UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

JUN 21 1989

MEMORANDUM FOR: Christopher I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

FROM: H. Shannon Phillips, Senior Resident Inspector for Inspection Programs
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

SUBJECT: TU ELECTRIC RESPONSE TO EA 88-310

The information presented by TU Electric during the enforcement conference related to the SWS coating removal conference and their subsequent response to EA 88-310 on that matter is innacurate and incomplete. The deficiencies in their review of procured services (Code V) are addressed in my inspection report 50-445/446 89-23, as a follow-up to that action. However, other aspects of TU Electric's position during the enforcement conference and their attitude regarding the lessons learned from the SWS coating removal project are not included in that report, at the direction of my management. Nevertheless, I feel very strongly that this additonal information is relevant to the enforcement action and may warrant a higher severity level upon review of new information.

The following is a brief summary of examples which show that TU Electric did not provide complete and accurate information to the NRC concerning enforcement matters that were being evaluated. Details which support these examples are discussed in Enclosures 1 through 8.

- TU Electric management reacted emotionally to the SWS deficiencies identified in the exit for 50-445/88-47; 50-446/88-42. This caused TU Electric's staff to provide incomplete information. (See Enclosure 1 for details.)

- TU Electric management was aware of other Code V procurements for services (work) on the CCW heat exchangers, steam generators, and emergency diesel generators that were similarly deficient, but did not provide this information to the NRC. (See Enclosure 2.)

- TU Electric management erroneously concluded that the procedures, work, inspection, and surveillances were adequate because a comprehensive review of the procedures, work, and records was not performed. Instead, they relied on inspections and QA surveillances that apparently were inadequate. (See Enclosure 2.)

- TU Electric management stated that spinblaster damage did not occur in Train B, but three inspectors observed apparent damage. (See Enclosure 3.)

- TU Electric management stated that damage to the piping did not affect the integrity or the functioning of the piping. Also, the defects were not considered significant. This statement is misleading, because the integrity and the function was affected and the defects were significant from a partial QA program breakdown and construction deficiency standpoint (50.55[e]). (See Enclosure 4.)

- TU Electric management stated that a contributing cause was work occurring at the safety/nonsafety interface of the metal surface of the piping and the plasite coating. This statement was misleading because the impact of nonsafety-related activity on safety-related activity must be considered from the start of construction through deactivation of nuclear plants. This issue had previously arisen and caused problems and was not a new problem. (See Enclosure 5 and 6.)

- TU Electric management inferred that technical and QA controls were comprehensive and the deletion of QA requirements had no effect on the outcome. This apparently was not the case based on NRC findings. (See Enclosure 7.)

- TU Electric management stated that project uniqueness contributed to the deficiency. This is no defense if true as many unique activities must be controlled, for example, setting the vessel at a one unit site is unique in that it occurs once. This does not excuse deficiencies and damage and would not be considered an extenuating circumstance. (See Enclosure 8.)

I believe that the first three examples alone would be sufficient grounds for reconsidering the enforcement (EA-310) for a higher severity level. The other examples show that a pattern existed, that is, TU Electric staff responded to the highest management request for information to discredit the findings. I believe the attitude displayed in response to the NRC findings is a more serious problem than the SWS deficiencies that were identified. Accordingly, I recommend that EA-310 be considered for a higher severity level.

H. S. Phillips

H. S. Phillips, Senior Resident
Inspector for Inspection Programs
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

Enclosures:
Details of Incomplete Inaccurate Information

cc: R. F. Warnick, NRR
H. H. Livermore, NRR

ENCLOSURE 1

In May 1988, the NRC identified potential violations and made TU Electric aware that the NRC did not think that the appropriate QA/QC and technical controls were applied to the SWS coating removal project. TU Electric middle management (engineering, project, and QA) took little or no action in response to the NRC, but maintained that they were confident that the project and QA controls were entirely adequate. The NRC received feedback from meetings conducted by TU Electric that construction management recognized the fact that controls were inadequate and asked that the project be stopped. Needless to say, the project managers told them all was well and refused to listen.

On July 29, 1988, TU Electric discovered a 1/2-inch hole caused by a lack of QA/QC and technical controls applied to the sandblasting (spinblasting) of the 10-inch SWS piping. Subsequently, eighty-eight other defects were found in 650 feet of the piping. As TU Electric had done little or nothing to correct the generic deficiencies, these defects left middle management without any real defenses and the NRC exit for inspection 50-445/88-47; 50-446/88-42 was only three days away. The defect was found on Friday, July 29, 1988, and was reported to the NRC on August 1, 1988, (one day before the exit).

On August 2, 1988, the NRC summarized the findings that had been identified during the three month period including the most recent development, the hole in the pipe. This information was provided to the TU Electric representative who routinely provided the information to Messrs. Counsil and Nace, top management prior to the exit. When Mr. Counsil learned of the NRC findings, he contacted Mr. Partlow, NRC Headquarters Office of Special Projects. Mr. Partlow in turn contacted Mr. H. Livermore, NRC site supervisor, who informed the NRC inspector of Mr. Counsil's protest. Mr. Counsil protested to Mr. Partlow because he thought there was an agreement between him and NRC site supervision. He said the NRC had agreed that Mr. Phillips, NRC inspector, would not give the findings at the exit. He said that the NRC inspector was trying to embarrass TU Electric in front of CASE, the intervenor (the first exit CASE attended after the settlement). The NRC inspector and supervisors were unaware of any such agreement. The NRC inspector offered to delay giving the findings, but supervision directed the inspector to give the findings.

After the inspector gave the findings (violations) on the lack of control of work activities on SWS piping, Mr. Counsil challenged the inspector. That is, he reiterated that the NRC was not supposed to give the findings per an agreement. The inspector stated that the

NRC was unaware of any such agreement. Mr. Counsil was visibly angry and turned to two senior managers and said, "load up your guns on this one." Several NRC inspectors commented that Mr. Counsil's behavior was very inappropriate. (There was a virtual repeat at the next exit with operations personnel on another violation.)

NRC inspectors received feedback that gave further insight about what happened. About midway through the coating removal project, construction management recognized the lack of controls and recommended stopping work until adequate controls were put in place. Engineering and the project management basically told these managers to sit down and be quiet as they were running the show and had everything under control. After the damaged piping was found, a pre-exit meeting was held and the same managers reiterated their concerns about the lack of controls they had been concerned about and now the same ones had been identified by the NRC. These managers suggested that TU Electric should simply admit to the errors, fix the problems, and assure the coating removal on Unit SWS was adequate. The project manager maintained that the QA and technical controls were applied, but testing simply was not correctly modeled. Mr. Counsil decided to listen to the project manager. At the post exit meeting Mr. Counsil was described as highly emotional and was livid. These demonstrations in front of his staff let his staff know he wanted to discredit the NRC findings. The Enforcement Conference handout did the job of discrediting the NRC findings by providing incomplete and inaccurate information.

The project manager provided a major portion of the input for the enforcement conference. In discussions with this manager (whose nuclear experience was limited), it was evident that he believed they had imposed all necessary controls and had just not foreseen the test modeling problem. With this belief, he could provide inaccurate information. It appears that other managers provided Mr. Counsil with the information to discredit the NRC findings by accenting the positive and leaving out the negative. The wording in the Enforcement Handout is worded to the legal limit, that is, it is true in part, but not in the whole. I have no evidence that there was intent to deceive the NRC, but it appears that the highest management caused the staff to skew the information.

Without accurate and complete information, the NRC understandably could not adequately evaluate the enforcement matters under consideration. Accordingly, the severity level was reduced from Level III to Level IV. The previous enforcement needs to be reconsidered. In addition, the failure to provide accurate and complete information is really more serious than the SWS deficiencies that were identified.

ENCLOSURE 2

TU Electric did not provide information at the Enforcement Conference that was later found in TU Electric's memorandum NE 22156. The information would have provided six examples of deficient Code V procurements for services (work) on safety-related components in addition to service water. TU Electric's finding in response to TXX-89070 dated February 8, 1988, stated that the inspection and surveillance reports associated with the six Code V procurements for services showed that the requisitioned work was satisfactorily completed, but did not discuss deficiencies in memorandum NE 22156. An NRC inspection determined that TU Electric's review of inspection and surveillance reports alone and limited work records would not address the QA program deficiencies or assure that work was successfully completed. As a minimum procedures, work, and records should have been reviewed. In addition, one could argue that such documents existed for SWS activities but despite this damage occurred because QA requirements were not established, procedures were inadequate, inspection was inadequate, and nonconformances were not identified and documented. The following are the inspection findings concerning the six services provided.

Chemical Cleaning of CCWHXs

- TU Electric Surveillance Activity Report 87-022 and Memorandum TCP-87027 indicated that overall chemical cleaning process for Train A (Units 1 and 2) was not appropriately controlled. These deficiencies were not documented in deficiency reports and evaluated to assure correction before cleaning Train B (several months later).

- Inspection and surveillances concluded that vendor chemical procedures were adequate when they were not.

- No documented evidence was provided to show that vendor personnel were appropriately trained to follow TU Electric's QA program.

- There were no inspection reports for the chemical cleaning process.

- Surveillance checklists were generic and did not adequately and specifically address process controls. The conclusions for different checklist items were conflicting.

Cutting CCWHX Tube Ends

- 5720 tube cuts were made for 2 CCWHXs, however, only 25 were inspected to assure the cut met dimensional requirements. No in process inspection controls for the cutting process was described.
- DCA 25192, Revision 0, required 1/8 inch minimum radius; however, this was not inspected.
- The surveillance checklist and evaluation of this process did not address the above issues.
- The surveillance summary contained a comment that the vendor lacked discipline, tools, and experience probably should have been a finding.

Coating of CCWHXs

- Surveillance SR-86-007 concluded that the surface preparation was acceptable based on inspection report IR-86-0289. The inspection of surface was either not done or if done, it was not documented in IR-86-0289.
- Inspection of areas, where spark testing was not possible, were not inspected or documented.
- There is no evidence that repair areas were repaired and inspected to SPECO Bulletin 35.
- The final protective coating was inspected; however, other coats were not inspected to assure proper application.
- Curing time and temperature was not confirmed by TU Electric inspection.
- There was no evidence that vendor measuring and test equipment was calibrated.
- The surveillance was based on a generic checklist that appeared to be inadequate, as applied.

Measurement of Steam Generator Nozzles

- The work on the steam generators was in progress before QA was aware the vendor was onsite. QA discovered the work was in progress and performed surveillance CSR-87-003.
- The surveillance concluded that QA did not know about special requirements until after the fact.
- The procedures, tools, and training was not certified by QA prior to the beginning of work as required by Procedure ECE 6.11.

ENCLOSURE 3

TU Electric stated during the enforcement conference, in part, that "[d]amage did not occur following modifications to spinblaster." "Pipe Damage Limited To Small Portion of One Train - Not Safety Significant." "Process Control Adequate Based on Successful Implementation After Modification."

Contrary to the above, my inspection determined that damage did occur after modifications to the spinblaster. Shortly after damage was found in Train A of the SWS in July 1988, the NRC inspector specifically asked whether damage occurred on Train B after the modifications and informal information received from engineers indicated damage occurred in Train B. In March 1989, three NRC inspectors performed a field inspection to view video tapes of Train B after they were reinspected for damage. Engineering Report ER-ME-19, Revision 0, stated that a reinspection of the tapes was performed by the applicant for 10-Inch piping using high resolution monitors. The NRC requested that this inspection process be duplicated so the NRC could observe the inspection methodology. The NRC was interested in the inspection of both the corrosion defects and spinblaster damage. The following was found by the NRC:

- Defects caused by the spinblaster were observed in Train B (Spool SW-1-SB-7-14A-8 frame 1484). The misidentification of video tapes of Train A and Train B 10-inch piping occurred during the process of video taping. This was corrected and the TU Electric representative assured the NRC that they were looking at the correct tape. He also agreed that the damage looked like spinblaster marks.

- Standards or examples of the damaged piping for comparing observed defects to known defects (as seen in tapes of known damaged piping) were not available for simultaneous viewing.

- Video tapes were made at an angle instead of perpendicular to the surface. The view was distorted and shadows made it difficult if not impossible to qualitatively evaluate the depth of corrosion defects and spinblaster damage. The wheels on the carriage that traveled through the piping left track marks. At least one pile of sand was observed and it was evident that the pipe surface under the sand was not inspectable. All of these conditions hampered the inspection of the 10-inch piping. Note: The NRC was informed that a different camera will be used for Unit 2 and will eliminate the above problems. If the new camera were used for Unit 1 it could show that all defects were identified. Or, alternatively, the old and new camera could be used for a section of piping and then the disposition could be independently evaluated and then compared to judge the adequacy of inspection in Unit 1 to detect minimum design stress wall thickness.

- A comparison could prove the process in Unit 1 was valid.

- Eighty-four 10-inch spool pieces (each approximately 20 feet long) were removed and cleaned in the yard. These pieces were visually inspected by TU Electric for defects by viewing the inside surface of the piping from the end of the piping. I do not believe corrosion defects could be identified by such visual examination except for the surfaces near the pipe ends.

In addition the engineering report stated that two defects were not measured because they were inaccessible.

ENCLOSURE 4

TU Electric Enforcement Conference Document stated that the spinblaster ". . . damage did not affect the integrity or the functioning of the single train affected, nor other equipment, and was not safety significant."

Contrary to the above, 650 feet of piping contained significant damage and some of the piping had to be replaced as a result of spinblaster damage. The average pipe wall thickness before coating removal was 0.390 inches but was reduced in various areas. Approximately 80 spinblaster marks were identified by TU Electric after the hole in the piping was identified including 8 that were greater than .100 inches deep and 4 where projected corrosion lifetime was less that 20 years. One mark was .307 inches deep. And several lengths of pipe were replaced. The integrity of the piping was obviously affected.

Given the breakdown in part of the QA program for SWS coating removal, this made the construction deficiency, as defined in 50.55(e) was significant. The additional six Code V services that were deficient are added support that the deficiency was significant but was not considered significant. It also met the definition or criteria of 10 CFR 50.55(e) because the damaged piping required extensive evaluation or repair.

ENCLOSURE 5

TU Electric Enforcement Conference Document states, in part, "Contributing Causes: . . . ASME Applicability Not Clear".

This statement was inaccurate. The ASME Code Section XI does not allow metal removal without being under the auspices of the authorized nuclear inspector and under Code control. Obviously sandblasting can remove too much metal and violate the Code.

In addition, page 5 of Appendix H of TU Electric Specification 2323-MS-100 states, in part, "Note: Under ASME XI any metal removal is considered a repair, even though that activity may have been considered rework when working under ASME III (i.e., removal of an arc strike is an ASME XI repair even if minimum wall is not violated)." Obviously sandblasting can cause more severe damage than arc strikes and must be controlled in accordance with ASME XI Code. The March 14, 1988 TU Electric Meeting Notes document a meeting between O. B. Cannon Company and TU Electric. It appears from these notes that sandblasting and metal removal was recognized as an activity that could adversely affect ASME Class 3 components and should have been controlled as such. Interview with personnel showed that some TU Electric managers wanted the process stopped. Construction management challenged this process in mid-project and wanted to stop work to gain control. Engineering knew at the beginning of the project that the blaster stalled and may have violated ASME Section XI, but did not test the areas where the stall occurred.

ENCLOSURE 6

Enforcement Conference Document states, in part, "Contributing Causes: . . . Work To Occur At Safety/Nonsafety Interface."

Three NRC inspections reviewed the coating issues concerning the SWS and the EDG fuel oil tanks. It was clear that the concept of protecting safety-related equipment or components while working on nonsafety-related parts within or adjacent to safety-related components is a principle that should have been established before plant construction. TU Electric failed to clearly establish the requirement that coating activities affecting the quality of components must be controlled. The NRC inspector found that confusion about nonsafety activities that can adversely affect safety-related components has existed for a long time without resolution. The following examples support this conclusion:

- In 1980 Brown and Root, Inc. procured and applied a coating to SWS piping in the field without Appendix B QA/QC controls. Subsequently this was discovered but these areas were not extensively and thoroughly inspected and evaluated. In 1988, the Stone and Webster Engineering Corporation (SWEC) corrosion report stated that the greatest damage to the coating and piping occurred in these areas. The failure to inspect and evaluate the coating in 1980 eventually led to coating and piping degradation and finally coating removal/spinblaster damage.

- In 1980, a site engineer questioned the coating procured and applied with QA/QC controls. The corrective action was to downgrade the specification to read that coating was not safety-related instead of evaluating the effects of a lack of proper QA/QC controls could have on safety-related components.

  Page 10 of TU Electric Engineering Report ER-ME-19, Revision 0, September 21, 1988, concluded that the action taken by TU Electric and Gibbs and Hill, Inc., was adequate at the time given the information available.

  The NRC determined that the TU Electric's assessment of this corrective action was inadequate. In the coating industry it was well known and information was available that the application of any coating to any improperly prepared surface would probably result in nonuniform coating and accelerated corrosion and/or sheet mode failure of the coating. In 1983 two subsequent opportunities (INPO SER 68-83 and IE Notice 85-24) occurred to identify and correct the QA/QC and degrading coating and piping deficiencies, but two additional inadequate evaluations occurred.

A similar example of problems caused by the confusion over safety related versus nonsafety-related work is discussed in paragraph 8 of NRC Inspection Report 50-445/89-23; 50-446/89-23, application and removal of coatings from diesel generator fuel oil tanks. In 1983, one engineer recognized the problem with diesel storage tank coatings and revised this specification to read safety related; however, this corrective action was reversed in 1985.

As a part of the corrective action concerning SWS deficiencies, TU Electric failed to recognize the earlier deficiencies and the root causes. This 50.55(e) deficiency was also considered not significant and not reportable.

ENCLOSURE 7

The Enforcement Conference Document stated that deletion of the QA responsibilities from the requisition (6R-350338) did not represent a reduction in the level of quality and that the QA program was still required. Also, the Enforcement Conference document stated that the deleted QA requirements were replaced by QA surveillances and that verification activities were assigned to engineering. Therefore, TU Electric stated no violation occurred.

