6329

RELATED CORRESPONDENCE

CASE

(CITIZENS ASSN. FOR SOUND ENERGY)

1426 S. Polk
Dallas, Texas 75224

214/946-9446

DOCKETED
USNRC

'88 MAY 16 P5:47

May 11, 1988

Administrative Judge Peter B. Bloch
U. S. Nuclear Regulatory Commission
Atomic Safety and Licensing Board
Washington, D. C. 20555

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Elizabeth B. Johnson
Oak Ridge National Laboratory
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Oak Ridge, Tennessee 37830

Dear Admin[illegible]ve Judges:

Subject: In the Matter of
Texas Utilities Electric Co., et al.
Comanche Peak Steam Electric Station
Units 1 and 2

Application for an Operating License
Docket Nos. 50-445-OL and 50-446-OL
and
Construction Permit Amendment
Docket No. 50-445-CPA

RELATED CORRESPONDENCE

In accordance with Mr. Roisman's letter of May 6, 1988, to the Board, we are enclosing copies of the following documents received on discovery from the minority owners in the above-referenced proceedings:

Technical Analysis Corporation, The Quality Assurance Program at the Comanche Peak Steam Electric Station (4/30/88), Parts I and II

Tex-La Electric Cooperative of Texas, Inc., Brazos Electric Power Cooperative, Inc., Analysis and Evaluation of the Project Management Services Provided by Texas Utilities in the Construction of the Comanche Peak Steam Electric Station (2/15/88)

Whitfield Russell Associates, Damages to Brazos Electric Power Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc., Related to Participation in Comanche Peak Steam Electric Station (February 1988)

Victor Gilinsky, Comanche Peak Licensing Delay, A Report to Brazos Electric Power Cooperative, Tex-La Electric Cooperative of Texas (2/15/88)

Southern Engineering, Report on Rural Electric Cooperatives (February 1988)

DS03

Randel Associates, Inc., Addendum to Review & Analysis of Engineering, Construction & Testing at the Comanche Peak Nuclear Project (4/29/88)

Randel Associates, Inc., Review & Analysis of Engineering, Construction & Testing at the Comanche Peak Nuclear Project (2/12/88) *

* Please note that the last report listed above was inadvertently not included in our 5/6/88 listing. In addition, we did not note in that listing that the first report listed (the Technical Analysis Corporation report) was in two volumes. However, we are enclosing these reports herewith.

CASE also is filing these reports in both the operating license (OL) and construction permit (CPA) proceedings, since we believe they are relevant to both.

Respectfully submitted,

CASE (CITIZENS ASSOCIATION FOR SOUND ENERGY)

Juanita Ellis

(Mrs.) Juanita Ellis
President and Co-Representative

cc: Service List

Enclosures as shown on attached Service List

cc: Enclosures to those marked with an asterisk *
Without enclosure to all others.

* Administrative Judge Peter B. Bloch
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*Adjudicatory File (2 copies)
Atomic Safety and Licensing Board
Panel Docket
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

NOTE: Some copies may not actually be placed into the mail until May 12, 1988.

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May 6, 1988

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RE: Texas Utilities Electric Company, et al. (Comanche Peak Steam Electric Station, Units 1 and 2), Dkt. Nos. 50-445-OL, 50-446-OL

Lady and Gentlemen:

Pursuant to an agreement reached with the minority owners regarding discovery in this proceeding, we have received the following documents:

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Tex-La Electric Cooperative of Texas, Inc., Brazos Electric Power Cooperative, Inc., Analysis and Evaluation of the Project Management Services Provided by Texas Utlities in the Construction of the Comanche Peak Steam Electric Station (2/15/88)

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Southern Engineering, Report on Rural Electric Cooperatives (February 1988)

Randel Associates, Inc., Addendum to Review & Analysis of Engineering, Construction & Testing at the Comanche Peak Nuclear Project (4/29/88)

Inasmuch as the contents of these documents, which we understand were delivered to the Applicants some time ago, bear directly on the issues in this proceeding, we wish to advise you of their existence. We will send copies under separate cover as soon as practicable.

We have not had time to review all the documents but we do believe it important for the Board to see the attached summary and conclusions of the Technical Analysis Corporation document as soon as possible.

Sincerely,

Anthony Z. Roisman
Counsel for CASE

AZR/bp
enclosure
cc (w/enc.): see attached list

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TECHNICAL ANALYSIS CORPORATION

THE QUALITY ASSURANCE PROGRAM
AT THE COMANCHE PEAK STEAM ELECTRIC STATION

REPORT SPONSORED BY

DON H. BECKHAM
TECHNICAL ANALYSIS CORPORATION

April 30, 1988

THE QUALITY ASSURANCE PROGRAM AT THE COMANCHE PEAK STEAM ELECTRIC STATION

1. Summary

In 1973, Texas Utilities (TU)[1] filed a request with the U. S. Atomic Energy Commission for a Permit to construct a two unit nuclear power plant at Comanche Peak. The units were to be known as the Comanche Peak Steam Electric Station (CPSES). The AEC granted the Construction Permit in December 1974. One condition on the permit was that the plant was to be constructed in accordance with the Quality Assurance (QA) requirements established by the Commission and adopted by TU as described in the Preliminary Safety Analysis Report (PSAR) that accompanied the application for the Construction Permit.

In the early stages of the project, even before the Construction Permit was issued, the AEC staff had been critical of the development and implementation of the QA program for CPSES. Only a last minute push by TU and the Architect/Engineer for the project, Gibbs and Hill (G&H), resolved the AEC staff's criticism of the written program. Over the next few years the AEC and NRC[2] staff would identify several deficiencies in the implementation of that written program. The TU QA staff attempted to bring the contractors' programs into compliance with the NRC requirements.

By 1976, TU was experiencing difficulty maintaining the pace of construction necessary to complete the first unit by the planned date of 1980. The Constructor for the units, Brown and Root (B&R), was critical of the TU QA staff for being too rigid in its enforcement of the QA requirements. By mid 1976 B&R was becoming more vocal in its criticism and was being joined in the criticism by TU project officials. At the same time, TU was being criticized by the NRC for apparent deterioration of the QA Program. In the fall of 1976, the TU QA Manager was appointed

---

1 Except where necessary to distinguish between different organizations, the term TU will be used to refer to any of the major organizations (e.g. TUGCO, TUSI or TUEC) within the Texas Utilities organization.

2 In 1975 the Atomic Energy Commission was disbanded by Congress in the Energy Reorganization Act. The regulatory responsibilities of the AEC were transferred to the newly created Nuclear Regulatory Commission (NRC). The regulatory and inspection staff of the AEC was transferred to this new agency, so there was little loss of continuity during the transition. In this report we will use NRC to mean the AEC or NRC unless a distinction is required for clarity.

Project Manager of CPSES. The position of QA Manager was filled by an individual with no previous nuclear or QA experience. A short time later, the TU executive in charge of design and construction of CPSES was replaced. After this new executive was briefed on B&R and Project complaints about TU QA, the Site QA Supervisor was replaced. Some months later the Project Manager (and former QA Manager) was assigned to a position not involved with construction or QA. The new CPSES Project Manager stressed that <u>everyone</u> must cooperate with construction to maintain the project cost and schedule.

By mid 1977, the cost and schedule goals were continuing to elude the project managers. A major source of delay was resolving field originated design changes. These changes are required when the design of a building or system cannot be built the way the drawings produced by G&H indicate that it should be. This could be because another component had already been installed in the designated location (called an Interference), because the drawing was in error, because required material was not available, or because the component was not built in accordance with the approved design drawing. These field originated changes are supposed to be reviewed by the original design organization (G&H) and approved as a change to the design before construction continues on the affected system. In an effort to maintain the construction schedule, TU directed that field originated design changes be given a preliminary review on site and approved for construction. A full design review of the change was to be conducted by G&H at a later date after the changed design had been constructed. This practice became know as the "after-the-fact" or "at risk" design review. The names stemmed from the fact that the review took place after construction instead of before, and if the design change is not approved by G&H then the work that was done to the revised drawings would have to be removed or reworked. Hence the work is done at risk of future rework.

TU was warned several times by G&H, by consultants hired by TU to advise them, and by the NRC staff that the "at risk " method at worst does not meet the NRC QA requirements and at best was a poor QA and construction practice. TU repeatedly acknowledged that it was willing to accept the risk to maintain the construction schedule.

The QA program was being implemented under a QA Site Supervisor characterized as dictatorial and brusque. Indeed the TU management style was characterized as "top down" communication with little opportunity to communicate upwards. In this atmosphere there were repeated incidents of allegations to the NRC that TU was not properly implementing the QA Program. Finally, the allegations were taken before the Atomic Safety and Licensing Board (ASLB). The ASLB is a part of the process through which a utility's application for a license to operate a facility is reviewed. TU had applied in 1978 for a license to operate CPSES. The three member Board reviews the technical information prepared by TU and the review conducted by the NRC staff. The Board also allows members of the public, whose interests might be affected if the facility gets licensed, to participate in the hearings conducted by the Board. If after holding hearings and considering the evidence presented on the record, the ASLB determines that the utility has met the applicable requirements, it will issue an "initial decision" recommending that the facility be licensed.

The ASLB required TU to respond to the allegations, and in the course of these hearings, the practice of "at risk" design review was revealed. In December 1983, the ASLB ordered TU to initiate a program to provide an independent verification of the design of CPSES. The NRC staff also initiated special inspection efforts to determine if the design and as built plant met relevant design requirements. As these independent reviews identified additional deficiencies, TU expanded the program of review. In 1984 and 1985 significant changes were made in the management of the project. For the first time, personnel with significant previous nuclear experience from outside of TU were brought in to key positions. A program called the Comanche Peak Response Team (CPRT) was initiated by TU and then expanded. In 1985, TU withdrew its request for an Operating License, stating that it did not have sufficient confidence that the plant had been constructed in accordance with the NRC requirements.

As of today the CPRT effort is continuing. Significant review, analysis, verification, and rework have already been completed. More will be required to complete the effort. Whether or not the efforts will be sufficient to convince the ASLB and NRC that the project then meets all applicable regulatory requirements and can be licensed to operate remains to be seen.

8.0 Conclusions on TU Implementation of the QA Program at CPSES

In conducting our review and drawing our conclusions we were careful to evaluate the Quality Assurance program at CPSES from the earliest records of design and construction activities. From this review we determined that the history of CPSES could be classified in three phases, as described in Section 5.2. These are Phase I, Rigorous Application of QA; Phase II, The Cooperative Phase; and Phase III, The Response Team Phase. We concluded that TU management priorities in Phase II were overwhelmingly concerned with completing construction in the most expeditious manner. Part of the result of these priorities was ensuring that the QA organization adopted an attitude of "cooperation" with construction to maintain schedule and hold down costs.

These management priorities were manifested in several ways, but the most significant in terms of QA were replacement of the QA Manager and QA Site Supervisor, dissolution of the Quality Surveillance Committee, and the decision to implement a process to review field generated design changes after the changed design had all ready been constructed (after-the-fact design review.) The new QA management was determined to cooperate with construction to maintain schedule. When deficiencies were noted by internal audits, NRC inspections, or third party reviews, the response of the QA managers was either to fix only the specific deficiency, or if pushed to resolve the growing problems associated with changing designs in the field, to postpone review and resolution until the "final design review and verification."

These practices led to three types of deficiencies: actual hardware deficiencies that had to be reworked; designs that did not meet the applicable requirements but which could be reanalyzed and used without modification; and hardware and designs for which sufficient documentation could not be located and actual measurement and testing of installed equipment and components had to be made to verify that the installed equipment was adequate.

From the point of view of protecting health and safety there are no significant differences between these three deficiencies. Before a nuclear power plant can be operated there must be positive evidence that it meets rigorous safety standards. The consequences of an accident are too great to permit any other approach. Not only must the hardware be correct, but the utility must be able to demonstrate that it is right. By adopting the "after-the-fact" design review, TU intentionally delayed the review and verification of the conformance between the as-built hardware and the design specifications as required by the NRC.

In 1984 the Atomic Safety and Licensing Board required TU to prove that the plant did indeed meet these requirements. The investigations by the NRC, TU and independent contractors led to the formation of the Comanche Peak Response Team. In carrying out the review of design documentation and as-built verifications within the scope of CPRT, TU is finally performing the "after-the-fact" design review that had been promised since 1977. The attendant cost, delay, and rework that is the direct result of this program stems directly from the liability that TU specifically accepted repeatedly in 1977, 1978, 1982 and 1983.

We conclude that TU subordinated the Quality Assurance program to the priority of maintaining project schedules and holding down costs. As a result of this Quality Assurance managers adopted a "cooperative" attitude toward construction and implemented a program of "after-the-fact" design review. The evaluation, rework and delay are attributable to the liability accepted by TU management as a result of the QA approach during the "cooperative" phase.

TECHNICAL ANALYSIS CORPORATION

THE QUALITY ASSURANCE PROGRAM
AT THE COMANCHE PEAK STEAM ELECTRIC STATION

REPORT SPONSORED BY

DON H. BECKHAM
TECHNICAL ANALYSIS CORPORATION

April 30, 1988

Part 1

THE QUALITY ASSURANCE PROGRAM
AT THE COMANCHE PEAK STEAM ELECTRIC STATION

REPORT SPONSORED BY

DON H. BECKHAM
TECHNICAL ANALYSIS CORPORATION

April 30, 1988

IMPLEMENTATION OF THE QUALITY ASSURANCE PROGRAM AT
THE COMANCHE PEAK STEAM ELECTRIC STATION

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A. The Development of Nuclear Quality Assurance within the Nuclear Industry and its Development at Comanche Peak.

B. Regulation of Nuclear Power Plants and Sources of Regulatory Requirements.

C. A Review of the TU Audit Program at CPSES.

D. Overview and Statistical Analysis of the NRC Inspection Program at CPSES.

E. Issue Specific Action Plans and Discipline Specific Action Plans

THE QUALITY ASSURANCE PROGRAM AT
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1. Summary

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2.0 Introduction

2.1 Purpose

Technical Analysis Corporation has been engaged by Tex-La Electric Cooperative of Texas and Brazos Electric Power Cooperative to provide an evaluation of the Quality Assurance Program developed and implemented by Texas Utilities (TU), the principal owner and licensee for the Comanche Peak Steam Electric Station (Comanche Peak or CPSES.) Because there are still a number of significant verification programs under way at Comanche Peak and because the discovery process is not complete at this date, this review should not be considered complete. The principal purpose of this report is to present the results of the review to date and to highlight patterns in the development and implementation of the Comanche Peak QA Program.

2.2 Introduction

The remainder of this report is divided into six major sections. They are:

3. The Requirements of the Quality Assurance Program

Discussion of the requirements of the Nuclear Regulatory Commission (NRC) concerning the responsibilities of the participants in a nuclear power project. This includes a brief description of the 18 criteria of Appendix B to 10 CFR Part 50, the NRC regulations on QA.

4. Project Chronology

Year by year listing of the major events related to the development of the QA program, the Construction Permit and the granting of licenses for Comanche Peak by the NRC. The chronology concentrates on the events that affected the QA program and its implementation and is not intended to be an exhaustive project time line. Included are events such as Enforcement Conferences, Enforcement Actions, Project reorganizations, major licensing milestones, and development of the Technical Review Team and Comanche Peak Response Team programs.

5. TU Implementation of the QA Program

Discussion of the actual implementation of the QA Program by Texas Utilities on the Project. This is the major analysis of the QA program during the design and construction of the Project. This section includes discussion of the management actions to establish, support and oversee the QA Program, the information being made available to management, the responses of management to this information, and the interactions with the NRC prior to establishing the CPRT.

6. Regulatory Actions for CPSES Licensing Proceedings

Discussion of the actual licensing actions before the Atomic Safety and Licensing Board (ASLB) that were required of TU to receive the Construction Permit. This section also includes a discussion of the ASLB proceedings associated with TU's request for a license to operate CPSES, the information presented to the Board, the Board's orders to TU and the NRC staff, and the NRC staff actions in response to the Board.

7. TU Comanche Peak Response Team and Corrective Action Program

Discussion of the formation of the Comanche Peak Response Team (CPRT) and Corrective Action Program (CAP) by Texas Utilities (TU). This includes the major modifications to the CPRT scope and charter, the interaction with the NRC in evaluation of the scope and charter, the CPRT findings to date, and a discussion of the root causes of the findings.

8. Conclusions on TU Implementation of the QA Program at Comanche Peak

Discussion of the conclusions reached in this review. This includes evaluation of the QA program from project initiation through the end of January 1988. Because the evaluations being conducted by the CPRT and the NRC Office of Special Projects are not complete, these conclusions are subject to modification as more information becomes available on the nature and extent of deficiencies.

2.3 Method of Evaluation

This report was prepared by reviewing the contemporaneous project documentation available in the NRC Public Document Room and documents obtained through discovery requests to TU. Most of the discovery documents were identified through the ATLIS and ASPEN systems and reproduced for our use. We have used information from depositions of Project personnel to identify additional source documentation and to confirm existing documentation. Since all documents have been received and all depositions have not been completed at the date of completion of this report, information identified in subsequent depositions may result in modification of the conclusions.

Our evaluation was conducted by collecting and reviewing Project documents from Project initiation through the latest information available publicly or through the discovery system. Our initial review focused on the NRC Inspection Program as recorded in the Inspection Reports and the TU responses. In parallel we reviewed the TU audit program, concentrating on the TU audits of its own organization (audits designated TIN and TCP), audits of the plant designer, Gibbs and Hill (designated TGH), and audits of the plant constructor, Brown and Root (designated TBR).

Based on information identified in the inspection and audit reports and third party audits, we developed additional information and identified supporting documentation. The basic standard of performance used in this review is the standard of prudent utility practice. By this standard, an action or decision is unreasonable if a person with appropriate qualifications (education, training, experience), applying a degree of care appropriate to the circumstances, using knowledge and information available at the time, applying the use of orderly, rational ways of thinking, comprehending and inferring ("reason"), would not have acted or decided. An outcome will be judged unreasonable if it would not ordinarily have occurred without an unreasonable action or decision, even though the specific action or decision, and the person responsible for it, are not known. Perfection is not required of Texas Utilities actions, decisions or supervision. The reasonableness of actions, decisions and supervision under the circumstances will be judged. However, an organization that undertakes construction and operation of a nuclear power plant must be knowledgeable that it is responsible for the reasonable expenditure of large amounts of money. An organization that undertakes construction and operation of a nuclear power plant must also be knowledgeable that it will be required to comply with Nuclear Regulatory Commission safety, safeguards, environmental and anti-trust requirements.

After we had developed preliminary conclusions as to the implementation of the QA program, we evaluated the results of the programs underway by TU and the NRC to reassess the Project quality. Our conclusions identify the problems that developed early in the Project that led to the deficiencies being identified today.

3.0 Requirements of the QA Program

3.1 Introduction

The origin and historical development of the NRC's Quality Assurance regulations and guidance are described in Appendix A. The purpose of this section is to briefly examine the basic NRC requirements as contained in 10 CFR Part 50 and Appendix B to that Part. It is noted all these requirements were in place at the time Texas Utilities (TU)[1] received the construction permit for CPSES. It is also noted these requirements are derived from 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants". Criterion 1, "Quality Standards and Records" of Appendix A states in part,

> "Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. ... A quality assurance program shall be established and implemented in order to provide adequate assurance that these components will satisfactorily perform their safety functions. Appropriate records shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the plant." (Underlining added)

In other words,

- o A high degree of care must be exercised in the design, construction and testing of items that have a high degree of importance to the safe operation of the plant. A lesser degree of care is permissible for items of lesser importance to safety. Thus, there are gradations in the safety margin incorporated in the design and fabrication of various structures, systems and components. As a practical matter two levels of Quality Assurance Program requirements have developed in practice. The "safety-related" or "Q" systems receive a high level of scrutiny. These systems are the Reactor Coolant System Pressure Boundary, the Reactor Protection Systems, the Emergency Core Cooling Systems, Emergency Power Systems and the like. Other systems that are not safety-related receive a lesser degree of scrutiny. Those systems include power production systems, condenser support and condensate

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1 Except where necessary to distinguish between different organizations, the term TU will be used to refer to any of the major organizations (e.g. TUGCO, TUSI or TUEC) within the Texas Utilities organization.

systems and the like. Separate practices have also developed for some systems, like the Fire Protection System and the Security System. For these, selected portions of the "safety-related" QA program are applied, while some others are not. Since there have been several instances where failures of systems classified as not important to safety have triggered reactor transients and challenged safety systems, the NRC is reviewing the regulatory position for this area.

- The utility must establish a Quality Assurance Program that will provide "adequate" assurance that structures, systems and components important to safety will perform their safety function. This means the program should assure that the item is designed to accomplish its safety function under the specified conditions, that the item is constructed in accordance with the design and that insofar as practicable the item is tested to verify it will perform the specified function.

- Finally, records of the design, fabrication, erection and testing must be maintained throughout the life of the unit. The purpose of the records, of course, is to confirm the item was properly designed, constructed, etc., and also to allow appropriate and correct modification if determined later to be necessary.

In addition to these requirements stated in Criterion 1 of Appendix A, 10 CFR Section 50.34 sets forth the information that must be included in the application for a Construction Permit. Section 50.34(7) requires the application contain a description of the Quality Assurance Program to be applied by the Applicant and how the program will meet each of the criteria contained in Appendix B.

3.2 Appendix B to 10 CFR 50

Because the QA criteria of 10 CFR Part 50, Appendix B, Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants, are frequently referenced in this report, the following is a brief discussion of the types of requirements included in each of the criterion of Appendix B. The entire Appendix is only four pages long in the Regulations.

3.2.1 Introduction

Applicability of the Quality Assurance Program: Structures, systems and components which prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public.

Activities covered: Designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling and modifying.

Definition of Quality Assurance: All those planned and systematic actions necessary to provide adequate confidence that a structure, system or component will perform satisfactorily in service. Quality Assurance includes Quality Control.

Definition of Quality Control: Those Quality Assurance actions related to the physical characteristics of a material, structure, component, or system which provide a means to control the quality of the material, structure, component or system to predetermined requirements.

3.2.2 The Eighteen Criteria

The highlights of the 18 Criteria of Appendix B are given below.

I. Organization

- The utility is responsible for establishing and executing the Quality Assurance Program. The work of establishing and executing all or part of the Quality Assurance Program may be delegated to contractors, but the utility retains the responsibility for the acceptability of the program and its execution.

- The authority and duties of individuals and organizations performing work within the scope of the program shall be clearly established and delineated in writing.

- The persons and organizations performing quality assurance functions shall have sufficient authority and organizational freedom to identify quality problems; to initiate, recommend or provide solutions; and to verify implementation of solutions. Such persons and organizations shall report to a management level such that this required authority and organizational freedom (including sufficient independence from cost and schedule when opposed to safety considerations) are provided. Individuals assigned the responsibility for effective execution of the quality assurance program shall have direct access to such levels of management as may be necessary to perform this function.

II. Quality Assurance Program

- A Quality Assurance Program shall be established at the earliest practicable time consistent with the schedule for performing quality related activities. The program shall be documented by written policies, procedures and instructions.

- The utility shall identify the structures, systems and components covered by the QA Program.

- Activities affecting quality shall be accomplished under suitably controlled conditions, including the use of appropriate equipment, a suitable environment, completion of prerequisites, the use of special test equipment and tools, the application of the necessary skills, and verification of quality by inspection and test.

- Indoctrination and training shall be provided to assure that suitable proficiency is achieved and maintained.

- The utility shall regularly review the status and adequacy of the Quality Assurance Program.

III. Design Control

- Measures shall be established to assure that the basic design and performance as described in the PSAR are correctly translated into specifications, drawings, procedures and instructions. These measures shall assure that appropriate quality standards are included in design documents and that deviations from such standards are controlled.

- Procedures shall be established for the identification and control of design interfaces and for coordination among participating design organizations. This will include procedures for the review, approval, release, distribution and revision of documents involving design interfaces.

- Measures shall be established for verifying the adequacy of the design, such as design reviews, use of alternate or simplified calculational methods or by testing. The verifying process shall be performed by individuals or groups other than those who performed the original design.

- Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design unless the utility designates another responsible organization.

IV. Procurement Document Control

- Measures shall be established to assure that requirements necessary to assure adequate quality are suitably included or referenced in the documents for procurement of material, equipment and services.

- Procurement documents shall require contractors or subcontractors to provide a quality assurance program consistent with the pertinent provisions of Appendix B.

V. Instructions, Procedures, and Drawings

- Activities affecting quality shall be prescribed by documented instructions, procedures or drawings and shall be accomplished in accordance with these instructions, procedures or drawings.

- Instructions, procedures or drawings shall include quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

VI. Document Control

- Measures shall be established to control the issuance of documents (instructions, procedures, drawings, etc.), including changes thereto, which prescribe activities affecting quality. These measures shall assure that these documents and changes are reviewed for adequacy and approved for release by authorized personnel and are distributed to and used at the location where the activity is performed. This last requirement, of course, is intended to assure that personnel are working to the latest revision of the document.

- Changes to documents shall be reviewed and approved by the same organizations that performed the original review and approval unless the utility designates another responsible organization.

VII. Control of Purchased Material, Equipment, and Services

- Measures shall be established to assure that purchased material, equipment and services conform to the procurement documents. As appropriate, these measures will include evaluation of the supplier (QA Program, QA procedures, and qualifications), objective evidence of quality furnished by the supplier (e.g. material certifications, results of inspections, etc.), inspection at the source and inspection upon receipt.

- The above documents shall be available at the site prior to installation or use of the material or equipment, and shall be retained to identify the specific requirements met by the purchased items.
- The effectiveness of the control of quality by suppliers shall be assessed by the utility at appropriate intervals.

VIII. Identification and Control of Materials, Parts, and Components

- Materials, parts and components, including partially fabricated assemblies, shall bear appropriate identification markings either on the items or on records traceable to the items. This identification shall be maintained throughout fabrication, erection, installation and use of the items.
- These identification markings are intended to prevent the use of incorrect or defective material, parts and components.

IX. Control of Special Processes

- Welding, heat treating, nondestructive testing (radiography, magnetic particle, ultrasonic, liquid penetrant, etc.) and other special processes shall be performed by qualified personnel using pre-qualified procedures in accordance with applicable codes, standards and other requirements.

X. Inspection

- Inspections of activities affecting quality shall be performed to verify conformance with the documented instructions, procedures or drawings describing that activity.
- These inspections shall be performed at each step of the process as necessary to assure quality.
- The utility or its representative may establish mandatory inspection points beyond which work may not

proceed without the consent of the utility or its representative.

XI. <u>Test Control</u>

- o A test program shall be established to assure that structures, systems and components will perform as intended. The tests shall be performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in the applicable design documents.

- o Test results shall be documented and evaluated to assure test requirements have been satisfied.

XII. <u>Control of Measuring and Test Equipment</u>

- o Measures shall be established to assure that tools, gages, instruments, etc. used in activities affecting quality are properly controlled, calibrated and adjusted at specified intervals to maintain accuracy within the necessary limits.

XIII. <u>Handling, Storage and Shipping</u>

- o The handling, storage, shipping, cleaning and preservation of material and equipment shall be controlled and performed in accordance with work and inspection instructions to prevent damage and deterioration. For certain products, special environmental conditions such as humidity and temperature limits, or an inert atmosphere may be required. One example is coated weld rod.

XIV. <u>Inspection, Test, and Operating Status</u>

- o This is an important requirement for items that undergo several stages of construction or installation. For example, a pump will have to be set on its base and leveled and aligned, bolted down, possibly grouted, connected to piping, and electrical power and control wiring installed. Each of these steps may involve one or more inspections; and the item is not complete and ready for testing until all of these inspections have been completed. This criterion says that one must keep track of these steps of the inspection status so that it is possible to determine what inspections remain to be performed and when all inspections have been completed. Similar requirements apply to keeping track of testing and the operability status of completed installations.

XV. Nonconforming Materials, Parts, or Components

- o This criterion requires that procedures shall be established to identify items that do not meet design or performance requirements to prevent their inadvertent use or installation. In addition, the disposition of such items (e.g. reworked, repaired, accepted-as-is, or rejected) must be documented in accordance with written procedures.

XVI. Corrective Action

- o Procedures must be established to assure that failures, malfunctions, deficiencies, nonconformances, etc. are promptly identified and corrected. For "significant conditions adverse to quality", procedures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. In addition, the cause of "significant conditions adverse to quality" and the associated corrective action shall be documented and reported to appropriate levels of management.

XVII. Quality Assurance Records

- o The utility must maintain sufficient records to demonstrate the quality of the plant. These records shall include at least the following: the result of reviews, inspections, tests, audits, monitoring of work performance, and materials analyses. The records shall also include: the qualifications of personnel, procedures and equipment. Inspection and test records shall include as a minimum, identification of the inspector or data recorder, the type of observation, the results, the acceptability, and the action taken regarding any deficiencies noted. These records must be identifiable and retrievable; and they must be maintained for a period of time consistent with regulatory requirements.

XVIII. Audits

- o The utility must conduct a planned and comprehensive system of audits to verify compliance with all aspects of the QA program and to determine the effectiveness of the QA program.

- o The audits shall be performed in accordance with written procedures or check lists by appropriately trained personnel not having direct responsibilities in the areas being audited.

- Audit results shall be documented and reviewed by management having responsibility in the area audited.
- Followup action, including reaudit of deficient areas shall be taken where indicated.

4.0 Project Chronology

This section provides an over view of some of the important milestones in the Comanche Peak Quality Assurance Program development and implementation. It is not intended to be all inclusive.

Highlights

02/15/73	Region IV meeting with TU to explain AEC inspection program and QA requirements (Inspection Report (IR) 73-01)
07/20/73	Application for Construction Permit Docketed
12/3-6/73	Pre-CP QA Program inspection - numerous deficiencies.
12/19/74	Construction Permit Granted
09/10/76	H.C. Schmidt, formerly Manager, QA appointed Project Manager, Nuclear Plants. Chapman replaces Schmidt.
02/15/77	R.G. Tolson promoted from QA Engineer to Site QA Supervisor, replacing P.M. Milam, Jr.
04/24/78	TU application for CPSES operating license docketed. (TU application submitted 2/27/78).
05/00/78	Unit 1 Reactor Vessel set (Unit 2 set in July 1979).
08/01/78	R. Taylor assigned as first NRC Resident Construction Inspector.
01/00/79	Unit 1 Containment Building concrete "topped out" (Unit 2 in Oct. 1979).
04 & 05/80	National Board of Boiler and Pressure Vessel Inspectors conducts audits at CPSES to investigate complaints made by Authorized Nuclear Inspectors. Second audit moderates findings of first audit, but still requires corrective action by B&R.
07/00/81	NRC issues SER for OL Stage
09/00/81	NRC issues final Environmental Statement (OL stage)

10/12-14/81	Routine ASME N stamp survey leads to expiration of B&R certification effective 1/8/82.
11/00/81	ACRS issues letter - OL stage.[1]
11/06/81	NRC Inpsection Report 81-15 issued. Documents significant breakdown in coatings program for steel inside containment.
12/00/81	ASLB Hearing Begins
01/18-20/82	ASME N stamp recertification survey conducted. Leads to recertification following revision of B&R QA Manual to satisfy ASME requirements.
07/00/82	Successful cold hydro test of RCS
07/29/82	First ASLB appearance of Walsh/Doyle (Contention 5 - construction QA/QC)
09/13-14/82	Second ASLB appearance of Walsh/Doyle
10/00/82	Sargent and Lundy perform Self-Evaluation of CPSES to INPO criteria. Evaluation result in 47 findings. Report submitted to ASLB by letter dated May 2, 1983. (83-24)
10/13/82	Special Inspection Team (82-26) commences investigation (Walsh/Doyle allegations).
11/10/82	Report 82-22 issued. Documents what appears to be a significant breakdown in TU's vendor inspection program.
12/10/82	TU presentation to NRC staff argues that IDVP not needed.
01/00/83	Successful Containment Integrated Leak Rate and Structural Integrity Tests.
01/24/83	Construction Assessment Team (CAT) commences inspection.

1 Some entries taken from Comanche Peak Progress Report # 14, dated July 22, 1983, frame CF00011843.

01/31/83	Region IV issues SALP report for period 10/81-10/82. Four "1"s, two "2"s and two "3"s in Preop testing and Vendor Procurement Cycle Controls (see 11/10/82 entry). TU letter from Gary to Madsen, 12/27/82, states TU has engaged Reedy, Herbert, Gibbons & Assoc. to retrain source inspectors in weld inspection.
02/00/83	Unit 1 Hot Functional Test begun.
02/15/83	Special Inspection Team (82-26) issues investigation report (Walsh/Doyle allegations).
03/03/83	CAT concludes inspection.
03/10/83	NRC tells TU that based on CAT results, added assurance of design adequacy is needed.
04/00/83	Turbine rolled on steam first time.
04/11/83	CAT issues Inspection Report (83-18) containing 16 potential enforcement findings.
05/00/83	Unit 1 Hot Functional Test completed.
05/02/83	ASLB receives copy of Self-Evaluation of CPSES performed by Sargent and Lundy to INPO criteria. Report notes 47 findings.
05/31/83	Region IV issues followup to CAT report citing 4 of CAT's 16 findings as Violations. (83-18 followup)
06/10/83	TU proposes Independent Assessment Program to be performed by CYGNA.
07/29/83	ASLB issues Proposed initial decision. Has questions regarding allegations that: o Protective coatings inspectors directed not to write NCRs. o Craft personnel harassed QC Inspectors. o Coatings inspectors fired for refusing to work under unsafe conditions. o Poor coating adhesion to Westinghouse equipment.
10/00/83	TUEC initiates a Hot Line for employee concerns (IR 85-12).

12/12/83	Enforcement Conference regarding intimidation of civil QC inspectors. (83-50) Led to Enforcement Action EA 83-132. Investigation also reviewed intimidation identified in CAT report (83-18).
11/14/83	TU submits draft CYGNA report, IAP Phases I and II.
12/28/83	ASLB issues memorandum questioning TU's QA/QC program for the design of certain portions of the plant and requests that TU offer additional proof of adequate design.
02/28/84	Region IV issues report on allegations referenced in ASLB proposed initial decision of 7/29/83. Allegations not substantiated.
03/12/84	EDO establishes Management Team to review CPSES management of construction, inspection and test programs.
03/16/84	Vega replaces Tolson as Site QA Manager.
03/17/84	EDO directs NRR to manage all NRC actions leading to licensing decisions for Comanche Peak and Waterford.
04/02/84	Special Review Team (Region II) formed and briefed on significant issues raised as a result of licensing review, hearing contentions and allegations.
04/03-13/84	Special Review Team conducts investigation at CPSES.
04/15/84	Approximate date of formation of Region IV Comanche Peak Task Force.
06/22/84	Region IV issues SALP for 10/82 to 10/83. Overall performance satisfactory. Five "1"s, three "1"s have gone to "2", and one "3" in HVAC.
07/00/84	Separate ASLB convened to consider allegations that QC inspectors at the plant have been subjected to harassment and intimidation.
07/09/84	Technical Review Team (TRT) begins review.

