made on January 16, 1992. The licensee plans to replace the fasteners in both units with approved material. Of the 76 affected valves in Unit 1, the licensee identified 17 which could have their yoke-to-bonnet bolts replaced at power. The bolts on these valves were scheduled to be replaced as replacement bolts become available. The remaining valves will be scheduled for rework during any forced outage with completion scheduled during the next refueling outage.

6.3 Summary of Findings

After the reactor trip, plant systems responded as expected and operator actions were appropriate. Review of the post-trip data and subsequent interviews of operators indicated that the trip was caused by operator error and that insufficient system knowledge was a contributing factor.

The licensee is following a conservative philosophy and replacing all identified deficient yoke-to-bonnet bolts on the identified Copes Vulcan valves at the earliest appropriate date. A voluntary Part 21 report was issued to alert other utilities of the potentially generic problem.

7. MONTHLY MAINTENANCE OBSERVATION (62703)

Station maintenance activities for the safety-related and nonsafety systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with the Technical Specification. The following sections describe the maintenance activities observed.

7.1 Emergency Diesel Generator

The inspectors observed mechanical maintenance personnel performing two maintenance activities on the emergency diesel generator. The first maintenance activity sampled and changed oil in the auxiliary jacket water pump (Work Order P91-9249 and Procedure MSM-GO-101). Good mechanical practices were being used and no discrepancies were noted.

Two maintenance personnel and a quality control inspector performed reverification of applied torque to the air start valves (Work Order P90-9123). No discrepancies were noted.

7.2 Balance-of-Plant

The inspectors observed several maintenance activities associated with balance-of-plant equipment. The repairs observed were due to water-hammer induced damage brought about by large secondary transients associated with a loss of a main feedwater pump and an associated turbine runback. The repairs observed were sealant injection to stop a steam leak caused by a cracked weld on a high-pressure drain (Work Order C91-10811) and replacement of the air operator for Valve 1-LV-2514, a high-pressure drain to the main condenser. The and test data was reviewed for accuracy and completeness. The inspectors ascertained that any deficiencies identified were properly reviewed and resolved. The following sections describe the surveillance test activities observed.

8.1 Containment Spray Pump

The inspectors observed portions of two associated surveillance activities. The surveillance testing involved Slave Relay K645 actuation test (Work Order S91-2998 and Procedure OPT-454A), which started a containment spray pump and allowed testing of containment spray system operability (Work Order S91-2914 and Procedure OPT-205A). No discrepancies were noted during performance of the surveillances. Good communication and procedural adherence were observed throughout the test.

8.2 Turbine-Driven Auxiliary Feedwater Pump

The inspectors observed surveillance testing of the turbine-driven auxiliary feedwater pump (Work Order S91-3130 and Procedure OPT-206A, Section 8.1.6). The inspectors noted a small discrepancy in Step 8.1.6Y, which required pump lubrication levels to be recorded. The required level was greater than or equal to one half. Initially, the level was reported based on sightglass level. The reported level was outside of the specified band and, when the auxiliary operators were told this level was out-of-specification by the reactor operator, they subsequently reported that level was greater than one-half of column height. Based upon the changes in the reported oil level, the inspectors went to the turbine-driven auxiliary feedwater pump room to observe the indicator.

The bearings are equipped with a column type level indicator that measures the level of oil in the bearing housing (slinger ring lubrication). The oval sightglass is mounted in the top quarter of the metal column; therefore, any level indication in the sightglass could be interpreted as greater than one half of column height.

No operability concerns were raised. However, the inspectors felt that the procedure could be clarified with respect to what indication is expected.

The steam supply valves to the turbine failed their stroke times. This was noted on the surveillance sheet and the valves were satisfactorily retested after adjustment.

Overall, the surveillance was conducted with good coordination and control. Communications between all involved parties was excellent.

8.3 Auxiliary Feedwater Pump

The inspectors observed surveillance testing of the Train B motor-driven auxiliary feedwater pump (Procedure OPT-206A, Section 8.1.4). The surveillance was performed to verify pump operability after repacking the outboard stuffing box. During performance of the surveillance, the inspectors observed maintenance personnel verifying proper stuffing-box temperature and gland leakoff.

Communications were good and no discrepancies were identified.

8.4 Solid State Protection System

The inspectors observed performance of the surveillance test for the Train A solid state protection system actuation logic (Procedure OPT-445A and Work Order S91-2930). No discrepancies were noted during the initial system lineup, procedural testing, or system restoration. All applicable referenced documents were used during the surveillance.

The inspectors noted excellent coordination between all participants. Verbal commands and repeat-backs were used throughout the evolution. During one portion of the surveillance, steam generator levels were fluctuating erratically and the surveillance was temporarily interrupted while the operators adjusted the main feedwater pump speed controller and steam generator levels were returned to normal operating levels.

8.5 Channel Calibration

The inspectors observed performance of rack calibration on Train 2B pressurizer pressure protection channel (Work Order S91-2366 and Procedure INC-7724A). This surveillance was accomplished by two instrument and control personnel. All appropriate documentation was completed and the required procedure was followed during the performance and restoration steps of the procedure. Communication and coordination with the reactor operators were excellent. No discrepancies were noted.

8.6 Service Water

The inspectors observed performance of Section 9.3 of Procedure OPT-207A, "Service Water System Operability Verification" (Work Order S91-2703). This surveillance involved operating service water pumps and recording data, exercising valves, and verifying valve position indication.

The inspectors noted that the reactor operator had not done a complete review of the applicable section within the procedure. The reactor operator did partially brief the auxiliary operator involved in the surveillance and good communications were maintained at all times. No procedural discrepancies were identified.

8.7 Slave Relay Test

The inspectors observed the Train B safeguards slave Relay K631 actuation test (Work Order S91-2963 and Procedure OPT-485A). The reactor operator held a briefing with the participating auxiliary operators to ensure valve manipulations and system restoration steps were understood. Procedures and good communications were used during the surveillance. No discrepancies were identified.

8.8 Summary of Findings

Procedural compliance and communication practices were excellent. No violations or deviations were identified.

9. EXIT MEETING (30703)

An exit meeting was conducted on January 31, 1992, with the persons identified in paragraph 1 of this report. The licensee did not identify as proprietary any of the materials provided to, or reviewed by, the inspectors during this inspection. During this meeting, the NRC inspectors summarized the scope and findings of this inspection.