The NRC inspector found that the surveillances were almost meaningless because the procedures were inadequate. The Stone and Webster Engineering and Ebasco coating engineers were responsible for the coating removal work. They thought all of the activities were nonsafety related. The deletion of quality requirements from the purchase requisition removed the quality organization from the spinblaster testing activities. This decision to delete the requirement for the quality organization to witness the test was very important because test and results were later found inadequate. The test determined parameters for controlling the spinblast process. In reality quality organization did not object because they viewed the operation on the whole as a nonsafety-related activity and performed little or no inspection of the critical characteristics. For example, the Engineering Report (ER-ME-19) indicated that the quality organization was not at a mobilization meeting on April 6, 1988. Procedure EC 6.11 required the QA department representative to certify that procedures were approved, training had been given on owner/contractor procedures, and appropriate contractor supplied materials and/or special tools had been received. Later TU Electric QA surveillance personnel wrote a deficiency report (C-88-03361) because QA did not attend the meeting and certify the activities were completed. Instead of finding QA at fault for not certifying the required activities, the disposition of the deficiency found the procedure at fault and the only action needed was to revise the procedure. If QA had been at this meeting the QA/QC deficiencies concerning service water may have been identified before coating removal began.

TU Electric's argument gives the impression that a one time work activity should be an excuse for not applying QA/QC and technical controls. Every utility is expected to consider and master the concept of the impact of nonsafety-related activities on safety-related systems before the construction permit is issued. For example, the two over one concept is essential to the design of piping. Adjacent nonsafety work must not damage the steam generator. The vessel is only set one time. This is the reason that controls must be developed to perform the activity correctly the first time. The above argument is misleading.

The Enforcement Conference Document and ER-ME-19 gave the impression that the quality assurance organization performed meaningful QA surveillances when in reality five surveillances performed using a checklist based on procedures that did not contain the necessary parameters to control the sandblast/spinblast process. The surveillances only verified if coating was removed (a nonsafety function). Manufacturer's minimum specified wall thickness of SWS piping and other meaningful characteristics were not checked.

At meeting May-July meetings, a TU Electric QC supervisor and SWEC/Ebasco engineering thought the NRC inspectors were strange for thinking that the sandblasting was safety-related and argued that metal removal by sandblasting was not safety related. Page 34 of the engineering report indicates that QA became involved with wall thickness measurements in June 1988 but the report fails to state that this was in reaction to the NRC inspection concerns and was well after damage had occurred.

The QA organization was not involved with the problems that occurred with the spinblaster when the vendor first encountered process control problems. As a result no deficiency report or corrective action request was made. The engineering report (ER-ME-19) stated that the problems encountered early should have warranted a stop work order but one was not issued. The spinblaster problems resulted in retesting the spinblaster to determine the necessary modifications but again the quality organization was not involved.

The NRC inspector also found that TU Electric never audited any Code V procurements for vendor services even though the NRC surfaced deficiencies early in the SWS process. No audit was performed after problems were evident.

ENCLOSURE 8

TU Electric Enforcement Conference Document states, in part, "Contributing Causes: Coating Removal was Unique Task . . . Process Not Previously Employed/Development Work Needed."

Contrary to the above the sandblasting/spinblasting process is an old manufacturing/construction process that is not unique. The process can be controlled provided process parameters are specified and followed. The TU Electric test failed to establish parameters and did not duplicate environmental conditions. Even the parameters (blast material/size, air pressure, blasting rate, and process hold points) that were developed by TU Electric were not incorporated into procedures. Quality assurance was not at the critical TU Electric mobilization meeting and was insufficiently involved to monitor and inspect in-process work to prevent wall thinning. In fact, QA did no inspection monitoring or testing in April and May for wall thinning. Until such controls are implemented, the claim that uniqueness caused the damage is without foundation.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

In Reply Refer To:
Dockets: 50-445/89-23
50-446/89-23

Mr. W. J. Cahill
Executive Vice President
TU Electric
400 North Olive Street, Lock Box 81
Dallas, Texas 75201

Dear Mr. Cahill:

This refers to the inspection conducted by Mr. H. S. Phillips during the period April 5 through May 2, 1989, of activities authorized by NRC Construction Permits CPPR-126 and CPPR-127 for the Comanche Peak Steam Electric Station, Units 1 and 2, and to the discussion of our findings with Mr. H. D. Bruner and other members of your staff at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of selective examination of procedures and representative records, interviews with personnel, and observations by the inspector.

During this inspection, it was found that certain of your activities were in violation of NRC requirements. The apparent violation is being reviewed for appropriate enforcement action. An enforcement conference to discuss the findings will be scheduled. Following the enforcement conference you will be notified of the resolution of these findings.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosed report will be placed in the NRC Public Document Room.

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

C. I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

Enclosure:
Inspection Report 50-445/89-23; 50-446/89-23

cc w/enclosure:
See next page

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In Reply Refer To:
Dockets: 50-445/89-23
50-446/89-23

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400 North Olive Street, Lock Box 81
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SRI:IP:CPPD:NRR	IP:CPPD:NRR	AD:IP:CPPD:NRR	D:CPPD:NRR
SPhillips	HLivermore	RWarnick	CGrimes
7/10/89	7/ /89	7/ /89	7/ /89

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

C. I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

Enclosure:
Inspection Report 50-445/89-23; 50-446/89-23

cc w/enclosure:
See next page

U. S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

NRC Inspection Report: 50-445/89-23
50-446/89-23

Permits: CPPR-126
CPPR-127

Dockets: 50-445
50-446

Category: A2

Construction Permit
Expiration Dates:
Unit 1: August 1, 1991
Unit 2: August 1, 1992

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

Facility Name: Comanche Peak Steam Electric Station (CPSES), Units 1 & 2

Inspection At: Comanche Peak Site, Glen Rose, Texas

Inspection Conducted: April 5 through May 2, 1989

Inspector: ______________________________ __________
H. S. Phillips, Senior Resident Inspector Construction — Date

Reviewed by: ______________________________ __________
H. H. Livermore, Lead Senior Inspector — Date

Inspection Summary:

Inspection Conducted: April 5 through May 2, 1989 (Report 50-445/89-23; 50-446/89-23)

Areas Inspected: Unannounced, resident safety inspection included: (1) exit meeting with management, (2) applicant action on previous findings, (3) follow-up on violations, (4) evaluation of corrective action on enforcement, (5) review of component cooling water heat exchanger work, (6) repair of diesel generator heat exchangers, (7) vendor services to measure steam generator nozzles, and (8) application/removal of coatings from diesel generator tanks.

Results: Within the areas inspected, one apparent violation was identified: failure to provide accurate and complete information relative to corrective action concerning Enforcement Action EA 88-310, paragraph 4.b; and additional examples of violations similar to those identified in EA 88-310, paragraphs 5, 6, 7, and 8. An enforcement conference will be scheduled to discuss these findings.

DETAILS

1. Persons Contacted

*R. W. Ackley, Jr., Director, CECO
*G. K. Afflerbach, ASM Startup, TU Electric
*M. Axelrad, Newman and Holtzinger
*J. L. Barker, Manager, Engineering Assurance, TU Electric
*D. P. Barry, Senior Manager, Engineering, Stone and Webster Engineering Corporation (SWEC)
*J. W. Beck, Vice President, Nuclear Engineering, TU Electric
*O. Bhatty, Issue Interface Coordinator, TU Electric
*M. R. Blevins, Manager, Technical Support, TU Electric
*H. D. Bruner, Senior Vice President, TU Electric
*J. H. Buck, Senior Review Team, IAG
*J. T. Conly, APE-Licensing, SWEC
*R. J. Daly, Manager, Startup, TU Electric
*J. W. Donahue, Operations Manager, TU Electric
*D. E. Deviney, Deputy Director, Quality Assurance (QA), TU Electric
*D. M. Ehat, Consultant, TU Electric
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*T. G. Tyler, Director of Projects, TU Electric
*R. D. Walker, Manager of Nuclear Licensing, TU Electric
*R. G. Withrow, EA Systems Manager, TU Electric

The NRC inspectors also interviewed other applicant employees during this inspection period.

*Denotes personnel present at the May 2, 1989, exit meeting.

2. Applicant Action on Previous Inspection Findings (92701)

a. (Closed) Open Item (445/8908-O-01): The documentation file relating to the auxiliary feedwater motor fans being installed backwards contained two nonconformance reports (NCRs) not previously reviewed by the NRC. The NCRs described arcing between the fans and brass rings on the rotor winding. The arcing was attributed to the condition of having reversed fans. The W analysis concluded that the reversed fans would not cause motor failure or reduce the level of safety during operations. The NRC questioned whether the W analysis included the NCR conditions.

During this inspection, TU Electric met with the NRC and presented additional information. That is, W reevaluated the NCR conditions in connection with the fan reversal issue and concluded that their original analysis was not impacted by these NCRs. This item is closed.

Note: In NRC Inspection Report 50-445/89-08; 50-446/89-08 the tracking number for this item contained a typographical error. The number shown above (445/8908-O-01) corrects the number error (445/8808-O-01).

b. (Closed) Open Item (445/8908-O-03): No NCR was available on stripped threads in bearing holes for an auxiliary feedwater (AFW) motor. The NRC inspector confirmed that operations/maintenance had issued NCR 88-03638, Revision 0. This item is closed.

c. (Closed) Open Item (445/8908-O-04): QC did not verify temperature control during the welding on the AFW rotor bar assembly. The maintenance instruction stated that extreme caution must be taken not to concentrate an excessive amount of heat on the rotor bar assembly. The NRC inspector was concerned that QC had not verified that the instruction was followed.

TU Electric met with the NRC to provide information about this concern. The NRC inspector asked what type of material was used and what heat input controls were necessary. TU Electric did not have a welding engineer present, so a subsequent meeting had to be arranged. During that subsequent meeting TU Electric revealed that an electrical engineer had inserted the caution about heat input. The welding specialist identified the material as a low carbon steel and provided information about the energy input. The NRC inspector has no further questions. This item is closed.

d. (Open) Unresolved Item (445/8908-U-02): TU Electric maintenance personnel substituted Grade 5 carbon steel bolts for the silicone bronze bolts that secured AFW fans in the motors. The NRC inspector learned that a W field representative had directed this material change because past experience had shown that the silicone bronze bolts were cracking and failing because of fatigue. The NRC inspector stated that this material change was improperly authorized unless an engineering change had authorized the change. The inspector also questioned if this was a weakness in the maintenance program.

During this inspection, TU Electric met with the NRC and made a presentation on this subject. They admitted that the material change was not authorized. They were unable to find the W field representative as he was a consultant and performed this work for W. TU Electric submitted a large amount of material on this subject. The NRC inspector considers this to be a potential violation; however, this item will remain unresolved pending the completion of the NRC evaluation.

3. Follow-up on Violations (92702)

a. (Open) Violation (445/8847-V-01a): Failure to establish QA and technical requirements in procurement documents for coating removal from service water system (SWS) piping.

b. (Open) Violation (445/8847-V-01b): Failure to establish adequate controls for the coating removal process.

c. (Open) Violation (445/8847-V-01c): Failure to provide adequate QA/QC procedures for the coating removal process.

d. (Open) Violation (445/8847-V-01d): Failure to take corrective action relative to coating problems and coating removal.

The above violations were doucmented as Enforcement Action (EA) 88-310 in an NRC letter to TU Electric dated January 9, 1989. TU Electric's response to the violations is discussed below in paragraph 4.

4. Evaluation of TU Electric Corrective Action on Enforcement (35065, 49063, 49065, 92702)

a. Background

- NRC Inspection Report (50-445/88-34; 50-446/88-30 for May 1988) identifies open items concerning the removal of Plasite 7122 from SWS and potential wall thinning by sandblasting.

- NRC Inspection Report 50-445/88-47; 50-446/88-42 was issued on September 2, 1988, and identified one apparent violation (breakdown in the QA program relative to the removal of the protective liner from the SWS piping).

- On September 13, 1988, TU Electric responded to the findings at a public meeting on site.

- On November 9, 1988, the NRC held an Enforcement Conference at the NRC's Rockville, Maryland, office. TU Electric made a presentation and provided a handout. The handout was attached to NRC Notice of Violation 50-445/88-47; 50-446/88-42 dated January 9, 1989. The handout stated that problems in the implementation of QA program requirements occurred but were isolated and were not significant. The handout also stated that corrective actions were completed and included (1) evaluating/replacing worst damaged piping, (2) evaluated other spinblast indications with satisfactory results, (3) performed critical self-evaluation, (4) reviewed other Code V services (other than SWS) procurements with satisfactory results, and (5) reviewed previous CPSES enforcement action and found no precursor events.

- On January 9, 1989, NRC issued the NOV for NRC Inspection Report 50-445/88-47; 50-446/88-42. It stated that after careful review of information, the NRC decided that four Severity Level IV violations were appropriate instead of the one Severity Level III that was initially considered. It also stated that the NRC was concerned that once it was recognized that the coating removal process needed to be modified, adequate measures were not taken to inspect for damage caused by early process problems. The NRC letter stated that if the violations were not fully corrected they may lead to more significant concerns.

- On February 8, 1989, TU Electric issued their response (TXX-89070) with one attachment to the NRC.

b. Incomplete and Inadequate Information Provided Concerning Concerning EA 88-310

The NRC inspector reviewed the TU Electric Enforcement Document which was docketed with the NRC Enforcement Action EA 88-310 and Notice of Violation 50-445/88-47, 50-446/88-42. TU Electric Response TXX-89070 to the enforcement action was also reviewed. These documents provided TU Electric's overall response. At the Enforcement Conference information was provided to the NRC which advocated a reduction in the proposed severity level from Level III to Level IV and V. During the enforcement conference TU Electric made several statements, some of which are discussed below, to show that QA/QC deficiencies identified by the NRC were not program breakdowns and, therefore, were not significant. The NRC inspector found that specific information related to the results of TU Electric's review of other Code V procured services was not included in the information provided to the NRC. Thus, the information provided by TU Electric concerning the enforcement action was incomplete and apparently inaccurate. Further, the inspector believes that other information provided by TU Electric during the enforcement conference was misleading and misrepresented the deficiencies encountered during the SWS coating removal project.

NRC Regulation 10 CFR Part 50.9 requires the applicant/licensee to provide accurate, complete, and significant information to the NRC.

(1) TU Electric stated during the enforcement conference that they had "[r]eviewed other Code V services activities with satisfactory Results."

Contrary to the above, the NRC inspector determined that TU Electric failed to provide significant information concerning the results of their review of six Code V service procurements which would have shown that these Code V procurements for services were not satisfactory. These deficiencies are described in TU Electric memorandum NE 22156 dated September 30, 1988. That memorandum indicated that there were deficiencies in the six Code V service procurements. These deficiencies were similar to the Code V procurement for service water system piping coating removal. Further, this information was not provided to the NRC in the meeting on September 13, 1988, in TU Electric Engineering Report ER-ME-19, Revision 0, or in the TU Electric Enforcement Conference Document handout.

The deficiencies documented in Memorandum NE-22156 were:

- Except for two purchase orders for vendor services (661-74340 and 661-74038), the procurement documents did not clearly define the relationship between the organizations involved and the TU Electric QA Program.

- None of the procurements (requisitions or purchase orders) addressed the identification and disposition of nonconforming conditions.

- Verification Plans (engineering and QC inspection points) for each requisition lacked detail.

- Work on the component cooling water heat exchangers should have fallen under the auspices of ASME Section XI.

- Work on the steam generators was performed before the purchase order was approved.

- The procurement documents in general were of similar quality to those associated with Service Water coating removal.

(2) TU Electric's response to EA 88-310 (TXX-89070 dated February 9, 1989), stated in part that "six previous Code V services procurements were identified . . . review of the associated inspection and surveillance reports showed that the requisitioned work was successfully completed and documented."

Contrary to the above, the NRC inspector interviewed the TU Electric representative who coordinated the response to these deficiencies. The NRC inspector questioned the apparent contridiction between the response (TXX-89070) and the internal memorandum (NE-22156). TU Electric responded that the inspection and surveillance reports showed that the work was successfully completed and documented. When asked if QA records were reviewed, the TU Electric representative responded that they had not.

Subsequently, during a meeting on May 1, 1989, TU Electric pointed out that procurement documents and some work orders had been reviewed, while reviewing project files.

TU Electric had not performed an adequate review of the other Code V service procurements to support the conclusions they presented. In addition, during the course of the review of this material, the inspector identified additional deficiencies associated with the subject procurement, as described in more detail in paragraphs 5 and 7.

(3) TU Electric stated during the enforcement conference, in part, that "[d]amage did not occur following modifications to spinblaster."

Contrary to the above, the NRC determined that damage occurred during coating removal of Train B after modifications were made to the spinblaster after damage was found in Train A of the SWS in July 1988. In March 1989, three NRC inspectors performed a field inspection to view video tapes of Train B after coating removal. Defects caused by the spinblaster were observed in Train B (Spool SW-1-SB-7-14A-8 frame 1484). Although the video tapes of Train A and Train B had been misidentified during the video review, blasting marks on the Train B piping were confirmed by the inspectors. The TU Electric coating specialist was present when the NRC viewed Train B tapes and the NRC pointed to the marks that were apparently made by the spinblaster. When directly asked if they appeared to be spinblaster marks, he agreed that they appeared to be spinblaster marks.

The three items described above are apparent violations of 10 CFR Part 50.9 (445/8923-V-01; 446/8923-V-01).

5. Review of Component Cooling Water Heat Exchanger Work (50073, 50075)

During NRC Inspection Report 50-445/89-16; 50-446/89-16, the NRC inspector performed a follow-up inspection to verify the corrective actions taken for Code V service procurements, as described in TXX-89070. Records at the procurement vault, construction QA records vault, and the QA Records Center were reviewed. The QA Records Center personnel provided the NRC inspector with a computer run which listed all QA records available for the component cooling water (CCW) heat exchangers. (One of the previous six Code V procurements was for work on the CCW heat exchangers.) Records for CP1-CCAHHX-02 were selected for review. About March 29, 1989, the NRC inspector met with TU Electric to discuss the results of the NRC review. TU Electric was informed that the available records were insufficient to demonstrate that the work activities were properly controlled, conducted, and documented as stated in TXX-89070 and TU Memorandum NE-22156. TU Electric was provided specific questions regarding how the criteria of 10 CFR 50, Appendix B, were implemented. TU Electric was asked to provide additional records to demonstrate implementation of the criteria necessary to control work. TU Electric was unable to locate or produce additional QA records before the exit meeting on April 4, 1989, and the inspection was not completed.