07/13/84	Special Review Team report issued by Eisenhut. Report states, "The Special Review Team found during this limited review that your management control ... is generally effective and is receiving proper management attention. The Special Review Team concluded that your programs are being sufficiently controlled to allow continued plant construction while the NRC completes its review and inspection of the facility."
07/16/84	CYGNA issues final report for IAP Phase III.
09/18/84	NRC holds meeting with TU in Bethesda to discuss TRT findings. TRT issues first report (TRT #1); includes requests for additional information.
10/08/84	TU submits initial CPRT Program Plan to NRC in response to TRT #1 requests for additional information.
10/12/84	CYGNA issues final report for IAP Phases I and II.
10/19 & 23/84	NRC meets with TU in Bethesda to discuss proposed CPRT Program Plan.
11/19/84	TU issues CPRT Program Plan Rev. 1. Review Team Leaders appointed from organizations external to TU.
11/29/84	TRT issues second report (TRT #2).
01/08/85	TRT issues third report (TRT #3).
01/14/85	SAFETEAM implemented (IR 85-12)
01/17/85	TU meets with NRC in Bethesda to discuss findings of TRT #3.
01/25/85	CYGNA withdraws Phase I-III conclusions on design adequacy. Will provide revised conclusions in Phase IV report.
02/19/85	TU reorganizes QA/QC; replaces Chapman and Vega.
06/28/85	TU submits Rev. 2 of CPRT Program Plan; adds DAP and QOC efforts. Fikar and Clements no longer on SRT of CPRT. Fikar probably replaced by Counsil at this time.

07/31/85	Counsil becomes Exec. VP, Nuclear (approx. 7/31/85) (IR 85-08)
11/01/85	Austin Scott appointed VP-Nuclear Opns of TUGCO. James Kuykendall appointed VP in TUGCO Nuclear organization (S00806)
02/28/86	CPRT Program Plan in essentially final form (Rev. 3, with supplements dated 1/31, 2/7 and (2) 2/28/86)
11/21/86	Stone & Webster replaces G&H as Lead Contractor for Mechanical and Nuclear engineering and design. (S01993)

5.0 Texas Utilities (TU)[1] Implementation of Quality Assurance (QA) Program

5.1 Introduction

Before the NRC can issue an operating license for a nuclear power plant, it must conclude, among other things, that the completed facility conforms to regulatory requirements and the utility's commitments to the NRC with respect to the quality of design and construction have been met. The NRC places the responsibility for ensuring the construction and operation of the facility in accordance with the Commission's requirements on the Licensee (the utility that will be operating the facility.) The NRC Commissioners rely on information provided by the Licensee, NRC inspections, the ASLB hearing process and, since 1981, on independent design verification programs to develop their conclusions with respect to the quality of design and construction. In early 1985, when construction of CPSES Unit 1 was substantially complete, the NRC determined there were serious questions as to whether an affirmative conclusion could be drawn. At the same time TU asked the NRC to suspend processing of its application for an operating license for CPSES Unit 1 while it investigated these questions and took the actions necessary to resolve the NRC's concerns.

In the three years since that time, TU has been involved in a major reinspection, reverification, reanalysis and modification program in an effort to demonstrate that CPSES, either as originally constructed or as modified, is designed and constructed in substantial conformance with regulatory requirements and TU's commitments to the NRC. This effort is continuing.

One of the purposes of the Quality Assurance Program for a nuclear plant is to provide assurance the facility is designed and constructed in accordance with regulatory requirements and the utility's commitments. Therefore, the necessity for conducting a major reinspection and reverification program raises a serious question as to the adequacy of implementation of the Quality Assurance Program for design and construction by the utility. The following sections address this question.

5.2 Phases of Implementation of the QA Program

Our review of the documents describing the implementation of the QA Program at CPSES indicates there were three relatively

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1 Except where necessary to distinguish between different organizations, the term TU will be used to refer to any of the major organizations (e.g. TUGCO, TUSI or TUEC) within the Texas Utilities organization.

distinct phases of implementation. Each of these phases involved a different group of key individuals and a different level of effectiveness of implementation of the QA Program.

Phase I

This phase extended from the inception of the project until about mid-1976. A number of significant quality problems occurred during this phase. Initially the problems were identified by the NRC and involved deficiencies in the written QA programs of TU, Gibbs and Hill (G&H), the Architect/Engineer for CPSES, and Brown and Root (B&R), the Constructor for CPSES. After the deficiencies had been identified, the TU QA Department attempted to resolve these problems. Later in this phase TU identified numerous problems in Design activities at G&H and numerous problems in excavation and concrete placement in the construction activities of B&R. After the initial input by the NRC, this phase was characterized by vigorous attempts to implement the QA program by the small TU QA staff. This is evident from numerous documents showing the dissatisfaction of TU QA with G&H and B&R activities. This phase started coming to a close in mid-1976 as the project recognized it was facing major cost overruns and significant schedule delays. The key individuals during this phase were Forbis and Bradley (TUSI VP, Design and Construction), Schmidt (QA Manager) and Milam (Site QA Supervisor).

Phase II

This phase extended from about mid-1976 until about March 1985. This phase began as TU management became increasingly concerned regarding project cost over-runs and schedule slippage. During this phase TU management emphasized that everyone's cooperation was required to meet the revised cost and schedule estimates. On this basis, this may be characterized as the cooperative phase. During this phase TU QA appeared to be less vigorous and dedicated in the implementation of the QA program and more interested in cooperating with B&R construction in getting the plant built. Available evidence for this period indicates that B&R and G&H question the propriety of TU QA practices. It was also early in this period when TU took over management of the Site QA/QC Program (except for ASME components). This phase is also marked by friction between the TU Site QA Supervisor and other individuals in the QA/QC organization regarding strict observance of quality requirements. The key individuals during this phase were Fikar (TUSI VP or Executive VP, Construction), Clements (VP Nuclear, August 1980 -1985), Chapman (QA Manager), Tolson (Site QA Supervisor, 1977 - March 1984), and Vega (Site QA Manager, March 1984 - March 1985).

Phase III

This phase covers the period from about March 1985 to the present. This phase is characterized by TU's efforts to respond to the findings of the NRC's Technical Review Team (TRT), by the formation by TU of the Comanche Peak Response Team and by a significant reorganization by TU in the management and QA areas. Although the initial formation of the CPRT occurred in October 1984, we have selected March 1985 as the beginning of this phase because this is when the TU QA Manager and TU Site QA Manager were reassigned to non-nuclear work and replaced by personnel from outside TU. In addition, a number of other major management changes were effected. The key individuals during this phase were Counsil (Exec. VP), A. Scott (VP Operations), Wells (Director QA), McAfee (QA Mgr.), and Halstead (QC Mgr.).

5.3 Management Priorities

Individuals and organizations manage their activities and adopt attitudes in accordance with their perceived priorities. Most individuals will have not one, but several priorities, and often these priorities conflict with one another. The challenge to management, therefore, is to balance these conflicting priorities such that an acceptable end product is achieved. This section examines the facts surrounding the construction of CPSES to identify the TU management priorities, and determine how the conflicting priorities were balanced.

5.3.1 Project Costs and Schedule

In September 1972, approximately ten months before TU formally submitted its application for a Construction Permit for CPSES, the estimated cost of the completed plant was $762 million[2] and the first unit was expected to enter commercial operation in 1980.[3] By October 1976 it was clear neither of these goals would be met. The informal cost estimate had grown to $987 million and commercial operation of Unit 1 was not then expected until 1981.[4]

It was also clear at this time that even the cost estimate of $987 million was far too low. At this time TU requested B&R to prepare a definitive cost estimate. In October 1976 the preliminary definitive cost was $1,380 million;[5] and by December

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2 Caudle memo to Administrative Committee dtd 9/5/72, (S00097/CS00131195)

3 Ghiotto memo the TU management dtd 10/5/76 (S00097/TUD00280034)

4 Ibid

5 Ibid

it was $1,545 million, including a contingency of $95.5 million.[6] In a period of four years, the expected cost had doubled. This development over the last half of 1976 coincides with the transition from Phase I to Phase II.

The task of preventing further cost increases and schedule delays became one of TU management's highest priorities - if not the highest. For example, Mr. Gatchell has testified that the TUSI VP Design and Construction, Fikar, "... reminded us continuously" [of the necessity for maintaining a ceiling on costs].[7] That project cost was a continuing management concern is illustrated by documents issued over the course of the project, including a May 1983 letter from Mr. George to G&H.[8]

This view of management's priorities is also reflected in the notes of the February 1985 interview of Assistant Project General Manager J. Merritt conducted by Cresap, McCormick, and Paget, consultants retained by TU.[9] In these notes Mr. Merritt is reported to have summarized the CPSES management credo as,

> "Managers are given a charge (i.e. get this building done on schedule) and they are free to 'have at it' anyway the (sic) want"

That cost was a major management concern is illustrated by a document intended to explain the changes in cost and schedule to parties outside TU.[10] At the bottom of page 2 this document states,

> "In building the Comanche Peak nuclear plant, it has been the System's objective to meet all construction and operating requirements at a cost which compares favorably with similar installations. Thus, the plant would provide a needed alternate fuel source in the 1980's with economic benefits to customers, compared to

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6 Fitch (B&R) letter to Fikar dtd 12/13/76 (S04019/BH00050478)

7 Oral deposition of Charles Henry Gatchell, July 24, 1987, pp. 201-203, (S009^3)

8 George letter to Scheppele (G&H) dtd 5/16/83, G&H budget, Vega Exh. 578 (S01376/CS00101228)

9 Cresap, McCormick & Paget February 1985 Interview Notes, J. Merritt and others (S02213).

10 Ghiotto memo to TU management dtd 10/5/76 (S00097/TUD00280034)

"other available options at that time. Despite increasingly stringent requirements and continuing abnormal escalation of virtually all construction costs, we still believe that these original objectives can be met."

Another document illustrating TU's deep concern regarding cost is a Caudle confidential memo to Bradley dated May 27, 1976.[11] In this memo the Project Manager, Caudle, tells the TUSI Vice President, Design and Construction,

> "It is my estimate that we are approximately 6 months behind schedule. We can regain the schedule if all parties associated with the project will cooperate to the fullest. Everyone must be cost and schedule conscious. ... We must have complete cooperation of all parties." (Underlining in original)

The context of the memo makes it clear that this comment is intended to include QA.

An example of the level of concern regarding schedule held by TU senior management is provided by Mr. Fikar's testimony before the ASLB in 1984.[12]

> Q But it's a fact that scheduling and staying on schedule is an important thing, isn't it?
>
> A In all plants, in everything we do it's important.
>
> Q How much is that stressed that the plant be on schedule?
>
> A As much as it needs to be.
>
> Q Is it a great concern?
>
> A In all of my affairs it is, regardless of what plants or what process we're in, we need to maintain our -- whatever we plan to do.

And later in his testimony:[13]

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11 Caudle confidential memo to Bradley dtd 5/27/76, Review of Comanche Peak Cost, (S01834/TU00280028)

12 Deposition of Louis F. Fikar, July 11, 1984, p. 46,031. (S02374)

13 Ibid., p. 46,111.

Q Mr. Fikar, do you receive reports or updates or some kind of evaluation from your staff regarding scheduling of construction and whether you're on the time table?

A Oh, yes.

Q How often do you receive those reports?

A Well, I receive them daily, hourly, weekly. All the time. I'm down at the project most of the time, so I'm very aware of where we are. We specifically go over it at least once a week.

Thus, it is clear that for the TU executive in charge of design and construction of CPSES, adherence to the project schedule was a matter of utmost priority.

Based on the foregoing, we conclude limiting further project cost increases and schedule delays were major TU management priorities beginning in mid-1976 and extending to the end of Phase II.

5.3.2 Management Attitude Toward QA

Another factor which should be a management priority with a nuclear power plant is assuring the quality of the design and construction of the plant. This is necessary for the safety of the public, to assure a reliable source of power and to permit licensing. The priority TU management applied to Quality Assurance over the course of the project is discussed in the next Section.

Phase I

As stated in Section 5.2, a number of significant quality problems were identified during Phase I by both the NRC and the TU QA function. We have also stated our review indicates these issues were vigorously pursued by the TU QA staff.[14] Indeed, the implementation was sufficiently vigorous as to cause several complaints by B&R.[15] Prior to mid-1976 TU management with direct responsibility for implementing the QA program supported the QA effort. In particular, we have found no references issued prior to mid-1976 stressing the need for all parties to cooperate in

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14 See for example, Milam conference memos to Bussolini dtd 5/20/76 and 5/25/76, (S00380/CS00151319 and S00379/CS00151317)

15 Gamon (B&R) memo to Munisteri (B&R) dtd 1/29/76, Meeting with H. Schmidt, 1/27/76, (S04008/BH00140569)

supporting the project budget and schedule. Accordingly, we conclude that during Phase I TU senior management had a neutral or hands-off policy regarding QA.

Phase II

As indications were received that project costs were increasing and schedules slipping, the TU Managers outside of the QA organization became more polarized and vocal in criticizing the QA program. An indication of TU management's attitude toward QA near the beginning of Phase II is provided by the previously cited Caudle confidential memo to Bradley dated May 27, 1976.[16] In this memo, the Project Manager, Caudle, blames much of the increased cost and schedule delay on QA requirements which he believes are escalating. He also blames TU's own "rigid interpretation" of QA requirements for slowing the work and reducing productivity "below what we expected", and states "... we must take a more reasonable and less rigid stance on QA".

Mr. Caudle's perception that QA requirements were escalating was consistent with the view he expressed five months earlier when commenting on a request by Gibbs & Hill for additional fees.[17] One increase requested by Gibbs & Hill was based on the additional costs involved in meeting the requirements of the Quality Assurance Standard ANSI N45.2.11, "Quality Assurance Requirements for the Design of Nuclear Power Plants". Mr. Caudle endorses the Gibbs & Hill requests as follows:

> "The QA requirements of 10CFR50 Appendix B and ANSI 45.2.11 (sic) can be interpreted in varying degrees. The NRC (AEC) has gradually enforced more rigorous requirements since the issue of these standards. As we meet one requirement, the NRC sets a more rigid requirement. It is this increasing requirement that is bases (sic) for G&H request for an extra. I concur that the QA requirements have increased in scope and this a reasonable claim."

While Mr. Caudle believed QA requirements were escalating, the perception in this instance, at least, was simply incorrect. This is shown by the memorandum from the TU QA Manager, Schmidt, in which he addresses the G&H request.[18] In this memorandum, the

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16 Caudle confidential memo to Bradley dtd 5/27/76, Review of Comanche Peak Cost, (S01834/TU00280028)

17 Caudle memo to Bradley dtd 12/30/75, Supplement No. 4 to Gibbs & Hill Inc. Contract, (S00795/CS00140764)

18 Schmidt memo to Forbis dtd 8/18/75, Gibbs & Hill Inc. Request for Extras, (S04005/CB00321970)

QA Manager, who should be most knowledgeable concerning QA requirements, argues G&H is not entitled to any additional fee because N45.2.11

> "... does not impose on G&H new QA requirements that did not already exist as part of Appendix B to which G&H had already made a commitment prior to our contract. Rather, N45.2.11 provides guidance for methods and procedures for design control which would satisfy the AEC intent of the legal requirements contained in Appendix B."

Later Mr. Schmidt adds,

> "It is difficult to understand why G&H feels justified in requesting additional man-hour costs and fees for normally required QA activities when B&R and Westinghouse have apparently not felt justified in doing so. Furthermore, if this has been of such valid concern to them, why have they waited till now to state their concern?"

Mr. Caudle perceived QA requirements to be increasing when, in fact, according to the TU QA Manager, they were not. It is true some NRC requirements were being escalated at this time, particularly in the area of increasing the sophistication required in design calculations; but this was a design analysis issue, not a QA issue.

Another document indicating TU's attitude toward QA is a December 1976, confidential Crane memo to Fikar.[19] This short memo is quoted in full,

> "It is the considered opinion of our Resident Manager, Charlie Gatchell, at Comanche Peak that the TUGCO Quality Assurance site manager's overall attitude in respect to an objective cooperative approach on Brown & Root's construction efforts has deteriated (sic) to a point beyond recovery. A transfer and replacement should be arranged by TUGCO if other parties concur. Other parties you may wish to contact are Brown & Root construction, Brown & Root Q.A., Homer (who probably will have difficulty viewing impartially), and Robert Caudle."

The "Homer" referred to in this memo was the TU Project Manager

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[19] Crane confidential memo to Fikar dtd 12/10/76, QA Problem, Gatchell Exh. 89, (S00934/PT00650550)

at that time, Homer Schmidt[20], who until three months earlier had been the TU QA Manager. This is the same Schmidt mentioned above in connection with the Gibbs & Hill request for extras. As discussed in the next section, one of the actions by TU management was to replace the TUGCO Site QA manager (Milam) as suggested by the Crane memo.

The record also indicates that beginning in mid-1976, the NRC's Region IV Office and inspectors were beginning to be concerned about TU's attitude toward QA. For example, on August 19, 1976, the TU QA Manager, Schmidt, announced a "Special Called" meeting of the Quality Surveillance Committee (QSC) partially as a result of a discussion with the assigned NRC inspector.[21] During this meeting of high level managers (Bradley, Caudle, Crane, Kuykendall and Clements) Schmidt reviewed the objectives and procedures of the QSC as described in the CPSES PSAR and QA Plan, and conducted a comprehensive training session on NRC QA requirements. When asked during his deposition why this training session was conducted, Mr. Schmidt answered,[22] "... in conjunction with the discussions that Bradley and I had in the NRC exit critique from Mr. Stewart, that we apparently felt it was appropriate to provide a refresher on those subjects for the benefit of the committee ..."

In addition, about two weeks later Bradley and Schmidt met with Region IV supervision and inspectors to "... discuss further NRC's concerns on the Comanche Peak project and the TU company's corrective action that has been in progress since May."[23] According to Schmidt, two specific concerns were expressed by the NRC at that meeting: (1) The NRC believed that whereas "QA problems were being identified at the site by capable people, it was not apparent that appropriate corrective action was being taken by TUSI top management."; and (2) "... a similar lack of top management support for QA at Brown & Root."[24]

Thus, by mid-1976, TU's concern regarding cost and schedule was

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20 Oral deposition of Homer C. Schmidt, December 2, 1987, Vol. V, p. 101. (S02362)

21 Schmidt memo to Brittain, QSC Meeting Minutes dated 8/27/76, (S01140/CS00100561)

22 Oral deposition of Homer C. Schmidt, December 2, 1987, Vol. V, p. 75. (S02362)

23 Schmidt memo to Brittain, QSC Meeting Minutes dated 9/2/76, (S01140/CS00100555)

24 Chapman memo to Brittain, QSC Meeting Minutes dated 10/12/76, (S01140/PT00521111)

sufficiently obvious to raise NRC concerns about the commitment of TU's senior management to the QA program. In response to these concerns, NRC Region IV requested a meeting with a senior TU representative. In the meeting the senior representative of TU, Bradley, assured the NRC TU was taking steps to address the NRC's concerns.[25]

However, a short time after the meeting with Region IV officials, Mr. Bradley was replaced by Mr. Fikar as TUSI Vice President, Design and Construction. Because of this change in responsible management, the previously expressed concerns of the NRC, and TU's commitment to correct the concerns, as expressed by Bradley, had little lasting influence on TU management attitudes. This is shown by the minutes of a management meeting held January 12, 1977.[26] At this meeting, under the heading "VI. TUSI Management Concerns", the statement appears,

> "TUSI is confident that costs can be controlled without sacrificing any degree of quality.
>
> "However, a more moderate approach in resolution of quality assurance problems is needed. This will be the subject of continuing management attention."

Thus, TU management is back to "encouraging" QA to "cooperate" with Construction.

We note this management meeting occurred at the approximate time the "overly conscientious" Mr. Milam was replaced by Mr. Tolson as TUGCO Site QA Supervisor.

An interesting sidelight to this reassignment is provided by the TU Construction Manager, J. B. George in a memorandum written a few weeks later to the TU Project Manager, Schmidt.[27] In this memorandum Mr. George records some discussions with the NRC. Regarding one item, he states,

> "They also questioned as to why P. M. Milam was moved to my staff. I told them he had done a good job in QA and I thought he could be of more help to me in the overall project. They seemed to be satisfied with this."

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25 Ibid

26 Moorhead (G&H) letter to Schmidt dtd 1/13/77, Minutes of Meeting, Project Status Review, 1/12/77, Gatchell Exhibit 66, (S00945/RL20060110)

27 George memo to Schmidt dtd 3/3/77, NRC Concerns, (S00946/CB00010401)

Mr. Milam's characterization of his responsibilities under Mr. George indicates, however, that his subsesquent position was hardly one that would be afforded an individual because he had done a good job. When asked what his responsibilities were as a Senior Engineer under Mr. George, Milam responded, "Basically, I was a go-fer for Joe George. Anything he wanted me to do or look into, that's what I did."[28]

This statement by George is in direct conflict with the deposition testimony of Mr. Gatchell. Mr. Gatchell states Mr. Milam was transferred because his conscientious QA efforts were impairing construction progress.[29]

Another indication of the role of QA in the thinking of TU management is provided by the minutes of the management meeting of April 20, 1977.[30] This meeting was attended by the highest TU officials (T. L. Austin, Jr., Burl B. Hulsey, Jr., and Perry G. Brittain, as well as L. F. Fikar). The minutes of this meeting record that Fikar will "... hold B&R's (JM) feet to fire on (certain project costs)" and will "... hold G&H's feet to fire on (certain other costs)." Also, the last page of the memo summarizes the results of the meeting. One of the points is that B&R will "(e)mphasize importance of schedule and cost to lower level employees," and B&R "(m)anagement needs to <u>emphatically</u> support schedule and cost control efforts." (Underlining in original.) Thus, the importance of cost and schedule, emanating from the highest management levels, is to be clearly emphasized to all levels working on the project. At the same time, the minutes of the meeting do not include a single reference to Quality Assurance, or to the need to maintain quality standards. In the absence of some concurrent positive statement in support of quality, it is not surprising that many project personnel, including QA/QC supervision would try to "cooperate" by "taking a less rigid stance" on quality concerns.

Mr. Fikar, as Vice President, Engineering and Construction, was the TU corporate officer responsible for getting the plant built on schedule and within the budget. Mr. Fikar, however had a limited knowledge of federal regulations concerning quality. This is explained by his lack of previous nuclear experience and the fact he never bothered to personally read the regulations, as

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28 Deposition of Prentice M. Milam, Jr., January 19, 1988, Vol. I, page 107.

29 Oral deposition of Charles Henry Gatchell, July 23, 1987, p. 141. (S00932)

30 Fikar letter to Munisteri (B&R) dtd 4/27/77, Minutes of Management Meeting, (S04023A/BH00130284)

shown by his testimony before the ASLB:[31]

> Q Mr. Fikar, I'm sure you have read many regulations, federal regulations regarding nuclear power plants in your job as a corporate officer at Comanche Peak, is that right?
>
> A I don't read it personally.
>
> Q Are you familiar with some?
>
> A I'm familiar with some. I know we have a lot of them.

Again, Mr. Fikar's lack of nuclear experience and the fact he relied on others for his understanding of QA requirements also accounts for his belief that "reasonable" quality was good enough, as illustrated by his further testimony before the ASLB:[32]

> Q And based on your knowledge of that statute [10CFR50], how does it deal with it?
>
> A Well, we want to be sure the plant is built properly, <u>has the best quality that we can achieve reasonably</u>, and make sure it operates properly. And that's in our best interest too. (Underlining added.)

Here, the inference is clear: as long as quality can be achieved "reasonably", we will do it. However, if we deem a requirement unreasonable, we will ignore it or circumvent it.

An illustration of the Construction attitude towards "reasonable quality" at CPSES is provided by an internal B&R memo written during Phase I. Recalling that 10CFR50, Appendix B, Criterion V states, "Activities affecting quality shall be prescribed by documented instructions, procedures or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures and drawings", this memorandum complains that the TU Site QA Manager (Milam) "... has taken criteria (sic) V of 10CFR50 literally to mean B&R Construction should prepare detailed, written, step-by-step plans

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31 Deposition of Louis F. Fikar, July 11, 1984, p. 46,095. (S02374)

32 Ibid.

and instructions ..."[33] By inference, a reasonable approach would not necessarily require literal adherence to Appendix B requirements. As noted in Sections 5.2 and 5.4.1, following the reassignment of personnel, TU QA management took a more "reasonable" and practical approach toward QA requirements during Phase II.

This more "practical" attitude of TU QA management is illustrated by a report of an investigation of allegations of cover-up and intimidation by TUGCO Dallas QA. In discussing their conclusions, the investigators state:[34]

> "... It appears that there is a difference in philosophy between QA management and some audit team leaders. QA management takes a practical approach to the application of the quality criteria of appendix B. Audit leaders who also adhere to this philosophy have no problems with the report review process. On the other hand, the purist philosophy of some audit team leaders is directly opposed to that of management. This may be the source of their problems with the report review process. These team leaders often feel they must go to great lengths to justify to their own management the validity of their findings. Apparently, QA management has not been able to convey their philosophy to all of the audit group members."

Thus, these investigators confirm there is philosophical difference between TU QA management, who want to take a "practical" approach, and the purists, who presumably believe in literal conformance with requirements.

An example of the attention given to quality matters early in Phase II is provided by the discovery by the NRC inspector in late April 1977, of a B&R DDR dated March 31, 1977, which recorded the omission of fifty-five two-inch anchor bolts from a reactor containment building #1 concrete pour.[35] When the NRC inspector returned to the site three weeks later, he performed a follow-up inspection of this issue. The TU minutes of the inspector's exit meeting record that he stated, "... TUGCO QA was lax in assuring that B&R and TUSI took positive action on the

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33 Whitworth (B&R) memo to Gamon (B&R) dtd 3/25/76, CPSES QA Program Underlying Problem Areas. (S00068/BH00310648)

34 Report on Allegations of Cover-up and Intimidation by TUGCO, Dallas Quality Assurance, 8/19/83, p. 7 of 12. (S02447)

35 NRC CPSES Inspection Report 77-04 dtd 5/17/77

anchor bolt omission problem to ensure that it did not occur again." The inspector also stated 44 safety related pours had been completed since the 55 missing anchor bolts were identified and that 14 more anchor bolts were left out on May 4, 1977.[36] This instance where corrective action on a previously identified significant problem was not effectively implemented by TU until the problem was identified by an NRC inspector strongly suggests a fundamental deficiency in the TU management oversight and direction of the QA program. Expressed differently, in comparison with the level of emphasis placed on construction activities, TU management was placing inadequate emphasis on effective implementation of the QA program and timely completion of corrective action.

Furthermore, it is questionable just how effective or lasting the corrective action was, and whether it was applied in a generic sense (as it should have been) or only a very limited sense, i.e., only for anchor bolt embedments. Long after this early warning, the NRC-TRT identified an issue concerning the omission of reinforcing steel (rebar) from a concrete pour and the CPRT's investigation into the issue[37] confirmed not only that rebar had been omitted in the specific case identified by the NRC, but it also identified numerous other discrepancies concerning rebar and embedments in concrete.

Another example of TU management attitude towards QA is provided by a 1977 Fikar memo to George.[38] In this memo Mr. Fikar, TUSI VP, Design and Construction, questions the budgets for various tasks as set forth in the definitive estimate. In the QA area, Fikar states, "The whole area of QA/QC man-hours and salaries looks entirely too high." In this regard it should be noted that Schmidt was installed as Project Manager while Bradley was TUSI VP - Design and Construction. This occurred during the time Bradley was trying to improve the NRC's perception of QA at CPSES. About nine months after succeeding Bradley, Fikar appointed J. B. George (who had no previous QA experience) as Project General Manager and Schmidt was reassigned to the position of Manager of Nuclear Services. Mr. Schmidt's earlier replacement as TU QA Manager, D. Chapman, similarly had no previous QA experience. Thus, the TU individual most experienced in QA was no longer in a line position in either QA or Construction and therefore could not adversely affect

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36 Tolson notes of NRC exit meeting on 5/13/77, Gatchell Exh. 52, (BH00091815)

37 CPRT Results Report ISAP: II.a, Reinforcing Steel in Reactor Cavity, Rev. 1, 10/6/87.

38 Fikar memo to George dtd 5/4/77, Review of Definitive Estimate, Gatchell Exh. 67, (S00934/BH00040766)

construction progress. Such an assignment clearly was not consistent with a management policy that placed a high level of emphasis on project quality.

One of the most illuminating examples of the attitude towards quality, and the qualifications of the TU QA Manager during Phase II is provided by the deposition testimony of Mr. Chapman regarding the dissolution of the Quality Surveillance Committee (QSC).[39] The QSC was an original element of the TU Quality Assurance Program; and based on our review of the Committee minutes, the focus of the QSC during Phase I was centered on quality. This was consistent with the purpose of the QSC as stated in the CPSES PSAR:[40]

> "The Quality Surveillance Committee provides a means for the management of TUSI to review the status and adequacy of the quality assurance program and the project QA plan and to evaluate the effectiveness of its implementation."

During Phase II, however, Mr. Chapman was QA Manager and Chairman of the QSC. Regarding the Committee, Mr. Chapman testified as follows:[41]

> Q. Could you tell us what the functions or responsibilities of that committee were?
>
> A. Of course, I didn't set the committee up, I don't know what its original charter was. ...it was just for a general discussion of among the management of TUGCO/TUSI, not just QA, but also the engineering construction, discussion of the various problems and items that needed management attention, and basically it was used in that period as sort of a problem-solving tool I guess.
>
> .
> .
> .
>
> Q. Can you tell us why the committee was disbanded?

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39 Oral deposition of David N. Chapman, October 26, 1987, pp. 131 - 133.

40 CPSES Preliminary Safety Analysis Report, as amended through Amendment 5, 4/5/74, p. 17.1-9. (S00754)

41 Oral deposition of David N. Chapman, October 26, 1987, Vol. II, pp. 131 to 132. (S02318)

A. Well, various committee members talked it over, and we felt that most of us or a lot of us were, the key people were all new and we had all made a commitment to communicate openly, freely, one on one or in a group as we had to, and that really if we're going to solve problems that way, we don't need to wait until once every two months or however often it was that we met. We shouldn't solve problems by committee is basically what we had decided. We could use our time more judiciously going about our management functions on a day-to-day basis with each other.

This testimony tells us: (1) The QA Manager in Phase II, who was also the chairman of the QSC, did not know what the charter of the QSC required of the committee; and (2) He considered the purpose of the committee was just to provide a forum for general discussion among the management of TUGCO/TUSI of project items needing management attention, not just QA. Nowhere in this testimony is there any mention of oversight of the status and adequacy of the QA program or the effectiveness of its implementation.

In any nuclear organization, one of the responsibilities of the QA Manager is to be well informed concerning QA requirements and to advise management accordingly. Indeed, this is required of the TUSI QA Manager by the PSAR commitments.[42] In addition, he would normally be the advocate and defender of QA. However, given the Phase II TU QA Manager's attitude towards oversight of the quality assurance program, as illustrated above, it appears little QA understanding or leadership was provided. This, in turn, would account for a diminished sensitivity to QA requirements on the part of TU senior management. This does not in any way relieve TU of the responsibility for providing oversight of the effectiveness of the QA Program - this requirement is clearly specified in Criterion II of Appendix B. Rather, it appears to be the result of failure to place a well qualified person in the position of QA Manager.

That TU management in Phase II lacked an appreciation for the importance of QA is also indicated in the CPRT Collective Evaluation Report. In drawing its conclusions regarding TU's historical audit program, the CPRT states:

"These problems [with the historical audit program] were attributed to lack of full appreciation by the previous TUEC management of the role and benefit of an

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42 CPSES PSAR, Amendment 2 dated December 21, 1973, pg.17.1-6.

effective audit program."[43]

As another example of management attitude toward QA/QC, it is noted that in mid-1979 NRC Region IV again became concerned regarding the effectiveness of the QA/QC program at CPSES. In this instance the concern centered on alleged problems with site management and quality control in certain areas of construction. Messrs. Gary and Fikar attended a meeting at the Region IV offices on June 22, 1979 at which the NRC described their concerns. As documented in Inspection Report 79-15,[44] Region IV states,

> "... we did find that the allegations were essentially true. We also noted during this investigation that a thread of continuity existed between this investigation and others recently conducted relative to alleged problems with site management and quality control in certain areas of construction. ... there appears to be a morale problem which is evidenced by several of the allegers and may be attributable, in part, to communication problems between the workers and supervision. In our June 22 meeting, you indicated that you would look into these apparent communication problems along with the adequacy of QA/QC indoctrination of plant supervision and workers and take appropriate action to correct any weaknesses that you detect in these areas. We intend to follow this matter closely during subsequent inspections."

As a result of this meeting, as well as "rumbling" heard at the site, the QA Manager, Chapman, directed that an investigation be conducted of QC Inspector concerns.[45] This investigation, which began a few months after the above meeting with the NRC, was conducted by a group of QA personnel which was referred to as the TU QA Management Review Board. This board undertook an extensive program of interviews of Site QC personnel.

The results of these interviews[46] provide insight into the QC

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43 Comanche Peak Response Team Collective Evaluation Report, Revision 0, approved 12/23/87, Executive Summary, p. 18.