During this inspection period, the NRC inspector completed the inspection discussed in the previous paragraph. TU Electric never provided answers to the questions concerning which criteria were applicable for each procurement and how they complied with those criteria. As a result, the NRC inspector performed a comprehensive review to obtain the answers. During March and April 1989, procurement documents, work procedures, inspection reports, QA contractor surveillance reports, startup work authorizations, work orders, correspondence, and miscellaneous records were reviewed to evaluate how work was done, inspected, and documented by TU Electric to show that the QA program was implemented in accordance with 10 CFR 50, Appendix B, QA requirements. The NRC inspector found that the QA program was not adequately implemented for four Code V procurements for vendor services for work on the Unit 1 and 2 CCW heat exchangers. Multiple examples of inadequacies and program deficiencies similar to those identified for SWS coating removal were identified.

The NRC met with TU Electric on April 28, 1989, and provided the findings similar to those that were provided in March 1989; that is, the QA program was not adequately implemented. On May 1, 1989, TU Electric requested another meeting during which they concluded that the program for procured services was adequate and was appropriately implemented except for the specification issues and the contract for steam generators which was marked nonsafety. However, the NRC inspector identified deficiencies in these activities, as follows:

a. <u>Chemical Cleaning of CCW Heat Exchangers</u>

In 1985, serious corrosion problems were identified inside the CCW heat exchangers (Problem Report 85-302). Several actions were taken to correct these problems and one action in the process involved chemical cleaning. Requisitions 6R-282724 and 6R-340403 were processed and respective Purchase Orders 661-74038 and 661-74340 were issued to Haliburton Industrial Services Division (HISD).

Procurement

The NRC inspector identified the following deficiencies with the Code V procurement for chemical cleaning the CCW heat exchangers: (1) contracts did not reference or discuss the fact that vendors would be required to comply with TU Electric's QA program which implements 10 CFR, Appendix B, QA Program, and 10 CFR Part 21, defect reporting requirements; (2) the requisitions and contracts did not address the training of vendor personnel (who must help implement TU Electric's QA programs since the vendor has no Appendix B QA and 10 CFR Part 21 program); (3) technical and QA requirements were not explicitly defined; (4) activities concerning ASME components were not done under the auspices of ASME XI; (5) verification and inspection plans lacked specific requirements as they generally stated: "QA shall monitor the vendor's work", and (6) vendor work plans and procedures were inadequate.

Project Plan and Procedures

The NRC inspector reviewed the plan and procedure that were used for chemical cleaning and found that the same plan and procedure were used for both purchase orders referenced above for work performed in February and May 1987.
Project Plan for Chemical Cleaning CCW HX CP1, CP2-CCAHHX-01 and -02, Revision 0, did not adequately describe the QA and technical requirements needed to control the process. The plan failed to:

- Describe the purpose of fiberoptic inspections,
- Describe the criteria for determining when the metal surface was clean and corrosion products were removed, and
- Describe the criteria for and the hydrolazing/flex lining operation.

After the chemical cleaning was completed in February 1987 such criteria were discussed in TU Electric Maintenance Engineering Evaluation (MEE) No. 88-003 dated January 13, 1988, but were not factored into the plan before the second job. The evaluation stated that the comparison of fiberoptic videos of tubes before and after flex lancing would be compared with a second video recorded after consistently low copper concentration was reached during chemical cleaning. It further stated, "A comparison of the before and after videos would be the final determination of adequate tube cleanliness." These actions were not accomplished.

"Procedure for Chemically Cleaning Component Cooling Water Heat Exchangers," Revision 2, was inadequate in the following respects.

- The chemical cleaning (vendor) procedure did not contain information such as a reference section, purpose, scope, responsibility, definition, instruction, or records. (See TU Electric Startup procedures for cleaning the diesel fuel/lube oil piping for an example of a good procedure.)
- The vendor procedure does not describe or reference the ASTM standard which governed chemical testing to assure proper chemical concentration.
- The vendor procedure does not describe how the blended solution was to be mixed.
- The vendor procedure does not describe the mixing of nitrogen gas with the foam solution. Also, there was no description of how much heat should be added at Step 2 prior to adding the nitrogen (which is referenced in Note 1).
- Step 6 of the vendor procedure did not describe where samples were to be taken nor how to ensure a representative sample.
- Step 8 requires an inspection of the CCWHX tubes to determine the degree of scale removal, but does not specify the method or any specific criteria.
- Step 9 should read: "repeat steps 5-9" instead of steps 7-9.
- Step 10 states, in part, "that once inspection reveals the desired degree of scale removal," but gives no description of the desired surface condition or criteria for inspecting. This step did not incorporate the criteria described in Maintenance Engineering Evaluation (MEE) 88-003.
- Step 11 does not specify the quality of the water.
- Step 13 does not describe specific mixing instructions for the soda ash and sodium tolyotriazole (500 ppm).
- The procedure did not describe the Haliburton operator's log nor any requirement to record various data such as type of operation, time, temperature, chemical concentration, and pressure. There were no

Haliburton signatures on the data forms to authenticate the data. Only the TU Electric Project Manager signed Haliburton's log. However, the project manager did not perform the steps or operations and was not always present to verify each aspect of the operation.

- The vendor procedure (Attachment 1 to Work Order CP7-2347) had no TU Electric approval on it.

- The vendor procedure did not address the calibration of the gauges and other measuring devices used for process control. Pressure and temperature were at least two parameters which should have required measuring equipment and calibration. TU Electric memorandum TCP-87027 described this deficiency after the first job, but no nonconformance report or corrective action request was evident.

  Note: The project manager's log for the second job indicated that TU Electric took measurements, but there is no record of these measurements. It was also indicated that the project manager was issued calibrated measuring and test devices that did not work. In discussions with the project manager, it was determined that the vendor's equipment had gauges that were not under an approved calibration program (Appendix B requirement). Finally, the temperature as measured by the project manager was 117° F versus 122° F as measured by site chemistry. No deficiency report was issued to document and evaluate this deficiency.

- The procedure did not address acid spills.

- The procedure did not address passivation after cleaning.

Support Procedures - The NRC inspector found that a number of other work activities were required to support the chemical cleaning process. Specifically, three work activities were an integral part of the cleaning process: (1) fiberoptic examination, (2) flex lancing or hydrolazing, and (3) eddy current testing. Procedures to control these activities were not referenced in the chemical cleaning procedure.

Work Order C870000585 contained a revision to require Hydro Nuclear Company to flexlance the tube side of the heat exchanger, not to exceed 10,000 lbs pressure. Since no procedure was found, it is not clear if quality was sufficiently involved to verify and document this work.

Other TU Electric activities concerned the fiberoptic examination and hydrolazing performed by Hydro Nuclear. It is unclear if the flexlancing and hydrolazing was the same operation. Finally, eddy current testing was performed, but was not discussed in the Project Plan or cleaning procedures. Documented evidence of controls for these activities were not provided to the NRC.

Control of Work Activities - The subject purchase orders resulted in the chemical cleaning of Unit 1 and 2 CCW heat exchangers. The first work occurred in February 1987 under Purchase Order 661 74340. During the first cleaning job in February 1987, the vendor experienced a number of problems as described in TU Electric office Memorandum TCP-87027: nonuniform distribution of chemical cleaner (which prolonged the cleaning process), flow rate considerably below estimated flow rate of 24 gpm, quality of chemical foam inconsistent; gas flow meter was not calibrated for expected flow rate; long interruptions occurred while foaming; nozzles were not the correct type for most effective cleaning; nozzles plugged up several times; defoamer equipment was inadequate to deliver the chemicals and caused interruptions; and the vendor had insufficient manpower for the task causing TU Electric to supplement the vendor's work force. The memorandum concluded by recommending a penalty for poor performance. This memorandum appears to be in contrast to TU Electric Contractor Surveillance Report CSR-87-002 which concludes that contractor performance was satisfactory (except when the vendor removed a red danger tag without authorization).

Although the chemical cleaning job for Unit 1 and 2 CCWHXS, Train B, (performed in May 1987) was better than Unit 1 and 2 CCWHXs, Train A, the NRC inspector determined that no deficiency/nonconformance report or corrective action request was generated to identify, evaluate, disposition, and correct the following deficiencies. Also, the causes of these deficiencies were not identified.

- The process problems discussed in Memorandum TCP-87027 and surveillance summary 87-022 were not documented in deficiency reports and evaluated to determine if the requirements were adequate. The QA and technical requirements were identical for both requisitions and purchase orders. Considering the problems discussed in the memo and summary 87-022 chemical cleaning of CCWHXs, it should have been evident that the requirements were either inadequate or the vendor was not meeting the requirements.

The chemical cleaning process deficiencies documented in Memo TCP-87027 were: nonuniform distribution of chemical cleaner, inadequately measured flow rate, chemical mixing inconsistency, process interruptions, inadequate equipment, and inadequate manpower, were not documented as deficiencies and formally evaluated to assure correction before the award of the second contract for chemically cleaning CCWHXs for Train B and before work was completed on the second chemical cleaning job. TU Electric memorandum TIM-870301 estimated a loss of 0.01 mils of metal surface except for areas where active pits were and the loss there was estimated to be 0.2 mils of metal. Since the CCW heat exchanger is an ASME, Class 3 component, the deficiencies in memorandum TCP-87027 should have been formally documented, evaluated, and dispositioned to assure the process did not result in excessive metal attack, especially in active pits.

- After the chemical cleaning was completed (per the procedure), two hours worth of chemicals were left over. Rather than waste these chemicals, one hour of additional cleaning was added to each heat exchanger. This action was taken without obtaining authorization to change the process procedure.

  NOTE: On May 1, 1989, TU Electric stated that the process was not continued on the basis of chemicals left over, but acknowledged the log stated that. The NRC inspector is of the opinion that additional chemical use should have been based on inspection criteria to determine if the surface was cleaned.

- A projects summary (Theimer 6-18-87) listed ten comments/recommendations based on the second chemical cleaning job in May 1987. These comments are further indication that the chemical cleaning and support procedures were not well developed to achieve an integrated approach which would assure the work was properly controlled. The main comments discussed deficiencies in these areas: (1) organizational interfaces, (2) acceptance criteria to avoid unnecessary attack, (3) chemical and point indication, (4) sample not taken from main tank supply, (5) PH sampling locations, (6) passivation, and (7) timely chemical analysis. The objective and acceptance criteria were not described in the vendor procedure, but this memo stated, "The acceptance criteria [sic] is a visibly clean heat exchanger tube surface without unnecessary base metal attack." This criteria should have been established in February 1987. One important comment on a support activity concerned TU Electric analyses of chemicals and corrosion product (for copper) versus the vendor's analyses. The comment suggested a time lag had occurred between the vendor's analyses and TU Electric's chemical analyses. Also, it recommended agreement of ± 20% between values. This suggested a large difference had occurred and after the fact correlation was made. Since these analyses control the rate of attack and along with visual inspection, indicate the process end point, this should have been documented as a deficiency.

QA Surveillance and Inspection - The NRC inspector reviewed QA Surveillance Reports CSR-87-002 dated March 2, 1987, and backup files for the first chemical cleaning of the CCWHXs. The checklist for CSR-87-002 included 11 attributes, 4 of which were marked not applicable. The NRC inspector determined that:

- Item 1 checklist characteristic was marked satisfactory and required verification of contractor prepared procedures reviewed and approved by appropriate "TUGCO" personnel prior to use. No signatures for review and approval were on the procedure. Rather, the surveillance report stated that approval was accomplished by attaching the chemical cleaning procedure to the Plant Operation organization's work order.

- Item 2 checklist characteristic was marked satisfactory and it required the verification that contractor prepared procedures for special process were qualified in accordance with industry standards while Item 5 addressed contractor personnel performing special processes. This characteristic and finding for Item 2 is contradicted by Item 5. That is, Item 5 was marked not applicable. As both address special processes, they are either both applicable or not applicable.

- Item 3 checklist characteristic was marked satisfactory and required verification that contractor personnel performed in accordance with procedures. This finding does not reflect and is in opposition to process deficiencies that were identified in TU Electric Memorandum TCP-87027. Since the procedure was not properly reviewed, approved, and contained shortcomings, the finding for this characteristic was of questionable value.

- Item 4 checklist characteristic was marked satisfactory. The comment indicated the vendor completed documentation as specified in the purchase order. This finding is contradictory as no such documentation requirement was in the purchase order. (See TU Electric Memo NE 22156).

- Item 7 checklist characteristic was marked not applicable. The checklist characteristic required TU Electric to verify that safety-related material supplied met CPSES requirements and material certifications. The vendor furnished chemicals which should have been checked or verified when received. The surveillance could have verified that appropriate chemical grade materials were received before use. TU Electric Procedure EC 6.11 requires engineering, construction, and QA to certify that all contractor supplied material, and/or special tools be received by the TU Electric QA warehouse and accepted by QA. There was no reference to the "Contractor Work Release Authorization Form" which is required by EC 6.11.

- Item 9 checklist characteristic was marked not applicable. Item 9 required the verification of contractor supplied measuring and test equipment. The comment on this item stated that, ". . . our chemical dept. provided cal. equip. . . . ." This statement shows that equipment furnished by TU Electric should have been verified as a part of the surveillance because TU Electric assumed all QA responsibility. In addition, the project manager indicated that vendor furnished equipment had gauges which helped control the process. The surveillance should have addressed the calibration or lack thereof.

- Item 10 checklist characteristic was marked satisfactory. Item 10 stated: "Chemistry provide periodic oversight of process & take samples to test for Fe & citric acid concentration." This was followed by a comment "incorrect requirement. Checked for copper & nickel." The procedure misstated which test should have been performed. The satisfactory finding was contradicted by the negative finding.

- Item 11 checklist characteristic was marked satisfactory. In this case an attribute was added to verify that passivation was done after cleaning and before the demineralized water flush. As this chemical passivation operation was not in the procedure, the source of the characteristic is not clear. If no procedure was established, this characteristic should have been marked unsatisfactory and a deficiency written because it was not an approved step in the procedure.

The NRC inspector also reviewed Surveillance Activities Summary (SAS) 87-022 which was referenced by CRS-87-002. The NRC inspector did not find the Surveillance Activity Summary in the QA records. It was furnished in a personal file and was not signed by the Quality Surveillance supervisor. This summary only addressed chemical testing and appeared to contradict the surveillance report. The summary indicated that the overall chemical cleaning process was not appropriately controlled as analyses of copper concentrations indicated an unstable condition, verbal agreements allowed acceptance because of cost considerations, discrepancies between times (that chemical foam was stopped) were recorded by project manager and Haliburton data sheets, no chemical analysis during approximately two hours of continued cleaning, samples were not taken and analyzed, pH values for ammoniated solutions were not adjusted for temperature, sample location was improper, and large differences between TU Electric and the vendor's chemical analyses results. This surveillance summary concluded that only two of five findings were deficiencies and reports were written. The NRC believes the three remaining findings should have been documented as deficiencies. Finally, surveillance summary 87-022 stated that the chemical cleaning process is defined as a special process in paragraph 5.2.18 of ANSI N18.7 while CRS-87-002 stated it was not a special process. The summary of 87-022 stated that inconsistent in-process controls coupled with "cost-effective" decisions in Train B cleaning activities may have a detrimental effect on the heat exchangers at a later time. There is no evidence that the potentially detrimental effect discussed in this report was ever formally addressed in a deficiency report.

The NRC inspector reviewed Surveillance Report CSR-87-005 dated May 13, 1987, which covered activities on the second chemical cleaning operation by Haliburton. The quality of this surveillance was about the same as CSR-87-002.

Based on the available documentation that was reviewed, the NRC inspector believes the QA surveillances were not completely adequate. In addition, all deficiencies identified in surveillance activity summary SAS 87-022 were not documented in a deficiency report to assure evaluation, disposition, and corrective action.

The NRC inspector reviewed the records and files, but found no inspection reports for chemical cleaning. Work

Order C870000585 indicated that QC would be involved, but no inspection report was required. The work order stated that QC shall provide personnel and equipment to perform fiberoptic examination, but no inspection report was required.

b. <u>Cutting Heat Exchanger Tube Ends</u>

A Code V procurement for this service resulted in issuing Requisition R-49642 dated August 18, 1986, and Purchase Order CPF-13593-S. The purchase order was issued to Perflex Services. This work was a prerequisite to recoating of the heat exchanger. The work involved cutting 5720 tube ends to lie flush with the tubesheet, grinding rough surfaces, preparing ends for coating and removing brass plugs. Such preparation was necessary to obtain a quality coating to protect the surface from corrosion.

<u>Procurement</u> - The NRC inspector reviewed the procurement files and found that the Code V procurement deficiencies described in TU Electric Memorandum NE 22156 generally applied to this procurement.

<u>Project Plan and Procedures</u> - The NRC inspector determined that the work activity (cutting heat exchanger tube ends) was not part of a project plan such as STA-TP-87-3 which described a plan for cleaning the CCW heat exchanger. No individual project plan was found.

Perflex Services Procedure CPF 13593-S, Revision 2, dated September 4, 1986, was approved by Stone and Webster Engineering Corporation who was project manager for this job. The procedure submitted by Perflex was a one page procedure which did not:

- Describe how the vendor's personnel would interface with various organizations such as SWEC, Brown and Root, Inc., TU Electric Construction, and Operations.

- Describe the inspection to be performed by Perflex Services personnel and or the personnel qualifications.

- Describe criteria for rough grinding tubes after being cut or specify a surface finish or generally state that burrs, rough edges, and other defects be removed.

- Describe the steps to meet DCA 25192, Revision 0, which required that sharp outside corners be 1/8-inch radius (minimum) and inside corners be welded (ASME

Section III, Division ND) to build up to this radius. Revision 4 of the DCA specified the radius requirement, but this should have been addressed in the subject procedure unless the cutting caused no sharp corners.

NOTE: Interviews with the project manager did not clear up this matter and no answer was provided specific to whether welding occurred or not. However, the QC inspector stated that welding did not occur.