44 NRC CPSES Inspection Report 79-15, dated 7/2/79

45 Deposition of David N. Chapman before the ASLB, 7/9/84, page 35,615, (S00739)

46 Management Review Board memoranda to Chapman/Tolson dtd 10/79. Interviews with Site QC Personnel, (S00257 to S00268/CS00381733 - CS00381799)

inspectors' perception of the management attitude toward quality. Specifically, of the twelve disciplines interviewed, one or more representatives of the following groups expressed the view that the main emphasis at CPSES was on production, not on quality: Electrical, Mechanical, Instrumentation, Civil and Surveillance QC Inspectors; the QA Administrative Staff, the QA/QC Staff, and the QC Documentation Staff. In addition, the comments of the Protective Coatings QC Inspectors inferred a similar view was held by that group. Three of the groups referred to the authoritarian attitude of QC supervision. In one of these instances it was characterized as a "parent/child" relationship and in another as a "master/slave" attitude. This perception of an authoritarian attitude is consistent with the findings of a study performed four and one half years later which is described in the next section.

It should be noted that as a result of actions initiated by the QA Manager following this survey, there was an apparent improvement in the relations between QC personnel and their supervision. This was evidenced by reduced allegations to the NRC over the next two to three years, after which the number of quality concerns expressed by QC personnel again increased.

A final example of the attitude of TU management towards QA is provided by Mr. Clements' testimony concerning the after-the-fact or at-risk design verification process adopted by TU in 1977 to expedite construction. Mr. Clements was appointed Vice President, Nuclear with responsibility for QA in August 1980. Shortly after assuming this position he learned of the after-the-fact design verification process. He concluded that although this approach was not expressly forbidden by NRC regulations or the CPSES QA program, it was a poor practice because there was a high risk of QA problems. Mr. Clements expressed this concern to Mr. Gary during a meeting in late 1980 or 1981. As recorded in Mr. Clements' testimony,[47]

> Q. ... As best you can recall, what was the substance of what you told Mr. Gary then?
>
> A. I told Mr. Gary, and I think maybe Chapman was involved, that we felt that it put a strain on the design verification to do it that way, but that it was legal, and within the QA program, within 10 CFR Appendix B, and we just wanted him to know that we felt like that at-risk meant at risk.
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> .
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> .

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47 Oral deposition of Billy Ray Clements, December 15, 1987, Vol. II, pp. 93 to 98. (S02461)

Q. When you made your position on this issue known to Mr. Gary, what was his response?

A. Well, I've forgotten exactly but it was basically he was in the same boat that we were, as long as that program -- or what did we call it, the at-risk --

Q. At-risk design change verification?

A. -- design verification, as long as that meets the criteria and as long as that meets the QA program, and as long as that meets with the NRC approval, which all those things it did, then all QA does -- the QA department does is make sure that they adhere to the QA program.

Based on this description, we conclude the TU attitude regarding QA at this time was such that even if a certain policy or procedure constituted a poor QA practice, as long as it was not expressly forbidden, it was acceptable if it would expedite construction. This appears to be a clear example of subordinating concerns regarding QA to concerns regarding cost and schedule.

Phase III

Early in 1984 in the wake of the Construction Appraisal Team (CAT) inspection, and the continuing Atomic Safety and Licensing Board (ASLB) Hearings, the NRC's Executive Director of Operations had taken the unusual step of directing the Office of Nuclear Reactor Regulation to manage all NRC actions leading to prompt licensing decisions with respect to CPSES.[48] This action had led to the formation of the Technical Review Team (TRT) and performance of their inspections/investigations. The inspections/investigations of the TRT called the licensability of CPSES into serious question. For example the first TRT report states,

"You are requested to submit additional information to the NRC, in writing, including a program and schedule for completing a detailed and thorough assessment of the issues identified. This program plan and its implementation will be evaluated by the staff before NRC considers the issuance of an operating license for

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48 Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Units 1 and 2, NUREG-0797, Supplement No. 8, February 1985, (S00745)

Comanche Peak, Unit 1."[49]

This threat to the timely licensing of the nearly completed plant appears to have dramatically changed the priorities and attitudes of TU management. No longer was construction progress the dominant priority - now it was licensing.[50] And, since the quality of the completed plant was the central question,[51] management's main priority became that of demonstrating the quality of the plant. Further, because plant quality was now in question as a result of allegations and inspection findings suggesting earlier inadequate implementation of QA/QC requirements, management now undertook to demonstrate that current activities rigorously adhered to all licensing requirements.[52] In addition, to demonstrate adoption of a new QA attitude by TU, all individuals in the TU chain of command having construction QA responsibilities, from the VP level to the Site QA Manager were replaced between March and June 1985 with individuals from outside the company who had extensive prior nuclear and/or QA experience.

We therefore conclude that during Phase III, because of concern regarding the licensability of CPSES, the TU management attitude was to support the programs that directly contributed to establishing the licensing basis for the plant, including QA.

5.3.3 Management Style

"Management Style" can be described as a characterization of how management conducts its business, implements its policies and reacts to external or internal stimuli. In a study of an alleged climate of intimidation of QA/QC personnel at CPSES performed by the Idaho National Engineering Laboratory (INEL),[53] the reviewers included an assessment of the management "style" at Comanche Peak. Some of the findings of this study are quoted below:

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49 Eisenhut (NRC) letter to Spence dtd 9/18/84, Comanche Peak Review (TRT #1)

50 Oral deposition of Billy Ray Clements, December 15, 1987, Vol. II, p. 107. (S02461)

51 See TRT reports and SSERs 7 -11 and 13

52 For example, see the description of the CPRT Program in Section 6.

53 INEL Report "Comanche Peak Steam Electric Station Alleged Climate of Intimidation", September 1984 (S00269/CS00381800)

"Management Philosophy: Given the extent and complexity of the job environment, the primary management role is viewed as one of control. The management style is basically conservative with an emphasis on error prevention. The primary vehicle for influencing behavior and getting the job done is the exercise of authority and, in this sense, management has little tolerance for ambiguity or for the questioning of supervisory demands."

"Organizational Atmosphere: There is little doubt that the atmosphere can be characterized as task-centered. Getting the job done is the most important priority and consumes much of the attention of supervisory personnel. The atmosphere is tense and stressful due to the complexity of schedules and interfaces which tend to be potentially conflictful."

"Communication: The management style with regard to communications is primarily downward. There is very little opportunity for interaction and, given some of the above descriptions, there is little tolerance for deviating from information communicated downward."

The INEL study also addressed the managerial problem-solving style. Here the reviewers note there are two basic options: fix the immediate problem, or fix the system that caused the problem. Regarding allegations of intimidation of QC inspectors, the study notes that in most instances,

"... management took the approach of fixing the immediate problems at hand rather than fixing the system that caused the problems. They consider each complaint, or each set of allegations as a single and self-contained issue to be addressed and resolved. Indeed, they do not appear to see the relationships between recurring patterns of complaints and the inherent difficulties which reside in the management and organizational system within which they function."

TU management responded to the ASLB concerning the INEL findings on "management style"[54] stating "in several respects it was a fair appraisal, although it is difficult to generalize over a ten-year construction period ... ." TU also states,

"Our current view is that these findings, (if confirmed ...), while clearly overgeneralized, reflect a

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54 TU Submittal to the ASLB dtd 6/28/85, Applicants' Current Management Views and Management Plan for Resolution of All Issues, (S04067/NP00110288)

management style that has not been ideal for handling employee relations in the complex world of nuclear power today. However, we have no basis upon which to conclude that Applicants' prior management was not fully committed to the quality of construction and safe operation of the plant."

We are uncertain what TU meant in the last sentence of this quotation. If, by "quality of construction", TU means effective implementation of the QA program for design and construction, we take strong exception to the portion of the above sentence that applies to construction. Using this definition, there is ample basis provided in this report for concluding that the prior TU management and supervision[55] were not "fully committed to the quality of construction". Similarly, if "quality of construction" meant that QA received the same emphasis from management as cost and schedule, we would have the same conclusion. Further, we do not know what a commitment to "quality of construction" means if management is not experienced and well informed regarding QA requirements. In short, we find no basis for concluding TU's prior management was fully committed to the quality of construction.

Given the premise that "getting the job done was the most important priority" (a fact that TU acknowledges[56]) combined with a strongly authoritarian management, it is reasonable to conclude that any activity likely to interfere with "getting the job done" would either be deleted, ignored, deferred, or critically examined and subjected to the maximum compromise consistent with meeting the letter of the requirement. We believe the project history at CPSES demonstrates this included Quality Assurance measures.

As for personnel below the management level, many of these had sincere and valid concerns regarding plant quality. However, in an environment where "getting the job done" was the most important priority, where communications were "primarily downward", and where there was "little tolerance for ... the questioning of supervisory demands", it is clear few QA/QC concerns (since they inherently flow from the bottom upward) that would impact construction progress would be transmitted very far up the chain of command. Given this resistance, it is not surprising many of the employee concerns regarding quality were transmitted to the intervenor (CASE) or to the NRC in the form of allegations.

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55 We believe there were some individual exceptions to this conclusion, but their influence was not decisive.

56 Management Views, June 28, 1985.

5.3.4 Conclusions

Based on the priorities and attitudes of TU management discussed above, the authoritarian TU management style, the personnel changes effected by TU management, the views expressed by the NRC, and the results of the TUGCO QA Management Review Board Survey, we conclude that during the Phase II period (mid-1976 to about 1984), TU's support of the QA effort was subordinated to its concerns for the plant cost and schedule.

5.4 Management Administrative Actions Affecting QA

This section of the report examines TU's actions over the course of the project to determine to what extent those actions may have contributed to the present situation. It is concluded that the present condition was created because TU subordinated Quality Assurance to Cost and Schedule.

5.4.1 Replacement of TU QA Management.

Section 5.3.2 made reference to some of the changes in TU QA management between Phases I and II. This Section describes those changes in greater detail and presents information on the qualifications of some of the individuals involved. This Section also discusses the effect of the changes on the implementation of the QA program.

Section 5.3.2 discusses some of the NRC concerns with QA at CPSES in the summer and early fall of 1976. During this time, Messrs. Bradley and Schmidt attended meetings with the NRC to discuss those concerns and made commitments to actions to resolve those concerns. A very short time after the September 3, 1976 meeting with the NRC, the QA Manager, Mr. Schmidt, was appointed Project Manager of CPSES, replacing Mr. Caudle. As shown in Section 5.3.2, Mr. Schmidt had a more positive attitude towards QA than Mr. Caudle. Mr. Schmidt's replacement as QA Manager was Mr. Chapman.

At this point it is informative to summarize the QA experience of Mr. Schmidt when he left the position and the experience of Mr. Chapman when was he was appointed to the position.

Mr. Schmidt[1]

- Served in position in QA for five years.
- Looked at QA programs of about five other nuclear utilities.
- Became a member of an industry group of QA managers.
- Attended training sessions on QA sponsored by Edison Electric Institute and others.
- Attended several meetings with NRC regarding QA (Regional meetings and in Bethesda).
- Employed a consulting firm to assist in preparing the TU QA Program.

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1 Oral deposition of Homer C. Schmidt, November 24, 1987, Vol. II, pp. 76 to 88. (S02359)

Mr. Chapman[2]

- o Attended required TU indoctrination training on QA for persons associated with nuclear project.
- o Audited by QA during period he was in charge of files.

In other words, Mr. Chapman had no more qualifications in the area of QA at the time he replaced Mr. Schmidt than would be typical for any of the other engineers assigned to the nuclear project. In view of the limited nuclear experience available within TU, one must ask why Mr. Schmidt's position was not filled with an experienced nuclear QA manager from outside TU or one of the relatively more experienced individuals from inside the QA department - e.g., Vega, Boren, Milam, Tolson? Although TU officials were generally lacking in nuclear or QA experience from any source other than their work at CPSES, any one of the other TU QA individuals at least already had several years of QA experience at CPSES. In terms of fully supporting the quality effort at CPSES, we find TU's failure to appoint a QA-experienced successor to Mr. Schmidt to be a major error on the part of TU senior management.

Mr. Schmidt had no more experience when he assumed the position of QA Manager than did Mr. Chapman. The difference, of course, is that at the time Mr. Schmidt was appointed to the position, the project was just beginning, formal QA efforts were just evolving as a result of new NRC regulations and guidance, and the beginning of CPSES construction was more than three years away. When Mr. Chapman was appointed to the position of QA Manager, construction had been under way almost two years and was proceeding at a high rate. Indeed, Mr. Chapman was appointed to the position at a time when, as previously noted, TU was very concerned about cost overruns and schedule slippages, and was taking determined action to prevent further erosion of cost and schedule goals. Thus, the person entering the position of QA Manager at this time needed experience at least comparable to what Mr. Schmidt had accumulated by that time.

Even without extensive prior QA experience, Mr. Chapman might have been able to more effectively carry out the responsibilities of QA Manager had he had the benefit of an orientation concerning the position from Mr. Schmidt. That such an orientation did not occur is apparent from Mr. Chapman's testimony.[3]

> Q. Did you have any discussions with Mr. Schmidt during this period of time?

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2 Oral deposition of David Chapman, October 26, 1987, Vol. I, pp. 53 to 58. (S02317)

3 Ibid, p. 51. (S02317)

A. Which period of time?

Q. When you first assumed the job as manager of quality assurance?

A. Yes.

Q. Is this in that transitional nature, in other words, trying to learn from Mr. Schmidt what your responsibilities were?

A. No.

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.
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Q. You didn't have any discussions, though, with Mr. Schmidt in terms of finding out what he had done as the prior quality assurance manager?

A. I might have had casual conversations but nothing major.

Regarding qualifications, Mr. Chapman's testimony also indicates that after he assumed the position of QA manager, he also read a number of documents pertaining to QA, such as Regulatory Guides, ANSI standards and the section of the PSAR dealing with QA.[4] As indicated in Section 5.3.2, however, his reading did not include the sections dealing with responsibilities and functions of the Quality Surveillance Committee (QSC), of which he was the chairman. This can be contrasted with the actions of Schmidt who, when he was QA Manager, conducted a refresher training session for the members of the QSC regarding its responsibilities and functions (see Section 5.3.2) Absent the knowledge of the purpose and function of the QSC, Mr. Chapman acquiesced in its dissolution.

The CPRT Collective Evaluation Report makes the following statement regarding Mr. Chapman's qualifications:[5]

"The historical TU Electric Manager, QA, while having extensive experience and adequate education, had no nuclear or QA experience prior to his assignment to the

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4 Ibid, pp. 59 to 60. (S02317)

5 Comanche Peak Response Team Collective Evaluation Report, Revision 0, dated 12/13/87, Part IV, p. 11. (S02449)

project. This would have been of lesser concern had key members of his staff and other TU Electric personnel had more extensive nuclear and QA experience. However, as described above, there was a lack of nuclear and QA experience on the part of TU Electric personnel assigned to the project."

As noted in Section 5.3, TU had serious concerns regarding project cost over-runs and schedule slippages during the second half of 1976. In addition, in late 1976, Mr. Fikar was appointed to the position of TUSI VP, Design and Construction, replacing Mr. Bradley, who was assigned to a position outside the CPSES construction effort. In this position, Mr. Fikar was responsible for the construction of CPSES, and obviously was vitally interested in avoiding further over-runs or schedule slippages. On January 6, 1977, Mr. Fikar attended a meeting at the CPSES site to discuss problems between TUGCO QA and Brown & Root construction.[6]

One of the problems discussed was the processing of Discrepancy Disposition Reports (DDRs), particularly as regards specifying corrective and preventive action. An indication of Mr. Fikar's appreciation of QA problems is provided by his reported remarks following a lengthy discussion of DDR closeout problems. In this instance, he is reported to have said, "I don't believe it. How could we spend two weeks and many manhours to close out some simple unimportant items such as some of these. What are we going to do to correct it?" What Mr. Fikar did not understand was that the underlying issue was not how to deal with the individual "simple unimportant" problems, but the fundamental QA issue of the proper approach to dealing with corrective and preventive action for all problems. Because he did not understand this, he did not understand why a great deal of effort had been required to resolve the items. Mr. Fikar's reaction to this discussion is also consistent with one of the INEL conclusions regarding management style cited in Section 5.3.3; specifically, the characteristic of dealing with the immediate issues and neglecting the underlying cause.

Later in the meeting a B&R representative summarizes B&R Construction's position that if they followed TUGCO QA requirements, "... in the next few years we would spend many millions of TUSI's money to achieve perfection in lieu of acceptable quality. For instance, TUGCO QA has requested a calibration building in excess of $140,000.00 which we know is not required and are now making studies to see what an acceptable building would cost." The B&R minutes of this meeting clearly indicate Mr. Fikar sided with B&R on this issue. Mr. Fikar's

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6 Dodd (B&R) memo to Ashley (B&R) dtd 1/7/77, Summary Meeting - 1/6/77, Gatchell Exh. 88, (S00934)

support of B&R construction is also confirmed a few weeks later by the previously mentioned transfer of the Site QA Supervisor (Milam) to a position on the construction staff.[7]

According to Mr. Gatchell's deposition, the Site QA Manager was transferred because his conscientious QA efforts were impairing construction progress.[8] At least a portion of the philosophical problem is illustrated by the minutes of the above January 1977 meeting with Mr. Fikar, where Milam states that all identified deficiencies should be reported by QA/QC regardless of apparent significance. The point being that Engineering should decide what is important, not QA/QC -- a view also endorsed by Mr. Vega in his deposition.[9] Mr. Milam also appeared to hold the view that construction should not proceed until deficiencies were properly corrected. The view taken by B&R was that B&R QA/QC supervision could decide what was significant and could accept a less comprehensive response in such cases. This view, of course, had a lesser impact on the progress of construction.

The QA Manager at the time of Mr. Milam's transfer (Chapman) has testified Mr. Milam was transferred because he had trouble dealing with people.[10] The testimony in this instance provides insight as to the Phase II TU QA manager's attitude toward QA.

> Q When you say he was having problems dealing with people, would you elaborate on that, please?
>
> A Well, he was kind of feisty and reacted -- he did not suffer what he considered to be ignorance or sloth well. He did not have a lot of patience with people who -- who he felt might not have the right-- the right attitude about the quality of a nuclear power plant.

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7 While Mr. Chapman states the decision to transfer Milam was his, he also acknowledges he consulted with Messrs. Gary and Fikar on his decision, Oral Deposition of David Chapman, October 26, 1987, Vol. I, p. 77. (S02317)

8 Oral deposition of Charles Henry Gatchell, July 23, 1987, p. 141, (S00932)

9 Oral deposition of Antonio Vega, October 8, 1987, p. 125 (S01371)

10 Oral deposition of David Chapman, October 26, 1987, p. 74. (S02317)

Q Mr. Chapman, isn't that the type of individual that you want as a quality assurance employee?

A Yes. I say yes. I also want somebody that can deal with people, also.

About nine months after the replacement of Mr. Milam as TU Site QA Supervisor, the CPSES project was reorganized. In this reorganization Mr. J. B. George was named Project General Manager and the former TU Project Manager, Mr. Schmidt, was assigned to the position of Director, Nuclear Services. It should be recalled that Schmidt was the former TU QA Manager -- who was appointed Project Manager by Mr. Bradley during a period when TU was trying to re-establish the NRC's confidence in the QA Program at CPSES. Thus, during 1977 two of the persons in the organization most knowledgeable concerning QA requirements were placed in positions where their QA knowledge would not impair construction progress.

Mr. Tolson was the replacement for Mr. Milam as TU Site QA Supervisor. He held this position from about January 1977 to March 1984, when he was replaced by Mr. Vega. Mr. Tolson brought a new attitude to the job, as illustrated by the following examples.

While B&R construction had difficulty with Mr. Milam because they believed he was too strict, other documents suggest B&R QA had difficulty with Mr. Tolson because he was not strict enough. This is particularly illustrated by Attachments 2 and 3 to a letter from Munisteri of B&R to Gary.[11] These attachments, written from the B&R perspective describe an incident where Mr. Tolson directed that unacceptable inspection results on soil compaction be accepted, that the responsible B&R Civil QC Supervisors be transferred and that in the future, Civil QC would report to TU.

The attachments to a memorandum from Tolson to Klimist[12] describe a concern by the B&R Site QA Manager regarding plant licenseability because nonconforming conditions (two specific examples are cited) are being dispositioned without providing documented traceability to the applicable design references, calculations and analyses. Mr. Tolson responds by stating he does not have a problem with the examples and believes that

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11 J. Munisteri, B&R, confidential letter to R. Gary, TU, dated May 11, 1978, with attachments (S00105).

12 R. Tolson, TU, memorandum to R. Klimist, B&R, dated March 18, 1980, with attachments (S00491).

routine audits will assure the design control loop is properly closed. He does, however, request the TU audit organization to audit these two specific examples but does nothing to prevent recurrence of such instances. Mr. Vega's response to Klimist[13] confirms that audits of the two specific items will be performed and generally reflects a greater appreciation of the requirements. These two items were addressed in Audit TGH-13.[14] One item was closed. The second item was to be "examined in the followup audit." The followup audits, TGH-15,[15] TGH-19,[16] and TGH-20[17] have no reference to resolution of this nonconforming item. Therefore, even the specifically identified items were not resolved. This does not indicate a program likely to identify other deficiencies in the design change process. It is clear, however, that design traceability ultimately became a significant issue for CPSES Unit 1 licensing as evidenced by the formation of the Design Adequacy Program as one of the two major efforts under CPRT.

Another example of Mr. Tolson's expedient approach to QA is provided by his combative response to some audit deficiencies identified in his area of responsibility. One example is provided by Mr. Tolson's response to Deficiency No. 5 in Audit TCP-12[18]. In this instance it was found that a design change issued to correct the identification of the cable reel used in certain work was recorded on the "pull" card but not on the associated "megger" and "termination" cards. In addition, the QC inspection report, which required verification of cable and termination card agreement was marked "satisfactory" even though the correct cable reel number was not marked on the "termination card". As TU Site QA supervisor, Mr. Tolson's initial response deserves quoting:

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13 A. Vega, TU, memorandum to R. Klimist, B&R, dated March 26, 1989 (S00490).

14 Letter from D.N. Chapman, TU, to H.R. Rock, G&H, dated May 30, 1980, Subject TGH-13 (S00534) CS 00391930

15 Letter from D.N. Chapman, TU, to H.R. Rock, G&H, dated October 23, 1980, Subject TGH-15(S00584) CS 0040363

16 Letter from D.N. Chapman, TU, to N. Keddis, G&H, dated August 12, 1982, Subject TGH-19(S00566) CS 00040236

17 Letter from D.N. Chapman, TU, to N. Keddis, G&H, dated January 11, 1983, Subject TGH-20(S00562) CS 00040209

18 R. Tolson, TU, memo to D. Chapman, TU, dated October 21, 1980 (S00922).

"We do not plan to take corrective or preventive action for this item. By way of explanation, the cable pull card and/or QC Inspection Reports are the primary records in the cable arena. The meggar (sic) and termination cards are of secondary importance and virtually insignificant from a QA Records viewpoint. ..."

The response provides useful insight into Mr. Tolson's attitude toward providing correct records. In addition, his response fails to address the specific requirement to verify agreement between the cable and the cable termination card. Because Mr. Tolson did not respond to this last item, the TU QA Manager requested a further response addressing this issue. Mr. Tolson's response to this was, "No corrective action of this identified item is planned as we do not consider this a deficiency." Mr. Tolson then provided two paragraphs of what appears to be rationalization for not meeting a simple and straightforward records requirement. We have not found documents showing any further disposition of this issue.

Another example of Mr. Tolson's approach to audit findings in his area of responsibility is provided by Audit Report TCP-74 and Mr. Tolson's response to item six (the only deficiency applicable to his area)[19,20]. This finding relates to a procedure used by Design Change Verification (DCV) personnel to review electrical design changes as shown on Design Change Authorizations (DCAs) and verify their incorporation into the physical plant. The deficiency is that the DCV personnel had been verbally directed to review only the DCAs which were "most important", but had not received training or indoctrination to identify DCAs by degree of importance. Mr. Tolson's response is blunt and pugnacious:

"We do not agree that this is a deficiency for the reasons stated below. We also note that there is no logical tie between the requirement stated and the finding and we therefore conclude that we are addressing an opinion."

Mr. Tolson then argues the system must be flexible, but also gives specific examples of DCAs that do not affect plant safety. He does add, however, that each safety related DCA is reviewed and "statused".

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19 D. Chapman, TU, audit report to J. Merritt, TU, dated August 1, 1983 (S01056).

20 R. Tolson, TU, memo to D.Chapman, TU, dated August 23, 1983 (S01061).

Apparently, as a result of Mr. Tolson's statement that all safety related DCAs are reviewed, the deficiency is closed. The fact Mr. Tolson considers it only an opinion of the auditor that DCV personnel should have training or indoctrination on what is "most important" is revealing as to the TU Site QA supervisor's attitude toward QA requirements. The supervisor's response is also informative in that it states the DCV effort developed from a concern that the volume of design changes at CPSES created the possibility that some required QC inspections may not have been accomplished. The issue of a large volume of design changes is discussed further in Section 5.4.3.

Another assessment of Mr. Tolson's attitude toward QA requirements is provided by Mr. Joseph Lipinsky. Mr. Lipinsky was an engineer for a coatings (paint) application company and, at the request of TU, performed a study of the adequacy of the coatings program at CPSES. Mr. Lipinsky recorded in his testimony before the ASLB,[21] that upon reporting to TU that his preliminary findings indicated several potential problems, he found Mr. Tolson's attitude toward his findings unexpected and inappropriate for a QA Supervisor.

Mr. Tolson's expedient approach to QA/QC matters was not lost on QA/QC personnel. As a result, numerous allegations of poor quality construction were forwarded to and investigated by the NRC during this phase. For example, in May and June 1979, the NRC Region IV Office performed an investigation of allegations of poor construction practices. In the cover letter forwarding the results of the investigation to TU,[22] Region IV states,

> "We also noted during this investigation that a thread of continuity existed between this investigation and others recently conducted relative to alleged problems with site management and quality control in certain areas of construction. ... when these allegations are taken collectively, there appears to be a morale problem which is evidenced by several of the allegers and may be attributable, in part, to communication problems between the workers and supervision."

As noted in Section 5.3.2, these NRC concerns led to the TU survey of QC inspectors conducted by the TUGCO QA Management Review Board. It will be recalled the results of these surveys indicated a widespread belief among the interviewed inspectors

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21 Testimony of Joseph J. Lipinsky before the Atomic Safety and Licensing Board, Docket 50-445/446, NP 0015-1480, page 8. (S04065)

22 NRC CPSES Inspection Report No. 79-15, dated July 2, 1979.

that the emphasis on the project was on production, not quality. In addition, the survey indicated many of the QC inspectors were concerned because an inordinate number of the deficiencies they had identified were subsequently dispositioned "use-as-is" by engineering without a reasonable explanation as to why the deficiency was acceptable. Both of these concerns expressed by the QC Inspectors, as well as the numerous allegations concerning poor quality construction, indicate the actions of TU Project and QA/QC management had created the perception that quality was being subordinated to considerations of cost and schedule. Since this perception was widely held among the first line workers charged with inspecting for conformance to quality requirements, we believe the perception was valid.

Other examples of the attitude toward QA of the TU Site QA Supervisor during Phase II are provided by the TCP-66 Audit and the T-Shirt incidents. The report of the investigation of the TCP-66 Audit incident[23] discloses the following:

- "The person accused of intimidation (Tolson)[24] has a strong personality and all parties who have had dealings with him indicate that his normal demeanor in meetings and discussions is for him to come on strong and abrasive. Depending on the personality of whom he is dealing with, his manner could be considered intimidating."

- "He has told his people to quit taking issue with QA personnel and wait until an audit report comes out."

This last conclusion indicates it was not an unusual practice for Tolson's Site QA/QC personnel to take issue with the TU Dallas QA auditors. Inasmuch as both groups are supposed to be working toward the same goal, we consider it inappropriate that Site QA/QC should be taking issue with the findings of the Dallas QA auditors. If Site QA/QC was to be involved in disagreements, we believe such disputes normally should have been with Construction and/or Engineering, not other branches of the QA organization. The most prominent incidents involving the TU Site QA Supervisor during Phase II involved disputes with QA/QC personnel (or B&R personnel who argued that a condition did not meet specifications) rather than Construction. The TU QA Manager permitted this behavior to continue.

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23 Report on Allegations of Cover-up and Intimidation by TUGCO, Dallas Quality Assurance, 8/19/83, p. 9, (S02447/CS00151802)

24 Videotaped Deposition of Roland F. Cote', 9/10/87, p. 31, (S02465)

Although this attitude was shared or tolerated by the TU QA Manager, it did not necessarily extend to the individual to whom he reported after August 1980, the Vice President, Nuclear (Clements), who also had responsibility for QA. This is indicated by the vigorous investigation of the TCP-66 Audit incident ordered by Clements, and his close personal interest and involvement. At the conclusion of the investigation Clements held a meeting with the TU QA professional staff to discuss the results of the investigation of the TCP-66 Audit. The minutes of this meeting[25] indicate Clements met with Mr. Tolson and informed him that his behavior during this incident was inappropriate.[26]

That the attitude of the TU Site QA Supervisor continued to be a problem for Site QC personnel is further illustrated by the T-Shirt incident. In his deposition for the ASLB Mr. Tolson states his belief that the incident was directed personally against him.[27]

> Q What kind of display? What is your perception of what this display was?
>
> A I took that as a personal slap at me and my office.

That this TU Site QA/QC attitude persisted until Mr. Tolson's reassignment out of QA in early 1984 is demonstrated by the interviews of Electrical QC inspectors conducted by Mr. Grier on March 8 and 9, 1984.[28] These interviews disclosed the same concerns mentioned in the earlier survey of QC inspectors. In addition, three fourths of the inspectors interviewed believed that inspection procedures were changed too frequently and that the changes had been in the direction of relaxing requirements.

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25 Report on Allegations of Cover-up and Intimidation by TUGCO, Dallas Quality Assurance, 8/19/83, (S02447/CS00151802)

26 Although the vigorous actions of the VP Nuclear can be complimented in this instance, it should be noted that they occurred in mid-1983 when the NRC and ASLB were already expressing serious concerns regarding QC inspector intimidation and harassment.

27 Deposition of Ronald D.Tolson, July 10, 1984, p. 40,551. (S00740)

28 Grier memo to Tolson dtd 3/15/84, Interviews of Electrical QC Inspectors, Safeguards Building Task Force, Vega October 13, 1987 deposition Exhibit 538, (S01374/PT00921540)

Further understanding of the image projected by Mr. Tolson is provided by the testimony of Mr. Clements,[29]

> Q. All right. Did you ever reach the conclusion that Mr. Tolson had some personality problems? By that I mean in terms of dealing with doing his job.
>
> A. Tolson was what we'd call a real construction man. And I'm talking about the big boots and the hard hat and so forth. He was one of the best QC guys I've ever seen, but after seven years down there, Chapman and I came to the conclusion that he needed to be transferred.
>
> .
> .
> .
>
> Q. All right. You've probably already answered this in a different form but let me cover it anyway. Did you ever see any evidence that Mr. Tolson had sacrificed QA at the -- for or in favor of the construction schedule?
>
> A. I just told you that Mr. Chapman -- Mr. Tolson is one of the best QC men I've ever seen and that wouldn't be consistent with what I just said.
>
> Q. Wouldn't be consistent. All right. But when you said he was a construction -- a real construction man, I sort of had the impression that he is one who took a strong interest in seeing that the construction schedule was maintained and that the plant was built.
>
> A. He had nothing to do with cost and schedule whatsoever.
>
> Q. All right.
>
> A. I'm just trying to paint a picture of a man that -- well, is kind of a rough and tough character on the outside. He really wasn't, but he gave the impression that he was.

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29 Oral deposition of Billy Ray Clements, December 15, 1987, Vol. II, pp. 174 to 175. (S02461)

Thus, even the Vice President, Nuclear (Mr. Clements) grants that Mr. Tolson presented the image of a "rough and tough character"-- an image that would be intimidating to some individuals. Although Mr. Clements perceived Mr. Tolson's lack of concern for schedule, the working level QC inspectors were in a far better position to make such a judgement, and did, on more than one occasion.

A further measurement of the effectiveness of the TU QA/QC effort during this phase is provided by the report of the NRC's Special Review Team. This team conducted an inspection at CPSES in April 1984, a few weeks after Mr. Vega replaced Mr. Tolson as TU Site QA Manager. A portion of the inspection was devoted to formal interviews of QC personnel (five management personnel and 28 inspectors). Regarding communications, the report states,[30]

> "Many of the inspectors indicated that communications were improving and the assignment of the new site QA manager was a positive step in improving communications. It was clear that some communications problems had existed in the past and rapport between inspectors and their management had been strained previously in some areas. Communications in the ASME code construction area appeared to be exceptionally positive."

Thus, it is clear that under Mr. Tolson, communications between QC inspectors and their supervision was poor and the relationships between these two groups were strained. Such conditions are fully consistent with an authoritarian management style that does not want to hear about quality problems and is disposed toward minimizing the significance of those of which it does become aware. It is also clear that the QC inspectors believed their work situation had improved with the arrival of Mr. Vega. It is also a measure of TU performance that communications were considered "exceptionally positive" in the ASME area where TU did not have technical jurisdiction.

Based on the foregoing, we conclude that late in Phase I and early in Phase II, responsible TU management perceived that overly conscientious implementation of the CPSES QA Program was adversely impacting construction progress, and hence, cost and schedule. Accordingly, TU management decided to reassign the conscientious TU Site QA Supervisor to a non-QA position and replace him with an individual who had a more "cooperative" attitude toward construction. The preceding discussion has shown that the individual selected was less dedicated to rigorous application of QA requirements than his predecessor and was

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30 Eisenhut (NRC) letter to Spence dtd 7/13/84, Comanche Peak Special Review Team Report, p. 62

frequently involved in disagreements with those who sought rigorous implementation. In addition, his position and his personality could be perceived as intimidating by some individuals who did not agree with his interpretation of QA requirements. That this individual remained in his position for over seven years demonstrates that TU management was satisfied with his attitude and his performance.

5.4.2 TU Assumption of Management of Site QA/QC Program.

On January 3, 1978, TU (TUGCO) assumed the overall technical management of QA/QC functions for CPSES except for those activities under the jurisdiction of the ASME Code, Section III, Division 1.[31] This responsibility previously had been assigned to B&R. The practical effect of this change, as shown by the organization chart attached to the referenced letter, was that the B&R QA, QC and Vendor Surveillance functions located at the CPSES site would now report to the TU Site QA Supervisor, Mr. Tolson, instead of to the B&R QA Manager located in Houston.

Some of the reasons for this change appear in a Gamon to Munisteri memorandum dated December 12, 1977.[32] A central issue appears to be B&R's desire to use its generic procedures versus TU's desire that the procedures be customized to the needs of CPSES. In his deposition, Mr. Vega states that the development of procedures acceptable to TU was the overwhelming reason for the change.[33] Review of the Gamon memo, however, indicates there were other sources of friction between B&R and TU; for example,

> "B&R QA has been increasingly concerned by an apparent growing attitude by TUGCO to run all phases of the project without regard to normal organization and planned programs. Thus at a meeting at the site on November 15 B&R complained to Mr. Chapman about Mr. Tolson giving direct orders to B&R QA personnel rather than through appropriate B&R QA supervision and about Mr. Tolson directly establishing a meeting relative to planning for cold weather concrete placement control."

The reorganization, therefore, would not only solve the problems associated with procedures, but would give TU Site QA, direct control over most site QA/QC activities.

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31 R. Gary, TU, letter to J. Munisteri, B&R, dated January 3, 1978 with attachments (S00102).

32 T. Gamon, B&R, memo to J. Munisteri, B&R, dated December 12, 1977 (S00101).

33 Oral deposition of Antonio Vega, October 8, 1987, p. 156

At first glance, TU's assumption of the management of site QA/QC might appear to be a positive step with regard to improving project quality. Indeed, based on the documents we have reviewed, when Mr. Milam was TU QA Site Supervisor, such an action clearly may have had a positive effect on project quality if the appropriate separation between QA and cost and schedule pressures had been provided. Under Mr. Tolson, however, it led to a condition where many QC personnel believed that production was more important than quality. This condition would persist, off and on, for six years.

5.4.3 Management Acceptance of Risk to Maintain Construction Progress.

Concerned with lagging schedules, TU management adopted methods of handling field-originated design changes at CPSES which were intended to maintain construction progress, but entailed a degree of risk. Criterion III, Design Control, of Appendix B to 10CFR50, requires that,

> "Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design unless the applicant designates another responsible organization."

Since TU did not designate "another responsible organization", all field-originated design changes required review by the original design organization. For many of these changes, the original designer was G&H.

A policy adopted by TU[34] for expedited handling of field changes at CPSES was to permit construction to continue immediately following on-site preliminary engineering review and approval of these changes, and prior to final design review. The risks associated with this approach are:

(1) Detailed review by the original design organization may disclose the change was not acceptable. In such a case, additional costs and delays may be incurred as a result of the need to redesign and modify the affected component.

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34 At the suggestion of B&R QA. See Minutes of Project Status Review Management Meeting, October 13, 1976, (S04016A/BH00210621)

(2) Operating in the environment of construction pressure, the on-site engineering review may be biased toward simply approving design changes so that construction may proceed. Such an attitude would, of course, increase the proportion of field changes that would require subsequent rework. Also, there would be additional pressure on the engineers performing the final review to accept nonconforming conditions to avoid the necessity for rework.

(3) If there are numerous field changes and they are not promptly reviewed by the original design organization, a large backlog would accumulate. As the backlog grew, the more likely it would become that field changes would be made to components already incorporating field changes that have not yet received final review and approval. Not only does this increase the magnitude of any possible rework, but it also makes it more difficult to know exactly what the approved design is at any given time, or if it is really acceptable.

At least two other types of documents were used at CPSES to record approval of deviations from the original designs: Nonconformance Reports (NCRs) and Component Modification Cards (CMCs).

NCRs were normally generated when a component was inspected by QC and found to be nonconforming with respect to some inspection attribute. If the project thought a nonconformance might not be functionally significant, the NCR could be referred to the original design organization for review. If this review indicated the nonconformance was not functionally significant, the NCR could be dispositioned "Use As Is". This meant that no repair, modification or replacement was necessary. Such a deviation, therefore, effectively became an accepted designed change for that component.

CMCs were primarily used in conjunction with drawings which showed "typical" designs of certain components -- normally supports or hangers for piping, cable trays, conduits or HVAC ducts and components. If the hanger or support could be used exactly as shown in the design (and was used in the proper application), engineering review was not required. In many instances, however, local congestion and/or interferences would require some modification of a "typical" design. In such a case, engineering review by the original design organization was required to assure the adequacy of the modified design.

NCRs and CMCs referred to the design organization therefore, were simply other forms of field-originated design change requests, and TU applied the same method of operation to processing these changes as it did to conventional field changes. TU recognized and accepted the risk inherent in this approach, as is apparent from several documents:

In a letter from Hersperger, G&H, to Schmidt of July 18, 1977,[35] Mr. Hersperger states that effective July 13, 1977, the G&H resident engineer at CPSES will have authority to approve construction nonconformances prior to the approval and design review of these nonconformances by G&H's Engineering Department. Mr. Hersperger adds,

> "This new policy is being implemented at TUSI's request, based on their receipt of verbal expressions of acceptance from the NRC, and, is intended to expedite the resolution of construction problems involving engineering review. It is understood by G&H that TUSI recognizes and accepts the risks of potential backfitting which this new policy may give rise to in the future."

That TU was aware of the risk involved in adopting this policy is shown by the testimony of Mr. Vega. In his deposition he stated,[36]

> "We [QA] expressed a concern that this was going to place additional emphasis or we were going to have to put additional emphasis on the tracking mechanisms for the CMCs in that we had to assure that these CMCs, if found unacceptable, would result in a rework relevant to what was approved which had been then later found to be unacceptable.
>
> "The second item was that we expressed to our management the awareness that it was extremely important to make sure that this approach did not in any way detract from the thoroughness of the design review when it was done later in New York. So, having expressed these concerns and then committed to making sure that the proper controls were in place, we agreed to implement this policy."

The memo from Ainsworth to Vega dated October 7, 1977,[37] records

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35 R. Hersperger, G&H, letter to H. Schmidt, TU, dated July 18, 1977 (S00908).

36 Oral deposition of Antonio Vega, October 8, 1987, p. 136. (S01371)

37 J. Ainsworth, TU, memo to A. Vega, TU, dated October 7, 1977 (S00394).

TU approval of issuance of drawings or specifications for construction which contain minor errors. The memo adds,

> "TUSI can obtain significant advantages if these documents are issued to the field - immediately followed by a DC-DDA."

Thus, in their desire to adhere to the construction schedule, TU authorizes the issuance of drawings and specifications containing known errors for client approval, and construction. Such a process is not one which favors the quality of construction. First, it is obviously not good quality practice to issue drawings which are known to contain errors because these errors could be translated into hardware. Second, even if the errors are accurately tracked and are not translated into hardware, the need to track these avoidable errors adds to the burden of the administrative system established to track unavoidable errors. And third, it is clearly a poor policy to allow designers to issue drawings containing known errors because this may then become the norm. For the above reasons, we conclude this policy subordinated consideration of good quality practices to consideration of schedule.

The Report of the 1978 MAC Audit of CPSES[38] directly addresses the issue of field changes. Paragraph III of Appendix B of the report states,

> "The present system of expediting field changes by referring design changes to the original design organization for approval after the fact does not meet the intent of 10CFR50 Appendix B nor of ANSI N45.2.11, which require that field changes be subject to design controls commensurate with those exercised on the original design. TUGCO audits have already disclosed that the Architect/Engineer has not been reviewing field originated changes on a concurrent basis, thus the design engineer's comments may be received after the specific construction work is complete resulting in possible loss of design integrity, undue pressure on the designer to justify what has been done, loss of designer responsibility or possible extensive repairs. It is recommended that a system for expediting review and approval by the original designer be established on all safety related changes using telephone, telecopier or telex as necessary to coordinate and document change approvals."

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38 J. Jackson, MAC, letter to P. Brittain, TU, dated May 17, 1978, with Attachments (M00041).

The TU internal response to this finding[39] was to reject it on the basis that TU had not experienced any significant problems thus far.

TU's position on the issue of unreviewed CMCs is stated in the TU response to Audit TCP-18.[40] The deficiency identified by the audit was as follows:

> "Measures have not been established for design review of CMC's in the Pipe Support Design Group (PSDG). No schedule has been established for these activities. Particular concern is extended due to CMC's being approved without supporting calculations and the nature of some CMC's involving the turned-over demineralized water system. ...."

TU's response was:

> "TUSI management accepts the liability of approving field design changes without supporting documentation. This direction has been established in order to support construction activities and is proceeding accordingly. We acknowledge the regulatory position that all field design changes must be reviewed/approved by the original design organization and subsequently scrutinized by an independent design verification function.
>
> "Where CMC's are issued without supporting calculations, such engineering documentation will be generated in the review cycle as applicable for significant changes. All such evaluations will be independently verified."

Here again, TU is saying "build it now, check it later" while acknowledging there is potential rework liability associated with this approach.

As disclosed by the CPRT Corrective Action Program on large bore piping and pipe supports (discussed later in this section), significant rework was required. The NRC Safety Evaluation Report Supplement which addresses large and small bore piping and

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39 R. Gary & L. Fikar, TU memo to P. Brittain, TU, dated July 11, 1978 (M00042).

40 J. Merritt and M. McBay, TU, memo to D. Chapman, TU, dated Feb. 4, 1981 (S01005).

pipe supports (SSER 14),[41] describes the underlying cause as follows:

> "... in the piping and pipe support area, significant design changes were implemented during construction to expedite hardware installation. Although the field designs and design changes did not necessarily result in an unacceptable design, the type of changes, in many cases, invalidated the the analytical assumptions made in the supporting calculations and thus caused a deficiency in the supporting calculations. Specific analysis methods to reconcile these designs did not exist to guide the designers consistently in their work. As a result, analytical justification was difficult and would have required extensive reanalysis, advanced analytical techniques, or experimental tests to adequately qualify the designs. The applicant's use of engineering judgment at the time to qualify the designs was found unacceptable because the designs transgressed the limits of standard industry practice into an area where that judgment had little or no basis."

In August 1980, TU had a corporate reorganization. As a result of this reorganization, Mr. Clements was appointed Vice President Nuclear and the QA Department was assigned to report to Mr. Clements. During his deposition Mr. Clements was asked about the after-the-fact design review practice and agreed that the after-the-fact (or at-risk) method of design change verification carried with it inherently a higher risk of QA problems than the front-end design change method.[42] Since this practice was adopted to expedite construction, Mr. Clements' testimony supports the view that considerations of quality were subordinated to considerations of cost and schedule.

It was mentioned at the beginning of this section that one of the risks of TU's method for handling field design changes was the accumulation of a large backlog. Our review of project documentation discloses that a large backlog did develop. One example of this is disclosed by a G&H letter to TU dated June 5, 1979.[43] In this letter G&H states "... CPSES Engineering (NY and

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41 Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2. NUREG-0797, Supplement No. 14, p. 5-1.

42 Oral deposition of Billy Ray Clements, December 15, 1987, Vol. II, p. 53. (S02461)

43 H. Rock, G&H, letter to J. Merritt, TU, dated June 5, 1979 (S00493).

Dallas) has reviewed the current situation where a large backlog of design changes exist without design review." G&H then outlines a program which will determine the "true size of the backlog", will process the present backlog, and provide for timely review of future design changes. Our review fails to disclose any significant action by TU to respond to this concern until more than a year later.

The action taken by TU appears to have been in response to TU QA Audit TCP-13[44] when TU ordered all Class III gang hangers placed on hold.[45] Finding 11 of this audit states, in part, as follows:

> "... CMC's on 8 c : of 11 hangers, which are part of Class III gang hangers, have not been design reviewed. ... The CMC's on 6 of the 8 have not been received by engineering for design review action. Of the four that have been design reviewed, instances were noted where the record indicates that design reviews have been done to non-existent revisions of BRH's. In other cases, reviews were done to obsolete revisions of the CMC. ...
>
> "In addition, design reviews of changes to NPS designs, have not been established on site. While we acknowledge evidence of efforts in this area, there is a significant backlog in this area. Four hundred nine (409) packages are presently awaiting design review, and "several thousand" which are progressing toward that point. (sic)"

It is noted that at the time this audit report was written (7/25/80) the estimated fuel load date was December 1981. Thus, all of the required design reviews, plant modifications and as-built verification would need to be performed in less than seventeen months to support preoperational testing.

About six weeks after the above audit report was issued, the TU Engineering and Construction manager requested an audit of the G&H activities on design review because there was "a lot of concern expressed in this area as to timely close out of field changes."[46] TU QA responded by performing QA audit TGH-15. The report of this audit characterized it as "... an early evaluation

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44 Chapman memo to Merritt dtd 7/25/80, Audit Report TCP-13, (S00191/CS00101290)

45 Memo from D. Chapman to J. Merritt dated November 25, 1980, Evaluation of Responses to Audit TCP-13 (S00197/CS00101238.)

46 J. Merritt, TU, memo to D. Chapman, TU, dated Sep. 9, 1980, (S00586).

of the program established to control the processing of field changes documented on Component Modification Cards (CMC's)".[47] The fact this was an early evaluation indicates the program had only recently been initiated -- approximately fifteen months after G&H notified TU of G&H's concern. The audit made several observations that are discussed later.

Other evidence TU management should have been fully aware of the risks presented by a large backlog is provided by the March 1981 Report of Audit TCP-6, Follow-up #2.[48] The summary of this report states:

> "It is the observation of the audit team that significant backlogs exist in the above areas. Issuing less than thoroughly reviewed engineering work adds to the existing backlogs. Even though the adverse cost and schedule impacts caused thereby are not the responsibility of QA, we are concerned that accelerated "back-end" efforts to clear the backlogs under time constraints could make design verification extremely difficult."

Another measure of the size of the CMC backlog (in the structural area only) almost four years after G&H raised the concern is given by the report of the NRC February 1983 CAT Inspection of CPSES.[49] On page IX-3 of this report, the inspector notes,

> "A review of the Gibbs & Hill 'CMC Master Index' (structural) indicated there were on the order of four-to-five thousand of such changes that had been generated but had not yet been 'final' reviewed by Gibbs & Hill.
>
> "It was determined that proper verification of such changes might ultimately be accomplished. However, the volume of CMCs and DCAs remaining to be reviewed by the original designer, as well as those designs that have as yet to be performed in the structural area, is of concern to the NRC CAT inspector. The concern involves the adequacy of review which will be provided considering the approaching September, 1983 Fuel Load Date."

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47 J. Merritt, TU, memo to D. Chapman, TU, dated Nov. 26, 1980, TUSI response to Audit TGH-15, (S00582).

48 D. Chapman, TU, letter to J. Merritt, TU, dated March 24, 1981, TCP-6 Follow-up #2, (S00199).

49 R. DeYoung, NRC letter to R. Gary, TU, dated April 11, 1983, with attachments.

Based on this observation by the NRC, any efforts made by TU during the preceding two and one half years to reduce the backlog of unreviewed design changes were totally ineffective. Not only had the number of unreviewed design changes grown to 4,000 to 5,000 (in the structural area only), but the time available for review, modification as needed, and as-built verification had shrunk from seventeen months to seven months.

It is also noted that in 1982, during the very time G&H was attempting to reduce the large backlog of unreviewed field design changes, TU was actually cutting the G&H budget.[50] Even if G&H's design efforts were nearing completion, G&H was still responsible under the provisions of 10 CFR 50, Appendix B, for reviewing the backlog of field initiated design change requests. Hence, any budget reductions at this time would act counter to achieving timely review of these design change requests and prolong the exposure to possible quality problems. The budget reduction at this time provides another example of a QA requirement or prudent practice (timely review of design changes) being subordinated to considerations of cost.

The large number of outstanding, unreviewed CMCs was not the only problem, however. Some CMCs had several revisions, and the basic design of many components was modified by several CMCs issued at various times. The CAT inspection report notes on page III-8,

> "A review of the documentation packages for the 24 supports/restraints listed previously was performed. The packages are difficult to follow due to the large number of changes involved with an average of over five CMCs per support and as many as 16 on one support."

The result of this "build now, check later" process, the accumulation of a large backlog of unreviewed design changes and the failure to provide timely review of the design changes, was a situation where it was very difficult to know if a component had been constructed in accordance with its design. For example, the CAT inspection report (page IX-3) notes that of 20 electrical supports examined, 12 were not inspected to the latest design--even though the inspections were designated as "final inspections" (i.e. the design had been revised after the "final inspection" had been performed). In other inspections, the inspection was performed using CMCs that were not the latest revision <u>at the time the inspection was performed</u>.

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50 Miller (G&H) memo to Ballard (G&H) dtd 8/13/82, Proposed Cuts to QA, (S02296/GH0032), and Rock (G&H) memo to Ballard (G&H) dtd 8/19/82, TUSI QA Budget Reduction, (S02297/GH00632189)

A similar finding was made by Cygna. In responding to an NRC question concerning cable tray supports, Cygna reported that during a walkdown of 49 cable tray supports, fifteen had major discrepancies between the latest design drawings, including applicable design changes, and the installation.[51]

The testimony of Ms. Hatley, a former QC inspector at CPSES, illustrates the practical effect of this condition on the work of craft personnel and QC inspectors:[52]

> "To explain to you briefly, a drawing, a blueprint, is supposed to be how the thing is built. It was not uncommon for there to be 300 design and part changes attached to a single drawing, so it became where the first design change got so far away from the last design change and what the original intent was ... The documentation then, when they had these mounds of documents, a package that a craft person had to take to the field weighed approximately two to three pounds."

A similar view was expressed by Cygna:[53]

> "In order to determine if there are any design changes associated with a cable tray support, it is necessary to check all design changes written against the G&H design drawing for applicability to a given support. Since more than one support design is shown on the design drawing and an average of 500 design changes, which includes revisions, may be written against a design drawing, the process of determining the latest design configuration is extremely cumbersome and time consuming. The field design organization maintains a listing of design changes by support number, but it is not controlled and was found to be inaccurate during the Cygna review. ...
>
> "... The practice of allowing so many design changes to accumulate against the design drawings and the inability to readily identify which changes are applicable to given details on the design drawings, appears to have increased the possibility that the QC

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51 Williams (Cygna) letter to Noonan (NRC) dtd 3/8/85, Response to NRC Questions, p. 1. (M00613)

52 Transcript of Contention 5 Panel meeting with CASE 2/7/85, p. 44. (S02450)

53 Williams (Cygna) letter to Noonan (NRC) dtd 3/8/85, Response to NRC Questions, p. 3. (M00613)

inspector may accept an installation which does not incorporate all of the necessary design changes."

Additional problems associated with having a large number of design changes on a project, even when they have been reviewed, are disclosed by the previously mentioned Audit TGH-15 and the TU response.[54] Audit TGH-15 was conducted in early October 1980, at the request of the TU Engineering and Construction Manager (Merritt), "... to provide an early evaluation of the program established by TUSI and Gibbs & Hill to control the processing of field changes documented on Component Modification Cards."

In its report the Audit Team complimented TUSI and G&H for the progress made thus far, but continued, "This has resulted in the first comprehensive accountability document that tracks the design review status of CMC's." This statement was made at a time when G&H had received approximately 9500 CMCs and approximately 2000 had not yet been reviewed. Thus, if there was not a "comprehensive accountability document" prior to this time, the accuracy of th review status of the approximately 7500 CMCs previously reviewed was indeterminate. As a result, some form of check or re-review would be necessary to establish reasonable confidence in the review status of the changes and the acceptability of the associated hardware.

While the report of Audit TGH-15 did not identify any deficiencies, the report did contain three recommendations and two unresolved items addressed to TUSI. One recommendation relating to the large number of CMCs was that high priority turnover system drawings be upgraded by incorporating all outstanding design changes. This was recommended because it would allow G&H to perform design reviews where the combined effects of all CMCs could be considered collectively, and because it would facilitate start-up/turnover activities. TU's initial response to this recommendation was that they had placed a freeze on revising such diagrams and CMCs would continue to be reviewed individually. Combined effects would be considered collectively during the final Code Analysis. In other words, TU will do it later.[55] After further discussion with TU QA, TU management agreed to a plan to update selected drawings to eventually provide formal "as-built" information.[56] This second response to

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54 J. Merritt, TU, memo to D. Chapman, TU, dated Nov. 26, 1980, (S00582).

55 Merritt memo to Chapman dtd 11/26/80, Response to QA Audit TGH-15, (S00582/CS00040358)

56 Merritt memo to Chapman dtd 2/13/81, Response to QA Audit TGH-15, (S00579/CS00040352)

TGH-15 also contains a comment that does not appear appropriate for a response to a QA audit. The comment is:

> "... TUSI (i.e., TU Projects) has committed to the constant monitoring of these activities via TUSI personnel at G&H/NY. The progress of these efforts from a cost and schedule perspective will be controlled and periodically reported to management."

In other words, TU Projects will make certain TU management knows how much this QA-recommended effort is costing the project.

Another problem mentioned by Audit TGH-15 is field changes which affect the stress analysis were not being included in the stress analysis, but were being dispositioned as "approved" by G&H. The TU auditors note, "It is necessary to define how these type changes will be tracked to assure they are considered in the final code analysis and how the interface between TUSI, Gibbs & Hill and Westinghouse will be accomplished." The auditors also requested TU to confirm that provisions will be established to assure that these interface agreements are defined. TU's response to this request was,

> "A general program for as-built piping verification has been procedurally established and will be expanded as necessary to completely encompass interface responsibilities. This program has been targeted for implementation on Jan. 1, 1981 or as project needs dictate."[57]

In other words, in November 1980 with scheduled fuel load barely a year away, TU was just developing a procedure for assuring design changes would be referred to the affected interfacing organization for review.

A final problem mentioned by Audit TGH-15 was that the G&H structural group was not reviewing CMCs involving interferences between cable tray supports and pipe hangers since they did not have access to all the necessary information, such as pipe hanger loads and other possible interferences. Accordingly, the auditors requested that TU define responsibilities for reviewing these CMCs and describe the methodology by way of which input from separate groups will be brought together so as to allow design reviews which consider complementary effects. TU's response was that CMCs which involve interferences with structural supports other than cable tray/conduit supports are currently not in the design verification process, but procedures for these activities will be developed. Thus, again, in November

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57 Ibid.

1980, TU has not developed the necessary procedures for processing this class of field design changes.

Regarding interferences between components (which was the reason for many of the CMCs), the number of such interferences could have been minimized by use of a detailed plant model. An interview of Bob Murray indicates such models included detail "... down to 1" conduit. They had conduit supports engineered."[58] Mr. Murray also stated in this interview that not spending $3 million for such a model in 1973 was one of the three worst decisions made by TU. Absent the model, it was more difficult to anticipate and thus avoid interferences. The occurrence of avoidable interferences thus not only increased the number of design changes that had to be written and reviewed (after-the-fact), but also increased the amount of rework, reinspection and documentation. Not only did these avoidable activities cause additional expense and delay to the project, they also added to the burden and complexity of trying to assure plant quality.

In July 1981, the NRC Resident Construction Inspector at CPSES performed an inspection of Field Design Change Activities. The inspector's findings included the following:[59]

> "The administrative control to achieve design review of all of the Design Change Authorizations has not yet achieved full effectiveness, primarily because the control was not initiated until after several thousand of the individual change documents had already been issued. There was substantial evidence, however, to show that the measures are in place to capture the older changes in the administrative, computer based, control mechanism and achieve full effectiveness prior to completion of construction.[60]
>
> "[Of 110 design changes classified by the inspector as design deviations] Eighty-six percent of these deviations covered specific cases where individual piping runs did not conform to one of four erection tolerances established within [Project Piping Erection Specification] MS-100. ... The vast bulk of these deviations would have been captured as nonconforming

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58 TWF notes of interview with Bob Murray, 4/17/85, (S02451/CR001794)

59 NRC CPSES Inspection Report 81-11, dtd 8/28/81

60 That is, in the next seventeen months. At this time the fuel load date had slipped to December 1982. [Frankum memo to George dtd 5/15/81, Update Cash Flow & Projected Cost for CPSES, (S04051/BH00051060)]

items had they been identified by the licensee's quality control personnel rather than by engineering personnel in conjunction with the craft. This is a permissable (sic) mechanism within Appendix B to 10CFR50."

"The RRI concluded that the Design Change Authorization portion of the licensee's program for effecting design changes was fully effective although relatively voluminous in terms of documents generated." (Underlining added)

The first NRC finding above confirms what other documents have already indicated; i.e., TU did not provide effective control over field design changes until several thousand had accumulated. It is noted this occurred despite the warnings by TU QA of the need for an accurate tracking system for field design changes (see previously cited testimony by Vega concerning after-the-fact design changes).

The second finding quoted above is similar to one of the findings of the MAC audit performed three years earlier (see Section 5.5.3.1). This involves circumventing the Nonconformance System by designating nonconforming conditions as design changes subject to after-the-fact review. This is a poor quality practice because not only are nonconforming conditions allowed to bypass the formal Nonconformance processing system, but it also adds to the burden of design changes that must be documented and reviewed. We are not aware of the NRC inspector's basis for concluding this was an acceptable practice within the meaning of Appendix B to 10CFR50. Our view is that it is not.

The third finding of the NRC inspector is that the Design Change Authorization portion of the licensee's program for effecting design changes was fully effective. It is noted this assessment is limited to the "Authorization" activity and does not extend to the followup actions or Nonconformance Control. The inspector's assessment of the overall activity is that no violations or deviations were identified.

The CAT inspection report summarizes its findings regarding the Design Change Process at CPSES on page IX-9, as follows:

"The design change process at CPSES is complex, and at times, cumbersome. The NRC CAT inspector's review of design change processes in the various disciplines revealed a design change program with controls incorporated under a "design-construct-design review" philosophy. This philosophy resulted in a large number of design changes and a repetitive inspection process. (NOTE: There are approximately 70,000 CMCs and 15,000

DCAs that have been issued. This number does not include revisions).

"Although this design change process may be difficult, there is nothing in NRC requirements to discourage or prohibit the use of such a system. In general, design change controls at CPSES satisfied the applicant's FSAR commitments and the ANSI standard requirements. However, with this type of system in-place, actual verification of hanger, support, electrical, and mechanical equipment installations to the appropriate design requirements cannot be performed until "work activities" have been completed. Few, if any, installations could be verified as few have been designated as completed under the licensee's context of "completion". Thus, the final adequacy of these controls could not be determined by the NRC CAT inspector."

Except for the conclusion as to the acceptability of the TU after-the-fact design review process (which is at odds with the MAC Report and ASLB view), we believe the above summary from the CAT inspection report provides an accurate description of the situation created by TU in their efforts to expedite plant construction. TU proceeded along this course despite the reservations of G&H, the reservations expressed in some TU internal audits, and the recommendations of MAC. Further, TU did not act in any effective manner to provide consistently timely review of field design changes as recommended by G&H and MAC. Nor did TU provide effective tracking of field design changes, as recommended by TU QA, until after several thousand changes had been initiated.

Mr. Clements' deposition also discloses that after the December 1983 ASLB order, there were discussions within TU regarding whether TU should continue the after-the-fact design verification process. As a result of these discussions it was decided to continue. The deposition transcript also describes the decision process.[61]

> Q. ... notwithstanding this December 1983 order, TUGCO stuck with the at-risk system of design change verification. And I think it's also clear from your testimony that that was apparently a decision that was made after some discussions back and forth, presumably in January of 1984. I'm simply asking at this point, can you offer or explain to the jury the rationale behind that?

61 Clements Deposition, December 1987, pp. 91 to 93.

A. No, I can't.

Q. But you were present at the discussions?

A. Some of them, but the decision was not made by the QA department, obviously; it was made by engineering/construction, and so I don't know what the rationale behind the decision was.

Q. Did you agree with the decision to stick with the at-risk system of design change verification?

A. Not really.

Q. Did you make that known to TUGCO top level management?

A. At this particular time, probably not.

Q. All right, sir. Did you ever make it known to --

A. Yes. (In late 1980/1981 to Mr. Gary -- p. 93)

This dialogue provides valuable insight into the decision making process at TU and into TU's priorities. First, despite the ASLB order that specifically objected to the at-risk design verification mechanism, TU decided to continue the practice. Second, although Mr. Clements, who was the corporate official responsible for QA personally believed the at-risk design verification process carried an inherently higher risk of QA problems, the decision was not made by the QA department; rather, the decision was made by "engineering/construction". Because of the importance of this decision to the licensing of CPSES, particularly following the ASLB order, it must be assumed TU upper management participated in this decision. And whether it was formally stated by TU upper management or not, Mr. Clements clearly understood that engineering/construction would make the decision, not QA. This is another illustration of the greater importance TU upper management assigned to construction relative to QA.

One may question the failure of Mr. Clements to express his concerns regarding the after-the-fact design verification practice to his superiors during these discussions. This is partially explained by the fact Mr. Clements had described his concern to Mr. Gary in 1980 or 1981, and concluded that inasmuch as the practice was not expressly forbidden by the regulations and the QA program, the company position was "set in stone".[62] As Mr. Clements stated in his deposition,

> Q. Okay. Did you ever bring it up again to Mr. Gary, that you can recall?
>
> A. I saw no point in bringing it up again; he knew how I felt.

However, Mr. Clements has also testified that Mr. Gary was not present at the January 1984 meetings that discussed TU's response to the ASLB order.

Ultimately, TU found itself in the position where the NRC no longer had confidence in the quality of the design and construction of CPSES. Following serious expressions of concern by the ASLB and TRT, TU established the CPRT Program Plan, including the Design Adequacy and the Quality of Construction elements.

These activities confirmed the indeterminate quality of CPSES construction. For example, in the area of large bore pipes and supports, two walkdowns of the system were performed. The purpose of the first walkdown was to "... establish sufficient confidence in the adequacy of dimensions and functions shown on the as-built drawings to support initiation of the pipe stress requalification effort."[63] In other words, the walkdown was done to provide an accurate basis for the re-analysis of <u>pipe</u> stresses, not the reanalysis of the adequacy of the <u>pipe supports</u>. Thus, the parameters examined in this analysis were limited to those needed for re-analysis of large bore piping. The cover letter transmitting this report of this walkdown states as follows:

> "The conclusions of this report indicate that generic concerns exist that require consideration by the Comanche Peak Response Team (CPRT) and TUGCO Quality Assurance (QA). These concerns are summarized as follows:
>
> ". The orientation of valves and supports in piping systems are not correctly documented in the as-built documents. ..

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62 Ibid, pp. 93 to 99.

63 Klause (SWEC) letter to Beck, dtd 10/10/85, Large Bore Field Walkdown Report, (CS02457/CW00051328)

". Some items requiring correction which were identified during the as-built program have not been resolved."

Thus, in October 1985, there was insufficient agreement between installed hardware and plant drawings to permit re-analysis of large bore pipe stresses until the differences were resolved. As a result of this walkdown, the tolerance for orientation of pipe supports was tightened. In addition, the orientation of all pipe supports, valves with extended operators, and component supports were reinspected, and the as-built conditions were documented.[64]

While the first walkdown was performed to permit re-analysis of pipe stresses, the second walkdown was performed to provide,

"... qualified piping and support engineers a detailed physical review of the piping system in its entirety, enabling SWEC to evaluate whether the analytical methods being implemented are adequate or if additional procedures are necessary to enhance the overall program."[65]

In other words, this walkdown would examine attributes affecting the adequacy of the pipe supports as well as attributes affecting the stress analysis of the piping.

The walkdown involved the examination of approximately 2,400 supports and resulted in 439 observations. About two-thirds of these observations did not require any new type of action by SWEC or TU because they could be addressed adequately by existing procedures or had been identified previously and had been, or were being, resolved as generic technical issues by TU. The remaining 174 observations would require new actions by SWEC and TU. These actions included the transmittal of additional design input, revision of specific piping and support drawings, generic reviews of certain types of installations, revision of key procedures involved in the pipe stress/support requalification effort (CPPP-6 and CPPP-7), and performance of specific analyses for evaluation of unique technical concerns.[66]

The effect of the second walkdown (and possibly other

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64 Counsil letter to NRC dtd 11/2/87, Project Status Report for Large Bore Piping and Pipe Supports, p. 5-2. (S02395)

65 Piping and Support System Engineering Walkdown, Final Report, June 4, 1986, p. 5, (S02456/CS00140625)

66 Ibid., p. 1

discoveries) is summarized in the TU CPSES Executive Project Report for October 31, 1987:[67]

> "The pipe support program progress has been adversely affected by the discovery of substantial deviations on as-builts which were previously assumed to be highly accurate (pre-stress walkdowns were limited to a check of attributes that could affect stress only). This has necessitated an additional support detail effort which was not anticipated. ... "

As for overall status, the Executive Project Report states,

> "The issues causing the largest variance to the major milestones are HVAC Program Rework, Pipe Support Modifications, Instrumentation and Control Inspection and Rework Program, Electrical Cable Seal Assemblies (ECSA) and the design resolution of attachment to concrete in accordance with validated design criteria."

Regarding the specific area of large bore piping and pipe supports in Unit 1 and common areas, the CPRT Program Plan has identified the following modifications which would be made as a result of the Design Validation effort:[68]

- o 209 of 1,166 Integral Welded Attachments would require modification as a result of pipe stress analyses.

- o 5,621 of 12,020 large bore pipe supports would be modified as a result of Pipe Support Analyses. These were distributed among the following categories:

Category	No. of Modifications
Prudent	1293
Recent Industry Practice	1883
Adjustment	393
Cumulative Effects	2052
TOTAL	5621

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67 TU ELECTRIC CPSES Executive Project Report as of October 31, 1987, Section VI, Part A, p. 3, (S02433)

68 Counsil letter to NRC dtd 11/2/87, Project Status Report, Large Bore Piping and Pipe Supports, pp. 5-23 to 5-26, (S02395)

Excluding the modifications related to "Recent Industry Practice",[69] approximately 3,738 large bore pipe supports would be modified. Of these, those in the "Prudent" category would be modified to conform to the design because modification was considered easier than performing an analysis that might show the supports, as-constructed, met design requirements. Those in the "Adjustment" category required minor modifications or adjustments (such as retorquing or shimming) due to improper initial installation; and those in the "Cumulative Effects" category would be modified due to the combined effects of the preceding issues.

The result for large bore piping and pipe supports in Unit 1 and Common Areas is that despite operation of the TU QA program, including prior QC inspection and acceptance of pipe supports, approximately 30% of the large bore pipe supports would be modified to demonstrate conformance to design. Excluding those supports in the "Recent Industry Practice" and "Adjustment" categories, we believe many of these modifications were the result of the policy of after-the-fact design change review, combined with failure to perform timely review of the changes and poor document control.

A similar view recently has been expressed by the NRC:[70]

> "Because the design process was not effective in promptly correcting these design deficiencies caused by construction, the staff found that many of the field design changes - and subsequent designs that may have been based on those field design changes - resulted in a large number of unacceptable pipe support designs at CPSES."