Inspection of Work Activities

Inspection of the tube cuts and removal was documented in TU Electric Inspection Report 86-0289. However, only 25 CCWHX tubes were inspected for one CCWHX. The purchase order stated that 5720 cuts would be made on the CCWHX, but Form TNE-PR-3.2 indicated two CCWHXs. It appears that the balance of the tubes, about 5670, were not inspected or were inspected by Perflex Services (who had no QA/QC program responsibilities in the contract). Such inspections should have been made by inspectors certified to ANSI N45.2.6. It appears that the inspection characteristic of 0.030 inches maximum protrusion was not verified by direct measurement with a go or no-go gauge. The vendor's procedure did not indicate how in-process work was monitored and no in-process inspection procedure was evident. No documentation was provided by the applicant to verify the inspection for minimum radius of 1/8-inch per DCA 25192, Revision 4.

QA Surveillance - The NRC inspector reviewed Surveillance CSR-86-004. The checklist was the same as others reviewed and it appears to be a generic checklist. Similar to previous surveillances, a large number (half) of the characteristics were marked not applicable. The summary of this surveillance was not complimentary to the vendor regarding the lack of discipline, tools, and experience.

c. Application of Epoxy Coating to CCW Heat Exchanger

Requisition 48370 dated July 10, 1986, and Purchase Order CPF-13597-S dated August 26, 1986, were issued to Specialties Engineering Corporation (SPECO).

Procurement - The NRC inspector determined that the general comments in TU Electric Memorandum NE-22156 applied to this procurement.

Project Plan and Procedures - The NRC inspector reviewed the plan and procedures. These were more detailed and technically comprehensive than other vendor plans and procedures. Work procedures (Attachment A, B, C, D, and E to SPECO letter FR-48370) described surface preparation, coating of channels, heads, tube sheets, and tube ends. However, these procedures were not dated and no signatures for review and approval were on the procedures.

One procedure required the applicator to visually inspect the coated area where spark testing was not possible, a practice that is generally not acceptable because an individual should not final inspect his own work. There is no indication that the TU Electric inspector inspected areas where a spark test was not possible. Also, Specialties Engineering Bulletins dated December 14, 1978, for repairs were not described in the procedure and were not in the onsite records.

Inspection and Test - The NRC inspector reviewed TU Electric Inspection Report 86-0289 and determined that:

- The inspection of the coating only addressed the inspection of the final dry film thickness. Such a final inspection would not assure that the epoxy was applied as required by Attachment B, "Coating Application Procedures for Channels Heads." Attachment B procedure required three coat applications and thickness was supposed to be controlled during each application.

- After after the final (third) coat it was to be cured for 16 hours at 70°F ambient temperature or 24 hours at 60°F ambient. Inspections of these characteristics, if performed, were not documented on the inspection report.

- No characteristic was included in the inspection report for repairs for SPECO Bulletin 35.

- The procedure (Attachment B) required measurements using a Bacharach Sling psycrometer and a Pacific Transducer Company surface thermometer. No TU Electric inspection showed that the vendor's equipment was calibrated.

- The inspection report had no characteristics to require inspection of the surface preparation or procedures (Attachments A and E).

QA Surveillance - The NRC inspector reviewed Contractor Surveillance Report SR-86-007 and the attached checklist.

The checklist contained 12 characteristics to be verified. The generic checklist had been modified to add characteristics to verify surface preparation, spark test, and 6 inches of tubes coated. All three were marked satisfactory. The basis of the satisfactory was a reference to Inspection Report IR-86-0289 and the inspection of surface preparation. However, the inspection of the surface was not in inspection report IR-86-0289.

Three characteristics on the checklist, including calibration, were marked not applicable. This decision appears questionable considering vendor personnel were inspecting with equipment that may or may not have been in the site calibration program. The surveillance was insufficient to fill the inspection gaps described in the paragraph above.

6. <u>Repair of Diesel Generators Heat Exchangers (50073, 50075)</u>

The NRC inspector learned that diesel generator jacket water heat exchangers were examined. Corrosion was found and Design Change Authorization (DCA) 21981, Revision 6, required repair, corrosion removal, and recoating. This involved removing the existing rubber liner, inspecting surfaces to be coated with Belzona Ceramic S-metal, welding to build up corroded areas (ASME III work), sandblasting in preparation for coating application, and coating application.

The NRC inspector evaluated selected areas where the above work was done. The quality of the procurement, inspection, QA surveillances, and corrective action concerning Requisition 6R-345080 and Purchase Order CPF-14220-S to Haliburton for the above work were similar to SWS and CCW work activities. The NRC determined that similar deficiencies existed with respect to the QA program implementation as described above in paragraph 5 above. One exception was the procedures developed by TU Electric Startup. They were a good example of how other procedures should have been developed and implemented to assure proper controls for work activities.

7. <u>Vendor Services to Measure Steam Generator Nozzles (50073, 50075)</u>

<u>Procurement</u> - The NRC inspector reviewed requisition 6R-356251 dated July 15, 1988. The requisition does not make clear whether this was a safety or nonsafety-related activity. Including the SWS requisition, three of seven Code V requisitions evidenced such confusion. Had TU Electric QA adequately audited the Code V procurements, this trend may have been identified and the problems associated with these procurements could have been identified and corrected. There

is no indication that adequate audits of the Code V procurements were ever performed.

A purchase order (661-74054) dated January 16, 1987, was issued to Nuclear Services, Inc. Sixteen nozzles on eight steam generators were to be measured and visually inspected to determine each nozzle diameter and radius, height of flange ring to nozzle and location of the 3/4 - 10 UNC tapped holes. This was necessary in order for TU Electric to procure nozzle dams to be used inside steam generators to temporarily isolate the steam generator primary channel head from the refueling pool and permit refueling and testing or repair of the steam generators to occur simultaneously.

In July 1988, requisition 356251 was issued to purchase the nozzle dams from Nuclear Energy Services. The requisition was marked Code N which meant that no 10 CFR 50, Appendix B, QA program or 10 CFR 21 requirements were applied. Code N was incorrect because the activity was safety related.

Inspection - The work on steam generators was in progress before QA was aware that Nuclear Energy Services was on site. Since this was a Code V procurement for services, TU Electric was required to provide the QA program and assume 10 CFR Part 21 responsibility for the vendor. As previously discussed, QA was required to certify that material and tools were received and personnel were trained prior to work (required by EC 6.11). This was not done. By chance, the QA organization discovered the work was in progress and decided to verify access control, surveillance CSR-87-003. No checklist was attached to the surveillance. TU Electric wrote a deficiency report (P87-0135) because the work was completed January 14, 1987, but the contract was not completed and dated until January 16, 1987, and maintenance engineering and QA did not receive it until January 19, 1987. The surveillance concluded that QA did not know about special requirements until after the fact. The NRC inspector found that TU Electric Memorandum NE-22156 concluded that this was "acceptable" because hardware was not changed. The basis for this conclusion is not evident.

The NRC inspector determined that the procedure for measuring and inspecting the nozzles was comprehensive; however, the procedure was not reviewed and approved to incorporate it into the TU Electric document control system and bring it under their QA program. Section 3 of Attachment 1, "Steam Generator Nozzle Measurement Procedure," stated that Nuclear Energy Services would furnish profile gauges and thread gauges to verify location and condition. The procedure did not state that this equipment would be under the TU Electric calibration program. There was no QC verification of the calibration of this equipment.

The NRC inspector determined that on December 1987 design modification request (87-1-237C) was issued to drill and tap eight additional holes in each nozzle to accommodate the nozzle dams when needed. Measurements and inspections to implement these proposed modifications and inspections were safety related.

8. <u>Application/Removal of Coatings from Diesel Generator Tanks (51053)</u>

NRC inspectors met with TU Electric in September 1988 and pointed out the similarity between deficiencies in the diesel generator fuel oil tank coating removal and service water system coating removal. TU Electric did not consider them to be similar because the procurement code was different. The NRC inspector believes the same lack of QA/QC controls existed, as documented below:

a. Initial coating requirements for the diesel fuel oil storage tanks were defined in the tank specification (2323-MS67A); this document did not require inspection or documentation of the coating process. In May 1979, a design change authorization (DCA 4665) was issued implementing the provisions of Specification 2323-AS-31 which included requirements for safety-related procedures, inspection, and documentation for protective coating work.

   In January 1983, the project recognized that the required documentation was lost and an NCR (C-83-00223) was generated. It was dispositioned "use-as-is" on the basis that coatings of the tanks were not critical since coating failure could be offset by alternate means of filling the day tanks. In August of 1983, blistering of the coating was noted in one of the tanks and an NCR (C-83-021615) was written and dispositioned "use-as-is" on the basis of insufficient blistering to warrant repair.

   In mid-1985, the safety-related coatings Specification (2323-AS-31) was reclassified to "Non-Safety Related".

   In 1986, during the cleaning of the Unit 2 diesel fuel oil storage tanks in preparation for startup testing, a band of rust spots approximately two (2) feet in width was observed in the Train A tank. DCA 4665 classified the coatings work as a safety-related activity, but the declassification of the Specification (2323-AS-31) removed the technical basis for implementing a repair of the safety-related coatings. This distinction between safety versus non-safety for coatings and similar activities requires resolution by TU Electric prior to initiating repairs on the Unit 2 tank and investigation of the Unit 1 tank coatings. TU Electric letter (TXX-6461) concluded that the coating was not safety-related and the walls were thick enough to withstand corrosion for the 40 year design life.

b. The NRC inspector reviewed the background of the issues and records for the above activities and determined the following:

- Similar to the service water coating, Gibbs and Hill failed to recognize that the procurement/application of coating is safety-related even though the coating may be nonsafety related. The coating subsequently failed and the tanks were attacked by corrosion.

- The initial corrective action (DCA-4665 dated 1979) attempted to correct the QA program deficiency by changing the specification (2323-AS-31) to require such controls. However, this action was reversed in mid-1985 by reclassification to nonsafety-related. This reversal was incorrect because it did not recognize the adverse effects the uncontrolled work activity could have on the safety-related fuel oil tanks.

- On September 4, 1986, TU Electric reported in a 10 CFR 50.55(e) report that the fuel oil tanks that were coated without QA/QC controls were acceptable and the first reclassification to safety-related was incorrect. Therefore, no QA/QC controls were needed. It was also concluded that since it was unlikely that fuel lines would become clogged with coating (if it failed), this item was not reportable. The final response (TXX-6461) dated May 22, 1987, failed to assure corrective action as follows:

  (1) Failed to consider the fact that activities affecting the quality of components must be controlled even though the purpose of the coating is considered nonsafety related.

  (2) Failed to address the fact that the coating material was not known for sure, but assumed it was AMERCOAT 395.

  (3) Failed to address the loss of the documentation of the type of coating and how it was applied.

- TU Electric failed to address the similarity between diesel generator and service water coating damage in the Enforcement Conference Document. Both involved the lack of QA/QC controls for coating procurement application, coating degradation, and corrosion of components. The NRC had pointed out the similarity before the Enforcement Conference.

- The removal of the coating from ASME tanks should have come under ASME XI for Unit 1 tanks. There was no indication that ASME XI was considered.

c. The NRC inspector found that TU Electric failed to take adequate corrective action as follows:

(1) The specification does not specifically address the controls of activities affecting the quality of the fuel oil tanks.

(2) TU Electric did not address why the documentation was lost.

(3) TU Electric did not specifically address the lack of ASME XI involvement.

The above work on the diesel fuel oil tanks was not a service procured under Code V, but the work was performed on site by a contractor. However, the similarity existed between work on the service water system and work previously done on the component cooling water, diesel generators, and steam generators, that is, the question about whether the procurement and application of coating were safety-related. Other similarities were that work was not done under ASME XI auspices, and documentation was not readily retrievable.

9. Exit Meeting (30703)

An exit meeting was conducted May 2, 1989, with the applicant's representatives identified in paragraph 1 of this report. No written material was provided to the applicant by the inspectors during this reporting period. The applicant 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 the inspection.

INSPECTION PLAN FOR COMANCHE PEAK OPERATIONAL READINESS ASSESSMENT (ORAT) INSPECTION

I. Objective

This inspection is being performed in accordance with draft Inspection Procedure IP 93806, "Operational Readiness Assessment Team Inspections," which is included as Attachment 1. The objective of this inspection is to provide a major input and basis for a NRC determination of the startup readiness of the Comanche Peak Steam Electric Station (CPSES). Operational readiness assessments are required before issuance of the low-power license, and before issuance of the full-power license or during power escalation. The major focus of the inspection will be the verification of an appropriate operating attitude well before fuel loading and initial criticality. In addition, programs that control construction completion, procedural use and work assignments should have been phased out or merged with operational control programs. The inspection will also emphasize the effectiveness of management oversight, corrective action programs, root cause analysis, and the readiness to support operations. At the conclusion of the inspection we will provide a recommendation on whether the applicant can safely proceed to fuel loading and low power testing.

II. Background

The Comanche Peak Steam Electric Station (CPSES) Units 1 and 2 are owned by Texas Utilities Electric Company (TU Electric), a subsidiary of Texas Utilities Company (TUCo), Texas Municipal Power Agency (TMPA), and Tex-La Electric Cooperative of Texas, Inc. (Tex-La). TMPA is in the process of transferring their ownership interest to TU Electric and Tex-La is transferring their ownership to TU Electric in the near future. The lead applicant is TU Electric, which has been designated Agent for CPSES by the owner-applicants. The facility is a standard 1160 MW Westinghouse four-loop pressurized water reactor with a steel lined, reinforced concrete containment. The units are located in Glen Rose, Texas, approximately 40 southwest of Fort Worth, Texas.

The applicant received a Construction Permit in December 1974 and had essentially completed construction and preoperational testing and turned the systems over to operational control in 1984. The original architect-engineer was Gibbs and Hill; however, they were replaced by Stone and Webster after 1985. Ebasco and Impell have also provided engineering support since 1985. In 1982 numerous adverse allegations were received, most of which concerned construction adequacy and quality assurance. These issues have been subsequently referred to as the "Walsh-Doyle" issues. In 1983 an NRC Construction Appraisal Team confirmed these allegations and the ASLB determined that TU Electric was not in accordance with Appendix B of 10 CFR 50.

The Office of Nuclear Reactor Regulation (NRR) assembled a Technical Review Team (TRT) onsite in 1984. The TRT included 50 technical experts from the NRC, national laboratories, and consulting organizations. The TRT spent four months investigating the allegations and documented their findings in five Supplemental Safety Evaluation Reports (SERs). In addition, numerous concerns about the design and construction of the plant evolved through contentions before the NRC's Atomic Safety Licensing Board (ASLB) and the Comanche Peak Independent Assessment Program review conducted by Cygna Energy Services.

In response to the concerns, the applicant implemented the Comanche Peak Response Team (CPRT) in 1984 to address all relevant issues, existing and future. This program involved a re-verification of the design and re-inspection of the construction of selected engineering disciplines. In 1985 the design review was initiated. Based on the extent of deficiencies identified, TU Electric developed the Corrective Action Program (CAP) in 1987 to require a complete design re-verification; hardware validation, including hardware re-inspection and modifications; and design and "as-built" reconciliation in a broad number of areas. The development and implementation of the CAP for design and construction deficiencies typifies the aggressive and thorough approach that TU Electric management has applied to safety issues. This attitude is regularly demonstrated by TU Electric managers, several of whom are former NRC employees, but not always by the working staff.

In 1987, the NRC Office of Special Projects (OSP) was formed to ensure comprehensive and timely resolution of complex regulatory concerns with a strengthened and integrated staff organization and direct lines of management responsibility and authority and appropriate high-level direction. This Office was incorporated into the Office of Nuclear Reactor Regulation (NRR) in January 1989 as the Associate Directorship of Special Projects and retains responsibility for all licensing and inspection activities.

There has only been one recent escalated enforcement case completed. In February 1989, the staff cited TU Electric with a Level III Violation for failure to submit a timely application for extension of the Unit 1 construction permit. The applicant had inadvertently allowed the original permit to expire.

There have been slightly over 1000 allegations received by the staff concerning Comanche Peak. All of the allegations received prior to formation of OSP have been closed. Of the remaining, approximately 13 remain open.

In July 1988, TU Electric reached an agreement with the remaining intervenor (i.e., Citizens Associated for Sound Energy) and the ASLB hearings were dismissed. As a result, Ms. Juanita Ellis, became a member of the Operations Review Committee and TU Electric compensated CASE for previous expenses. In August 1988, a new group, the Citizens for Fair Utility Regulation (CFUR), and an individual, Mr. Joseph Macktal, are attempting to gain status as intervenors.

The extensive corrective action effort to correct the numerous design and construction deficiencies has been underway at CPSES over the past several years. This program has resulted in a significant number of modifications to bring the plants into conformance with NRC requirements. In March 1988, the applicant temporarily suspended work on Unit 2 to concentrate resources on Unit 1 completion. The applicant is currently nearing completion of the corrective actions and has committed to re-perform greater than 90 percent of the preoperational tests as the Prestart Test Program. Hot functional testing (HFT) and integrated leak rate testing on Unit 1 was completed in July (Unit 1 previously underwent HFT in 1985).

The applicant has committed to begin a two-week operational readiness period following completion of construction and testing. The project status report currently shows a fuel load readiness date and the beginning of this "quiet time" on October 2, 1989. The applicant is running about two-weeks behind schedule; therefore, the earliest they should be ready for licensee issuance is during the second week of our inspection.

III. Inspection Plan

A. Objectives

The inspection has three major objectives:

(1) Independently assess the Comanche Peak Steam Electric Station (CPSES) power ascension, operations, and operations support programmatic and staffing readiness for operations.

(2) Monitor daily activities in the areas of operations, testing, maintenance, engineering and technical support, and quality assurance in order to assess whether the applicant is ready to operate the facility safely.

(3) Evaluate the status of the prestart testing program to determine whether testing has been essentially completed and that outstanding construction deficiencies will not adversely affect the safe operation of the plant.

B. Scope

The emphasize of the inspection will be an independent assessment of the effectiveness of management oversight, corrective action programs, root cause analysis, and the readiness to support operations. The inspection will verify that the applicant has established an appropriate operating attitude well before fuel loading.

In order to focus the inspection effort, we will limit our detailed review of safety-related activities, system alignments, material condition, surveillance testing, and operational procedures to the following systems:

(1) High Pressure Injection.
(2) Decay Heat Removal.
(3) Auxiliary Feedwater.
(4) Diesel Generators.
(5) Station Batteries.

This inspection plan has been developed to address the applicant's operational readiness in the six functional areas. A detailed evaluation criteria for each of the areas is provided in Appendix A. Any suggested changes should be provided to the team leader. The functional areas are:

(1) Plant Operations.
(2) Surveillance and Testing.
(3) Facility Management Organization.
(4) Power Ascension Test Program (PATP).
(5) Maintenance.
(6) Engineering and Technical Support.