In a deposition by Mr. Clements, who became Vice President, Nuclear in 1980, he confirms that the at-risk policy did result in conditions that required rework,[71]

> Q. Are you aware of any loss of designer responsibility or extensive repairs?

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69 "Recent Industry Practice" appears to be TU's term for the NRC's "Snubber Reduction Program". This program was initiated by the NRC in the mid-1980's.

70 Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2. NUREG-0797, Supplement No. 14, p. 5-1

71 Clements Deposition, December 1987, p. 68.

A. I'm aware of possible ex.enive (sic) repairs.

Q. And I mean extensive repairs that resulted because of this at-risk method of design change verification.

A. Yes. In a general sense I couldn't tell you hanger so and so, but I know --

Q. I understand.

A. -- there were hangers that had to be replaced because of the --

Q. Because of the at-risk design change verification?

A. Yes, sir.

Thus, the risks associated with the after-the-fact design review process were not simply theoretical. Actual rework was required, and Mr. Clements agrees.

As a final note on this issue, it is observed that after the TRT inspections/investigations in the latter half of 1984, TU partially recognized that the policy of after-the-fact design review was counterproductive. At that time the Project General Manager reversed the earlier policy and directed that all Field Design Changes (DCAs and CMCs) except pipe support and conduit support CMCs be design reviewed prior to issuance for construction work.[72] Excepting pipe support and conduit support CMCs from this policy was likely a contributing factor in why four[73] of the eleven disciplines in the ongoing Corrective Action Program (CAP) include investigation and validation of piping or conduit supports. (See Section 6.0)

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72 Merritt memo to distribution dtd 1/21/85, Design Verification of Field Design Changes, Vega Exh. 514, (S01379/)

73
- o Large Bore Piping and Pipe Supports
- o Small Bore Piping and Pipe Supports
- o Conduit Supports Trains A, B & C > 2"
- o Conduit Supports Train C ≤ 2"

5.4.4 Inadequate Management of the Design/Document Control Systems.

Given the TU decision to proceed with construction with after-the-fact approval of design changes, combined with the large number of such changes authorized and the large backlog of unreviewed changes that was permitted to develop, it is clear an excellent change tracking and document control system would be needed. Indeed, TU should have been keenly aware of this risk because they had been so advised by both the TU QA Department[74] and by the 1978 MAC audit. The MAC audit stated, "The current site DC DDA system of after the fact coordination of design changes with the original designer provides a significant risk of design error ...". Nevertheless, based on TRT report No. 3, as late as April 1984, one Document Control Center Satellite had an error rate of 30%, and an accurate system was not implemented at CPSES until August 1984 -- when the first iteration of construction was substantially complete.

One example indicating the design tracking and document control program was inadequate prior to August 1984 is provided by the previously cited CAT finding that some components were inspected using CMCs that were not the latest revision, and the designs of some components that had already been "final inspected" were subsequently revised. Irrespective of whether the components were subsequently "re-final inspected" to the new "final" design the process illustrates the need for an effective design and document control system.

Other examples of identification of deficiencies in design and document control are provided by earlier NRC inspection reports and by TU audits (e.g., TCP-6 and TCP-6 followups in 1980 and 1981), but it is apparent these findings did not receive prompt, effective, and comprehensive corrective action until very late in the project when the magnitude of the problem would be greatest.

Because of the absence of an accurate system prior to August 1984, the design adequacy of the plant as constructed was in question; and the question could not be answered without undertaking the current major reinspection and reverification program.

5.4.5 Inadequate Oversight of the QA Audit Program

Many findings of TU audits at CPSES did not receive prompt, effective and comprehensive corrective action. Instead, the

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[74] Oral deposition of Antonio Vega, October 8, 1987, pp. 135-136, (S01371)

responses frequently addressed only the immediate problem at hand and generally failed to examine the generic implications of the finding. This characteristic is consistent with the observations of the INEL study of management style with respect to allegations as discussed in section 5.3.3. We believe the fundamental reason for the inadequate response to audit findings was inadequate management involvement and concern with QA. We believe the best measure of management involvement and concern with QA is provided by management's response to the findings of QA audits. If management exhibits an active concern that audit findings are promptly, effectively and comprehensively addressed, this attitude will be communicated to the entire organization; and the converse is also true.

In the case of TU we have found very limited evidence of top management concern with correction of audit findings during Phase II. One example is provided by the March 1981 letter from Mr. Clements to Mr. Gary in which Mr. Clements notes that significant problems remain from Audit TCP-6 more than one year and two follow-up audits after the original audit.[75] Another example occurs almost four years later following completion of the TRT inspections. In this memorandum Mr. Clements states as follows:

> "As we have discussed, I am not satisfied generally with the responses to TUGCO QA Audits. In future responses to TUGCO QA audits and Plant Operations QA Surveillances, I would like the cause of the deficiencies, generic considerations, training/-retraining to be conducted, and any other aspects considered necessary by the responder to be addressed.
>
> "By copy of this memorandum, the Manager of Quality Assurance and the Manger of Plant Operations are directed to make these elements part of the audit and surveillance reports."[76]

This document is a strong indication of management neglect since this direction is not provided to the QA Manager until ten years of audits have been performed and the TRT has completed its inspections/investigations and issued it reports.

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75 Clements memo to Gary dtd 3/26/81, Audit Report TCP-6 Follow-up No. 2, (S00200/ 300080695)

76 Clements memo to Kuykendall dtd 1/18/85, Responses to TUGCO QA Audits and Surveillances, (S01313/LV0009/0562)

5.4.6 Dissolution of the Quality Surveillance Committee.

One of the original elements of the CPSES QA program was a Quality Surveillance Committee (QSC). This committee met quarterly to provide oversight of project QA and acted to keep TU management informed as to the results of audits and the status of corrective actions. The TU QA Manager was advised by the cognizant NRC inspector in 1976 that the inspector understood the QSC was the primary method of TU management review of the effectiveness of the QA Program (an NRC requirement).[77]

The operation of the QSC subsequently was reviewed by MAC during its 1978 audit of CPSES. Based on its review, MAC observed that the QSC was taking on the role of a task force or problem-solving group. MAC considered this undesirable because problems would tend to await the three month meeting cycle before the necessary management attention was effected. MAC therefore recommended that TU re-evaluate the charter of the QSC and serious consideration be given to its value recognizing that (1) action to resolve problems should be handled on a day-to-day basis through the functioning organization and (2) the objective of maintaining management awareness of QA status could be accomplished more efficiently, and on a more timely basis through a monthly QA progress report distributed to TU executives. The MAC report did not address the requirement for periodic management review of the effectiveness of the QA Program.

The TU response to this recommendation[78] was to discontinue the QSC and have the QA Manager issue a quarterly report to keep top management apprised of the status of QA matters.

This response provides clear evidence of TU Phase II management's lack of understanding of the purpose of the QSC. And this lack of understanding extended to the TU QA Manager who was chairman of the QSC. As discussed in Section 5.4.1, the TU QA Manager did not know the QSC charter, and therefore considered it merely a discussion and problem solving group. He apparently did not understand, as did his predecessor Schmidt, that the NRC considered the QSC to be the primary means by which TU management reviewed the effectiveness of the QA program.

The response is also deficient with respect to the intent of the MAC recommendations. First: it did not address the basic reason for examining the QSC charter -- to achieve problem resolution on

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77 Schmidt memo to Brittain dtd 8/27/76, Minutes of QSC Meeting on 8/19/76, (S01140/CS00100561)

78 R. Gary & L. Fikar, TU, memo to P. Brittain, TU, dated July 11, 1978, page 4 (M00042).

a day-to-day basis through the functional organizations -- it merely eliminated the QSC. Second: it did not address the second objective -- providing management with more timely notification of QA status through issuing a monthly report -- it merely proposed to continue issuance of a quarterly report on QA status, except that now it would be issued by the QA Manager -- an individual who may or may not possess the objectivity that should be a characteristic of the QSC. And third, it did not address the need for periodic management review of the effectiveness of the QA Program.

Regarding the objectivity that should be a part of the makeup of the QSC, our review leads us to the conclusion that little objectivity was present during Phase II. What little there was, was primarily directed toward suppliers -- not on-site construction activities. This is based on our review of the available minutes of the QSC meetings and an assessment of the attitude of Mr. Fikar toward QA (as discussed in Section 5.3.2). Our conclusion is also based on the fact that at the same time Mr. Fikar was responsible for the construction of CPSES, he was also the senior member of the QSC. This would appear to be a clear conflict of interest.

Based on our review of this issue, we conclude the elimination of this oversight group, although accepted by the NRC on the basis of commitments made by TU,[79] was a serious error by TU. Further, the error was compounded by the fact the QA Manager never submitted any of the quarterly reports that were to be part of the response to this issue.[80]

Regarding oversight of the QA program, the CPRT Collective Evaluation Report lists a number of concerns that were present in the "historical QA program" and adds:[81]

> "In addition, until 1986 TU Electric did not have a formal method of regularly assessing the adequacy of their QA program as is required by Criterion II. This may also have contributed to these areas of concern."

Thus, the CPRT agrees that the absence of a regular objective review of the effectiveness of the QA program could have contributed to some of the observed QA problems at CPSES.

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79 Annotated History Associated with CPRT ISAP VII.a.5 dtd 11/4/86, entry for 8/14/78, (S02060)

80 Ibid.

81 Comanche Peak Response Team Collective Evaluation Report, Revision 0, dated 12/23/87, Part IV, p. 85. (S02449)

5.4.7 Abridgement of QA Program and QA Plan

Before an applicant can be issued a license to construct a nuclear facility, he must describe in the Preliminary Safety Analysis Report (PSAR) how he will satisfy the applicable regulatory requirements. With respect to Quality Assurance requirements, nuclear facilities typically state they will utilize a hierarchy of QA documents to implement the QA program described in the PSAR. The first document below the PSAR level is frequently a "QA Program" or equivalent document that elaborates to some degree on the PSAR description. Typically below this is a "QA Plan" or equivalent document which provides further detail; and at the bottom of the hierarchy are the specific "implementing" procedures.

Such an approach was used by TU in the PSAR accompanying their application for the CPSES Construction Permit and in the Final Safety Analysis Report (FSAR) accompanying the TU application for an Operating License for CPSES. As stated in the CPSES FSAR:

> "TUGCO/TUSI's Quality Assurance Program and CPSES Quality Assurance Plan are the primary documents by which TUGCO/TUSI assures effective control of all project quality-related activities."[82]

The CPSES FSAR further states the QA Program and Plan are based on 10CFR50 and applicable industry standards and draft standards. The FSAR also states: "The Quality Assurance Program specifies the quality requirements to which the CPSES QA Plan complies." In other words, the QA Program establishes the requirements that must be met by the QA Plan.

Regarding the QA Plan, the FSAR states that it "... is the document by which the requirements of the program are transformed into specific procedures, methods(? legibility), and techniques." The FSAR then describes the contents of the Plan, stating that it will include a discussion of the Philosophy and Objectives of the Plan, as well as various specific procedures and auditing requirements.

During Phase I, TU implemented a fairly detailed QA Program. An incomplete copy of Revision 0, issued August 1, 1973[83] filled 90 pages and contained a level of detail appropriate for a document at that level in the hierarchy. Revision 7, issued April 23,

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82 CPSES FSAR, Sec. 17.1.1.2, March 21, 1978. (S00751)

83 TU Corporate Quality Assurance Program, Rev. 0, 8/1/73. (S00045/CS00090288)

1979 filled 145 pages and had a comparable level of detail.[84] Prior to February 1981, however, the QA Program was revised and abridged to 10 pages, which contained no detailed information.[85] Indeed, Section 3, Implementation, of this revision states as follows:

> "For each specific nuclear project, a Preliminary Safety Analysis Report (PSAR) and a Final Safety Analysis Report (FSAR) will describe details for implementation of this Corporate Quality Assurance Program and identify the organizations associated with each project and specific regulatory or industry code commitments."

Thus, there has been a complete turnabout. Notwithstanding that in the CPSES FSAR, TU stated the Quality Assurance Program and Quality Assurance Plan were the primary documents by which TUGCO/TUSI assured effective control of all project quality-related activities, TU was now stating that the FSAR would provide the details for implementing the Corporate Quality Assurance Program. In other words, TU has placed the TU Corporate QA Program above the FSAR/PSAR in the hierarchy of documents. Such an action is totally inconsistent with our experience and is totally incomprehensible. That it was permitted to occur indicates that either the TU QA management during this phase was inadequately qualified or was overruled by higher TU management.

A similar history was experienced by the QA Plan. The version dated April 24, 1974[86] consisted of about 160 pages; and the revision of June 16, 1975,[87] growing with the increased level and complexity of design and construction activity, required about 250 pages. The Plan continued its growth into Phase II, such that the revision of November 21, 1977[88] consisted of almost 400 pages. By July 1, 1978 (about four months after submitting the FSAR), however, the TU Phase II management had totally revised

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84 TU Corporate Quality Assurance Program, Rev. 7, 4/23/79. (S01131/TUD00211677)

85 TU Corporate QA Program, Rev. 10, 2/9/81. (S00045/CS00090379)

86 C.SES Quality Assurance Plan, Rev. 1, 4/25/74. (S00899/TUD00311274)

87 CPSES Quality Assurance Plan, Rev. 3, 6/16/75. (S00898/TUD00310483)

88 CPSES Quality Assurance Plan, Rev. 6, 11/21/77. (S00947/BH00211498)

the Plan and had reduced it to 44 pages[89] -- thereby deleting practically all of the detailed information needed for coordination, and effectively destroying the usefulness of the Plan. The TU QA Plan remained this size for at least the following six years,[90] i.e., during the period of most intensive and complex construction.

We have reviewed the QA Program Plan issued during this period. Basically, it consists of one section addressed to each of the 18 criteria listed in Appendix B to 10CFR50 plus three sections addressing ASME issues. Except for Section 1, which deals with Organizational structure and responsibilities (six pages and two Figures), three sections consist of two pages, and the rest of the criteria are addressed in a fraction of a page. In terms of detail, it provides little more information than Appendix B or the QA Program -- certainly insufficient detail to guide the development of a coordinated set of quality implementing procedures.

As discussed in Section 5.5.3.3, this condition was identified and criticized by the Lobbin audit. TU's actions in dealing with this issue are described in their response to the Lobbin finding:

> "... an all inclusive, Quality Assurance Plan for Design and Construction was developed at the beginning of the project. However, as the project evolved it became apparent that the many small changes made in lower-tier QA documents were requiring an unnecessarily burdensome number of revisions in the QA Manual. We therefore made the decision to minimize the amount of detail in corporate documents, their purpose being to define QA policy and management responsibility. Details are included in lower-tier documents such as work procedures and instructions, which are reviewed to assure that they are consistent with corporate policies and regulatory commitments."

This TU response rejecting the Lobbin finding indicates the TU

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89 CPSES Quality Assurance Plan, Rev. 0, 7/1/78. (S02169/CS00481479)

90 CPSES QA Plan, Rev. 14, 8/30/84. (S02035)

Phase II QA management did not understand the purpose of the QA Program or QA Plan, either in 1978 when the Plan was revised, or when the QA Program was revised, or in 1982 at the time of the Lobbin audit, or even in 1984. This further supports the view that the responsible TU Phase II QA managers were inadequately qualified for their positions.

As shown in Appendix D, Table D-1, TU was cited on numerous occasions during this period and immediately thereafter for inadequate procedures, failure to follow procedures and inadequate inspection. Examination of Figure D-6 shows that the three most frequent causes of citations were also in these areas (Criteria V-A, V-B and X). Based on these observations, we conclude the severely abridged QA Program and QA Plan used during most of Phase II was a significant contributing factor to the observed deficiencies in quality procedures and inspection procedures.

The foregoing conclusion is consistent with the findings of the CPRT Collective Evaluation Report regarding Appendix B, Criterion V:[91]

> "... It was determined these problems can generally be attributed to inexperienced personnel having written and reviewed the procedures and a weak procedure review process. A contributing factor was the lack of a well-defined procedure hierarchy that ensured QA program commitments were properly translated into lower tier procedural requirements. ..."

5.4.8 <u>TU Management of Piping and Pipe Support Design</u>.

The technical area of seismically qualified piping and pipe support design was one of the major challenges to TU in attempting to complete CPSES within the budget and schedule objectives. This is clear from a May 1979 memorandum from Mr. Hancock (B&R) to Mr. George outlining various areas of concern.[92] In this memorandum, Mr. Hancock writes,

> "The major area of concern for the Unit 1 and Common schedule is in the category of the overall status of supports and pipe restraint systems. Based on the

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91 Comanche Peak Response Team Collective Evaluation Report, Revision 0, dated December 23, 1987, Part IV, p. 26. (S02449)

92 Hancock (B&R) memo to George dtd 5/17/79, Area of Concern. (S02777/BH00130010)

level of current problems being experienced in the field with the installation of piping, raceway, instrumentation and HVAC supports coupled with a rather nebulous understanding of the status of remaining pipe and pipe hanger design, and with what appears on the surface to be a vast scope of work in design, procurement, fabrication and installation of the pipe rupture/jet impingement systems, it seems likely that we should prepare for much more severe interference and rework phases in design and installation than we have experienced to date or have allowed for in our schedule and budget. ... Combining all of the above concerns we see the potential for major impacts to the cost and schedule of CPSES."

Mr. Hancock then lists a number of concerns, some of which are quoted below:

- o Program for the redesign of some 1,000 large bore pipe hangers.
- o Hanger base plate system and design responsibility in question.
- o Present interference and rework in support systems is impeding installation quota.
- o "Anchor" supports that are welded to process pipe walls are forthcoming from engineering - slabs and walls for these components have been poured or are being poured (Unit 2) without anchor bolts or embeds.
- o Many interferences, take-downs and rework are being experienced at this stage of construction with defined components and commodities - much of the above is not defined and could influence site design decisions being made daily, i.e., rework on top of rework.
- o The potential impact of all of the above considerations on the quality documentation program is enormous (possibly the most severe problem).

These concerns were expressed by a B&R representative approximately two years after TU assumed overall management of the CPSES project (by establishing the Office of the Project General Manager) and had authorized the "after-the-fact" or "at-risk" design change review policy.

TU management actions in response to these concerns were ineffective as shown by a September 1981 letter sent by Mr. George to Mr. Fikar presenting a revised cost estimate and stating that Unit #1 fuel load was now projected for mid-1983.[93] In explaining the reasons for the additional cost, Mr. George states,

> "...the largest change of 245 million is in site engineering and client cost. This difference is a result of the fact that in July 1980 it was estimated that of the approximately 9000 large and medium Unit #1 remaining pipe supports to be installed could be installed as planned and at a rate of 100-150 per week. It has since been found that that assumption was in considerable error. In fact, it turned out the last 8000 of these supports required a total redesign with a field check here at the site. ...
>
> "The second largest difference between the 7/80 and 9/81 estimate is 204 million in construction labor. Again this was due in large measure to the above stated reason for site engineering difference plus much larger amounts of rework in pipe and electrical systems due to unforeseen changes and modifications. Another major factor in this difference as well as all other differences is the fact we were unable to meet the 7/80 estimated fuel load of 12/81."

As noted earlier, the policy of "after-the-fact" design change review was adopted so that construction could continue when interferences, inadequate design or inadequate construction were identified in the field. This policy was adopted in the belief that it would expedite construction. However, that the policy had at least three effects which were counter-productive.

- o In those instances where a "design change" was issued in order to "accept" a component that was not properly constructed, the required review of the design change added to the already heavy workload of the design organization.

- o Where field "design changes" were found to be unacceptable, the needed redesign further added to the workload of the design organization. The workload of the construction organization was also increased by the need to implement the required modifications. Further, because final design review was not completed in a timely manner, required modifications could be further complicated by accessibility problems created by subsequent construction.

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93 George letter to Fikar dtd 9/18/81, Revised Completion Date and Cost of CPSES. (S02639/TUD00280590)

- The numerous "design changes" that were issued added to the number of drawing revisions that were required to be issued and tracked, and further complicated the design review process, and the fabrication, installation and inspection of affected components.

The most significant of these effects was the added workload imposed on an already heavily loaded engineering and design organization. To address this problem, additional contractors were utilized to conduct the piping and pipe support engineering and design effort. For example, Westinghouse was engaged to assist G&H in the performance of pipe stress analyses,[94] and NPSI was hired to assist ITT Grinnel in the design of pipe supports.[95] In addition, the Comanche Peak Pipe Support Design Group was established to further support this latter effort.

While the mobilization of several organizations to perform a large task is certainly appropriate, the end product can only be acceptable if the work of the participating organizations is properly coordinated. This is especially true for the piping and pipe support discipline. As noted by the NRC staff in the CPSES Safety Evaluation Report, Supplement 14 (SSER 14),[96]

> "Piping design and pipe support design are so closely intertwined and technically interdependent that it is difficult to separate the two from a design standpoint. ... [when different organizations are used] it is necessary to have an established and functioning link between the group responsible for piping design and analysis and the group responsible for pipe support design and analysis."

Regarding the effectiveness of the effort at CPSES, the NRC staff concludes,[97]

> "... the responsibility placed on the utility coordinating the independent piping and pipe support design groups requires extremely close communication

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94 Parker (Westinghouse) letter to George dtd 4/2/79, Supplemental Stress Analysis Problems. (S03337/BH00310249(?))

95 Oral deposition of Michael R. McBay, Sept. 28, 1987, Vol. II, p. 70. (S02305)

96 Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2. NUREG-0797, Supplement No. 14, p. 5-2.

97 Ibid.

and coordination. The staff concludes that a lack of close communication and coordination existed at the time between the piping and pipe support design groups."

A similar view was expressed by Ms. Williams during a 1985 Cygna presentation to NRC management:[98]

"... the stress and the supports were separated contractually, and then there were one and two and eventually three groups doing pipe support designs.

"It appears that having divided the work up in that manner, although maybe more expedient, may have caused interface problems that were much more difficult to deal with."

Further, our review suggests that during Phase II, TU management devoted little attention to interface problems. One example is provided by the abridgement of the QA Program and QA Plan as discussed in Section 5.4.7. Another example is provided by two documents written about seven years apart.

The first of these documents is the "Emerson Report", prepared by Emerson Consultants, Inc. and transmitted by Mr. George to distribution by a Confidential Memorandum dated October 3, 1978.[99] While the report is primarily concerned with reducing project costs through elimination of excess personnel, page 6 of the report includes the following:

"Jurisdiction statements for each overhead and indirect service department, the Engineering Department, and the Construction Department are necessary to eliminate duplication of activities, to clearly define areas of responsibilities, and to obtain maximum operating efficiencies."

The second document is a short memorandum written seven years later by Mr. Merritt and addressed to Mr. George.[100] It is quoted in full:

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98 Cygna Briefing to NRC Management on Comanche Peak Steam Electric Station Independent Assessment Program. April 26, 1985, p. 38. (S02141/CB00160966)

99 George Confidential memo to Distribution dtd 10/3/78, Emerson Report. (S03323/BH00101750)

100 Merritt memorandum to George dtd 11/19/85, NEO Scope and Responsibilities. (S03558/CB000302387)

"As a result of the meetings with W. G. Counsil, it would seem the company needs to establish scope requirements for each organization, i.e. operations, engineering and construction.

"At a time of tight budgets and understaffed organizations, it would appear we could all better utilize the personnel we have in engineering if each group knew what its role and scope was. Then we would not find two groups doing the same thing."

Thus, apparently despite the findings of the Emerson Report and the desire to utilize personnel effectively, for a period of seven years during Phase II, TU management did not clearly define the responsibilities of the various organizations. Indeed, it was not until Phase III that the new TU management, more experienced in the field of nuclear power, suggested that such responsibilities be defined.

It is clear that in the absence of well-defined organizational responsibilities, the control of activities between interfacing organizations will be difficult. As noted above, in the area of piping and pipe support design, it is especially important that there be close communication and coordination between the participating design organizations.

We conclude that a major reason why extensive design validation, and hardware rework and modification efforts have been required at CPSES in the area of piping and pipe supports, was because TU management elected to use several organizations for the design of piping and pipe supports but did not ensure the close communication and coordination between interfacing organizations that was necessary to ensure an acceptable and verifiable end product.

5.4.9 Conclusions on TU Administrative Actions

TU senior management officials replaced TU QA managers in 1976 and 1977 with personnel who exhibited a "practical" approach toward QA requirements and a "cooperative" attitude with respect to construction efforts. In addition, while much more qualified personnel were available, TU selected an individual to be QA Manager who had no significant previous QA experience. TU took over management of all site QA activities except those under the jurisdiction of the ASME giving TU the control necessary to assure QA's "cooperation" with construction. TU knowingly accepted the risk of "after-the-fact" design review of field-initiated design changes without providing effective mechanisms to ensure that timely review of changes would be maintained, that the backlog of changes would be kept small and under control, and that the accurate design document controls known by TU to be needed would be implemented to minimize the risks of this policy. TU drastically abridged the QA Program and the QA Plan to reduce the burden of maintaining these documents, apparently without giving thought to the fundamental purpose of these documents, and thereby greatly reduced their usefulness and effectiveness. This, in turn, contributed to the number of procedures problems experienced by the project. In addition, during Phase II, TU provided inadequate management review of the effectiveness of CPSES QA Program and dissolved the one organization (the QSC) that was serving this function. In short, during Phase II, TU took several administrative actions that were unwise, such as appointment of a QA Manager with no significant previous QA experience, or took actions that served to subordinate rigorous application of QA requirements to construction priorities, such as the policy of "after-the-fact" design review.

5.5 Information Available to Management on Project Quality

5.5.1 Findings of TU Audit Program

5.5.1.1 Design Control

As can be seen from Appendix C, "A Review of the TU Audit Program at CPSES", design/design change problems were identified from the first audits in 1974 through 1983. Then in 1984 problems began to surface as As-Built deviations in the hardware. An example of the narrowness of view with which TU management looked at audit findings is given here: There were 22 findings of TCP-6 in the areas of design review/design change, lack of procedures, and inadequate Procedures,[1] primarily in the I&C and Electrical disciplines, with a few found in the Mechanical discipline. Six months later when a followup audit was conducted to close out the findings of TCP-6, 23 additional findings were identified,[2] primarily in the mechanical engineering area. TU summarized their findings as follows:

"1. Welding Engineering

One (1) general, across the board deficiency was identified regarding the lack of procedures covering the use of CMC's by Welding Engineering. The CMC is not being used for design changes and therefore, its use is not covered by existing procedures which identify the CMC as a design change/deviation tool.

"2. Mechanical

Twenty-three (23) deficiencies were identified in the Mechanical discipline. The following is a brief summary of each area.

A. On-site Pipe Support Design Group

A total of ten (10) deficiencies were observed in both the large bore and small bore design activities. The problems in the 2" and under area were presented generically due to the nature of the problems observed. This activity was being conducted in an uncontrolled manner. We acknowledge that TUSI Project Management has subsequently issued a stop work order in this area. In the large bore area, the deficiencies

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[1] TCP-6, dated February 6, 1980

[2] TCP-6, Follow-up, dated August 28, 1980

are specific to individual hangers and represent a breakdown in an established program.

B. Technical Services

Nine (9) deficiencies were identified which involve Technical Services, including the Hanger Drafting and Hanger Design Review Groups. We feel that these items are particularly serious in light of past findings in this area, and in light of TUSI's previous commitments in these areas. We acknowledge TUSI's intent to conduct an extensive evaluation by a management/supervisory board and take whatever measures are deemed necessary in this area.

C. Field Engineering

A total of four (4) deficiencies were observed involving the use of design changes. The most serious involved the erroneous declassification of Class 5 hangers in the safeguards building. Two hangers were sampled and both were declassified in error, thus leaving serious questions regarding the accuracy of the original declassification document.

"3. TUSI's Commitments to TCP-6

Commitments in response to deficiencies 8C, 10 and 17 have not been fully implemented. The deficiencies were in the areas of engineering produced quality records, IEEE-323 documentation and indoctrination and training. These findings will be carried as new deficiencies.

"4. TUSI's response to TCP-6 Deficiency Number 7 was not audited. Rather, TUGCO QA via QTN-295 has requested TUGCO Operations involvement in establishing a milestone by which as-built drawings, and associated change reviews, must be completed and organized into a turnover package. We will advise you of TUGCO Operations position as it becomes available."

If the findings of TCP-6 had been addressed generically or programmatically, all of these problems in the mechanical engineering area would have been addressed at the same time they were addressed for the I&C and Electrical engineering areas. These two audits alone should have alerted TU management to the significant problems that were to lead to the establishment of the CPRT and the formation of the Design Adequacy Program and the Quality of Construction element of the CPRT Program Plan.

5.5.1.2 Corrective Action Program

The corrective action audit trail is almost nonexistent. G&H and B&R corrective action programs were never audited by TU. The first NCR/Corrective Actions audit of CPSES was TCP-28 in 1981. An examination of that audit report reveals that only one minor deficiency was identified along with four comments. The area was not audited again until TCP-56, one year later. During this audit only one concern and one comment were identified in the area of NCR administration. TCP-87, conducted during October and November 1983, appears to be the first audit of any depth of the NCR/Corrective Action Program at CPSES but this was very late in construction, as the bulk of construction was completed by this time, many allegations were being made and the ASLB was raising questions about design and as-built conditions of the CPSES project. Therefore the TU Audit Program was ineffective in identifying problems in the NCR/Corrective Action Programs at CPSES.

5.5.1.3 Training and Indoctrination

The Appendix C, Audits, to this report reveals that B&R or G&H training and indoctrination programs were never the subject of a TU Audit. The CPSES project was not the subject of an audit on training or indoctrination until TCP-36, March 1982. However the audits of B&R should have alerted TU management that this was a problem area along with finding #17 of TCP-6. These audits are indicative of the low priority TU management placed on training and indoctrination, under B&R this area was a continuing problem. After TU took over management of the QA program, the area was not audited again for two years (TCP-6), and the subject of this audit was not training and indoctrination. Even though TCP-6 identified widespread lack of documentation of training and indoctrination, the area was not audited again for another two years (TCP-36).

5.5.1.4 Document Control

The document control audit trail is long and quite explicit (see Appendix C, Audits). The corrective actions were narrowly focused, and some of the specific problems identified by the audits were fixed, but the underlying cause was not. For example Audit TBR-3 found that DCC personnel needed training and indoctrination. Audit TBR-4 found two newly hired persons had not been trained. The audit corrective action program, thus, was ineffective, e.g., it took over 15 months to correct the procedure implementation problem at the Houston offices[3].

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3 Audit Report, TBR-8, dated 7/29/77

5.5.1.5 Summary

The preceding sections indicate that for the areas of design and document control, despite the generation of audit findings, corrective actions were not timely or thorough. In addition, there was very little auditing of the areas of Nonconformance Control and Training. These are indications of an organization that is not committed to an aggressive and meaningful audit program. That TU management in Phase II lacked an appreciation of the importance of QA audits is confirmed by the CPRT Collective Evaluation Report. In drawing its conclusions regarding TU's historical audit program, the CPRT states:

> "These problems [with the historical audit program] were attributed to lack of full appreciation by the previous TUEC management of the role and benefit of an effective audit program."[4]

The deficiencies noted in the CPRT findings resulted from an audit program that was criticized earlier by a consultant (Section 5.5.3.3) and by the TRT (Section 5.5.4.3). If TU during Phase II had insisted on an aggressive and comprehensive audit program, combined with prompt and generic correction of audit findings, many of the problems identified late in the project would not have existed.

5.5.2 Information from Contractors

5.5.2.1 G&H Concern Regarding "After-the-Fact" Design Review

TU's adoption of the policy of "after-the-fact" design review of field-initiated design changes to maintain construction progress has been described in Section 5.4.3. As noted in that section, G&H made it clear that this policy was implemented in 1977 at the request of TU and that TU was fully aware of the "risks of potential backfitting which this new policy may give rise to in the future." In addition, G&H expressed concern about the size of the backlog of unreviewed design changes in 1979 and attempted to initiate action to reduce the backlog. Despite this information from G&H, TU adopted the risky policy of "after-the-fact" design review and was ineffective in maintaining the backlog at a level which would permit timely final review.

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4 Comanche Peak Response Team Collective Evaluation Report, Revision 0, approved 12/23/87, Executive Summary, p. 18.

The effect of this policy was to add to the workload of G&H. This occurred because G&H was fully occupied in performing the detailed design of the plant and preparing the construction drawings at a rate to support an ambitious construction schedule. The need to meet this schedule, however, meant that review of field-initiated design changes would have to be deferred, thus creating a backlog. When these field-initiated design changes were eventually reviewed they could be found to be acceptable or unacceptable. If they were unacceptable, that design would have to be further revised and reviewed and the affected component would have to be modified. Even if the field-initiated design changes were individually acceptable, the final design would have to be revised to incorporate the changes, and this might invalidate the acceptability of the design of the affected total system. The problem, of course, was most severe when there were multiple design changes to a component or a system because this could lead to repeated reanalysis and redesign of the component or system.

5.5.2.2 B&R Concern Regarding TU QA Management Style

As discussed in Section 5.4.2, TU took over management of Site QA/QC (except for ASME activities) in early 1978. The stated reason for the takeover was to give TU the control needed to provide site procedures that were customized to CPSES rather than using B&R generic procedures. Having assumed control, however, TU QA/QC management's authority was not limited to dictating the types of procedures to be used; it had overall control of site QA/QC.

Several events over the course of Phase II, such as the QA Management Review Board interviews of QC inspectors in 1979, numerous allegations of quality problems and the T-shirt incident indicate that TU Site QA/QC exercised its authority in an overbearing manner in order to "cooperate" with construction and be "practical" about QA.

A dramatic example of this is described in an enclosure to a May 1978 confidential letter from Mr. Munisteri of B&R to Mr. Gary of TU.[5] As B&R described this incident, which involved the compaction of sand in an excavation surrounding two manholes, the TU Site QA/QC Supervisor directed that the degree of compaction be accepted "as is" even though it did not meet the specification. According to the B&R description, the B&R Site QC Supervisor was told by TU that if he still had a problem with the material, he should "write it up" but the Engineer would

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5 Munisteri (B&R) confidential letter to Gary dtd 5/11/78, Site QA/QC Activities, with 3 enclosures, (S00105/BH00221660)

disposition it "use-as-is". The B&R Site QC Supervisor was also told that "... if it was written up, somebody was going to take a heavy and it wasn't going to be TUGCO".