C. Team Members

In order to accomplish this inspection, the team will be divided into two sections -- operations and operational support. The operations section will focus on operations department activities and control room observations and the operations support section will focus on the system walkdowns and the operational readiness and support of the remaining departments. Continuous control room coverage is anticipated for at least 72-hours (Tuesday through Saturday) of the first week onsite). In addition, the operations support section will perform walkdowns of the selected systems during the same time period. On Sunday (October 22) the entire team will reconvene to determine the direction of the remainder of the inspection. The team members are listed below.

Chris A. VanDenburgh - Team Leader - NRR - (301) 492-0965
Dwight D. Chamberlain - Asst. Team Leader - Region IV - (817) 860-8249 (1/2 time)

Operations Section

Jay R. Ball - Discipline Lead - NRR - (301) 492-0962
~~William D. Johnson - Region IV/CP-SRI - (817) 897-1500~~ In Japan
Jackie E. Bess - Region IV/STP-SRI - (512) 972-2507
Larry R. Veeder - Prisuta-Beckman Associates, Inc. - (412) 872-9157
Robert L. Lewis - Prisuta-Beckman Associates, Inc. - (412) 872-9157
Bruce W. Deist - Consulting Services - (301) 972-1973

Operations Support Section

Thomas O. McKernon - Discipline Lead - Region IV/DRS - (817) 860-8153
Donald C. Kosloff - Region III/Davis-Besse - (419) 898-2765
Donald A. Beckman - Prisuta-Beckman Associates, Inc. - (412) 872-915a7
Gary G. Rhoads - Prisuta-Beckman Associates, Inc. - (412) 872-9157
Paul E. Harmon - Region II/Sequoyah-RI - (615) 842-8001

D. Team Assignments

The inspection report is required to be issued within 45 days of the end of the inspection. To simplify the development of the report, I have assigned the following topics for development and documentation. These assignments have been made based on my understanding of each inspector's experience and background and I have attempted to evenly distribute the workload. If any additional topics are identified (either before or during the inspection) I will make the required changes. These assignments are not final and any questions or suggestions should be identified as soon as possible.

An inspection report outline will be provided during the inspection which will be similar to the topics identified in Appendix A.

Operations

Ball - Shift Professionalism
Procedure Adherance

Harmon - Post Trip Review Process
Shift Communications
Shift Routine/Turnovers

Operations Support

McKernon - Facility Management
Outstanding Construction Deficiencies

Kosloff - Power Ascention Program
Surveillance and Testing
MTE Control

Bess -	Operability Determinations Response to Annunciators Off-normal Conditions	Beckman -	Maintenance Housekeeping Room and Area Turnovers Station Vital Drawings
Veeder -	Equipment Out-of-Service System Status Control & Logs LCO Tracking	Rhoads -	Engineering & Tech. Support 50.59 Safety Reviews Technical Specifications
Lewis -	Operating Procedures Abnormal Procedures Event Reporting	Johnson -	Self-Assessment Program System Valve Lineups Lessons Learned Programs
Deist -	Organization & Staffing Staff Stability and Experience Operator Training		

Attachments 2 and 3 contain background information on the facility provided by NRR's Special Project's Division and current organization chart. In addition, I have included a copy of the Shoreham ORAT Inspection Report (50-322/89-80) which will be the model for our inspection report. Also included are copies of the inspection report for the Augmented Inspection Team (50-445/89-30; 50-446/89-30) and resultant Information Notice 89-62 conducted following recent problems with Borg-Warner check valves at Comanche Peak. This inspection identified several weaknesses with the operation of the facility. These concerns were communicated to the applicant and are included as Attachment 4. And finally, I have included copies of recent inspections (50-445/89-58; 50-446/89-58 and 50-445/89-43; 50-446/89-43) concerning the implementation of the emergency plan which identified several problems concerning the knowlege level of the operators. I will be forwarding system descriptions and selected plant procedures after I complete the pre-inspection visit during the first week of October. In the meantime, please familiarize yourself with information provided and communicate any suggestions for organizing our task directly to me.

IV. Inspection Schedule

A. Inspection Preparation

Sept. 25	Receive ORAT inspection planner.
Oct. 2	Provide comments to team leader by COB.
Oct. 10	Receive pre-inspection review material.

B. Inspection

Oct. 15	Arrival at motel.
Oct. 16 (8:00 am)	Arrive onsite at Comanche Peak - Badging, entrance and site orientation.
Oct. 17-25	Perform system walkdowns, monitor control room activities, review procedures, and conduct interviews.

Oct. 26 (1:00 pm)	Conduct NRC management briefing and practice applicant exit.
Oct. 27 (8:00 am)	Conduct exit.

C. Inspection Report Preparation

Oct. 30 (8:00 am)	Arrive at NRC White Flint Offices.
Oct. 30 - Nov. 3	Entire team complete and approve draft inspection report.
Nov. 6	Submit draft inspection report to technical editors.
Nov. 14	Submit draft inspection report to Section Chief.
Nov. 21	Submit draft inspection report to Branch Chief.
Nov. 29	Submit draft inspection report to Division Director.
Dec. 6	Submit approved inspection report to Projects Division.
Dec. 11	Issue inspection report 45 days from inspection exit meeting.

V. Travel Itinerary

Reservations for fourteen single rooms at the government rate have been made in my name at the Plantation Inn in Granbury, Texas, for October 15 - November 3. Directions to the CPSES are included as Attachment 5. Please call (817) 573-8846 by September 4 to individually confirm and guarantee your reservation. I plan to arrive at the motel on October 10 at approximately 6:00 pm. The entire team will meet on October 16 at 7:00 am in the hotel lobby. I anticipate departing the site on October 27 at approximately noon, therefore your departure reservations should be made accordingly.

We will begin work on the inspection report on the Monday (October 30) following the conclusion of the inspection. The entire team will participate in this effort. Please plan on beginning work at the NRC White Flint offices at 8:00 am on October 30. The draft inspection report will be completed by COB November 3 and the inspection report will be issued within 45 days of the conclusion of the inspection.

Reservations for ten single rooms at the government rate have been made for October 29 - November 10 under a group reservation (i.e., NRC Group-VanDenburgh) at the Guest Quarters Inn located at 7335 Wisconsin Avenue, Bethesda, MD, 20814. The motel is within one block of the Bethesda station of the Metro Red Line. Please call 424-2900 or (301) 961-6400 by October 16 to individually confirm and guarantee your reservation. Please inform me of your travel itinerary for both trips, including rental cars plans, before COB October 10.

VI. Inspection Routine

Normal working hours will be 8:00 AM to 5:00 PM while onsite, including the first Saturday (October 4). All NRC employees should arrange to suspend their compressed and flexible time work schedules for the duration of the inspection. Overtime will be approved on a case basis by the team leader.

Team meetings will be held daily at 8:00 am. All team member's observations will be provided on Appendix B in sufficient detail to support their observations and conclusions. The team leader will meet with the applicant daily following the team meeting. The status of outstanding concerns and significant observations developed from the previous day's Appendix B forms will be discussed.

The inspection will be effectively over by noon on October 26. All further team efforts will be devoted to preparing for the NRC management briefing and the exit meeting with the licensee. The inspection report number is 50-445/89200. NRC personnel should charge their time to the following:

Docket Number	50-445
Inspection Report Number	89200
Inspection Procedure (IP)	93806
Inspection Procedure Elememt (IPE)	0A
Item of Major Interest (IMI)	10H1

Please contact me at (301) 492-0965 upon receipt of your review materials and for confirmation of assignments.

Chris A. VanDenburgh, Team Leader
Special Inspection Branch
Division of Reactor Inspection
and Safeguards
Office of Nuclear Reactor Regulation

Attachments:
(1) Draft Inspection Procedure IP 93806
(2) Comanche Peak Background Information
(3) Comanche Peak Organizational Chart
(4) NRC Concerns Regarding Operations Response to Check Valve Failures
(5) Maps to CPSES

APPENDIX A

OPERATIONAL READINESS ASSESSMENT EVALUATION CRITERIA

Plant Operations

Operations organization and staffing
Staff stability and morale
Operations experience and training (including remote shutdown training)
Operating shift professionalism
Methods for operability determination
Post-trip review process
Lessons learned (root cause) programs
Performance of safety evaluations
Event reporting
Response to annunciators and off-normal conditions
Nuisance alarm and indication controls
Shift routine and turnover
Equipment out-of-service controls
System status control and logs
Operating and emergency operating procedures
Procedure adherence
Verification of system line-ups (including use of local valve position indications)
Housekeeping and material control
Communications with other departments

Surveillance and Testing

Organization and staffing
Qualifications and training
Interface between operations and startup testing organizations
Completion of prestart (preoperational) testing
Observations of surveillance performance
Technical Specification technical adequacy
Technical Specification surveillance LCO tracking and control
Performance of 10 CFR 50.59 safety reviews
Calibration of installed and portable measuring and test equipment
Surveillance procedure review
Surveillance training of operators
Management and quality assurance overview

Facility Management Organization

Organization and staffing
Qualifications and training
Management oversight activities and goals
Applicant's operational readiness assessments (internal and external)
Onsite safety review committee
Lessons learned from previous new plant operating experience
Root cause and corrective action programs

Power Ascension Test Program (PATP)

PATP organization and staffing
Qualifications and training
Approval for plateau changes
Quality assurance controls for PATP
Staffing prerequisites for testing
Program change controls
Test status and scheduling

Maintenance

Maintenance organization and staffing
Qualifications and training
Construction deficiency "punch-list" items
Maintenance work observation
Material condition and labeling of systems and components
Predictive maintenance programs
Post-maintenance testing
Work planning and prioritization
Parts and material control

Engineering and Technical Support

Engineering organization and staffing
Qualifications and training
System engineering
Vendor manual control
Review of generic communications
Modification controls
Configuration controls
Temporary modifications

APPENDIX B

Subject :

Observation No. :

Revision :

References :

Discussion :

Significance:

Required Actions :

ATTACHMENT NO. 1

INSPECTION PROCEDURE 93806

OPERATIONAL READINESS ASSESSMENT TEAM INSPECTIONS

PROGRAM APPLICABILITY: 2514

93806-01 INSPECTION OBJECTIVE

The objective of this procedure is to provide guidance on conducting Operational Readiness Assessment Team (ORAT) inspections for new plants. Results from these inspections will provide a major input and basis for a NRC determination of startup readiness.

93806-02 INSPECTION REQUIREMENTS

02.01 Inspection Planning. Conduct of Operational Readiness Assessments is required before issuance of the low-power license, before issuance of the full-power license, or during power escalation. The inspection schedule and scope are to be tailored to the individual plant circumstances. The inspection should concentrate on perceived weaknesses and areas important to plant operations which have not yet been sufficiently reviewed. Attachment 1 provides an outline of the areas that may be covered during assessment of the readiness for power operation.

02.02 Plant Inspection. The following specific items, in addition to those listed in Attachment 1, should be considered during ORAT inspections:

a. Focus the inspection on safety-significant activities such as fuel loading, reactor startup, heatup/cooldown, and surveillances. Direct observations of activities are preferred and should be supplemented by personnel interviews and document reviews. Systems should be selected for walkdown and inspection on the basis of their potential to cause challenges to safety systems. (The results of similar unit design or generic probabilistic risk assessment studies should be used, if available.)

b. Evaluate licensee management transitional controls. Construction deficiency "punch" list items transferred to the operations organization for completion are either subject to contractor disposition or are converted to maintenance work order items. These items constitute incomplete construction phase work for which management controls are required to ensure readiness for operation.

Evaluate management oversight of and involvement in daily work and preparation activities. Review licensee performance in conducting preventive maintenance activities and controls over deferred preventive maintenance.

c. Review the licensee's program for operating experience feedback and verify implementation. Assess whether controls exist that continually implement lessons learned and that research the safety significance of problems that have developed during the startup of similarly designed plants. Select and review, in detail, several operational problems experienced by the licensee during the preoperational or startup test phase and assess whether the problem was fully reviewed and understood prior to further testing. Determine if the licensee has reviewed NUREG-1275 and applied lessons learned. Evaluate whether procedural problems related to operations are being effectively identified and expeditiously corrected.

d. Examine the licensee's self-assessment capability as it relates to readiness for operation, including the root cause analysis process, the corrective action program, and the trending and generic applicability review of self-identified problems. Determine the adequacy of the deficiency reporting system, including thresholds, and evaluate the effectiveness of prioritization of the identified problems. Review the root cause analysis training program. Assess the involvement of QA and engineering in problem resolution.

e. Determine whether operator training, including simulator usage, includes beginning-of-life core characteristics and system response. Through operator interviews, control room observations, and the review of alarm response procedures, determine whether shift personnel are prepared to respond to abnormal plant conditions, instrumentation and control setpoint and display anomalies, and the potential for a high number of challenges to safety systems during testing.

f. Evaluate whether there is any change in the Quality Assurance (QA) program effectiveness due to the differences in the QA organizational interactions with other station departments under operational controls versus what existed when under construction controls. Verify whether program requirements exist for quality assurance/quality control (QA/QC) personnel to be present during back shifts, and assess adequacy.

g. Determine whether the licensee has implemented an effective Technical Specification Appraisal process. Verify that plant procedures accurately reflect the applicable Technical Specification sections. Verify the adequacy of administrative controls to complement startup testing activities under Technical Specification constraints, as opposed to the latitude for "troubleshooting" problems that exist under preoperational testing controls.

h. Determine whether the licensee has implemented an effective program to review and focus attention on balance-of-plant (BOP) operations to reduce the frequency and severity of plant transients.

i. Evaluate the adequacy of licensee plans to resolve material and personnel access and work control problems once the radiologically controlled areas (RCAs) and protected/vital areas are established.

j. Evaluate the status of control room annunciators, alarms, and recorders. Verify the adequacy of the licensee's methodology for compensatory measures for those indications not operating properly.

k. Evaluate the licensee's program to review and evaluate the impact of the maintenance work request backlog on operational readiness, including the collective impact on safety system availability and operability. Determine if safety-related work is being accomplished by means other than the written administrative controls (e.g., "shop tickets").

l. Review the qualifications and commercial operating experience of key managers and operators and whether organizational responsibilities and interfaces exist to support an operating unit. Determine whether the licensee has staffed the organization to levels which are capable of successfully operating and supporting the unit.

m. Review the startup testing schedule and status of completion to ensure that the startup testing committed to in the final safety analysis report (FSAR) is, or will be, actually performed. If tests are deleted or modified, ensure that an adequate 10 CFR 50.59 review was performed and forwarded to NRC for review.

n. Review the method for keeping track of entry into and exit from Technical Specification action statements. Ensure that the operators are aware of all action statements in effect and their cumulative implications.

Twenty-four-hour inspection coverage of shift operations is necessary at various times during the startup sequence. Such coverage is routinely provided during initial criticality and other periods of startup testing by regional/resident personnel in the conduct of the NRC Inspection Manual Chapter 2514 inspection program. Judgment must be exercised in balancing such benefits against the requirement for additional inspection resources to conduct around-the-clock shift coverage.

02.03 Management Meetings. Frequent NRC management meetings with licensees are recommended before and after the ORAT inspection to maximize the effectiveness of the Operational Readiness Review process. Throughout the first few months of initial commercial operation, the NRC should review with the plant management and staff the root causes of all reportable events and planned licensee corrective actions at such periodic meetings. The ORAT exit meeting should emphasize the continuing nature of the NRC readiness review process.

93806-03 INSPECTION GUIDANCE

03.01 General Guidance. Previous NRC evaluations and Office for Analysis and Evaluation of Operational Data (AEOD) studies have shown that effective management of the transition from construction to operations and of the feedback of operating experience from other plants (and similar plants) can significantly enhance early performance. This inspection procedure provides general guidance on the scope, content, problem areas, and verifications relevent to the conduct of ORAT inspections.

ORAT inspections will emphasize the effectiveness of management oversight, corrective action programs, root cause analysis, and the readiness to support operations. The following major points should be assessed: the establishment of a basic framework of management programs to support the operation of the unit; the establishment and implementation of a program to gather and apply lessons learned from industry experience; the ability of the management team to establish a proper working atmosphere in which to operate the unit; the involvement of both site and corporate engineering in the operation of the unit; and the depth of QA involvement in plant operations and problems. For new plants it is essential that the licensee identify lessons learned from previous new plant operating experience and communicate these lessons to the senior management of the new plant. New plants that have come on line have shown significant improvement after establishing effective root cause analysis and corrective action programs. Effective station goals and actions that result from self-assessment demonstrate the readiness of the plant for safe operation and the readiness of its personnel for the conduct of the plant's safe operation.

However, one common element supports all Operational Readiness Reviews, including ORAT verification activities, and that is the fundamental need for the establishment of an appropriate operating attitude well before initial criticality. Programs that control construction completion should be phased out or merged with operational control programs in order to minimize the confusion associated with duplicate systems of controlling work. The same is also true for procedural use and personnel work assignments. Operational controls should be implemented as early as possible to allow for personnel acclimation and training.

It is also important that such operational controls, particularly in the areas of maintenance and modifications, be consistent with both the original bases of the plant design and the good work practices used during plant construction.

The planning for this inspection is an important element. Selection of the inspection team is a very important function during the planning phase. Operating experience of team members should be a primary consideration for selection, especially for the control room observations. The use of resident inspectors from similar sites and experienced regional/Nuclear Reactor Regulation inspectors should be emphasized. The inclusion of a licensing examiner may also be beneficial in evaluating operational readiness. Consideration should also be given to including a team member with expertise in management and organizational theory and/or human factors engineering, if applicable to the inspection scope. The size of the team will vary depending on the scope and duration of the inspection.

03.02 <u>Specific Guidance</u>

a. <u>Inspection Requirement 02.01</u>. The scheduling of the ORAT inspection shall be based upon the previous licensee experience and operating history as may be applied to the specific plant. An inspection of the first nuclear unit for a utility may require more lead time before the projected fuel load date than is needed for inspections of subsequent nuclear units. The timing of the inspection must be well coordinated with other NRC and third party inspection activities, such as:

(1) Inspection Procedure 94300 status report requirements.

(2) Issuance of the proof and review copy of the Technical Specifications.