Because B&R did not agree that this compaction condition was acceptable from the standpoint of QC, the B&R QC supervisor was told by the TU Site QA Supervisor to remove all B&R personnel from soils testing/inspection. In addition, B&R was directed to relieve two senior Civil QC personnel of their supervisory responsibilities, and was informed that henceforth the Civil QC group would report to TU QA/QC. In response, the B&R Site QC Supervisor expressed his concern to the TU Site QA Supervisor "... that such a dismissal at this time would be interpreted as 'TUGCO firing B&R supervision because they wrote up a nonconformance that TUGCO disagreed with,' would cause a morale problem and a bad image for TUGCO, and may establish an atmosphere for allegations." The reported response of the TU Site QA Supervisor was that these items would be his problem.

We note the warning of the B&R Site QC supervisor was prophetic: the TU QA Management Review Board interviews of QC personnel in 1979 were done because of poor morale among QC inspectors; these interviews revealed a widespread belief among the QC inspectors that TU's main emphasis at CPSES was production, not quality; and there were many allegations of poor quality. In addition, as discussed in Section 5.4.1, there were several other instances of development of deep-seated disagreements between the QC inspectors and the Site QA/QC supervision.

As for this specific incident, this information was addressed directly to TU top management via the previously cited letter. We have not yet identified what corrective action was undertaken by TU in response to this information from B&R. However, in view of succeeding events, we further conclude such corrective action, if any, was ineffective.

5.5.3 Information Available from Third Party Auditors and Internal Surveys

5.5.3.1 MAC Audit Concerns

After-the-Fact Review of Design Changes

As a result of the audit performed at CPSES in early 1978, the Management Analysis Company (MAC) identified several serious concerns. One of these concerns was "after-the-fact" design review of field-initiated design changes. This issue is discussed in Section 5.4.3, where it is made clear that MAC strongly recommended abandonment of this policy. Despite this warning, TU rejected the MAC recommendation and continued this practice until early 1985 when its use was restricted.

Control of Nonconformances

Another serious concern noted by MAC was in the area of control of nonconformances. Because of its significance, this MAC finding is quoted in full:

> "There appears to be an effort to reduce the number of documented nonconformances.
>
> "It was noted that DC DDAs were being utilized for nonconformance reports. Although this was observed on a small percentage of DC DDAs issued during the month of April, it is recommended that this practice be stopped immediately. The TUGCO system is correctly established whereby nonconformances are written after the fact (Reviewer's Note: i.e. after construction of a component or structure) and DC DDAs are reserved for design changes before the fact (Reviewer's Note: i.e. before construction of a component or structure). It is important that this practice be enforced since DC DDAs prepared after the fact necessitate that workers be directed verbally to violate the drawing since the deviation will be handled after the fact with DC DDAs. <u>This is a poor Quality Assurance Practice</u>. (Underlining added)
>
> "Procedure CPQ1-AB, Rev. 0, dated 5-5-78 was issued for the purpose of providing expedient disposition of concrete discrepancies. The procedure infers that discrepancies of 72°F versus 70°F or 6.2% air content versus 6.0% maximum is (sic) perfectly acceptable when it is signed off by the field engineer. Such a system shortcuts the established nonconforming material control system as defined in Brown & Root and TUGCO procedures and should be discontinued. If tolerances are unrealistic such that the 74°F is acceptable, then the design specification should be changed to so indicate.
>
> "It is recommended that good inspection planning be provided inspectors, identifying the characteristics to be inspected, the method of inspection and acceptance criteria and that inspectors identify nonconformances to such criteria. This will maintain the integrity of inspectors and provides identification of problem areas and provides a means for their correction.
>
> "It is reasonable to assume that on a project as large as Comanche Peak there will be several thousand nonconformance reports. The number does not reflect adversely on the quality of construction, but the

failure to identify nonconformances does reflect adversely on the integrity of inspectors and leaves unknown the quality of the plant."

The recommendations associated with this finding were also totally rejected by TU.

This is a particularly significant finding because it bears on several problems TU was to experience in the future. For example, writing field design changes (DC DDAs) to address construction deficiencies clearly added to the backlog of properly initiated field design changes requiring after-the-fact design review. In addition, it required additional design analysis and drawing revision that would not have been required if the work had been done properly in the first place, or if the inspection acceptance criteria had been properly selected. In addition, since it was not identified as a nonconformance, corrective action was not required, and the same problem could occur repeatedly. Worst of all, it was allowing Project personnel to implement design changes to facilitate construction progress and then putting the burden on Engineering to justify the acceptability of the change.

Another consequence of this decision was the adverse impact on QC inspector morale, which MAC refers to as inspector integrity. As previously noted, during Phase II there was a widely held belief among the QC inspectors that TU management was more concerned with construction progress than with quality. Obviously, this would have an adverse effect on QC inspector morale. One of the ways this was manifested was through what the QC inspectors perceived as excessive use of the "use-as-is" disposition of nonconformances. In other words, if a QC inspector identified a condition that did not meet the specified acceptance criterion for the characteristic being inspected, he would prepare a Nonconformance Report (NCR) describing the deficiency. If Engineering reviewed this NCR and decided the component was acceptable despite the deficiency, this would be classified as a "use-as-is" disposition. There are a number of statements in the interviews of QC inspectors conducted in 1979 by the TU QA Management Review Board and the 1984 interviews of electrical QC inspectors indicating there was excessive use of, or inadequate justification for "use-as-is" dispositions. A portion of the MAC finding quoted above relates to this very practice, i.e., allowing out-of-specification conditions to be "signed off by the field engineer." As MAC indicates, if tolerances are unrealistic, they should be changed to indicate the actual acceptable limits. As indicated above, TU rejected this finding in 1978, and MAC's predictions of adverse effects on QC inspector morale were validated.

Corrective Action

Section 5.4.2 discusses TU's assumption of management of the site QA/QC functions except for ASME activities. The discussion also indicates that during Phase II, quality concerns were frequently subordinated by TU management to concerns regarding cost and schedule. The MAC audit was conducted only three to four months after TU took over management of site QA/QC. Even in this short time, however, MAC was able to discern adverse effects on quality of TU management. For example, the MAC evaluation of Criterion XVI, Corrective Action, states, in part, as follows:

> "... Some of the changes in authority delegation to major contractors appears to be action taken to correct inadequate or untimely response by those organizations; however, other actions taken, such as handling of field changes and nonconformances, appear to be those of circumventing the problem rather than correcting it."

TU's response to this MAC discussion illustrates the narrowness of its perception of quality issues. The response was, "No specific findings."

Procurement Document Control

MAC's finding regarding procurement document control was as follows:

> "The Comanche Peak Quality Assurance Plan does not provide for a Quality Assurance review of procurement documents and changes thereto prior to purchase order placement, except for site originated procurements. Such a review is identified in 10CFR50 Appendix B, Criterion IV and is a requirement of ANSI N45.2.13. It should be required on all safety related procurements."

The TU response was,

> "We disagree this is a requirement. A separate QA requirement section, approved by TUGCO QA, is included with each purchase order and is applicable to all supplements. Changes to these requirements are authorized only by Quality Assurance."

TU and MAC thus disagreed, and TU chose to ignore the advice of its consultant. As to which party was correct, Criterion IV of Appendix B to 10CFR50 states, in part, as follows:

> "Measures shall be established to assure that applicable regulatory requirements, design bases, and other requirements which are necessary to assure

adequate quality are suitably included or referenced in the documents for procurement of material, equipment and services...."

Criterion IV thus requires that measures be established to assure that all information important to quality is included in procurement documents. MAC interprets this to mean (and we agree) that there must be a review of procurement document packages (presumably by QA or QC) to assure that all requirements, including design bases, are suitably included or referenced. TU apparently takes the very narrow view that simply including standard TU QA requirements in the procurement package satisfies this requirement. This is clearly incorrect because it does not provide the required review of the package to assure that all requirements are included. In addition, no document describing standard TU QA requirements can possibly provide a useful description or reference to the design bases for specific components. Thus, a specific review of each procurement package for safety related equipment should be performed.

TU's response to this MAC finding, however, was simply to continue its inadequate practice and ignore the MAC recommendation. An example of the results of sloppy procurement practices is discussed in Section 5.5.4.1, Inspection Report 82-01.

Conclusion

We conclude TU received clear warnings from MAC on the risks associated with "after-the-fact" design review of field changes, of the improper methods being used to handle nonconformances and the possible consequences, and of deficiencies in the QA review of procurement documents. MAC also advised TU that in some cases, TU's exercise of its authority as site QA/QC manager appeared to circumvent problems, rather than correct them. TU management reviewed these MAC findings and recommendations and rejected them.

5.5.3.2 TU QA Management Review Board Survey of QC Inspectors

Another source of information available to TU management concerning project quality was the survey of QC inspectors performed in 1979. As discussed in Section 5.3.2, this survey was undertaken because of a perception of poor morale among QC inspectors. Although job security and inspector pay were among the concerns expressed by the inspectors, Section 5.3.2 states that almost all the disciplines interviewed had the perception that the main emphasis at CPSES was on production - not quality. Some of the disciplines indicated that QA/QC management had an authoritarian attitude; and several disciplines expressed the view that an inordinate number of Nonconformance Reports were being dispositioned "use-as-is" without adequate explanation or justification.

Although the results of this survey were verbally conveyed to TU upper management by the QA Manager and the members of the evaluation team,[6] TU upper management did not issue any written directives ordering a comprehensive analysis and evaluation of the QC inspectors' concerns or implementation of corrective actions. Nor is there evidence TU management requested feedback concerning the effectiveness of the corrective action. Despite this lack of documentation of TU management concern, some corrective actions were implemented. For example, the pay schedule for QC inspectors was revised,[7] inspection procedures were improved,[8] the TU Site QA Supervisor met with small groups of QC inspectors in "fireside chats" to discuss their concerns and state management policy,[9] and a B&R Vice President spoke to B&R site personnel.[10] These actions appear to have had a temporary beneficial effect.[11] That these actions did not have lasting effectiveness is evident from the fact that some of the same concerns, such as emphasis on production and excessive "use-as-is" dispositions of NCRs, were still occurring more than four years later among the electrical inspectors.[12] In addition, TU management did not take any action to provide a protected mechanism for relaying quality concerns or allegations to management until the fall of 1983 when the Quality Hotline was established.[13]

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6 Deposition of David N. Chapman for ASLB hearings, August 2, 1984, p. 76,531, (S00742)

7 Ibid, p. 76,533

8 Ibid, p. 76,569

9 Ibid, p.76,531, and Deposition of David N. Chapman for ASLB Hearings, 7/9/84, p. 35656, (S00739)

10 Deposition of David N. Chapman for ASLB Hearing, 8/2/84, p. 76573, (S00742)

11 Vega memo to Tolson dtd 6/16/80, QA Audit TCP-7: Followup, (S00196/CS00100659)

12 Grier memo to Tolson dtd 3/15/84, Interviews of Electrical QC Inspectors, Vega Exhibit No. 538, (S01374/PT00921540)

13 TU Response to General Request CMP-JA-231 of the 1985 CPSES Retrospective Audit by CMP.

5.5.3.3 Lobbin Audit

Mr. F. B. Lobbin, a consulting engineer, reviewed the program and activities of the TUGCO QA organization in 1982 at the request of the Vice President, Nuclear. His review dealt with the period from the start of construction through 1981 and covered five areas:[14]

- o Quality Assurance Program Plan
- o QA Audit Program
- o Vendor Compliance Program
- o Surveillance Program
- o Inspection Program

QA Program Plan

Lobbin's most fundamental criticism of TU was his finding that there was no "Quality Assurance Plan for Design and Construction" in existence in 1982 (other than a general description in the FSAR), although the 1973 TU Corporate Quality Assurance Program explicitly required such a plan (Finding #1). The FSAR itself was "especially lacking in detail regarding organizational and individual responsibilities and interfaces". The detail lacking in the FSAR, Lobbin explained, was exactly what one should expect to find in the (non-existent) "Quality Assurance Plan for Design and Construction" which "apparently has never been developed". He concluded that this was a serious matter, because of the complexity of the project and because of the lack of nuclear plant design, construction, and QA experience on the part of various prime contractors (Finding #2).

Lobbin found that TUGCO QA was not exercising its authority, as owner, over ASME-related activities. He identified only one audit of that area and found that "(a) definitive written policy with regard to TUGCO's responsibility for the independent review, audit, and surveillance of the ASME program, including interface control with Brown & Root, (was) lacking" (Finding #3).

Lobbin's fourth and fifth findings were generally positive remarks on the procedures and instructions found in the various QA and QC manuals.

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14 Lobbin ltr to Clements dtd 2/4/82, Final Report of Audit, (S00777/CS00380616)

QA Audit Program

In Audit Program Finding #1, Lobbin concluded that "(t)he number and scope of design and construction audits by TUGCO QA to date has been limited". In Finding #4, he wrote that the low frequency of audits occurred because "[t]he TUGCO audit staff is too small and inexperienced to carry out effectively a full scope audit program". In other words, the design and construction QA audit program from 1974 through 1981 had been and was of limited effectiveness. Based on our review, the element of inexperience applied primarily to the 1980-1981 period. It was during this period the TU QA Manager decided to augment his audit staff with personnel who did not necessarily have a technical background and were not necessarily engineers. In fact, a number of the newly hired auditors were classified as technicians.[15] Since earlier audits had been performed by engineers with a growing background in nuclear construction, this use of less experienced personnel undoubtedly caused some reduction in the quality and perspective of the audits performed in the period after 1980. Not using graduate engineers as auditors also allowed the QA Manager to minimize QA costs.

In more detailed Finding #6, Lobbin "did not find a consistent use of detailed audit checklists for the planning and conduct of audits by TUGCO QA". Regarding deficiencies, he found that "neither TUGCO QA nor the audited organization appears to evaluate on a regular basis the impact of identified deficiencies on past activities" (Finding #5). Lobbin also found "little evidence" of any regular TU review of audits by contractors, while citing the explicit FSAR commitment to do so (Finding #7).

Finally, it should be emphasized that TU's FSAR committed the utility to the use of audits for two purposes: (1) to verify compliance with the QA program, and (2) to determine the effectiveness of the program. In fact, Lobbin concluded, the audit program focused on the first purpose and neglected the second: "Relatively little attention has been paid to evaluating the overall effectiveness of the controls established by TUSI and by TUGCO's prime contractors." (Finding #3) About three years later, the TRT would make the same finding.

Lobbin's criticisms of the design and construction audit program dealt with the period from 1974 through 1981. Lobbin's own summary of his findings described a program in trouble due to inadequate audits:

"The design and construction audit program is an area which, in the opinion of the author, requires considerable

15 Oral deposition of David M. Chapman, October 26, 1987, pp.38-40.

attention and improvement. Simply stated, the author believes that more audits of a broader range of quality related activities need to be planned and conducted. In addition, the focus of the audit program should be shifted somewhat from verifying compliance with procedures and instructions for the control of quality related activities to verifying that plant structures, systems, and components have been designed and constructed in accordance with the design and quality assurance criteria and commitments established for the CPSES. This shift in focus is recommended in part to compensate for the relatively low level of audit activity over past years."

Vendor Compliance Program

Lobbin stated, "(t)he vendor compliance program compliments (sic) the vendor audit program, and together these two activities serve to ensure that the safety related materials and equipment for the CPSES are provided by capable suppliers..." Lobbin found "no deficiencies with the vendor compliance function" and complimented the staff on its achievement.

Surveillance Program

The surveillance program should supplement the audit and inspection programs. Lobbin found "no clear management philosophy with regard to the objectives, design, or scope of the site surveillance program (Finding #1). "The Construction Surveillance staff (within QA Services) ha(d) very little commercial nuclear plant design and construction experience" (Finding #2). Further, "(a) review of Site Surveillance Reports reveal(ed) that the deficiencies being identified by the surveillance staff (were) not significant" (Finding #3). As a result of these problems, the surveillance group had not gained the respect of the project and was not effective.

Inspection ,rogram

The Construction QA department within TUGCO QA had responsibility for the inspection of quality related construction activities. Lobbin focused his review on staffing and on procedures and instructions for inspection. A carefully worded Finding (#1) expressed "concern with regard to the experience of inspection personnel, including individuals who perform ASME inspections". An audit of inspector qualifications had not been performed and "training remains an open question". QC inspector qualifications would become a TRT issue about three years after this finding.

Summary

The Lobbin review came in 1982, eight years after the date of the NRC construction permit. Thus, one would expect to find a mature organization, functioning effectively. Instead, Lobbin found an inexperienced staff without a quality-oriented guiding philosophy from higher management. He repeatedly remarked that the staff were interested in their work and wanted to do a good job, but were hindered by fundamental problems. The major findings as summarized by Lobbin were four:

- o "The level of experience within the TUGCO QA organization, in particular commercial nuclear plant design and construction QA experience, is low and is the prime contributing factor to other areas of concern identified during this evaluation."

- o "Staffing of the audit and surveillance functions should be increased."

- o "The number and scope of audits should be increased, especially audits of the site engineering and construction activities. The author (Lobbin) could find no direct evidence that quality program requirements are not being met in these areas. However, the lack of clear evidence, obtainable through audits, which indicates the program is effective and being fully implemented, erodes one's confidence that quality has and is being ensured."

- o "QA management has not defined clearly the objectives for the surveillance program resulting in a program which, in the author's (Lobbin's) opinion, is presently ineffective."

In addition, the following major findings by Lobbin were mentioned in the text of the report, but not included in the above summary:

- o The TUGCO QA organization had not provided the "necessary detail" required to describe QA program responsibilities and interfaces, although its 1973 program description clearly intended such detail to be provided early in the project (p. 6).

- o The design and construction QA staff was "too small to carry out an effective audit program" (p. 13). Elsewhere, it was "too small and inexperienced to carry out effectively a full scope audit program" (p. 15).

- o The design and construction QA audit program focused on "process and procedure audits" rather than on "audits of plant structures, systems, and components" (p. 14).

The Lobbin audit thus provided TU management with information concerning at least three deficiencies that were subsequently identified by the NRC: an inadequate audit program - identified by the CAT inspection about two years later, and failure to periodically evaluate the effectiveness of the QA Program, and QC inspector training and qualifications - identified by the TRT about three years later.

We have reviewed the TU response and planned corrective action regarding these findings.[16] Based on this review we find the TU response and corrective action was clearly deficient in at least two areas. These were: (1) providing sufficient detail to define responsibilities and interfaces; and (2) performing audits of the overall effectiveness of the implementation of the QA program.

The matter of providing "sufficient detail" is related to the fate of the CPSES QA Program Plan. This was intended to be a second tier document that provided uniform and comprehensive guidance for translating policies and commitments appearing in the overall QA Program document and PSAR/FSAR into working level procedures. Such second tier documents are typical for most, if not all, nuclear plants. During Phase I, TU had implemented a very detailed QA Plan; however, by the time of the Lobbin audit in Phase II, the Plan had been reduced to a skeleton. TU's actions in dealing with this issue are described in their response to Finding No. 2, QA Program Plan:

> "... an all inclusive, Quality Assurance Plan for Design and Construction was developed at the beginning of the project. However, as the project evolved it became apparent that the many small changes made in lower-tier QA documents were requiring an unnecessarily burdensome number of revisions in the QA Manual. We therefore made the decision to minimize the amount of detail in corporate documents, their purpose being to define QA policy and management responsibility. Details are included in lower-tier documents such as work procedures and instructions, which are reviewed to assure that they are consistent with corporate policies and regulatory commitments."

TU, thus, rejects this Lobbin finding.

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16 Chapman memo to Clements dtd 2/23/82, Response to Lobbin Report, (S00736/CS00392294)

We have reviewed the QA Program Plan issued during the period referred to in this response.[17] Basically it consists of one section addressed to each of the 18 criteria listed in Appendix B to 10CFR50 plus three sections addressing ASME issues. Except for Section 1, which deals with Organizational structure and responsibilities (six pages and two Figures), three sections consist of two pages, and the rest of the criteria are addressed in a fraction of a page. In terms of detail, it provides little more information than Appendix B -- certainly insufficient detail to guide the development of a coordinated set of quality implementing procedures. A review of the QA Plan in force at the time of the Lobbin audit indicates it was first adopted in its abbreviated form July 1, 1978 -- shortly after TU took over management of Site QA/QC; and was still in effect as late as August 30, 1984. Thus it was in effect for almost all of Phase II which covered the period of most of the construction activity.

As shown in Appendix D, Table D-1, TU was cited on numerous occasions during this period and immediately thereafter for inadequate procedures, failure to follow procedures and inadequate inspection. Examination of Figure D-6 shows that the three most frequent causes of citations were also in these areas (Criteria V-A, V-B and X). Based on these observations, we conclude the abbreviated form of the QA Plan used during Phase II was a significant contributing factor with respect to deficiencies in quality procedures and inspection procedures.

The foregoing is consistent with the findings of the CPRT Collective Evaluation Report regarding Appendix B Criterion V:[18]

> "... It was determined these problems can generally be attributed to inexperienced personnel having written and reviewed the procedures and a weak procedure review process. A contributing factor was the lack of a well-defined procedure hierarchy that ensured QA program commitments were properly translated into lower tier procedural requirements. ..."

Regarding the TU response to the Lobbin audit finding regarding failure to review the overall effectiveness of the QA program, our review of the response indicates the TU QA Manager either did not understand the finding or sought to resolve the problem without expenditure of additional resources. In either case, the

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17 TUGCO CPSES Quality Assurance Plan, dated 8/30/84. (S02035)

18 Comanche Peak Response Team Collective Evaluation Report, Revision 0, dated December 23, 1987, Part IV, p. 26. (S02449)

response was accepted by the TU Vice President, Nuclear. That the response was inadequate is confirmed by the subsequent re-identification of this issue by the TRT,[19] by the NRC citation issued in connection with Inspection Report 84-32, and by TU's acknowledgement of this deficiency and the formation of a Senior Management Quality Assurance Overview Committee.[20]

5.5.3.4 Self-Initiated Evaluation

During the period from October 18 through October 29, 1982, a Self-Initiated Evaluation of design, construction and testing activities was conducted at CPSES. The evaluation was initiated by TU and was conducted by an evaluation team comprised of senior technical and management personnel from Sargent & Lundy. The evaluation team utilized performance objectives and criteria developed by the Institute of Nuclear Power Operations (INPO)[21] specifically to support this type evaluation. Activities included in the evaluation were Design Control, Construction Control and the Quality Program.

In the area of Design Control the evaluation team noted thirteen findings and one good practice.[22] The good practice dealt with the G&H Pipe Rupture Damage Study Program. The thirteen findings included the following:

- o Inadequate procedure to update the line list (piping).
- o Uncontrolled documents used for design of small bore safety-related pipe supports and ASME Section III, Class 2 and 3 piping sleeves.
- o Some types of piping not included in reverification program prescribed by NRC IE Bulletin 79-14.

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19 Eisenhut (NRC) letter to Spence dated 1/8/85, TRT report No. 3. (S00003)

20 Counsil letter to USNRC dated 2/2/87, Response to Inspection Report 84-32.

21 The Institute of Nuclear Power Operations was created by officials of the utilities operating nuclear power plants in the United States after the accident at Three Mile Island. INPO was chartered to provide a method of self-regulation in areas that the Board of Directors, Utility Chief Operating or Executive Officers, determine are necessary. Its goals and directions are established by this Board.

22 Comanche Peak SES Design and Construction Self Initiated Evaluation, Report dated October 1982 (S00737)

- o Procedure for verification of small bore piping doesn't address measurement of angles.
- o Guideline for reverification of pipe hangers is not complete or issued although reverification is already in progress.
- o Composite piping drawings have not been updated recently. An average of 100 unincorporated changes were outstanding against each of nine composite drawings. (TU responded that updating of composite drawings had limited benefit.)

Although not a finding, the members of the evaluation team reviewing this area also expressed their concern regarding the "after-the-fact" design process, as follows:

> "Proposed revisions from the field are being approved by on-site personnel for both on-site designs and off-site designs. For off-site designs the party approving the design does not have the average design calcs. available to make a good determination of excess capacity in the average design to justify his/her judgement.
>
> "Site personnel say only 7 to 8% of the on-site approvals are rejected by the average designer- however, only a small % of hangers have been reviewed against as-built loads. It is probable that the rework % could increase as more as-built analysis is completed
>
> "Not a finding, but it would be well to track this activity for trending of rejected designs."[23]

In the area of Construction Control, the evaluation team identified eight findings. Among the more significant were:

- o Improper outdoor storage of piping sway struts.
- o Bypassing steps of welding procedure.
- o Inadequate procedures to control construction activities (water flowing in pipe while attempting to weld a pipe attachment).
- o Uncontrolled drawings used in modification of vendor-supplied equipment.
- o Indeterminate adequacy of storage environment for NDE records.
- o Procedure for visual weld inspection contains incorrect acceptance criteria.

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23 CPSES SIE, Performance Evaluation Details, DC-5, pp. 102-3. (S00737)

In the area of Quality Programs, the evaluation team identified seven findings. These included:

- o QA does not review and concur in TU engineering procedures.
- o The G&H Project Guide is not consistent with the current G&H scope of work.
- o There is inadequate explanation of the reasons for design changes. (Reviewer's Note: Many of the design changes were necessary because of physical interference between components.)
- o There is inadequate staffing of the group monitoring ASME activities.
- o There is no requirement for interdisciplinary review of design changes at the site. This creates the possibility of two disciplines issuing design changes to address the same problem.
- o The G&H surveillance reporting system needs strengthening.
- o The G&H management review of QA is done by the Vice President - QA, thus providing questionable objectivity.

The TU responses to the above findings may be summarized as follows. Where the finding applied to the activities of one of the CPSES contractors or subcontractors, e.g. B&R, G&H or Bahnson, and did not impact TU policies adopted to expedite construction and/or minimize cost, the response generally specified corrective action that should have been effective if properly implemented. Where the finding applied to items which were a matter of TU policy adopted to expedite construction and/or minimize cost, the response generally did not provide corrective action; instead, the response presented TU's reasons for adhering to that policy although it did not conform to INPO guidelines. Specific instances where this latter type response was provided were the findings regarding the updating of composite drawings, QA review of TU engineering procedures and the interdisciplinary review of design changes at the site.

TU management had the benefit of the information provided by the Self-Initiated Evaluation and utilized this information to achieve corrective action in areas that did not conflict with TU policy. Where the evaluation findings based on INPO guidelines conflicted with TU policies adopted to expedite construction and minimize cost, however, TU generally chose to reject the findings, and thus chose to reject the INPO guidelines which represented an industry consensus of good practice.

5.5.3.5 <u>The Institute of Nuclear Power Operations Evaluation</u>

INPO conducted an evaluation of CPSES Unit 2 during July 1985. Since this evaluation occurred several months after the formation of the CPRT and the completion of the TRT inspections, the information developed from the evaluation was not available to TU management in time to forestall the need for the CPRT. However, since the findings were the product of earlier practices of which TU should have been aware, some of the significant findings are listed below:

- "Improvements are needed in the project corrective action program. While changes have recently been made, elements of the non-conformance and trend analysis programs need strengthening. <u>Root cause analyses for non-conformances are not required</u>..." (Underlining added.)

- "Improvements are needed in the development and review of some electrical calculations to ensure that all design requirements are addressed. Some calculations were not available and some calculations identified limitations that have not been resolved. Examples were noted in calculations for voltage drop, cable and battery sizing, and protective relay settings."

- "Some design considerations for the routing of instrument tubing for high temperature sensing lines and control valve operation have not been updated or evaluated. Process tap movement data used for the design of instrument tubing arrangements are not reviewed against the movement data from the latest stress analysis. Flexibility requirements for some instrument air tubing installations to air-operated valves in high temperature process lines have not been determined." (Reviewer's Note: The TU response to this finding is similar to that previously used by TU for other findings involving unfinished work: "Pipe support engineering ... will provide final displacements after as-built configurations are available." This was a familiar theme wherever an audit or inspection found a component configuration that did not conform to the original design that had been analyzed.)

- "Improvement is needed in the implementation of the environmental qualification (EQ) program. The assumed start of qualified life for some equipment has not been supported by analysis or other documentation. A qualification report for the 6.9 KV switchgear utilized an ambient temperature that is less than the value stated in the FSAR, and an EQ report for the 480 V load center is incomplete." (Reviewer's Note: Despite this INPO finding, it was not until several months later following an NRC inspection that TU recognized it had a serious problem with Environmental Qualification of equipment.[24])

- "Some electrical documents need upgrading to ensure that all design and installation requirements are incorporated. Discrepancies were noted in the diesel generator neutral grounding equipment classification, battery installation tolerances, control circuit cable length verification, and lighting level requirements for emergency lighting."

- "Required clearance between various installed commodities are not being maintained. Several instances were observed where pipe, cable tray, conduit, and HVAC duct were either located in close proximity or in contact with each other."

- "Additional emphasis needs to be placed on erecting conduit supports and instrumentation correctly the first time. Some installations were observed to be made incorrectly and trend reports show that many deficiencies are not identified and corrected by craftsmen or foremen prior to final quality control inspection." (Reviewer's Note: Such a finding is obviously consistent with an environment which emphasizes production as opposed to quality. The hope is that the QC inspector can be convinced the defects are not important.)

As noted above, the information developed as a result of the INPO evaluation was not available to TU management in time to forestall the need for the CPRT. In addition, because of corrective action implemented during the preceding year in response to TRT findings, the number of INPO findings was undoubtedly reduced. Even so, the deficiencies INPO identified were predominantly the result of past TU policies and practices. These included failure to examine deficiencies for the root causes, inadequate design and design review, the postponement of definitive corrective action until the completion of "as-built verification", and a general environment of production pressure.

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24 Attachment to Spence memo to Brittain and others dtd 5/13/86, Report to Directors, (S04070/CB00031651)

5.5.3.6 Conclusions

TU management had clear and timely indications from internal and external sources of problems that threatened to jeopardize project quality. These problems included "after-the-fact" design review, inadequate management of nonconformances, ineffective design control, deficient construction and storage practices, insufficient and inadequate audits, failure to provide a QA Plan which provided sufficient detail to translate QA Program commitments into lower tier implementing procedures, failure to review the overall effectiveness of the QA program, deficient QC inspector training and qualifications and the QC inspectors' perception that production was to be emphasized over quality.

5.5.4 Information from the NRC

5.5.4.1 Region IV Inspections

5.5.4.1.1 Prior to Issuance of the Construction Permit.

The NRC[23] met with TU and initiated inspections of the Comanche Peak Steam Electric Station (CPSES) project well before the issuance of the CPSES construction permit. The purpose of these meetings and inspections was to assist TU in understanding its responsibilities as owner of the nuclear project and to assure that an effective Quality Assurance program was in place and implemented prior to the start of construction. Since plant design was already underway, it was particularly important to assure that design activities were being conducted in accordance with industry code and regulatory requirements. A Limited Work Authorization (LWA) for site preparation was granted prior to issuance of the construction permit; therefore, certain inspection activities were required to assure conformance with the provisions of the LWA. This section considers some of the meetings and inspections conducted by the NRC Regional Office prior to issuance of the construction permit.

On February 15, 1973, about four months before TU formally submitted the application for a construction permit for the CPSES, the Director of the cognizant NRC Regional Office and one of his managers met with the Executive Vice President of TU and members of his staff. The purpose of this meeting was to discuss the responsibilities of both the NRC and the utility with respect to the planned construction of the CPSES.

As documented in NRC Comanche Peak Inspection Report 73-01[24], topics discussed included:

- o The typical NRC inspection and the frequency of inspections.
- o The enforcement procedures available to the NRC, including civil penalties.

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23 In 1975 the Atomic Energy Commission (AEC) was split into the Nuclear Regulatory Commission (NRC), and the Energy Research and Development Administration (ERDA). In this report, the term NRC will be used to denote both the NRC and its precursor agency, the AEC.

24 It is the practice of NRC Regional Offices to utilize numbered inspection reports not only for documenting the results of formal inspections, but also to record the substance of meetings held with applicants and licensees.

- The conclusion the NRC must reach before an operating license can be issued and the role of the Regional Offices in reaching that conclusion.
- The necessity for complete documentation of deviations, including methods of resolution and approvals.
- The necessity for advising the NRC promptly of significant discrepancies, and a general coverage of regulatory reporting requirements.
- The need for correlating vendor procurement and site construction to the Safety Analysis report.
- An explanation of the requirements for a QA program, as defined by Appendix B, 10 CFR 50.

Specific topics discussed with respect to the QA program included:

- The responsibilities of licensees.
- Degree of involvement by the licensee.
- Independence of the QA organization.
- Involvement in the vendor programs.
- Audit programs.
- Programs for corrective actions.
- Establishment of permanent documentation.

Regarding this last point, the NRC representatives noted the emphasis the NRC places on QA/QC records for obtaining objective evidence relative to the quality of the plant. Inspection Report 73-01 adds:

> "The need for complete, accurate, and technically useful records was stressed."

The NRC representatives also discussed the planned initial NRC QA inspection, to be conducted for the purpose of reviewing the TUSI QA manual to determine its conformance to the requirements of 10 CFR 50, Appendix B and the PSAR. Inspection Report 73-01 concludes:

> "Special emphasis, during the initial QA inspection, will be placed on the controls relating to design, engineering, procurement, and vendor inspection."

On June 5, 1973, TU submitted its application for a construction permit for CPSES; the application was docketed by the NRC on July 20, 1973,[25] and on December 3, 1973, NRC representatives began the initial QA inspection mentioned at the February 15, 1973 meeting. Before describing the results of the December 1973 inspection, it is noted that in this time frame the NRC

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25 The Docket Numbers were 50-445 for Unit 1 and 50-446 for Unit 2.

established the policy that a pre-docketing inspection of quality assurance activities would be conducted for all plants submitting an application for a construction permit after September 1, 1973. The object of this policy was to assure the applicant had an effectively implemented quality assurance program in place before an application would be accepted for docketing. The CPSES application was not subject to this policy, however, because the application had already been docketed on July 20, 1973.

The results of the initial QA inspection that commenced on December 3, 1973, are described in Inspection Report 73-02. Three violations were identified as follows:

- o TUGCO's quality assurance program did not comply with all the requirements of 10 CFR 50, Appendix B (eleven different types of deficiencies were identified under this violation).
- o Certain written procedures or instructions were not established at a time consistent with the schedule for accomplishing design, procurement, and PSAR development activities.
- o The functions of the "Quality Surveillance Committee, Design", were not being carried out as described by written policies.