(3) Regional Office conduct of a team inspection for a Technical Specification Review in accordance with Inspection Procedure 71301.

(4) Conduct of the INPO Preoperational Assistance visit at the site.

(5) Conduct of utility self-assessment activities and availability of the resulting report(s).

Prior licensing and plant restart experience indicates that ORAT inspections can be optimally conducted about 3 months before issuance of the initial license. In the case of full-power operation for a new plant, another evaluation should be conducted 3 to 6 months after receipt of the full-power license to observe actual operational activities.

The areas of review should also be based on the previous experience of the licensee. For example, the inspection plan for the third unit in a three-unit station will differ considerably from the inspection plan for the station's first unit.

b. Inspection Requirement 02.02. For newly licensed plants, the status of the operational preparedness phase of the Preoperational Testing Program (NRC Inspection Manual Chapter 2513, Appendix B) should be reviewed to determine which inspections are incomplete and whether problems have been identified in the areas previously inspected. The NRC Inspection Manual Chapter 2513 Program Inspection Procedures that are incomplete or that resulted in identification of problems can be utilized to develop areas for review during the operational readiness team inspection. Current procedures exist in the following inspection areas, as listed in the NRC Inspection Manual Chapter 2513, Appendix B:

(1) Operations

(2) Maintenance

(3) Fuel Receipt and Storage

(4) Fire Protection

(5) Surveillance

(6) Plant Water Chemistry Controls

(7) Radiological Controls

(8) Security and Safeguards

(9) Quality Assurance

The operations phase inspection program (NRC Inspection Manual Chapter 2515) also contains inspection procedures that can be used to develop areas for further review of operational readiness. The following represent current, applicable procedures listed under the respective inspection functional areas that they support:

(1) Plant Operations

42700	Plant Procedures
64704	Fire Protection/Prevention Program
71707	Operational Safety Verification
71710	ESF System Walkdown

(2) Maintenance/Surveillance

61700	Surveillance Procedures and Records
61726	Monthly Surveillance Observation
61725	Surveillance Testing and Calibration Control Program
62700	Maintenance Program Implementation
62702	Maintenance Program
62703	Monthly Maintenance Observations
62704	Instrument Maintenance
62705	Electrical Maintenance

(3) Engineering and Technical Support

37700	Design, Design Changes, and Modifications
37701	Facility Modifications
72701	Modification Testing

(4) Safety Assessment/Quality Verification

35701	QA Program - Annual Review
40500	Evaluation of Licensee Self-Assessment Capability
92720	Corrective Action

(5) Security

81XXX	Physical Security (81000 series procedures)
81018	Security Plan and Implementing Procedures
81020	Management Effectiveness - Security Programs
8107X	Access Control (81070 series procedures)
81088	Communications

(6) Emergency Preparedness

82701	Operational Status of the Emergency Preparedness Program

(7) Radiation Controls

83750 Occupational Exposure, Shipping, and Transportation
84750 Radioactive Waste Systems; Water Chemistry; Confirmatory Measurements and Radiological Environmental Monitoring

c. Inspection Requirement 02.03. The scope of the ORAT inspection must be flexible enough to accommodate both the unique plant design and the plant inspection history, including systematic assessment of licensee performance (SALP). Thus, departures from standard nuclear steam supply system (NSSS) designs and first-of-a-kind plant features may provide areas for specific review at a new plant. Both the NRC Open Items List and the licensee's internal "punch" lists should be reviewed for planning input and to identify areas in which work may not be completed before criticality is achieved. Also, the results of past NRC team inspections at the plant should be considered not only to understand past problem areas, but also to review the effectiveness of licensee corrective action programs. The licensee's responsiveness to previously identified problems and issues provides one indicator of the licensee's progress toward developing a proper operating attitude and ensuring a high degree of readiness for conducting criticality and power operations.

Just as the scope of any Operational Readiness Review must be flexible, so must the ORAT inspection be adaptable to changes in direction and emphasis. Frequent team meetings are essential not only to identify any generic problems or concerns that may exist in the different inspection areas, but also to redirect inspection resources away from areas in which no problems are evident. Identification of acceptable areas should be made to allow the inspectors the latitude and time to thoroughly investigate the causes of identified problems. The ORAT inspection should be flexibly structured to adapt to the necessary changes in direction and scope that occur through the use of performance-based inspection techniques.

93806-04 RESOURCE ESTIMATE

This inspection is estimated to require 560 direct inspection hours of regional and headquarters resources. Actual inspections at a specific plant may require substantially more or fewer resources, depending on the inspection scope.

93806-05 REFERENCES

NUREG-1275, "Operating Experience Feedback Report - New Plants," July 1987

NUREG/CR-5151, "Performance-Based Inspections," June 1988

NRC Inspection Manual Chapters 2513 and 2515

Memorandum, J. Sniezek to Regional Administrators, dated April 23, 1987 (NUDOCS 68863/046).

END

Attachment 1

OPERATIONAL READINESS REVIEWS

I. Plant Operations

A. System Status Control and Logs
B. Organization and Staffing
C. Shift Routine and Turnover
D. Training
E. Response to annunciators and Off-normal Conditions
F. Housekeeping and Material Condition
G. Control Room Decorum
H. Reportability Requirements and Implementation
I. Communications with Interfacing Departments
J. Fitness for Duty Program
K. Overtime Controls
L. Procedure Adequacy/Adherence

II. Maintenance/Surveillance

A. Maintenance Management and Organization
B. Observation of Work Activities
C. Temporary Modifications
D. Preventive Maintenance Program
E. Failure Trending and Predictive Maintenance
F. Post-Maintenance Testing
G. Work Planning and Prioritization Processes
H. Training
I. Communications with Interfacing Departments
J. Rework Identification and Control
K. Implementation of TS Surveillance Requirements
L. Observation of Surveillance Activities
M. Procedure Adequacy/Adherence

III. Engineering and Technical Support

A. Modification Controls
B. Support to Operations and Maintenance
C. Configuration Controls
D. Interface with ALARA Program
E. Licensing Activities and Technical Specifications Management

IV. Safety Assessment/Quality Verification

A. Management Oversight Activities and Goals
B. Self-Assessment Capabilities (PORC, SORC, ISEG)
C. Quality Assurance/Quality Control Involvement
D. Corrective Action Programs
E. Post-Trip Review Process
F. Operating Experience Feedback
G. Independent Verification Policies
H. Licensee Readiness Assessment

V. Radiation Protection

A. Health Physics Organization and Staffing
B. Radiological Controls
C. Effluent/Waste Controls
D. ALARA
E. Materials and Contamination Control
F. Surveys and Monitoring
G. Respiratory Protection
F. Training

VI. Security

A. Organization and Staffing
B. Security Plan Implementation
C. Access Controls
D. Alarm Response
E. Communications
F. Training

VII. Emergency Preparedness

A. Emergency Plan and Implementing Procedures
B. Emergency Facilities, Equipment, Instrumentation, and Supplies
C. Organization and Management Control
D. Training
E. Independent Reviews/Audit

ATTACHMENT NO. 2

Attachment 2

BACKGROUND INFORMATION ON
COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)

Utility: Texas Utilities Electric Company (97.8% Ownership)
(TU Electric/Applicant or Applicants)
Location: 40 miles SW of Ft. Worth, Texas
Somervell County, Texas

	Unit 1	Unit 2
Docket No.:	50-445	50-446
CP Issued:	12/19/74	12/19/74
Low Power License:	Est. 10/89	Not Scheduled
Full Power License:	Est. 12/89	-
Initial Criticality:	Est. 11/89	-
Elec. Energ. 1st Gener:	-	-
Commercial Operation:	-	-
Reactor Type:	PWR	Same
Containment Type:	Steel-lined, reinforced concrete	Same
Power Level:	3411 MWT; 1159 MWE	Same
Architect/Engineer:	Original - Gibbs & Hill Current - Reverification and redesign effort by Stone and Webster, Ebasco, and Impell	Same
NSSS Vendor:	Westinghouse	Same
Constructor:	Brown & Root	Same
Turbine Supplier:	Allis-Chalmers	Same
Condenser Cooling Method:	Circulating Water System	Same
Condenser Cooling Water:	Squaw Creek Reservoir	Same

Licensing Project Manager: (see Projects group below)

NRC Responsible Office:

Associate Director for Special Projects, HQ
Dennis M. Crutchfield, Associate Director
(492-0722)

Comanche Peak Project Division, OSP
Christopher Grimes, Director
(492-3299)

~~Phillip McKee, Deputy Director~~
~~(492-3301)~~

CPPD Projects:

Assistant Director for Projects
James Wilson, Assistant Director
(492-3306)

Melinda Malloy, LPM
(492-0738)
Mel Fields, LPM
(492-0765)

Attachment 2

CPPD Technical Review: <u>Assistant Director for Technical Programs</u>
James Lyons, Assistant Director
(492-3305)

CPPD Inspections: <u>Assistant Director for Inspection Programs</u>
Robert Warnick, Assistant Director
(817) 897-1500 CP Site

Section Chiefs: Herbert Livermore (817) 897-1500
Joel Wiebe (817) 897-1500

Senior Resident Inspectors: ~~Shannon Phillips (Construction) (817) 897-1500~~
~~Stephen Burris~~ (Operations) (817) 897-1500
Bill Johnson

Resident Inspectors: Michael Runyan (C/S) (817) 897-1500
Steven Bitter (Ops) (817) 897-1500
~~Clifton Hale (QA) (817) 897-1500~~
Robert Latta (Elec) (817) 897-1500

<u>Region IV, Arlington TX</u>: Responsible for Operator Licensing Activities, Emergency Planning Activities, and Radiation Safety and Safeguards Inspections

Robert Martin, Regional Administrator
(8-728-8225)

John Montgomery, Deputy Regional Administrator
(8-728-8226)

Leonard J. Callan
~~James Milhoan~~, Director
Division of Reactor Safety
(8-728-8183)

A. Bill Beach, Director
Division of Radiation Safety and Safeguards
(8-728-8248)

William Fisher, Chief
Nuclear Materials Safety Branch
(8-728-8215)

Blaine Murray, Chief
Reactor Programs Branch
(8-728-8126)

Donald Driskill, Director
Office of Investigations Field Office
(8-728-8110)

TU Electric Corporate Management Personnel (Dallas, Texas)

Jerry S. Farrington, Chairman of The Board and Chief Executive, Texas Utilities Co.

Erle A. Nye, President, Texas Utilities Co. and Chairman and Chief Executive, Texas Utilities Electric Company

William G. Counsil, Vice Chairman TU Electric

Michael D. Spence, President TU Electric Generating Division

TU Electric Corporate Management Personnel (Site)

William J. Cahill, Executive Vice President, Nuclear

H. D. (Buz) Bruner, Senior Vice President Nuclear Engineering and Operations

R. A. Werner, Manager Safeteam

TU Electric Management Personnel - Operations (Site)

A. B. Scott, Jr., Vice President Nuclear Operations

J. J. Kelley, Jr., Plant Manager

J. V. Donahue, Operations

B. W. Wieland, Maintenance

G. J. Laughlin, Instrumentation and Controls

M. R. Blevins, Plant Support

M. J. Riggs, Plant Evaluation

J. S. McMahon, Training

T. L. Gosdin, Administrative Services

B. T. Lancaster, Plant Services

R. Daly, Startup

D. L. Davis, Results Engineering

S. L. Ellis, Test

D. W. Stonestreet, Outage Planning

Management Personnel - CPSES Nuclear Engineering/Engineering Construction (Dallas & site)

L. D. Nace, Vice President

J. W. Beck, Vice President,
Nuclear Engineering

J. B. George, Vice President,
Support

R. D. Walker, Manager
Nuclear Licensing

J. F. Streeter, Director
Quality Assurance

A. Husain, Director
Reactor Engineering

O. W. Lowe, Director
Engineering

T. G. Tyler, Director
Projects

D. M. Reynerson, Director
Construction

W. R. Deatherage, Director
Engineering Administration

J. W. Muffett, Manager of Engineering (CECO)

J. E. Krechting, Director
Technical Interface

Workforce As of April 8, 1989:

Organization	Onsite	Total
Eng. & Eng. Admin.	2351	2508
Construction	3694	3694
Projects	604	619
Operations	1686	1700
Nuclear Engineering	739	841
Support Services	275	277
NEO Administration	26	45
TOTAL	9375	9684

Reactor Operators

SROs	Operating	19	ROs	Operating	24
	Staff	24		Staff	1
	Total	43		Total	25

15 SROs and 10 ROs are required to operate Unit 1

Work Shifts

6 Shift Manning Cycle
- 3 shifts working
- 1 shift in training
- 2 shifts extra and off

As reflected in current proposed Technical Specifications each shift will be comprised of the following staff:

For one unit operation:

Shift Supervisor (SRO)
- 1 Assistant Shift Supervisor (SRO)
- 2 Reactor Operators
- 5 Auxiliary Operators
- Shift Technical Advisor (SRO/STA)

For two unit operation:

Shift Supervisor (SRO)
- 2 Assistant Shift Supervisors (SRO)
- 4 Reactor Operators
- 10 Auxiliary Operators
- Shift Technical Advisor (SRO/STA)

Reactor Operator Exams Administered by the Region

Date of Exam	Number of Applicants		Passed	Failed
12/21/88*	SRO	1	1	0
	RO	0	0	0
06/06/88	SRO	7	5	2
	RO	6	3	3
12/15/87	SRO	0	0	0
	RO	5	3	2
07/13/87	SRO	8	7	1
	RO	4	4	0
09/23/86	SRO	5	3	2
	RO	7	6	1
04/01/85	SRO	2	2	0
	RO	5	4	1
09/11/84	SRO	5	4	1
	RO	17	8	9
04/03/84	SRO	12	7	5
	RO	13	8	5
07/18/83	SRO	29	23	6
	RO	10	3	7
Totals		136	91	45

Requalification Exams Administered by the Region

Date of Exam	Number of Applicants		Passed	Failed
09/23/86	SRO	14	10	4
	RO	7	3	4
04/01/85	SRO	7	4	3
	RO	3	2	1
Totals		31	19	12

Next Examination Scheduled for: July 3-7, 1989 Requalification Exams

Number of Applicants: SRO 8
RO 4

Total 12

* This was a retake exam including the "Administrative Topics" and "Control Room Systems/Facility Walkthrough" sections of the operating exam.

Allegations (continued)

The staff has received 45 allegations since the formation of OSP. As of May 15, 1989, 10 allegations remain open. All of the allegations have been reviewed by the CPPD Allegation Review Committee to establish the necessary follow-up action required for closeout. All totaled, approximately 130 allegers have reported concerns about Comanche Peak.

Emergency Preparedness

The staff documented its review of Revision 8 (FSAR Amendment 48) to the Emergency Plan in SSER 6 (11/84). On the basis of a review of the Applicant's Emergency Plan against the (1) Planning Standards of 10 CFR 50.47(b), (2) requirements of Appendix E to 10 CFR 50, and (3) guidance criteria in NUREG-0654, Revision 1 (11/80), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (Regulatory Guide 1.101, Revision 2), the staff concluded that the Emergency Plan for CPSES Units 1 and 2 provides an adequate planning basis for an acceptable state of emergency preparedness and meets the requirements of Appendix E to 10 CFR 50. The Applicant provided Revision 9 to the Emergency Plan in FSAR Amendment 58 (6/86) and with Revision 10 (8/88), the Plan was separated from the FSAR and will be maintained as an independent report. The staff's review of the changes to the Plan was completed in February 1989 and affirmed the staff's prior conclusions on the plan's acceptability.

In addition to the Emergency Plan review, the staff completed an appraisal (September 6 through October 7, 1983) of the Applicant's implemented emergency preparedness program (Inspection Reports 50-445/83-33 and 50-446/83-17 dated February 8, 1984). Also, the Applicant's performance was observed during a full-participation exercise (December 12-15, 1983) with participation by the applicant, the State of Texas, and Hood and Somervell Counties (Inspection Reports 50-445/83-46 and 50-446/83-21 dated January 23, 1984).

By memorandum dated November 29, 1984, FEMA provided findings based on the review of the original and revised offsite Emergency Plans and the results of the December 14, 1983, full-participation exercise. FEMA determined that:

> offsite radiological emergency plans and preparedness for the Comanche Peak Steam Electric Station have been determined to be adequate. Consequently, there is reasonable assurance that appropriate measures can be taken offsite to protect the health and safety of the public living in the vicinity of the Comanche Peak Steam Electric Station.

Plant Simulator

The simulator was operational in 1985 and is Comanche Peak Plant specific. It is located in the Nuclear Operations Support Facility on-site and the vendor is Singer-Link.

Systematic Assessment of Licensee Performance (SALP)

The SALP process was suspended in February 1985, because of the TRT and Region IV special attention. The SALP process was resumed by the NRC for the period September 1, 1987 through August 31, 1988. The final SALP report (see Attachment 3), Inspection Report 50-445/87-40 and 50-446/87-31, was issued on December 9, 1988.

Overall, the recent SALP concluded that, while there have been some deficiencies in the complete implementation of Comanche Peak programs, TU Electric has established a solid foundation for excellent performance.

Escalated Enforcement Actions

On February 28, 1989, the staff cited TU Electric with a Level III Violation (EA-88-278) for failure to submit a timely application for extension of the Unit 1 construction permit. No civil penalty was imposed in consideration of the applicant's extensive corrective action programs, the age of the violation, and overall safety significance of the violation.

Investigation/Allegations Status

OI Investigations

OI has issued 14 investigation reports, 29 inquiries and 5 assists to Region IV. Areas include welding, QC, electrical, inspections, intimidation, procedures, management, NCRs, coatings, pipe hangers, firings, falsification of records, and construction practices. OSP/CPPD has referred 5 requests for investigation to OI. OI currently has 1 open investigation.

Allegations

Slightly over 1,000 allegations have been received by the staff on Comanche Peak. The evaluations of the majority of them (approximately 600) were documented by the NRC's Technical Review Team in SSERs 7-11 in the following areas: electrical/testing, civil, protective coatings, mechanical, and QA/QC. Approximately 200 allegations (received after the SSERs mentioned above were issued, but before September 15, 1985) in the areas of electrical, civil, mechanical, and QA/QC have been evaluated and documented. The QA/QC allegations were closed out in inspection reports, and the electrical, civil, and mechanical allegations are addressed in SSERs 14-20. From September 15, 1985 until the formation of the Office of Special Projects (OSP) in February 1987, Region IV processed construction and QA/QC-related allegations; 14 allegations were received during this time period. All of the allegations received prior to the formation of OSP have been closed.