The cover letter transmitting Inspection Report 73-02 to TU suggests the NRC Regional Office was concerned by the findings of this inspection. This is indicated by the statement:

> "Our findings are being forwarded through Regulatory Operations[26] Headquarters to the Directorate of Licensing[27] in order that a determination relative to your docket status may be established."

This appears to be a reference to the NRC pol cy cited above, and the Region's belief that since the CPSES QA program was not fully in place, consideration should be given to revoking the docketing of the project. No correspondence has been located, however, indicating the docketing was revoked or that revocation of docketing was considered by the NRC.

The next NRC inspection of CPSES occurred on March 13-14, 1974, and had as its primary purpose review of the corrective action taken by TU with respect to the findings of the previous inspection (73-02). NRC inspection report 74-01 records the

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26 An earlier name for what was later known as the Office of Inspection and Enforcement (I&E).

27 A precursor organization to the Office of Nuclear Reactor Regulation (NRR).

results of this March inspection and indicates most of the 73-02 findings were satisfactorily resolved.

Four additional inspections and one meeting were documented in the inspection reports for 1974.[28] The purpose of the inspections appears to have been to assure the readiness of the QA program prior to the initiation of construction. Although no violations were issued by the NRC for the balance of 1974, three of the four inspections identified concerns related to the CPSES QA program or those of the subcontractors. These concerns included:

- The architect/engineer's QA policy and procedures were not adequate for the status of the project.
- The constructor's QA manual was being revised to incorporate the requirements of 10 CFR 50, Appendix B.
- More specific delineation of interface activities and responsibilities was needed in the QA and QC procedures of the contractors involved in the design and construction of the safe shutdown impoundment (SSI) dam. (Note: At the time of this inspection July 18-19, 1974, initial excavation for the dam was tentatively scheduled to begin in less than two months, i.e., on September 15, 1974.[29])
- Additional QC procedures were needed by Freese & Nichols (F&N), the designer of the SSI dam, to implement the above responsibilities.
- The F&N audit procedure was deficient in several areas.
- TU was revising the CPSES QA Plan to include surveillance activities for the construction of the SSI dam.
- The B&R construction procedures for the dam did not reference the construction criteria of the soils testing contractor, Mason-Johnson Associates (MJA).
- B&R Quality Control procedures were not being adequately controlled.
- There was no procedural control of changes and revisions to the F&N QA manual.
- The F&N corrective action procedure did not provide specific guidance as to when status updates should be requested.

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28 For convenience, inspections documented by inspection reports with numbers in the 74-XX series, for example, will be referred to as 1974 inspections, even though the inspection may not have been completed or documented until 1975.

29 A Limited Work Authorization (LWA) was issued for the CPSES site, and site preparation under this LWA began October 18, 1974. (Inspection Report 74-04, p. 4)

- o F&N was developing (but had not completed) a procedure for inspection and testing to accompany an SSI dam inspection and test schedule.
- o The report of an F&N audit had not been issued in a timely manner and the corrective action requirements of the procedure had not been observed.
- o MJA procedures for onsite testing and inspection had not been fully developed.

On December 6, 1974, representatives of the NRC Regional Office conducted the inspection described in Inspection Report 74-05. Except for final approval of the B&R QA Program Manual (approval scheduled for January 1, 1975), and completion of some onsite construction procedures (prior to the date needed), the NRC inspectors concluded all of the above listed concerns had been resolved. This inspection report was issued on December 16, 1974; and the CPSES construction permit was issued on December 19, 1974.

The foregoing demonstrates TU was clearly and emphatically made aware of the NRC requirements for Quality Assurance - even before TU submitted the application for a construction permit. In addition, several NRC inspections were conducted during review of the application to assure an effective quality assurance program was in place prior to issuance of the construction permit, or, for some elements, at least prior to the time of need.

5.5.4.1.2 <u>After Issuance of the CPSES Construction Permit</u>.

Highlights of the results of some of the more significant NRC inspections performed after issuance of the Construction Permit are summarized below:

<u>Inspection Report 76-07</u>.

This inspection report documents an occasion where the NRC inspector visited the B&R Miscellaneous Steel Fabrication shop and determined that welding of safety related components was being performed without procedures in effect for control of important welding parameters. The NRC inspector identified this as a violation[30] of regulatory requirements and cited the licensee. In addition, the NRC inspector informed the TU Site QA Supervisor of the condition. The TU Site QA Supervisor indicated "...he was aware of the situation; but was hoping that an issue

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30 The NRC has used various terminology over the course of its inspection activities to identify items not in compliance with regulatory requirements. Notwithstanding the NRC's original description, this report will use the terms violation or finding to describe such noncompliances.

of the revised procedure would correct the problem." When the Site QA Supervisor was asked why he had not exercised his Stop Work authority to obtain necessary controls, "... he had no satisfactory answer." Accordingly, the NRC inspector cited TU because the Site QA Supervisor had not exercised his Stop Work authority.

As discussed in Section 5.4.1, the TU Site QA Supervisor at this time (Milam) appears to have learned from this incident and other NRC findings, and subsequently became more conscientious. This in turn, led to his subsequent transfer out of the QA organization.

Inspection Report 76-08.

This report notes two violations of interest. The first violation relates to failure to provide proper control of plant drawings and inspection documentation. This is of interest because it was the first violation issued on this subject subsequent to the start of construction, but it would not be the last. Indeed, as described in the TRT report dated January 8, 1985, in the period prior to 1984, the project suffered document control problems of such magnitude as to require implementation of a completely new document control and distribution system.

The second item involved inspection of TU Site QA Surveillance activities. This inspection revealed that a contractor's site QA manager had (engineering) responsibilities not described in the contractor's QA Manual. This was of concern to the TU QA Surveillance personnel (apparently because of possible conflicts of interest between the two sets of responsibilities) and, hence, had been documented in the monthly QA Activities report. The finding had not been documented, however, in the formal Surveillance Report as required by the TU QA procedures and therefore would not require formal resolution. Based on this procedure violation, TU was cited by the NRC inspector. This violation is of interest because TU's initially proposed corrective action for the item was sufficiently minimal as to move the NRC to request additional information regarding how TU would prevent future violations. TU's second response, included the statement:

> "The effectiveness of the corrective steps will be monitored by the Quality Surveillance Committee on a routine basis. The results of this monitoring will serve as a basis for any further actions proven necessary to assure full compliance with our commitments."

This response is of interest not only because of the casual approach to QA requirements exhibited by TU QA personnel in their implementation of requirements and in the TU response to the

NRC's notice of violation, but also because of the reference to the Quality Surveillance Committee (see Inspection Report 76-09).

Inspection Report 76-09

This report contains the following statement:

> "During the review, which included discussions held with TUSI and B&R personnel, the inspector observed that QA/QC records and internal correspondence reflect a weakness in the effectualness (sic) of the Quality Surveillance Committee. Although quality related problems are being identified during quarterly meetings of the Quality Surveillance Committee, a number of problems appear to be long standing, generic in nature, and without apparent resolution. These matters are of concern to the IE inspector and will be the subject of a discussion to be held with TUSI management September 3, 1976."

It is thus evident, even at this early point in the project, the NRC has developed sufficient concern regarding QA at CPSES that it has found it necessary to meet with TU management to discuss these concerns. In fact, an even earlier meeting was held with the NRC on June 11, 1976 to discuss the NRC's concerns regarding CPSES quality.[31]

Inspection Report 77-02

This report indicates that in February, 1977, R.G. Tolson became the TU Site QA Supervisor, replacing P.M. Milam. As indicated in Section 5.4.1, this was done to obtain a QA Supervisor who was less strict concerning QA requirements and more cooperative with Construction.

Inspection Report 78-07

This report involves a violation resulting from the decision to change the basis for performing concrete testing. The reason for the change was to expedite construction while somewhat reducing the test laboratory workload. The change, however, resulted in a violation of the American Concrete Institute (ACI) testing requirements. The incident is pertinent because the NRC inspector "understands" the change which resulted in the violation was proposed by TUGCO QA. This raises three questions: (1) Why is TUGCO QA interested in expediting construction at the expense of QA?; (2) Was TUGCO QA's knowledge and experience so limited they did not know they were violating a Code provision?;

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31 Schmidt memo to Brittain dtd 7/2/76, Minutes of QSC meeting of 7/1/76, (S01140/CS00100564)

and (3) What kind of review by knowledgeable persons did this change receive prior to its approval?

Inspection Report 78-10

This report describes a potential construction deficiency identified by TU QA during an audit of G&H. The audit, which was performed May 23-28, 1978, determined that several G&H Project Guides contained an equipment classification list that was more than three years old.[32] The significance of the finding was that the list was used to specify which pieces of equipment required a safety-related structural foundation, and erroneously classified at least sixteen safety related systems as non-safety related. As a result of this finding, installation of foundations for non-nuclear safety related equipment was stopped until a determination was made as to the proper equipment classification. In addition, a review was conducted of the foundations that had been installed for equipment previously erroneously classified as non-nuclear safety related.

Inspection Report 79-01 states this issue was closed by TU in January 1979, on the basis of the satisfactory results of tests of concrete expansion bolts which were not installed under the provisions of the QA/QC Program. While the final hardware results were satisfactory, the fact that a significant corrective action program was necessary indicates the TU audits of this area were either incomplete, not timely or both.

Inspection Report 79-04

This inspection report records a "deviation"[33] regarding failure to maintain physical separation between electrical wiring serving separate safety trains. This is noted at this point because the issue would arise on at least two more occasions and ultimately would be addressed by CPRT ISAPs I.b.1 - I.b.4.

Inspection Report 79-07

This inspection report discloses a significant construction error in that the concrete support structure for the reactor vessel in Unit 2 was misoriented by approximately 45 degrees. As a result, significant modification of the support structure and reinforcing steel was required in order to provide the necessary strength at

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32 Chapman letter to Rock (G&H) dtd 6/6/78, Audit TGH-8. (S00029)

33 As distinguished from a "violation" which involves failure to meet published regulatory requirements, a "deviation" is a failure to meet a commitment to the NRC, such as a statement made in the FSAR, or in correspondence to the NRC.

the proper locations. This involved drilling the concrete, installing additional rebar and steel plates and grouting the drilled holes. The reason for the error is not stated and the incident does not appear to be reported in the list of Significant Deficiency Analysis Reports[34] (SDARs). In the absence of any other stated reason, a contributing cause of the problem would appear to be ineffective QA/QC. Clearly, someone should have signed-off on the drawings, forms, rebar and embedments installation before the concrete pour.

The inspection report includes a discussion regarding the procedure for replacing the reinforcing steel severed due to the drilling operations. One view is to replace steel equal to an amount that assumes all the steel in the existing concrete has been severed. The other view is to replace only that reinforcement steel which has been documented to have been severed by the drilling. Regarding this latter approach, the inspection report states, "This could be a problem, as the unavailability of documentation would make it difficult to determine exactly what existing reinforcing steel has been severed." This sounds like the project does not have drawings showing the location of the rebar. The issue of severed reinforcing steel in the Fuel Handling Building ultimately became the subject of ISAP II.e.

Inspection Report 79-15

1979 was the year of allegations and investigations at Comanche Peak -- a total of eight investigations were conducted during this period, as documented in Inspection Reports 79-09, -10, -11, -12, -15, -20, -22, and -26. Inspection report 79-15 was the fifth in this series, and apparently raised the concern of NRC Regional management. As stated in the cover letter for this report:

> "Even though no items of noncompliance with NRC requirements were identified during this investigation, we did find that the allegations were essentially true. We also noticed during this investigation that a thread of continuity existed between this investigation and others recently conducted relative to alleged problems with site management and quality control in certain areas of construction. ... as we discussed in our meeting with you and Mr Fikar, in our office on June 22, 1979, when these allegations are taken collectively, there appears to be a morale problem which is evidenced by several of the allegers and may be attributable, in part, to communication problems

34 This is the term applied by TU to reports made pursuant to the requirements of 10CFR50.55(e)

between the workers and supervision. In our June 22 meeting, you indicated that you would look into these apparent communication problems along with the adequacy of QA/QC indoctrination of plant supervision and workers and take appropriate action to correct any weaknesses that you detect in these areas. We intend to follow this matter closely during subsequent inspections." (underlining added)

From this letter it appears that at this time NRC Regional management was once again becoming concerned that were quality problems at CPSES, and that these derived from a poor attitude towards quality on the part of TU management. It is noted that this expression of NRC concerns led to the interviews of the QC inspectors discussed in Sections 5.3.2 and 5.5.3.2.

Inspection Report 80-02

This report documents the investigation of allegations of poor workmanship and lax QA/QC. The allegations were made by three individuals who formerly worked at CPSES as Authorized Nuclear Inspectors (ANIs) for ASME construction activities. Within a period of about one year, one of the ANIs was transferred to another site and the other two quit - apparently as a result of continuing disputes with B&R construction and being overruled by their supervisor. This NRC report generally dismisses the charges on the basis that all known defects were corrected. The report, and attached newspaper article, make it clear there were very bad feelings between the ANIs and B&R.

Other documents, however, indicate it was not merely a problem of personalities, but was rooted in poor performance at CPSES. This is indicated by the fact that a few months earlier, in April and again in May 1979, the National Board of Boiler and Pressure Vessel Inspectors performed audits at CPSES and obtained significant corrective action from B&R.[35] The problems, however, were not limited to B&R. The National Board audit report indicates one of the problems identified was improper modification of Code Data Reports supplied by the manufacturers of ASME Code components. In this case, the modification was not performed by B&R personnel, but by a TU representative.

Although Inspection Report 80-02 dismisses the allegations as not significant, the overall assessment by the NRC is shown to be in error by the fact that a subsequent audit by the National Board in October 1981 led to the decision by the Board to allow the B&R ASME certificates to expire on the expiration date, January 8,

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35 Harrison (National Board of Boiler and Pressure Vessel Inspectors) letter to Gamon, B&R, dtd 6/8/79, Reaudit, CPSES Site. (S00011)

1982.[36] Upon completion of further corrective action by B&R, completion of a resurvey by the ASME and receipt of a commitment from B&R to complete additional corrective action, restored the lapsed certification to B&R on March 19, 1982.[37]

Inspection Report 80-12

This report documents a meeting at the NRC Regional Offices with Gary and other TU management to discuss reporting of significant construction deficiencies pursuant to 10 CFR 50.55(e). This meeting was apparently held because the Regional Office perceived TU as having too high a threshold for filing such reports. The SALP report for this period (80-25) indicates improvement was noted following this meeting.

Inspection Report 81-19

This inspection report records two Unresolved Items concerning pipe hangers and supports. The first item involved a question as to the applicable Revision No. of Appendix 8 to the G&H specification. The copy of the G&H Specification included Rev. 0 of Appendix 8. The copy of Appendix 8 used by the Stress Analysis Group was Rev. 4. This was an obvious design control problem that could lead to confusion, and possibly serious hardware problems, later in the project.

The second item involved the situation where a pipe hanger was fabricated, installed, inspected and accepted by QC -- then a revision is made to one of the installation documents (in the case of CPSES, the document was a Component Modification Card [CMC]). As stated by the inspector, "The TUSI mechanism for assuring that revisions to CMCs, issued subsequent to the installation inspection, are included in the installation package and verified by QC was not apparent." This is an early indication of the subsequent major problem experienced with pipe hangers. It is also an indication of problems in the document control area, which in turn created problems in QC inspection.

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36 Russo (ASME) letter to Vurpillat (B&R) dtd 11/25/81, NA & NPT Certificates of Authorization at CPSES, expiring Jan. 8, 1982. (S00012)

37 Spadafino (ASME) letter to Vurpillat (B&R) dtd 3/19/82, New Issuance of NA & NPT to B&R at CPSES. (S00375)

Inspection Report 82-01

On June 4, 1981, the NRC Resident Inspector was notified by TU that seismic design work for the safety related instrument tubing supports had been based on the Operating Basis Earthquake rather than the required Safe Shutdown Earthquake. This report records the followup to that notification, and includes the following statements:

> "The corrective actions ... involved a substantial reinspection and engineering analysis of already installed instrument tubing runs with attendant specific corrections on a cased basis ..."

> "... the vendor had undertaken the work on verbal orders from the licensee under an existing contract for supply of personal services rather than engineering services, had stipulated that the work involved non-safety applications, and had not invoked either Appendix B or Part 21 of Title 10 until after the vendor recognized that errors had been made and informed the licensee."

> "...the licensee's engineering personnel selected the lowest quality level since it represented the majority situation without due regard for appropriate technical or regulatory requirements."

This incident indicates an appalling lack of knowledge or disregard of regulatory requirements by the licensee's engineering personnel, and a QA program that was ineffective with respect to monitoring design and procurement activities. It also reflects a result of the failure of TU QA to review procurement documents as noted in Section 5.5.3.1.

Inspection Report 82-22

On August 20, 1982, the NRC issued Information Notice 82-34. This notice informed the addressees of unacceptable welding identified at three vendor facilities. Inspection report 82-19 records that in response to this notice, several installed control panels were inspected by the licensee and the Resident Inspector and a number of unacceptable weld conditions were identified. Since TU provided source inspection at the vendor's facility, the discovery of these unacceptable welds indicated a breakdown in the source inspection activity. Based on this finding, TU examined other components received on site which had been subject to source inspection, and found additional unacceptable welds. A main steam pipe-whip restraint fabricated by NPS Industries was found to have numerous weld defects despite the fact there were seven inspection reports signed by TUGCO source inspectors that stated the restraint was acceptable. In addition there were 122 welded components supplied by CB&I which were scheduled for reinspection. Because of these findings and earlier and later problems in this area (see Inspection Report 80-20 and 82-25), TU was given a Category 3 rating for Vendor Procurement during this SALP report period. In response to these developments, TU engaged Reedy, Herbert, Gibbons and Associates to assist in on-the-job training of source inspectors for the purpose of inspecting vendor welds [TU letter of Dec. 27, 1982-attached to SALP Report]. This appears to be another area where the TU QA/QC effort was either inexperienced, poorly qualified/trained or both. It also provides an example of the inadequacy of the TU audit activities in that the obvious lack of qualifications of the TU source inspectors should have been readily identified by TU audits much earlier in the project.

Inspection Report 82-26

This thick report documents the investigation performed by the Special Inspection Team into the allegations presented by Messrs. Walsh and Doyle during their appearance before the ASLB in July and September 1982. This team, which was made up of two individuals from Region IV, four individuals from NRR, one individual from I&E headquarters, and three consultants, concluded that of 19 broad areas of allegations identified by Walsh/Doyle, 12 areas were not substantiated, 6 areas were partially substantiated and the problems had been identified by TU in the course of their design review process, and one area relating to bending stress in a bolt had been partly confirmed. In addition, in the course of its review, the team identified four concerns, not identified by Walsh/Doyle, that did not require further assessment. In short, the report effectively concludes Walsh/Doyle were substantially correct in seven of their allegations.

Investigations of Allegations

There were seven inspection reports issued in 1982 which recorded the results of investigations of allegations or other matters. These reports were 82-05, -10, -11, -14, -26, -29, and -30.

Inspection Report 83-18

This report documents the results of the inspection of CPSES by the NRC's Construction Assessment Team (CAT) from January 24-February 4, and February 14 - March 4, 1983. At the close of the inspection, the Team identified 16 "potential enforcement items" involving the following areas: electrical and instrumentation construction; mechanical construction; welding and nondestructive examination; civil and structural construction; procurement, storage and material traceability; quality control inspector effectiveness; quality assurance; and design change controls and corrective action systems.

While space does not permit a comprehensive discussion of the CAT findings, two excerpts from the report illustrate what appear to be significant problems in the areas of design control and document control. These excerpts are taken from Section IX of the report and deal with Design Change Controls for cable tray and conduit hangers and supports.

> "The NRC CAT inspector sampled and reviewed sixty CMCs [Component Modification Cards] and fifteen DCAs [Design Change Authorizations]. About thirty of the CMCs and DCAs reviewed had not received the appropriate review and approval by the original designer, Gibbs & Hill as required by ANSI N45.2.11. Installations to the design document had been performed or were in-process, but the design document had not been 'final' reviewed. A review of the Gibbs & Hill "CMC Master Index" (structural) indicated there were on the order of four- to five thousand of such changes that had been generated but had not yet been "final" reviewed by Gibbs & Hill.
>
> "It was determined that proper verification of such changes might ultimately be accomplished, However, the volume of CMCs and DCAs remaining to be reviewed by the original designer, as well as those designs that have as yet to be performed in the structural area;, is of concern to the NRC CAT inspector. The concern involves the adequacy of review which will be provided considering the approaching September, 1983 Fuel Load Date [six months after the CAT inspection]."
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> "The NRC CAT inspector determined that inspections performed and completed were not always to the latest issued design document. For example, supports for twenty cable tray and conduit installations were examined. Of these twenty, twelve were not "final" inspected to the latest issued design document, even though records in the QA vault indicated "final" inspection had been performed. Later CMCs covering design changes existed for all twelve of these installations. In addition, the licensee's QC inspections were performed in six instances to CMCs with earlier revisions than the latest revision issued and in effect <u>at the time the inspection was performed</u> [Similar conditions were discovered and discussed in the Electrical and Instrumentation Construction Section of the report Section II]."

Similar findings were also made with respect to pipe supports.

This report thus documents a condition where components are being installed while there is a backlog of thousands of unreviewed design changes. In addition, many components have been final inspected to drawings which were either not current at the time of the inspection or the drawings have subsequently been revised. In short, the CAT inspector draws a clear picture of design and document control systems that are, at best, confusing, and at worst, out of control.

The consequences of such a situation are as follows: (1) If the drawings used for construction were not the same as the drawings used for inspection, the support would have to be modified or the inspection would have to be re-performed, depending on which drawings were the latest revision; (2) if the same drawing revision was used for construction and inspection, but it was not the current revision, then the support would have to be modified and re-inspected; and finally, (3) if the current drawing revision was used for construction and inspection, but further revision was required because of the large backlog of unreviewed design changes, drawing revision, modification of the support and re-inspection would all be required. In short, TU had the choice of reviewing field design changes promptly before installation and doing the job once; or utilizing after-the-fact design review with its known risks to get things built fast. As previously noted, TU selected the latter approach.

The CAT inspection report listed 16 "potential" enforcement findings (noted above.) According to NRC inspection and enforcement policy, however, the host Region normally has responsibility for final determination and implementation of enforcement actions related to these "potential" findings. After performing a followup inspection, discussing the matter with NRC headquarters and holding an Enforcement Conference with TU, Region IV determined that only four of the 16 items would be cited as violations. The items discussed above concerning design and document control were not among the four items cited.

Inspection Report 83-28

From June 27 to September 16, 1983, Region IV conducted a followup to the CAT inspection. The results of this followup are documented in Inspection Report 83-28. This report indicates Region IV had evaluated each of the remaining CAT concerns and concluded they did not represent violations. Based on our reading of the report and our previous experience with NRC inspection and enforcement activities, we believe the report is not objective in arriving at its conclusions, and it appears to be heavily biased in favor of TU. This view is further supported by the observation that conditions similar to at least five of the twelve potential violations not cited by Region IV in the follow-up to the CAT inspection were cited in later inspections.[38]

Inspection Report 85-12

This report presents the results of an inspection performed to evaluate TU's implementation of systems for employee's fe.dback of concerns. The report notes TU initiated the first version of this program in October 1983. This first version consisted of a hot line and interviews of personnel leaving QA/QC and all B&R construction employees who were being terminated. In November 1983, an ombudsman from an outside organization was added to the organization. This program was administered by the QA department and the report notes this provision had the weakness that it might not objectively process concerns reflecting on the QA department. In January 1985, the SAFETEAM program was initiated. The CPSES SAFETEAM program was modeled after a standardized and generally accepted program developed by an outside company. The NRC inspectors concluded that except for two minor weaknesses, TU was acceptably implementing the SAFETEAM program.

We note the reservation expressed by the NRC inspectors regarding the propriety of having the program administered by the QA Department. Since we believe much of the QA problem at CPSES during Phase II originated with the TU Site QA Department, we conclude the program was potentially not objective until replaced by the SAFETEAM program at the beginning of Phase III.

5.5.4.2 Region IV Trend Analyses

In January, 1977 Region IV initiated a Trend Analysis reporting requirement.[39] The Principal Inspectors for each plant prepared a report of their assigned plant covering the previous year for Region IV management. The reports included the following information:

- Number and repetitiveness of Construction Deficiency Reports
- Enforcement history, e.g., number and repetitiveness of non-compliance items.
- Responsiveness of licensee to enforcement action.
- Number of outstanding unresolved items and timeliness of resolution.

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38 Electrical and Instrumentation Construction Item 2, NRC Inspection Report (IR) 84-26; Mechanical Item 1, IRs 84-34 and 85-13; Welding and NDE Item, IR 84-29; QA Item 1, IR 84-32; and Design Change Item 2, IRs 85-11 and 85-14.

39 NRC Staff Exhibit 183 (M00420)

- Corporate management involvement in regulatory matters.
- Effectiveness of QA/QC program.

This trend analysis system was used by Region IV until 1980 when the Systematic Assessment of Licensee Performance (SALP) program was initiated in all Regions.

The trend analysis prepared by the Principal Inspector was a combination of facts and the inspector's opinions. A few examples of the items reported on CPSES follow:

1976 - "During the early part of 1976, it became apparent to the Principal Inspector that the effectiveness of the licensee's QA/QC Program was in a state of degradation as a result of a domineering and overpowering control by the contractors' site construction management."[40]

This observation is consistent with our observation that as cost overruns and schedule slippages became apparent during the latter part of Phase I, the construction effort gained increasing TU management support.

1977 - "The contractors' QA/QC Program is considered to be "too wieldy" in its structure and is undergoing progressive change by the licensee. A significant organization and management change initiated January 3, 1978, should improve overall QA/QC Program effectiveness."[41]

1978 - "The Licensees' QA/QC program is generally effective in my opinion. It is somewhat encumbered by too many procedures and occasionally by not having enough real talent to do the job correctly..."[42]

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40 NRC Staff Exhibit 184, (M0?420), p. 1.

41 NRC Staff Exhibit 187 (M00420)

42 NRC Staff Exhibit 191, (M00..0), p. 2.

1979 - Effectiveness of QA/QC Program

"This item seems to need addressing in two parts to be effective:

"Part one is the overall theory of Quality Assurance as a management tool. In this area, I believe that the licensee has been led down a poor path by Brown & Root during past years. It appears to me that Brown & Root has, in many instances, provided construction procedures to fulfill Appendix B that provide a minimum amount of direction to the construction force and yet comply to the words, if not the spirit of Appendix B. This is not too bad if the construction force is really a competent group but leads to some pretty bad things if that is not the case. What I have begun to see, but have difficulty proving, is that the Brown & Root construction philosophy is to build something any way they want to and then put it up to the engineer to document and approve the as-built condition. If the engineer refuses, he is blamed for being to (sic) conservative and not responsive to the client's needs. Thus the driving force behind my request for a special engineering audit of site operations.

"The second part of the addressment (sic) is to that phase called QC. Only recently has there been a real effort on the part of the licensee itself, or on the part of Brown & Root, to write explicit instruction (sic) to the line inspectors on what they were to inspect. Previously, the procedures were frequently pretty general, again not too bad if the inspectors are knowledgeable in the subject being inspected but terrible if they are not. In a couple of cases, I have been able to show them that their people are essentially incompetent even though they had been through the site training and had been certified as competent. I see a desire on the part of the licensee to turn this situation around in the important areas of electrical and piping installation. However, the situation discussed above has a bearing since too often an installation clearly accomplished other than as originally designed and buildable has been approved by the licensee's on-site engineering arm as fulfilling requirements. In effect, the engineer has approved a nonconforming installation in advance of QC being called. QC is then signing for the as-built condition and the underlying problem is not addressed. I'm not at all sure

> that what CPSES is doing in this area is very differert than what other utilities and/or engineers have done on other projects but I don't like it. I believe that much the same thing went on in Bechtel at ANO-2, but it wasn't as obvious nor was I there as much."[43]

The practice of engineering approving a nonconforming installation in advance of QC being called, is the same poor practice identified and condemned by MAC during their 1978 audit. See Section 5.5.3.1.

The report continues on page 3 describing "Any Other Trends Indicative of Poor Performance",

> "... It seems likely to me that the licensee will use his full powers to be less open with us in the area of identified construction deficiencies than he has in the past. I think he will take maximum advantage of part 50.55(e) and the [NRC] guidance to go through the necessary formalities but avoid, if at all possible, having to report to us. It is, of course, premature to really get into this arena until we prove a case."

In April 1980, TU management attended a meeting with Region IV Management where the reporting requirements of 10CFR50.55(e) were explained to TU (See Inspection Report 80-12). In addition, TU was cited in September 1980, for failing to report a significant construction deficiency (200 undersized welds). See Inspection Report 80-18.

5.5.4.3 <u>SALP Evaluations</u>

SALP reviews and reports are prepared by a Board of Senior personnel from the cognizant NRC Regional Office, the Office of Inspection and Enforcement, and the Office of Nuclear Reactor Regulation (NRR). The reports are based on seven evaluation criteria which are applied to various functional areas. The functional areas evaluated depend upon the status of the facility, i.e., whether it is in design, construction, pre-operation or operation status. The Board rates each of the functional areas based on defined categories. These reports were discussed with the applicant and placed in the NRC Public Document Room. The evaluation criteria and the performance categories are as follows:[44]

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43 NRC Staff Exhibit 195, (M00420), page 2.

44 NRC CPSES Inspection Report 82-24, dated Jan. 31, 1983.

Criteria

One or more of the following evaluation criteria are used to assess each applicable functional area.

1. Management involvement in assuring quality
2. Approach to resolution of technical or quality issues
3. Responsiveness to NRC initiatives
4. Enforcement history
5. Analysis and reporting of reportable events
6. Staffing (including management)
7. Training effectiveness and qualification

Attributes associated with the above evaluation criteria form the guidance for categorization of each functional area in one of three categories. Performance categories are defined as follows:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety or construction is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and are reasonably effective such that satisfactory performance with respect to operational safety or construction is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear to be strained or not effectively used such that minimally satisfactory performance with respect to operational safety or construction is being achieved.

Three annual SALP reviews were performed on CPSES covering the periods July 1, 1980 to June 30, 1981,[45] October 1, 1981 to September 30, 1982[46] and October 1, 1982 to October 31, 1983.[47] These assessments were fundamentally based on the Region

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45 SALP Report 81-20, dated March 28, 1982.

46 SALP Report 82-24, dated Jan. 31, 1983.

47 SALP Report 83-49, dated May 7, 1983.

inspection activities which previously had been published by the NRC. The SALP reports therefore are a composite or summary of inspection findings, violations and the general perception of the SALP Board members regarding licensee performance. These SALP reports, as a minimum, should remind the applicant of problems experienced.

The purpose of the three evaluation categories used in SALP evaluations is to identify functional areas where the amount of NRC/licensee attention should be increased or can be decreased. Because of the number and severity of problems identified in early 1984 the NRC established several special groups to review and monitor the activities at CPSES. This substantially increased the amount of NRC attention given to CPSES; therefore the SALP program for CPSES was discontinued at that time.

In 1980, the first annual Systematic Assessment of Licensee Performance report (IE Report #80-25, NRC Staff Exhibit 181), reported problems with the QA/QC program, personnel qualifications, and attitude toward regulatory requirements.

The report concludes the following about the effectiveness and attitudes of licensing personnel in complying with NRC requirements:

> Licensee construction and engineering management -- the NRC personnel stated that it appears there is a continuing tendency to engineer away construction problems rather than enforce compliance to drawings and specifications.

Again the Applicant promised to reform and correct its programmatic and personnel weaknesses by taking unspecific "management action with the engineering and construction personnel to alleviate this situation." (p. 5)

The 1982 SALP report noted the following noncompliances, during the 1981-82 review period:

- Personnel not properly trained and indoctrinated
- Failure to follow procedures for verification of the performance of automatic welding machines
- Failure to follow nonconformance procedures for electrical cable
- Failure to follow procedures for hoisting safety-related components
- Failure to update procedures

- Failure to provide appropriate instructions for installation for Class IE equipment

- Failure to follow welding procedures

- Failure to provide instructions and procedures appropriate to installation of Class IE battery chargers

- Failure to follow procedures for cable pulling

- Failure to follow procedures for reporting and repair of damaged electrical cable

- Failure to follow welding procedures

- Failure to follow electrical inspection procedures

- Failure to establish quality assurance program for Class 5 pipe support systems

- Failure to follow inspection procedure for returning inspection stamps

- Failure to follow inspection procedure to initial and date operations traveler

- Failure to report a significant construction deficiency (50.55(e))

- Failure to follow construction procedures required by drawings

5.5.5 Conclusions on Information Available to Management

TU management had information from a number of sources identifying policies, practices or conditions that posed a significant threat or risk exposure relative to the quality of CPSES. This included information on the risks of the "after-the-fact" design change process and the factors needed to minimize that risk, information on the large backlog of unreviewed design changes and the problems with the document control system that increased the risk associated with the "after-the-fact" policy, information concerning the poor quality practice of issuing design changes to resolve construction deficiencies rather than Nonconformance Reports, information on the high-handed and dictatorial manner of the Phase II TU Site QA Supervisor, the NRC's perception in 1976 that quality was being subordinated to cost and schedule, information on poor QC inspector morale, and numerous allegations of QC inspector intimidation and harassment and poor construction practices in 1979 and again in 1982-83.

Based on our review of the project history, we conclude that except for the issue of QC inspector morale in 1979, TU did not take timely action in response to the other items of information available to it concerning poor QA practices or conditions.

Regarding the "after-the-fact" or "at-risk" design change policy, both G&H and MAC provided timely warning of the risks associated with this policy. In addition, on at least two occasions, TU Dallas QA personnel expressed their reservations concerning this policy to TU management. TU audits identified problems with the document control system and in the size of the backlog of unreviewed design changes -- both conditions adding further to the risk exposure of the "after-the-fact" design change review process. The NRC's CAT inspection in 1983 also called attention to this problem and the associated risks, but TU persisted in the policy. It was the combination of this policy and the large backlog of unreviewed changes that was the central concern of the ASLB in its December 28, 1983 Memorandum and Order. Even then, however, TU persisted in this policy until January 1985. The effects of this policy are discussed in Section 5.4.3.