The staff has reviewed the FEMA findings and determined that they support the staff's recommendation that there is an adequate state of onsite and offsite emergency planning and preparedness for full-power licensing for the Comanche Peak Steam Electric Station.

In a subsequent letter dated July 15, 1985, FEMA transmitted its findings and determination in accordance with the FEMA rule (44 CFR 350). FEMA determined that:

> the Texas State and local plans and preparedness for the Comanche Peak Steam Electric Station are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken offsite in the event of a radiological emergency. The adequacy of the public alert and notification system has also been verified by FEMA in accordance with the criteria in FEMA rule 44 CFR 350; Appendix 3 of NUREG-0654/FEMA-REP-1, Rev. 1; and the "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants" (FEMA-43).

Further, consistent with the Commission's Statement of Policy regarding arrangements for offsite emergency medical services, the Applicant, by letter dated February 20, 1986, confirmed that the Emergency Plans of the involved offsite response jurisdictions contain a list of medical service facilities. The existence of such a list in the pertinent plans has also been confirmed by FEMA. Further, the Applicant has committed to fully comply with the Commission's final response to the Court's remand.

The last full-participation exercise was conducted in November 1984. A full-participation emergency exercise is scheduled for July 25-26, 1989. In a letter to FEMA dated March 24, 1989, NRC requested FEMA to (1) provide its evaluation of the upcoming 1989 full-participation exercise, (2) confirm that any revisions to the State and local plans since 1984 have not degraded the effectiveness of those plans, and (3) confirm that the emergency plans of the involved emergency response jurisdictions meet current regulatory requirements and guidance.

Emergency Response Facilities

The Applicant's Emergency Plan and Emergency Response Facilities (ERFs) provide for a Technical Support Center (TSC) which is separate from the Control Room but located adjacent to and above it. The TSC has the capability to display and transmit data and data summaries describing plant status to the Control Room and the Emergency Operations Facility (EOF). There is space in the TSC for management and technical personnel to perform their functions. The radiological habitability of the TSC is the same as the Control Room and communications are provided between the Control Room, the Operational Support Center (OSC), the EOF, the NRC, and other offsite agencies. The use of semi-portable continuous monitoring instrumentation is available to determine dose rate and radioactivity levels in the TSC.

The TSC appears to be capable of supporting reactor control functions, evaluating and diagnosing plant conditions, and serving as the main communications link between the Control Room, the OSC, the EOF, and the NRC. The TSC can carry out the EOF functions until the EOF is staffed.

Emergency Response Facilities (continued)

The Comanche Peak OSC is presently located in the Maintenance Building and provides a place where operations support personnel can assemble and report in an emergency as well as receive instructions from the operating staff. With Revision 10 to the Plan, the OSC is being relocated to the Radiation Control Access Office; the Maintenance Building will serve as an alternate OSC. The OSC has communications with the Control Room, the TSC, and the EOF.

The EOF is attached to the Nuclear Operations Support Center which is located within 1.2 miles from the Comanche Peak Steam Electric Station and has a Protection Factor of greater than 15. An alternate EOF is provided in Granbury (10 miles). There is space in the EOF for management and technical personnel to perform their functions. There are communications links between the EOF and the Control Room, the TSC, the OSC, the NRC, and other offsite agencies. The EOF appears to be capable of coordinating all the Applicant's onsite and offsite activities for reactor emergency situations.

In SSER 3 (3/83) and 6 (11/84), the staff concluded that the Applicant's emergency facilities and equipment are adequate to meet the requirements of 10 CFR 50.47 and Appendix E to 10 CFR 50 on an interim basis, subject to an onsite post-implementation review. This onsite post-implementation review will also be used to determine the adequacy of the final ERFs in accordance with the requirements and procedures given in Supplement 1 of NUREG-0737.

Significant Licensee Accomplishments

The development and implementation of the Corrective Action Program (CAP) for design and construction deficiencies typifies the aggressive and thorough approach that TU Electric management applies to safety issues. TU Electric's commitment to excellence is evident in their improvements to the security systems and emergency preparedness facilities. This commitment is regularly demonstrated by TU Electric managers, several of whom are former NRC employees, but not always by the working staff.

Plant Status

Schedule

In March 1989, the Applicant formally announced that the current schedule for Unit 1 fuel loading is "three months behind [our] ... mid-1989 schedule" which was announced in March 1988. Based on current construction activity schedules, TU Electric estimates that Unit 1 will be ready to load fuel in October 1989. Unit 2 construction was suspended in March 1988. TU Electric estimates that the Unit 2 fuel load date will be approximately two years after Unit 1 fuel load.

Plant Status (continued)

Hearing Status

Comanche Peak has been a heavily contested proceeding since 1981. On July 1, 1988 the Applicant, intervenor (Citizens Association for Sound Energy), and the NRC staff filed a Joint Motion for dismissal of the proceedings based on a Joint Stipulation describing the terms of a settlement agreement under which CASE President, Ms. Juanita Ellis, would become a member of the Operations Review Committee and TU Electric would compensate whistleblowers. The Joint Motion applied to the admitted contentions in both the OL and Unit 1 construction permit amendment (CPA) proceedings. At a special prehearing conference on July 13, 1988, the ASLB issued a Memorandum and Order dismissing the proceedings.

On August 11, 1988, the Citizens for Fair Utility Regulation (CFUR) filed, with the ASLB, a Request for Hearing and Petition for Leave to Intervene in both the OL and CPA proceedings in place of CASE. That petition was denied by the Commission in CLI-88-12. Mr. Joseph Macktal filed a motion on December 30, 1988 requesting the Commission to reconsider CLI-88-12, and CFUR petitioned the U. S. Court of Appeals for the Fifth Circuit in New Orleans on February 15, 1989 to review the decision. On January 19, 1989 Mr. Macktal filed a motion before the U. S. Court of Appeals for the D. C. Circuit to overturn CLI-88-12, which the Commission has moved that the Court dismiss. His December 30, 1988 motion was denied by the Commission on April 20, 1989 (CLI-89-06).

AEOD Analysis of Operational Data

N/A

NRR Operating Reactor Assessment

N/A

Public Issues

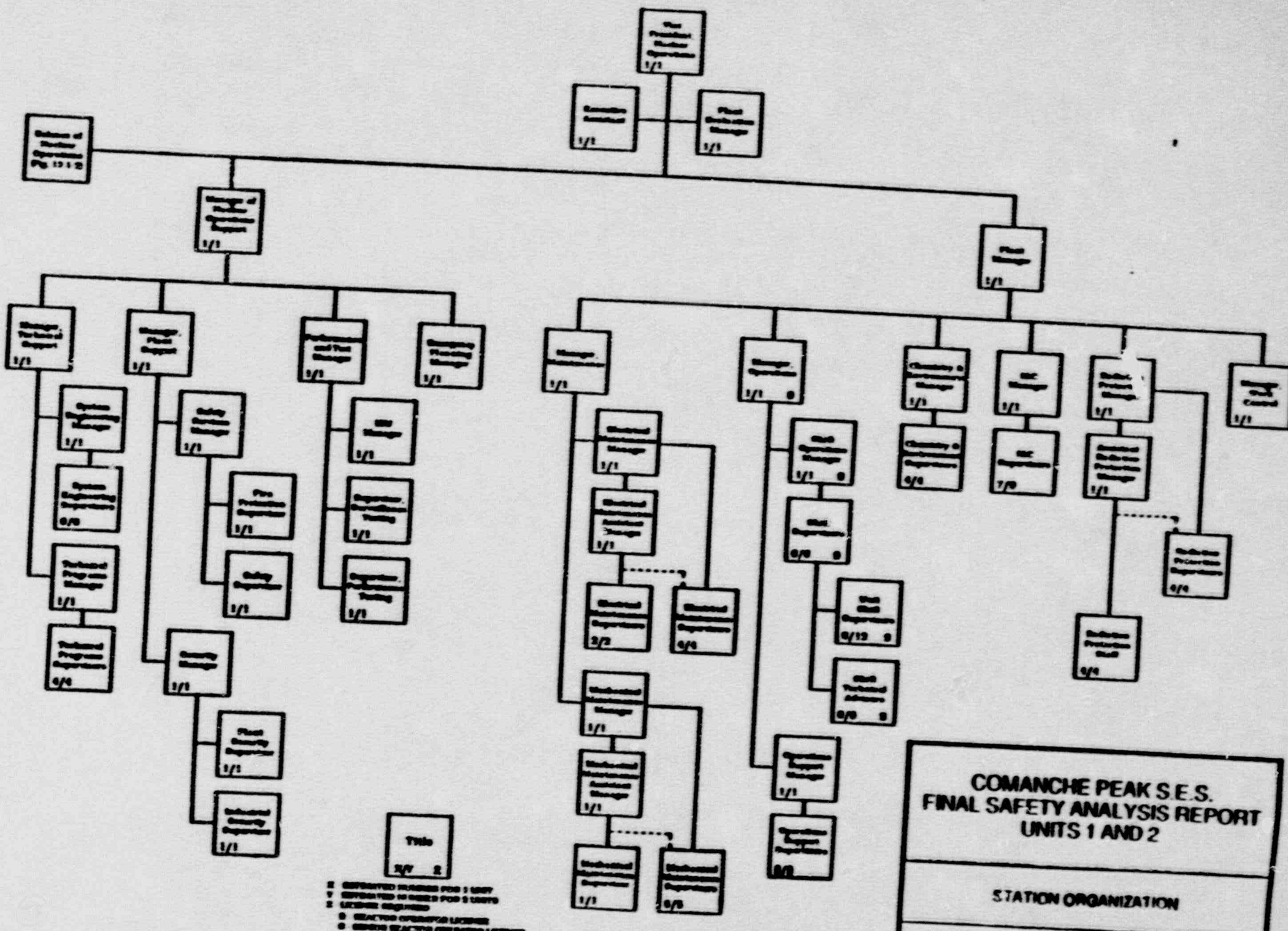
Except for the safety issues associated with the hearings, public sentiment in the Dallas and Fort Worth area, as reflected in newspaper articles, editorials and television news, is principally concerned with the plant's cost increases and the state's energy balance.

~~Attachments~~

1. ~~Figures~~
2. ~~Most Recent SALP Report (Inspection Report 50-445/87-40 and 50-446/87-31 dated October 21, 1988)~~

ATTACHMENT NO. 3

Attachment 20 TXX-88516
#80 7 of 20



COMANCHE PEAK S.E.S.
FINAL SAFETY ANALYSIS REPORT
UNITS 1 AND 2

STATION ORGANIZATION

FIGURE 13.1-3

~~Attachment to TXX-89626~~
~~Page 8 of 20~~

DRAFT | Resumes of the key TU Electric/CPSES personnel in the following order:

DRAFT	Larry G. Barnes	Shift Operations Manager
DRAFT	John W. Beck	Vice President, Nuclear Engineering
DRAFT	Michael R. Blevins	Manager of Nuclear Operations Support
DRAFT	Dudley M. Bozeman	Chemistry and Environmental Manager
DRAFT	H. D. Bruner	Senior Vice President
DRAFT	William J. Cahill, Jr.	Executive Vice President, Nuclear
DRAFT	Richard Daly, Jr.	Manager, Startup
DRAFT	Doug L. Davis	Manager, Technical Support
DRAFT	David E. Deviney	Deputy Director, Quality Assurance
DRAFT	Joseph W. Donahue	Manager, Operations
DRAFT	Stephen L. Ellis	Performance and Test Manager
DRAFT	Joe B. George	Vice President, Support
DRAFT	Phillip E. Halstead	Manager, Quality Control
DRAFT	Chuck Hogg	Chief Engineer
DRAFT	Ausaf Husain	Director, Reactor Engineering
DRAFT	James J. Kelley, Jr.	Plant Manager
DRAFT	John E. Krechting	Director, Technical Interface
DRAFT	Bobby T. Lancaster	Manager, Plant Support
DRAFT	G. Jay Laughlin	Instrument and Controls Manager
DRAFT	Owen W. Lowe	Director of Design Engineering and
DRAFT		Configuration Control
DRAFT	David R. Moore	Manager, Work Control
DRAFT	James W. Muffett	Manager of Engineering (CECO)
DRAFT	Robert J. Prince	Assistant Radiation Protection
DRAFT		Manager
DRAFT	Michael J. Riggs	Plant Evaluation Manager
DRAFT	Eric J. Schmitt	Radiation Protection Manager
DRAFT	Austin B. Scott	Vice President, Nuclear Operations
DRAFT	Peter B. Stevens	Manager of Operations Support
DRAFT		Engineering Group

ATTACHMENT NO. 4

1. Operators and startup failure to follow procedures. Valving errors to start the 2 backflow events, PT-0102, PT-3701, and PT6403

2. Operators' lack of sensitivity to the position of valves. Changing the AFW valves out of the proper order of sequence.

3. Operators' failure to recognize the significance of the checkvalve backleakage during the precursor event.

4. Operators' failure to make sure supervision was aware of the 3 check valves that had significant backleakage (precursor event).

5. Supervisors' failure to stay informed of plant evolutions and problems (the system flushing to solve the chemistry problem and the RHR valving problem during the remote shutdown test. If checkvalve had failed, it would have put RCS water to the RWST.)

6. Failure to accurately and adequately document the extent of a problem. (The precursor event Work Request said "repair check valve leakage.") No TDR on RHR event. No TDR on PT 4401 and QA person doing surveillance did not issue a surveillance deficiency.

7. Weakness in the documentation of equipment problems in the shift log.

8. Failure to recognize inoperable equipment.

9. Failure to recognize and document equipment out-of-service.

10. Lack of adequate communications between the operating shifts.

11. Weakness in the exchange of information at shift turnover. (Precursor event and April 23 event)

12. Supervision/Management review of problems documented on work requests. (Precursor event)

13. Failure of persons with knowledge of the precursor check valve problems to raise the information to management.

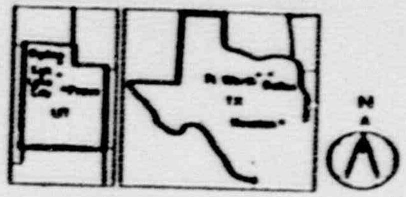
14. The slowness and lack of direction initially demonstrated by TUE following the April 23 event.

15. The perception that "Projects and the Schedule" were driving decisions at the time of the precursor event and the start of HFT.

16. The perception that the Operations staff are not in control of the plant.

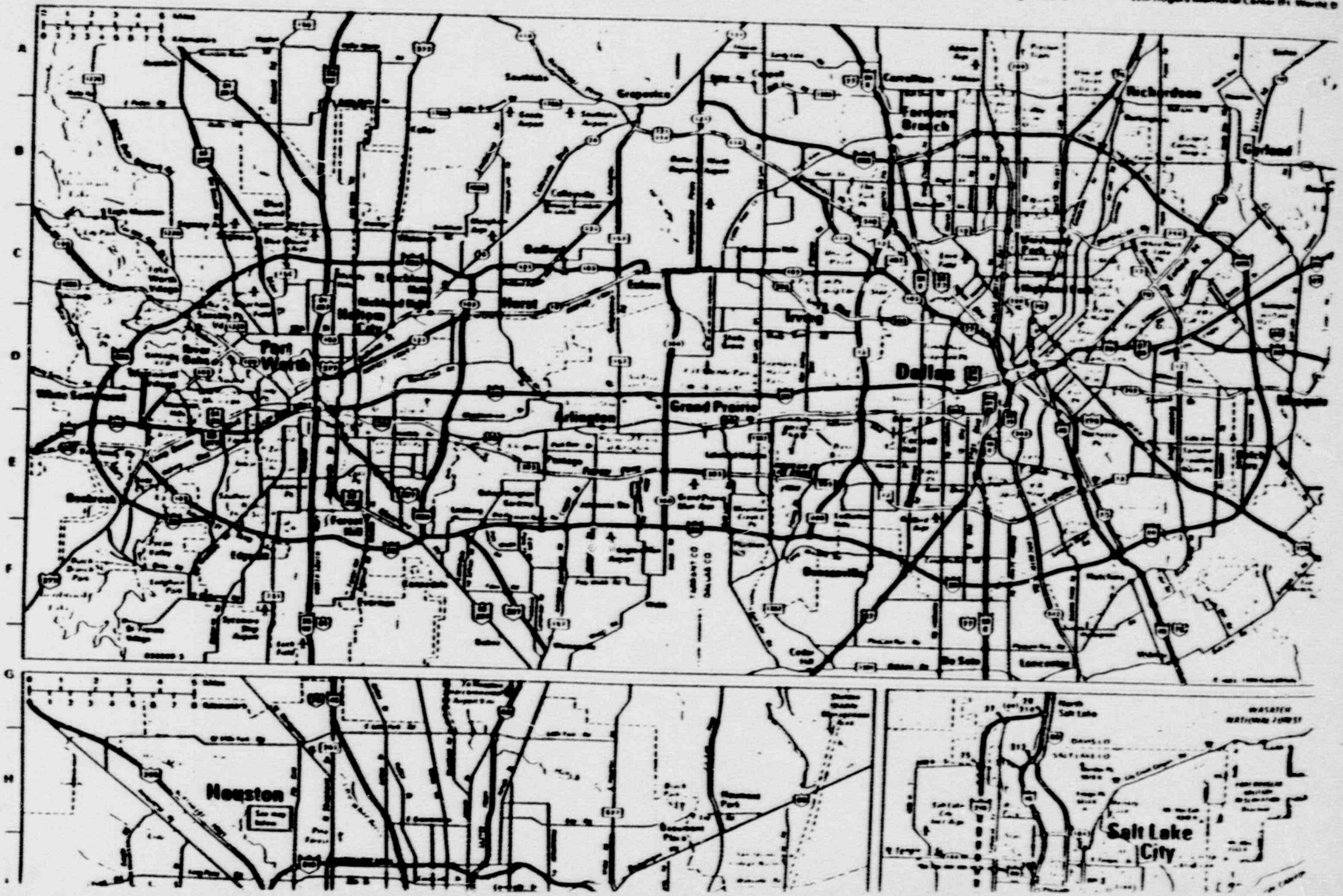
ATTACHMENT NO. 5

Texas & Utah City Maps

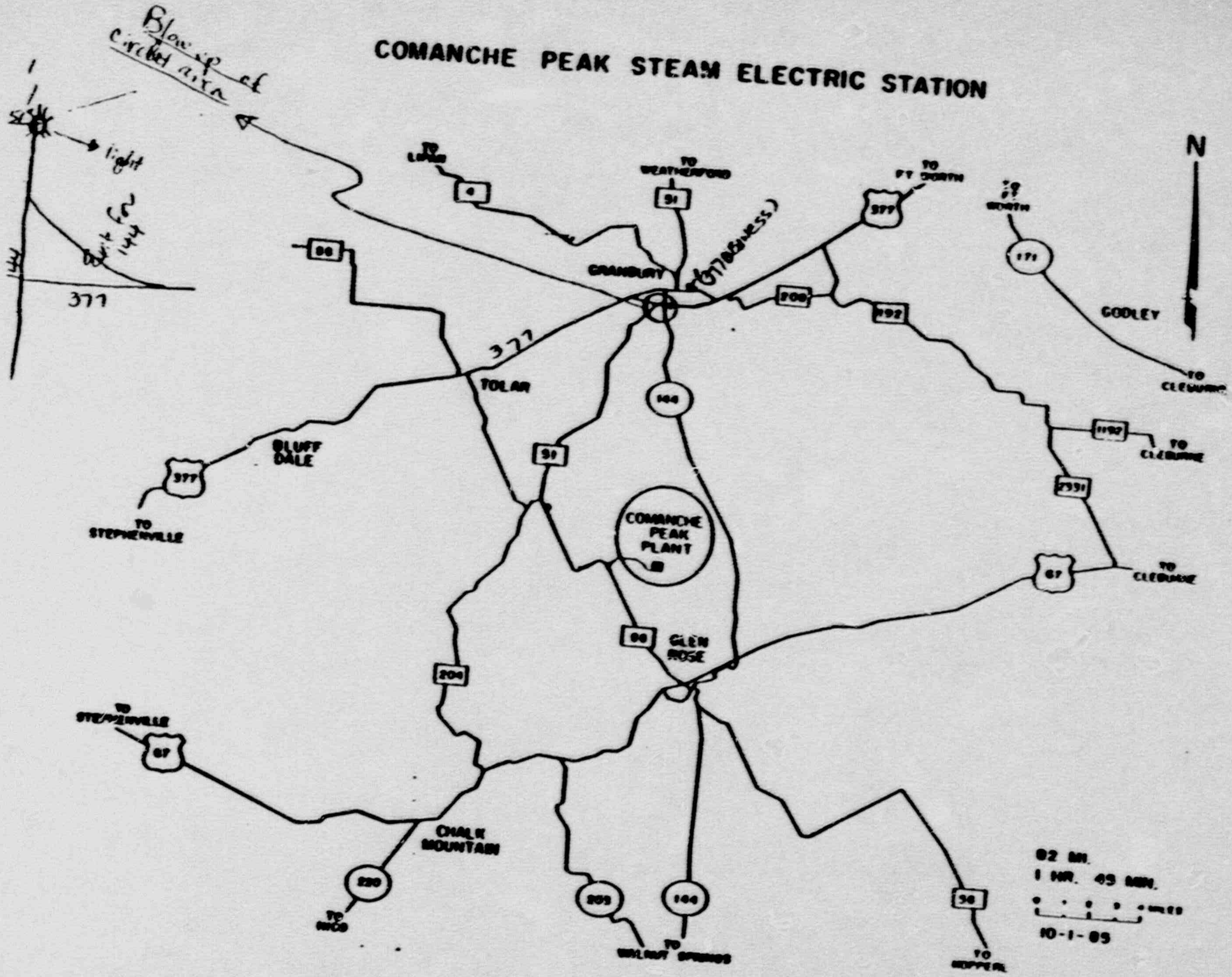


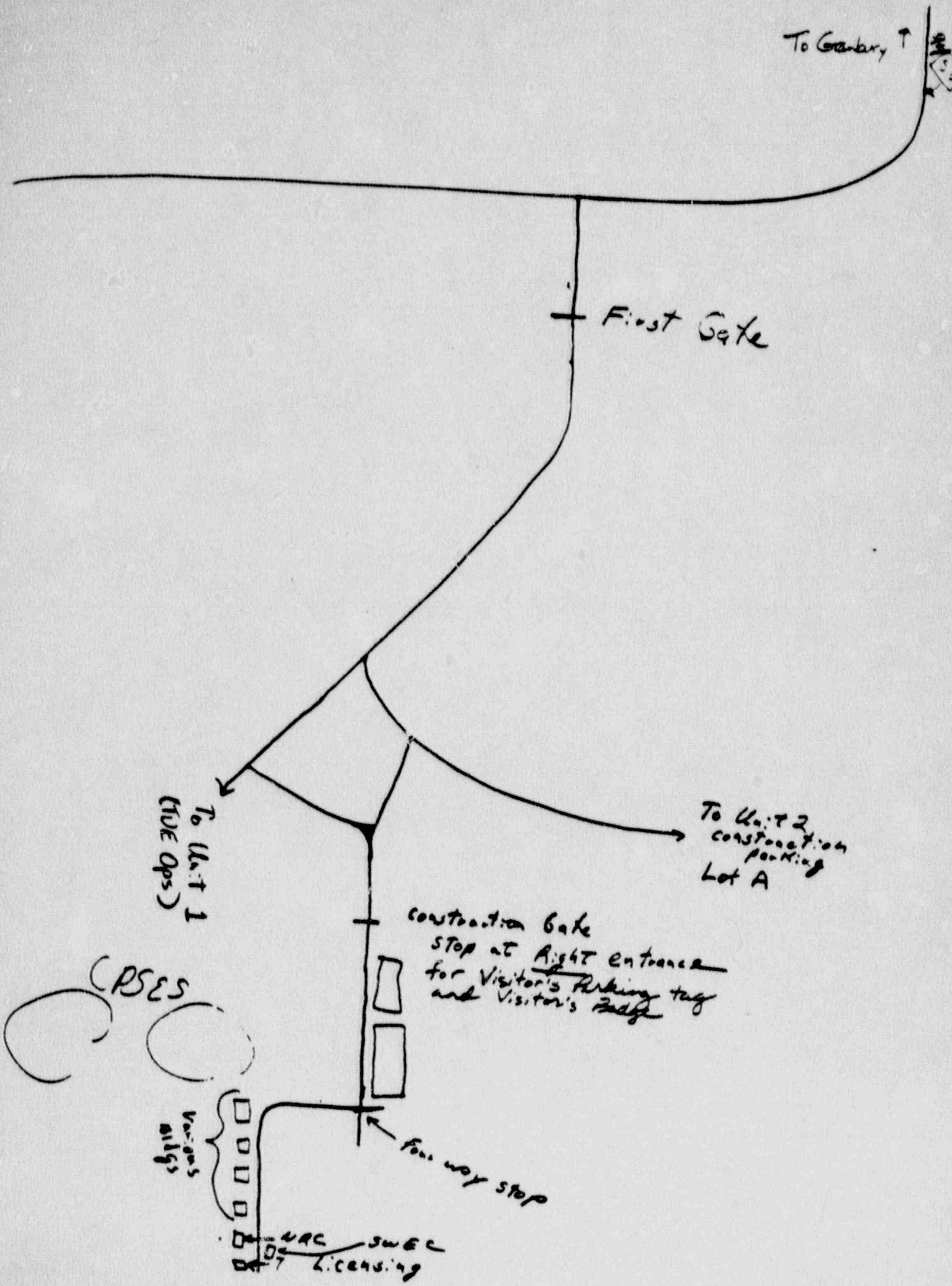
Selected Recreational & Historical Sites

Alley Theater (Houston) N 2
Arboretum & Botanical Garden (Houston) J 3
Arlington Stadium (Arlington) D 8
Astrodome & Astroworld (Houston) K 3
Bayou Bend Collection (Houston) J 3
Brigham Young University (Provo) O 11
Cotton Bowl (Dallas) D 10
Dallas–Ft. Worth Regional Airport B 8
Hermann Park (Houston) K 4
Museum of Fine Arts (Houston) K 4
Nat'l Space Hall of Fame (Houston) N 2
Ogden Depot (Ogden) N 7
Pioneer Museum (Provo) O 11
Pioneer Trail State Park (Salt Lake City) I 12
Salt Palace (Salt Lake City) I 10
Six Flags Over Texas (Arlington) D 8
Tabernacle Square (Ogden) N 7
Temple Square (Salt Lake City) I 10
Texas Stadium (Irving) C 8
Texas State Fair Park (Dallas) D 10
Utah Lake State Park (Provo) O 9
Utah State Capitol (Salt Lake City) H 10
Utah State Fairgrounds (Salt Lake City) I 10
Will Rogers Memorial Center (Ft. Worth) D

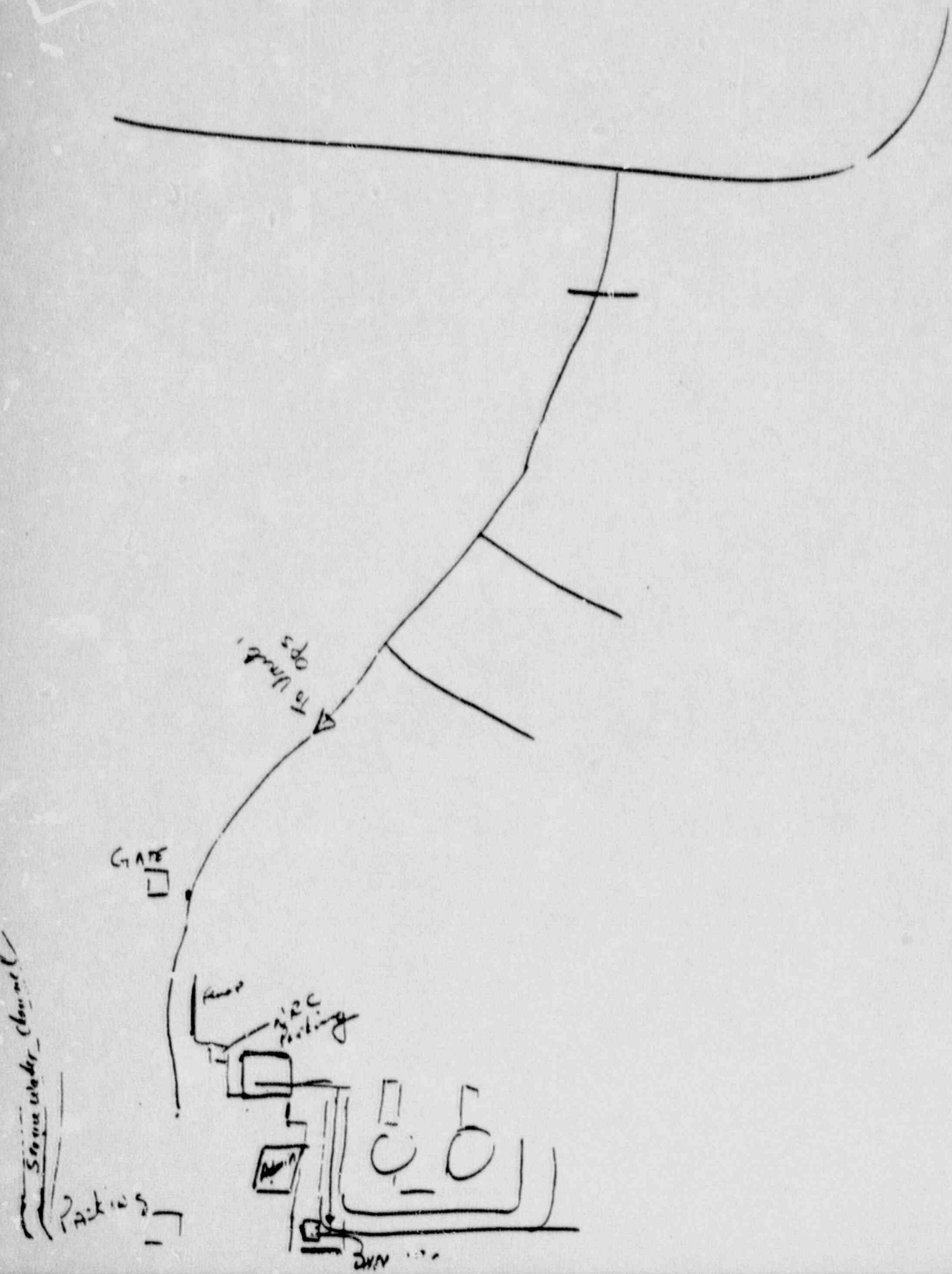


COMANCHE PEAK STEAM ELECTRIC STATION





To Granbury
First Gate
To Unit 1 (TUE Ops)
To Unit 2 construction parking Lot A
construction Gate
Stop at Right entrance for Visitor's Parking tag and Visitor's Badge
CPSES
Various bldgs
Four way stop
NRC
SWEC Licensing



GATE
NRC Parking
Storm water channel
Parking

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

October 3, 1989

MEMORANDUM FOR: All NRC Personnel Involved In Comanche Peak, Unit 1 Licensing Activities

FROM: Christopher I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

SUBJECT: IDENTIFICATION OF COMANCHE PEAK UNIT 1 ISSUES

As Comanche Peak Unit 1 nears completion, it is important that all safety-related concerns, which could have a bearing on satisfactory completion of construction and preparation for plant operation, be addressed. In order to ensure that all such concerns have been identified, we request that all professional staff who have been involved in the Comanche Peak licensing activities notify us if they know of any concerns that are not being tracked by inspection reports, Safety Evaluation Reports, or other public records.

In a memorandum to the NRR Branch Chiefs, dated August 29, 1989, I separately requested the status of the technical review activities and identification of those issues evolving from the review of the FSAR that will not be resolved before licensing. Those issues that will be reflected in a forthcoming SER input and/or associated staff positions need not be repeated for this effort, as long as the Comanche Peak projects staff is aware of the status of those issues.

The responses to this request may be made by telephone (FTS 492-3299) or in writing (Mail Stop 7H-17, OWFN). Your response should identify the specific concerns with sufficient details for follow-up action. Previously closed items need not be identified again, unless there is additional information or a change in the concern that may have an impact on plant licensing.

Your cooperation in this effort will be greatly appreciated. Should you have any questions regarding this matter, please contact me or Robert Warnick, Assistant Director for Inspection Programs (817-897-1500).

C.I. Grimes

Christopher I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

cc: T. Murley
J. Sniezek
D. Crutchfield
F. Miraglia
J. Partlow
J. Richardson
A. Thadani
E. Rossi
B. Grimes
F. Congel

8910160168 4p.

Enclosure 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

October 10, 1989

MEMORANDUM FOR: All NRC Staff Involved in Inspection Activities Related to Comanche Peak

FROM: Dennis M. Crutchfield, Associate Director for Special Projects
Office of Nuclear Reactor Regulation

SUBJECT: NRC STAFF DIFFERING PROFESSIONAL OPINION ON COMANCHE PEAK

In a memorandum to the Chairman dated October 4, 1989, an anonymous group identifying themselves as "NRC Staff Inspectors" asserted that the pending SALP report related to TU Electric's performance in the preparation of Unit 1 for plant operation is neither accurate nor complete. The memorandum is critical of both the SALP Board's findings and the qualifications of the Board members to draw conclusions on TU Electric's performance.

In order to assure that all concerns related to TU Electric's performance are clearly understood prior to the issuance of the SALP report, I request that each of you involved in the inspection activities for Comanche Peak review the enclosed initial SALP report and submit any comments you may have on the Board's findings within 15 days from the date of this memorandum.

In commenting on the enclosed report, you may want to review the procedural requirements and purpose of the SALP, as described in Manual Chapter 0516. You should also note that the enclosed SALP report is considered to be "predecisional" and, as such, this draft should not be released or discussed with unauthorized personnel.

Your comments should be as specific as possible and be submitted directly to me. They may be submitted anonymously if you so desire. Depending on the nature of the comments received, further action may be warranted before the report is issued.

Should you have any questions regarding this matter, please do not hesitate to contact me at FTS 492-0722.

Dennis M. Crutchfield

Dennis M. Crutchfield, Associate Director
for Special Projects
Office of Nuclear Reactor Regulation

9002140041 2PP

Enclosure 4

Enclosure:
Initial SALP Report

cc w/o enclosure:
T. Murley
J. Sniezek
J. Partlow
F. Miraglia
C. Grimes

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

October 10, 1989

MEMORANDUM FOR: Martin Malsch, Acting Director
Office of the Inspector General

FROM: Christopher I. Grimes, Director
Comanche Peak Project Division

SUBJECT: NRC STAFF DIFFERING PROFESSIONAL OPINION RELATED TO THE CONDUCT OF THE SALP FOR COMANCHE PEAK

In the enclosed memorandum to the Chairman dated October 4, 1989, an anonymous group of "NRC Staff Inspectors" asserts that (a) the Comanche Peak Plant is not ready for fuel loading and (b) the pending SALP report related to TU Electric's performance in the preparation of Unit 1 for plant operation is neither accurate nor complete. The memorandum also implies that NRC inspection reports and other documents have been edited to create an untrue impression of the plant. The memorandum is critical of both the SALP Board's findings and the qualifications of the Board members to draw conclusions on TU Electric's performance. Moreover, the memorandum specifically states that the NRC managers on the SALP Board deliberately excluded information so as to give a false impression of the plant. Accordingly, we are forwarding the memorandum for appropriate action.

As a result of this memorandum, we have issued the draft initial SALP report to all professional staff involved in the inspection activities related to Comanche Peak and requested their comments on the Board's findings within 15 days (copy enclosed). In addition, we are informing the Commission of the actions that will be taken to address the issues raised in this memorandum.

We have also enclosed for your information, a memorandum dated October 3, 1989 which requests that the NRC staff identify any issues that may have been neglected and may have a bearing on the licensing decision for Comanche Peak Unit 1.

CI Grimes

Christopher I. Grimes, Director
Comanche Peak Project Division
Office of Nuclear Reactor Regulation

Enclosures:
1. Memo to Chairman dtd. 10/4/89
2. Memo to Comanche Peak Staff dtd. 10/10/89
3. Memo to NRC Staff dtd. 10/3/89

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Enclosure 5