TECHNICAL ANALYSIS CORPORATION

THE QUALITY ASSURANCE PROGRAM
AT THE COMANCHE PEAK STEAM ELECTRIC STATION

REPORT SPONSORED BY

DON H. BECKHAM
TECHNICAL ANALYSIS CORPORATION

April 30, 1988

Part II

6.0 Regulatory Actions for CPSES Licensing Proceedings

The activities of the Atomic Safety and Licensing Board in the Comanche Peak licensing proceedings have been a significant contributor to the record of the project. This section discusses these activities from the initiation of the first hearing board proceeding associated with the granting of the Construction Permit through recent orders of the current Board. Also discussed are the special efforts initiated by the NRC staff, primarily responding to the Board requests for information and resolving issues raised in the Board proceedings.

6.1 Atomic Safety and Licensing Board

The following discussions of ASLB issuances are not intended to evaluate the legal process, but to reveal the Comanche Peak QA/QC problems which surfaced as a result of the ASLB proceedings and thus were made known to TU. The adjudicatory record is particularly pertinent to a review of Comanche Peak QA/QC performance, because it was the ASLB decision in December 1983[1] which effectively required a comprehensive investigation and resolution of QA/QC problems.

In January 1983 TU believed the construction of Unit 1 was 95% complete,[2] and on December 16, 1983, TU stated that construction of Unit 1 was essentially finished.[3] Prior to the December 28, 1983 ASLB decision, TU expected to load fuel into Comanche Peak Unit 1 in mid-1984.[4]

6.1.1 Construction Permit Decision

The ASLB's initial decision on the Comanche Peak Construction permits dated December 12, 1974[5] discussed the QA/QC program in considerable detail. The decision included a discussion of:

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1 ASLB Memorandum and Order LBP-83-81, December 28, 1983.

2 NRC Memorandum, D.L. Kelley & R.G. Taylor to S.B. Burwell, February 23, 1983.

3 TU News Release, December 16, 1983. M00384

4 Letter to the ASLB from Nicholas S. Reynolds, Council for Applicants, December 18, 1983. Letter to NRC Director of Nuclear Reactor Regulation from H.C. Schmidt, TU December 16, 1983. M00403

5 ASLB Initial Decision, LBP-74-88, 12/12/74.

- The applicant's program for obtaining acceptable QA and QC.
- The major contractors, Gibbs & Hill (A/E), Westinghouse (NSSS) and Brown & Root (construction) responsibilities and organization for QA and QC.
- The NRC staff acceptances of the applicant's QA Program.
- The Board's independent investigation of the applicant's QA program.
- The applicant's QA Organization, responsibilities and authority.
- The Design Review Committee responsibilities.
- The NRC staff acceptance of the applicant's QA Organization.

Based on the evidence on the record, the Board found that the applicant had provided a "Quality Assurance organization with the sufficient independence and authority to carry out effectively the quality assurance programs that had been described, and that the quality assurance programs themselves, which contain specific measures to implement the required quality assurance criteria of Appendix B of 10 CFR Part 50, provide assurance that the proper controls, elements and measures for quality assurance will be carried out for the Project."

This view of the acceptability of TU's QA program was seriously challenged by events over the succeeding nine years as evidenced by the ASLB order of December 28,1983.[6] The information available to the Operating License proceedings ASLB is discussed in the following two Sections of this report.

6.1.2 Operating License Proceedings - Early Phase

On February 27, 1978, TU submitted an application for an operating license to the NRC, including the Final Safety Analysis Report and the Environmental Report. On May 8, 1978, NRC published a notice of receipt of the application. In June 1979 the Atomic Safety and Licensing Board (ASLB) granted three petitions to intervene on health and safety issues and allowed Texas to intervene as an interested state.[7] Between the granting of intervention in 1979 and mid-1982, the adjudicatory activities involved the development and refinement of contentions, discovery, motions and appeals involving contentions, and public

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6 ASLB Memorandum and Order LBP-83-81, December 28, 1983.

7 Atomic Safety and Licensing Board Decision, LBP-79-18, 6/27/79.

hearings.[8]

A prehearing conference was held in Glen Rose, Texas on May 22, 1979 to consider petitions to intervene in the Comanche hearings. The ASLB admitted the following intervenors:

1. Citizens Association for Sound Energy (CASE)
2. Citizens for Fair Utility Regulation (CFUR)
3. Texas Association of Community Organizations for Reform (now West Texas Legal Services) (ACORN/WTLS).[9]

On June 16, 1980, the ASLB issued a prehearing conference Order admitting certain contentions, including a contention on QA and rejecting other contentions.[10]

In 1980 and 1981 the wording of the QA contention was argued in board motions.[11] During this time one of the intervenors dropped out of the proceedings for financial reasons, but the Licensing Board adopted some of that intervenor's (ACORN) contentions.[12] Another intervenor CFUR, subsequently dropped out[13] leaving Citizens Association for Sound Energy (CASE) as the only intervenor in the safety hearings other than the state of Texas.

Up to this point the records indicate that the Comanche Peak adjudicatory activities were proceeding without significant problems. There were contentions and controversy, but they were generally similar to most operating licensing cases of the late 1970's and early 1980's.

6.1.3 Operating License Proceedings - Later Phase

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8 Atomic Safety and Licensing Appeal Board (ASLAB) decision ALAB-599, 7/3/80; ASLAB decision ALAB-621, 11/24/80; Atomic Safety and Licensing Board (ASLB) decision LBP-81-22, 7/23/81; ASLB decision LBP-81-25, 7/30/81; ASLB decision LBP-82-18, 3/8/82; ASLB decision LBP-82-59, 8/4/81.

9 ASLB Order LBP-79-18, June 17, 1979, p. 728.

10 Unpublished ASLB Order, June 16, 1980.

11 CASE motion to keep present wording of contention 19 on QA/QC. (NRC and TU had attempted to narrow contention)

12 LBP-81-38, 9/25/81.

13 LBP-82-17, 3/5/82.

On December 28, 1983, the Licensing Board issued an order[14] containing a clear statement of concern that TU had not demonstrated adequate design quality assurance and had not adequately responded to design questions. Although there had been indications of QA problems (see Section 5.5.3.2) the Licensing Board order is the clearest indication prior to the end of 1983 of a significant concern about the Comanche Peak Project by an NRC organization. The Board in fact was highly critical of the NRC staff licensing review and inspection programs.

CASE, ACORN and CFUR had filed contentions concerning QA with the Board in May 1979.[15] These QA contention ultimately became consolidated as contention 5 that stated:[16]

> "The Applicants' failure to adhere to the quality assurance/quality control provisions required by the construction permits for Comanche Peak, Units 1 and 2, and the requirements of Appendix B of 10CFR Part 50, and the construction practices employed, specifically in regard to concrete work, mortar blocks, steel, fracture toughness testing, expansion joints, placement of the reactor vessel for Unit 2, welding, inspection and testing, materials used, craft labor qualifications and working conditions (as they may affect QA/QC) and training and organization of QA/QC personnel, have raised substantial questions as to the adequacy of the construction of the facility. As a result, the Commission cannot make the findings required by 10CFR 50.57(a) necessary for issuance of an operating license for Comanche Peak."

Although a QA contention had been around since mid-1979, the sequence of events that ultimately culminated in the Board's order started in mid-1982.

<u>Walsh/Doyle Concerns</u>

Mr. Walsh, a former group leader in a Comanche Peak support group made a limited appearance before the Licensing Board on July 28,

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14 LBP-83-81, 12/28/83.

15 CASE Motion in Support of Retaining Present Wording of Quality Assurance/Quality Control Contention (CASE Contention 19) May 12, 1980, p. 3, (M00999)

16 LBP-83-81, December 28, 1983, p. 1416. (M00999)

expressing concerns about piping design.[17] Following these hearings, CASE requested and received a subpoena to depose Mr. Jack Doyle, who CASE contended had information supporting Mr. Walsh's allegations.

Subsequent to Mr. Walsh's limited appearance before the Licensing Board, he appeared as a witness for CASE at the September 1982 sessions. Prior to the resumption of hearings on September 13, 1982, TU and the NRC staff filed rebuttal testimony on the allegations of Mr. Walsh. CASE submitted the deposition of Mr. Doyle as his direct testimony and later introduced supplemental testimony for Mr. Walsh and Mr. Doyle.

Messrs. Walsh and Doyle had been engineers assigned to TU's Structural Design Language (STRUDL) Group involved in the mathematical modeling of pipe supports.[18] Their testimony was based on their concerns regarding pipes and pipe supports. The following are some of the areas of the Walsh/Doyle concerns:[19, 20, 21]

1. Consideration of LOCA[22] in piping design.
2. Stress in pipes caused by cinching up U-bolts.
3. American Welding Society (AWS) Code
4. Upper lateral restraint beam
5. Differential seismic displacement
6. Component cooling water supports
7. Richmond inserts
8. Organizational and design interfaces.

TU Response to the Walsh/Doyle Concern

At the September 1982 hearings, TU presented its prefiled rebuttal testimony on Mr. Walsh's allegations and provided additional written rebuttal testimony on Mr. Doyle's allegations. TU's witnesses were experts in the area of (1) the ASME Code (Mr. Reedy), (2) structural engineering (Mr. Scheppele and Mr.

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17 LBP-83-81, 12/28/83.

18 LBP-83-81 December 28, 1983, p. 1425. (M00999)

19 NRC Hearing Transcript pp. 2712-18, July 28, 1982.

20 LBP-83-81, December 31, 1983. (M00999)

21 CASE Proposed Findings of Fact and Conclusions of Law (Walsh/Doyle Allegations), August 22, 1982. (M00999)

22 Loss of Coolant Accident - a specific accident that must be considered in the design of a nuclear power plant.

Finneran), (3) pipe support engineering and Structural Design Language (STRUDL) code (Dr. Chang), and (4) pipe stress analyses (Mr. Krishnan). These witnesses were subject to extensive cross-examination and Board questioning.[23]

TU responses to the Walsh/Doyle allegations include some direct responses to specific issues but generally indicated that the specific issues would be adequately resolved by their iterative design process. TU described the process as follows:

> The process for the design of piping and supports is iterative in nature. In fact, it is unrealistic to expect to design piping and supports to satisfy all applicable requirements the first time through the process. Such an iterative design approach is employed throughout the nuclear industry and is utilized in the design of other nuclear components as well. Briefly, the design of an individual support begins with an initial design based on the known initial piping stress analysis. When it is impractical to construct the support as originally designed, a new supp-rt scheme is required and an update of the original pi,ing analysis will be performed. This process continues until the final as-built analysis confirms the adequacy of both the piping and supports.[24]

The process focused upon a piping "stress problem" which consisted of a design length of pipe for which a pipe support is an accessory that cannot be designed separately from the length of pipe. The steps in the iterative design process were as follows:

1. A conceptual design for a length of pipe is prepared using the piping plan and elevations and/or isometric drawings for the plant.

2. An initial pipe stress analysis on the conceptual piping design is performed to calculate the forces and types of loads on proposed supports on the conceptual piping design.

3. The description of the acceptable piping layout (including the proposed support locations with accompanying directions of restraint and magnitude of forces) is sent to one of the three support design groups.

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23 LBP-83-81 December 28, 1981, pp. 1417, 1418. (M00999)

24 LBP-83-81, December 28, 1983, p. 1421.

4. During the installation of the supports, field engineers are available to authorize changes to support designs as necessary to produce a usable design.

5. Once piping and some of the accompanying supports are installed, a QA inspection of the as-built dimensions of the piping and installed pipe supports is performed. The drawings utilized at this step are then stamped "as-built verified" and transmitted as a package to the appropriate piping stress analysis organization (Gibbs & Hill or Westinghouse) for a preliminary stress analysis.

6. The pipe stress analysis organization conducts its preliminary stress analysis, adjusting the piping stress problem for any new factors which impact on the pipe or support stresses. The stress problem is rerun to determine new stresses in the pipe and new loads on the pipe supports.

7. The stress package is then returned to the appropriate design group, which reviews the new piping loads to determine whether the particular hanger is still appropriate. Supports which are found to be satisfactory are stamped "vendor certified" and if found to be unsatisfactory are modified and a new as-built design package is sent to the pipe stress analysis organization.

8. Upon completion of installation of all supports, a stress problem package (incorporating changes to the supports since the problem was last run) is prepared and provided to the pipe stress analysis organization for reanalysis. A pipe stress problem will be rerun if the new as-built configuration impacts the pipe stresses.

9. This package is once again returned to the appropriate design group to determine whether any supports need be modified as a result of the new stress problem and if so, will be modified and returned once again to the pipe stress analysis organization until all pipe stresses are acceptable and all pipe supports are vendor certified to the loads developed in the last run of the stress problem.[25]

Further, TU believed it had at least two processes in place to

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25 LBP-83-81, 12/28/83, pp. 1421, 1422.

check the validity of the final vendor certification process. The first was a design control group within the pipe support engineering organization on site that was responsible for randomly sampling final vendor certified drawings to assure satisfaction of applicable requirements. Second, TU audited the vendor certification process and final designs from both a programmatic and technical viewpoint. Accordingly TU believed that adequate controls were in place to assure the effectiveness of the iterative design process.

The TU argument was that the iterative design process had caught or would eventually catch and correct any of the Walsh/Doyle concerns that were found to be substantiated. TU witnesses Reedy and Finnernan, indicated that they did not believe the NRC regulations (10CFR, 50, Appendix B) require design deficiencies to be identified in nonconformance reports until after the iterative design process is completed.[26]

<u>NRC Response to the Walsh/Doyle Concerns</u>

During the September 1982 sessions, the NRC staff presented a panel whose testimony consisted of prefiled direct testimony and oral examination. The Licensing Board was dissatisfied with the NRC staff's preparation and interrupted the cross-examination and the NRC staff's direct testimony was never admitted into evidence.[27]

Following the September 1982 hearing session, the NRC formed a Special Inspection Team (SIT) to investigate and evaluate the Walsh/Doyle concerns. The SIT investigation began on October 13, 1982 and was completed on January 18, 1983. The SIT performed special inspections of the pipe support engineering program. During the inspections the team:

- o Identified 19 broad areas of concern.
- o Determined the design status of the piping supports cited as examples of the Walsh/Doyle concerns.
- o Evaluated the validity and safety significance of each concern.
- o Inspected the design procedures and practices of the pipe support design which had passed through the complete design review process.[28]

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26 LBP-83-81, 12/28/83, pp. 1423, 1424.

27 LBP-83-81, December 28, 1983, p. 1418.

28 CASE's Proposed Findings of Fact and Conclusions of Law (Walsh/Doyle Allegations), August 22, 1983.

- Identified no violations of NRC regulations.
- Identified four matters requiring follow-up during construction inspection program. In each of these matters NRC stated that TU had identified a similar problem in its design review program and corrective action would be taken.[29]

The NRC concluded that TU's design program and design review procedures were adequate to provide reasonable assurance that appropriate corrective action would be taken.

In addition to inspecting the alleged defective supports, the SIT investigated the design practices in 19 broad areas encompassing the Walsh/Doyle concerns. In 6 of these areas some aspects of the concerns had been identified by TU during its design review and the problems had been or were being corrected; other aspects of these concerns were not substantiated. In one area, Mr. Doyle's concerns related to the bending stress in the bolt was partly confirmed. Twelve of the areas were not substantiated. None of the concerns raised by Walsh and Doyle were substantiated as demonstrating serious deficiencies in the pipe support design program.

6.1.4. The Board's Decision

The Licensing Board rejected TU's arguments and the NRC staff's support of the iterative design process because they did not consider it proper to wait until the end of the design process to locate and correct design errors. The Licensing Board stated that 10 CFR 50, Appendix B requires that the process for correcting errors be reasonably prompt and waiting until the end of the design process does not satisfy this requirement. The Licensing Board concluded that there should be quality assurance for design as a part of the iterative process, not just QA inspection of construction at the end of the process. The Board considered the absence of a program to correct design deficiencies promptly to be a serious TU deficiency, mitigated only slightly because it was acquiesced in by the NRC staff.[30]

In addition to its conclusion regarding the lack of an adequate design QA system, the Licensing Board addressed specific technical issues raised by Messrs. Walsh and Doyle. In most cases, the Board concluded that TU had not carried its burden of proof to resolve the concerns and this contributed to the Board's lack of confidence in the design of Comanche Peak.

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29 NRC Inspection Report 50-445/82-26, 50-416, 182-14, February 5, 1983, transmitted to TUEC, R.J. Gary, by letter of 2/5/83 from G.L. Madsen, NRC Region IV.

30 LBP-83-81, December 28, 1983.

The Licensing Board's Initial Decision included the following:

> "The Licensing Board finds that applicant has not demonstrated the existence of a system that promptly corrects design deficiencies and has not satisfactorily explained several design questions raised by the intervenor. The Board suggests the need for an independent design review and requires applicant to file a plan that may help to resolve the Board's doubts.
>
> "QUALITY ASSURANCE: DESIGN
>
> "Appendix B to Part 50 of the regulations requires that there be a quality assurance system that will promptly identify and correct deficiencies in the design of the plant. Applicant may not delay design review until the plant is nearly complete and claim that it is thereby complying with this regulatory requirement.
>
> "QUALITY ASSURANCE: INDEPENDENT DESIGN REVIEW
>
> "The Board issues criteria for an independent design review that would satisfy it, including specifications governing the independence and qualifications of the review group, rules assuring organizational independence during the review, reliability measures of the review, sampling concerns, the scope of the review (including in-depth consideration of each of the intervenor's concerns), methods of documenting and presenting findings, provisions for review of findings and provisions for hearings concerning the findings."[31]

6.1.5 Licensing Board Activities After Identification of Design QA Problems

Since the ASLB revealed Comanche Peak's serious design QA problems in December 1983,[32] there has been little progress in resolving adjudicatory issues. Nevertheless there has been a considerable amount of activity. Adjudicatory activities include TU, intervenor, and NRC staff actions in response to the Board's December 1983 order, further action on miscellaneous technical issues and allegations, proceedings involving Construction Permit

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31 LBP-83-81, December 28, 1983.

32 LBP-83-81, December 28, 1983

Extension, and various disclosures to the Board by parties to the proceedings.

TU Actions in Response to the Board Order Concerning Design QA

In its design QA decision, the ASLB suggested an independent design review and required TU to file a plan to help resolve the Board's doubts.[33] On January 17, 1984, TU requested reconsideration of the Board's decision. TU moved that the Board reconsider its conclusion that TU's pipe support design process did not satisfy 10 CFR 50 Appendix B, and instead find that the record was insufficient to allow the Board to conclude whether or not the design process satisfied Appendix B.[34] TU stated that there was, in fact, a system for promptly identifying and correcting design deficiencies. TU also moved that the Board reconsider several of its findings on specific design matters raised by Messrs. Walsh and Doyle. The NRC staff supported TU's motion regarding the pipe support design process, but it opposed TU's motion regarding the specific Walsh/Doyle concerns.[35] On February 8, 1984, the ASLB denied the TU and NRC staff motions to revise or clarify its design QA decision.[36]

TU's motion for the Board to reconsider its December 1983 decision indicates that as late as January 1984 TU did not recognize or acknowledge that the Comanche Peak design QA program was inadequately implemented. The NRC staff apparently agreed with TU about their QA program although they disagreed on some of the specific Walsh/Doyle issues.

After unsuccessfully trying to get the board to change its initial decision, TU filed a plan in response to the Board's

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33 LBP-83-81, December 28, 1983, p. 1410.

34 TU Motion for reconsideration of Memorandum and Order (Quality Assurance for Design), January 17, 1984. M00999

35 NRC Staff Response to Applicant's Motion for Reconsideration of Memorandum and Order (Quality Assurance for Design) January 27, 1984. M00999

36 ASLB decision LBP-84-10, February 8, 1984. M00999

concerns.[37] In the plan TU stated "Overall, the Plan comprises the performance of several tests and analyses, the preparation of detailed testimony and documentary evidence, and the performance of an independent and reliable review of these efforts." TU commissioned Cygna to perform an independent design review of piping and pipe support systems on a segment of the component cooling water system and on the main steam line from the steam generator to the main steam isolation valve. TU indicated that the plan could be fully implemented in approximately two months.

The portion of the plan dealing with documentary evidence and preparation of testimony, and the short estimated schedule suggest TU still believed the hearing record was its main problem. In commenting on TU's plan, the Board suggested that TU broaden its plan beyond the Walsh/Doyle concerns and consider Criterion I (Organization) and Criterion XVI (Corrective Action) of 10 CFR 50 Appendix B.[38] The Board's major concern was the QA for design, and the specific allegations of Messrs. Walsh and Doyle were additional concerns. TU chose to look narrowly at the Walsh/Doyle concerns and not to consider the broader issue of the QA process.

In March 1984, TU supplemented its plan[39] in response to the ASLB comments. With respect to Criterion I, TU would review the following:

(1) responsibilities for design activities and design reviews (independent design review);
(2) interfaces within the organization;
(3) interfaces outside the organization;
(4) audit/surveillance independence;
(5) responsibilities for corrective action responses;
(6) control of design process (design input/analysis);
(7) design verification performance/documentation;
(8) design changes;
(9) transmittal of design information; and
(10) organization independence.

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37 Applicants Plan to Respond to Memorandum and Order (Quality Assurance for Design), February 3, 1984. M00999

38 ASLB Transcript, February 24, 1984. M00999

39 Supplement to Applicants' plan to Respond to Memorandum and Order (Quality Assurance for Design), March 13, 1984. M00999

Assessment of Criterion XVI would include review of the following:

(1) mechanisms to identify design deficiencies;
(2) tracking of design deficiencies;
(3) methods for correcting/treating design deficiencies;
(4) processing of reports required by 10 CFR 50.55(e) and Part 21;
(5) auditing of design activities;
(6) surveillance programs; and
(7) corrective action systems employed.

Through these reviews of Criteria I and XVI, TU believed that Cygna would assess whether an appropriate design quality assurance program has been in place and effectively executed at Comanche Peak. The Cygna assessment would consider:

- o effectiveness and timeliness of methods to identify and resolve design deficiencies;
- o adequacy of corrective action process for dealing with poor quality; and
- o Design Input Document Control and Design Verification Control elements of ANSI 45.2.11.

In response to the Board's suggestion to broaden the plan beyond the Walsh/Doyle concerns, TU had Cygna conduct a multi-discipline independent design review of the component cooling water system. The review would include mechanical equipment, electrical equipment, instrumentation and controls, and other related structures, systems and components. TU stated that as modified, their Plan now included not only independent design reviews of the pipe supports and piping of all four main steam lines from the steam generators to the main steam isolation valves, and a segment of the component cooling water system (with a focus on, but not limited to, the Walsh/Doyle concerns), but also an expanded independent design review of all disciplines for the component cooling water system.

Regarding schedule, TU stated in its March 13, 1984, Supplement that they were hopeful that the issues could be addressed in hearings commencing in April. (This schedule is about the same as the schedule given prior to increasing the scope of work.) However, TU recognized that a more realistic schedule might call for these issues to be addressed in hearings in mid- to late-May. TU expected that the Cygna review of the piping and pipe support systems for the component cooling water system and the main steam lines, and the Cygna reviews of Criterion I and XVI and of the two elements of ANSI N45.2.11, also could be addressed at that time or shortly thereafter.

In October 1984 the ASLB expressed concern about another phase of

QA, startup QA.[40] In closed sessions of parallel proceedings concerning the Comanche Peak Construction Permit extension (discussed later in this section), the Board received evidence that raised concerns about the adequacy of TU's quality assurance of startup testing activities. The Board's concerns were:

(1) Startup engineers and QA technicians apparently incorrectly interpreted the phrase "independent verification" in test procedures. QA technicians merely verified that there were "numbers -- any numbers -- on test data sheets".

(2) Apparent failure to document important deficiencies and follow-up in an appropriate fashion, e.g., supervisors knew of charges that test engineers had intentionally falsified a test without initiating a deficiency paper.

(3) Failure to document apparent design deficiencies in the reactor protection system, with the consequence that there may be unexpected generic deficiencies in the design.

(4) Written procedures governing the filing of Non-Compliance Reports (NCRs) altered by oral directive and a written memorandum.

(5) Defective test procedures were not detected during their first use in a test situation. These failures "call STE [System Test Engineer] qualifications into question."

In October 1984, the ASLB expressed its intent to review TU's response to the findings of the NRC Technical Review Team (TRT).[41] After the ASLB decision of December 28, 1983, the NRC established the TRT to investigate the Board's concerns and other allegations (see Section 5.5.4.3 of this report). In March 1985 the Board ruled that it would delay making findings about the adequacy of QA until TU had a chance to respond to the TRT findings.[42] In the meantime, the NRC had formed a panel to

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40 ASLB Memorandum, October 1, 1984.

41 ASLB Memorandum, October 4, 1984.

42 ASLB Memorandum, March 12, 1985.

develop an NRC position on Contention 5 concerning QA which by this time was the only hearing contention that had not been resolved.[43]

TU filed Applicants' Current Management Views and Management Plan for Resolution for All Issues[44] on June 28, 1985, in response to a Board order[45] to file a statement of "Current Management Views as to the status of the plant, including an assessment of the adequacy of the record Applicants have created in this case." TU management stated that although Comanche Peak was "generally well designed and constructed," the intensive investigations had identified discrepancies of concern to TU. TU stated:

> "TUGCO management is not satisfied with the status of the plant and would not proceed to operate it, even if authority were to be granted, until all of the outstanding concerns have been addressed, their safety significance determined, generic implications and collective significance considered, and necessary corrective actions have been completed."

This filing indicates that TU finally, a year and a half after the Board made its QA findings and after drastic TU management changes, acknowledged there were potential problems in the plant and not just in the hearing record.

TU's current management believed:

- It was premature to assess prior management actions.
- Prior management had strong engineering credentials in the design construction and operation of fossil-fueled generating plants.
- Management was always committed to constructing and operating a safe plant.
- Management style was not ideal for handling employee relations in the complex world of nuclear power.

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43 NRC Internal Memorandum from the Executive Director for Operations (EDO) to the NRC staff forming the panel on the QA contention, December 24, 1984.

NRC Internal memorandum from the EDO to the NRC Staff, February 28, 1985, enclosing the QA Panel Charter.

44 TU filing Applicants' Current Management Views and Management Plan for Resolution of all Issues, June 28, 1985.

45 ASLB Order LBP-85-16, May 24, 1985.

TU current management also acknowledged:

> "One of the lessons learned by the nuclear industry in recent years is that successful nuclear utilities generally are those staffed with individuals experienced in nuclear power, including construction, operations and regulatory activities. This has not been lost on Applicants, and the recent addition of managers with substantial nuclear experience in programs with broad-based success in all facets of the industry reflect that the lesson has been learned. Further, Applicants are intent on further staffing their nuclear organization with personnel with more experience in the nuclear power industry."

The above quotation regarding lessons recently learned makes us wonder why TU should be so slow to learn, and why the prior management had not learned the lessons. About 15 years earlier, in 1970, Mr. Caudle of TU documented his visits with two nuclear utilities.[46] Mr. Caudle reported the lessons the experienced nuclear electric utilities had learned were:

- o The time to build a nuclear unit is long.
- o The paperwork can become a monster.
- o The utility, not the AEC, is responsible for safety
- o The number of engineering personnel required for a nuclear unit is much greater than for a fossil unit.

The two experienced nuclear utilities, VEPCO and CP&L, tried to give TU the advantage of their experience. Fifteen years later, TU may have learned the lessons VEPCO and CP&L tried to teach them in 1970. CP&L appears to have been prophetic when it said "Your top management will not believe you when you get back and tell them of the problems and the amount of work required to install a nuclear unit."[47] Apparently TU top management did not believe or chose to ignore the lessons learned by more experienced nuclear utilities.

In mid 1985 TU's current management indicated that the hard-nosed, task oriented style of prior management and the lack of nuclear experience of prior management contributed to the Comanche Peak problems.

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46 Memorandum from Caudle to Robuck, August 3, 1970.

47 TU memorandum from Caudle to Robuck, August 3, 1970.

TU further stated in Applicants' Current Management Views that the real issue of the hearing had moved beyond the question of specific QA lapses and the question now was whether TU could assure that errors had been corrected and confirm the adequacy of the plant. TU believed that its program (the Comanche Peak Response Team (CPRT) program and management Plan) would resolve all outstanding issues. The Board, however, declined to adopt the TU Management Plan as the sole basis for continued litigation of the case. The Board stated:

> "Where Applicants sought to exclude litigation of prior QA/QC and design practices because of a comprehensive program of reexamination of the safety of the plant, it would not be proper to determine whether the study adequately resolves the issues until the results of the study are available for examination and challenge."

The Board continued to require and receive information from TU concerning the Management Plan and CPRT effort. The Board, NRC staff and CASE commented on TU submittals. The adjudicatory chronology from TU's filing of its Management Plan[48] on June 28, 1985 to the present show the Board closely monitored TU's attempts to resolve its QA problems. The Board required periodic status reports, asked questions about CPRT reports, and made comments about the CPRT Program.

To date the QA contention has not been resolved. During this three and three-quarter years of hearings and litigation:

(1) TU finally accepted that there was a potential QA problem at the plant and not just a hearing record problem.

(2) TU acknowledged that its prior management had contributed to the QA problems due to its hard-nosed management style and lack of nuclear experience.

(3) TU proposed that the hearings had passed beyond the question of specific QA lapses and the question now is whether TU can confirm the adequacy of the plant through its Management Plan and CPRT.

(4) The Board adopted a policy of closely monitoring TU program to resolve the QA problems and the QA contention.

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48 TU filing, Applicants' Current Management Views and Management Plan for Resolution of all Issues, June 28, 1985.

6.1.6 Adjudicatory Action on Miscellaneous Allegations and Technical Issues

A number of adjudicatory actions were concerned with allegations and technical issues related to QA. One of these incidents illustrates the importance that the ASLB places on receiving accurate information from the licensee. The incident also reflects the problems faced by a Licensing Board when trying to deal with the broad range of issues in a licensing hearing and reveals why the Quality Assurance Program is of such importance to the Board. The ASLB determined that TU witnesses made false statements and that there were inconsistencies in TU's filings concerning U-bolt testing.[49] To correct the misrepresentation and inconsistencies in testimony, the Board reopened discovery relating to the credibility of TU's witnesses. Although the NRC staff determined TU's false and inconsistent statement was not a material false statement, the Board found TU's testimony misleading, an adverse reflection on the credibility of TU's expert witnesses, and cause for reopening discovery.[50]

TU's motion for summary disposition of the U-bolt contention relied on a testing program. TU stated:

> "[T]o assure that the tests and analyses accurately represent plant condition, Applicants conducted a survey of the torque on a representative sample of cinched down U-bolts ..."[51]

The Board concluded that the sample was neither representative nor random. The Board stated:

> "First, the "sample" was collected with no written procedures. Second, there was no method of drawing a random or representative sample; the sample included U-bolts that could be found...that were unpainted. Third, the sample was restricted to Unit 2, because Unit 1 had already been painted, thereby allegedly making it impossible to obtain a relevant sample from Unit 1, however, this sampling restriction was not disclosed and therefore not subject to challenge until after the Board requested the raw data from Applicants.

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49 ASLB Memorandum and Order LBP-84-56, December 18, 1984.

50 ASLB Memorandum and Order LBP-84-56, December 18, 1984.

51 ASLB Memorandum and Order LBP-84-56, December 18, 1984.

"Fourth, Applicants stated that they "inspected the torque of a randomly selected representative sample of cinched down U-Bolt supports" and presented the results of the sampling in Table 2, which provides the "Torque Range (ft-lbs)." However, Applicants failed to mention that Table 2 was constructed using the average torque on the two bolts on each U-bolt. They also failed to mention that the torques were not always the same -- a condition that may or may not be material but that differed from the test that was conducted, suggesting that the test may not have been representative of field condition because torques used in the test were equal.

"Fifth, although Applicants claim that the torquing practices in both units were the same, their own filing discloses that the procedure changed."

On August 20, 1985, the NRC staff announced its determination that TU's U-bolt statements did not constitute a material false statement within the meaning of Section 186 of the Atomic Energy Act.[52]

In response to TU's motion for reconsideration of the Board's "misleading statement" memorandum, the Board decided to leave the initial order in effect but to clarify it somewhat.[53] In its November clarification, the Board stated:

"We hold Applicants to a very high standard concerning the completeness and persuasiveness of proof. Litigation of technical issues can be difficult. Simplification is feasible if a party attains mastery of the technical issues and communicates them so clearly that the outcome becomes evident.

"In licensing cases, applicants are expected to master the technical issues affecting their plant. Their mastery flows from:

- o the availability of the sophisticated technical staff needed to build a sound nuclear plant and to defend it before the Nuclear Regulatory Commission (NRC), and

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52 NRC Memorandum to the Commissioners from Vincent S. Noonan, August 20, 1985.

53 ASLB Memorandum, November 25, 1985.

- o the seriousness of their commitment to understand their plant in sufficient depth to be able to assure themselves, the public and their stockholders of the soundness and safety of their plant.

> "If an applicant masters technical issues, implements its knowledge during design and construction, and describes its knowledge in detail, the case can become simple. If mastery of technical issues is not attained or if the presentation is lacking in thoroughness or clarity, then the work of the Licensing Board becomes far more difficult and the outcome may be clouded by doubt."[54]

The Board further stated:

> "Did the statement matter? Yes. Assuredly it did. The only way the Board can trust the Applicants is if their filings communicate clearly and are trustworthy. That requires care. Otherwise, each word or phrase must be parsed and distrusted. We would be driven to examine closely how we might be misled if we accepted the obvious meaning of the words Applicants used. Unless Applicants' language is careful, precise and trustworthy, we would need to approach their filings with suspicion."

The Board also said:

> "Licensing cases before the NRC are not ordinary litigations. They are not games of persuasion. Facile, simplified arguments do not show an awareness of the seriousness required for building and running a safe plant. Clear, careful arguments (and admissions of error when error is pointed out or detected) inspire trust and confidence. In this proceeding, where time means money and carefulness protects lives, we urge Applicants to consider the importance of assuring that we can place trust in their filings. Careful filings are the key to the efficient conduct of this hearing from this time on.

In spite of the NRC staff's determination that TU's statement did not constitute a material false statement, the Board's "clarification" makes abundantly clear how serious a mistake TU made. At the very least, careless and misleading statements make

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54 ASLB Memorandum, November 25, 1985.

the Board's task more difficult and can lengthen hearings. However, a likely and much worse outcome is loss of the Board's (and NRC staff's) confidence in the applicants' credibility and technical competence. Such loss of confidence can take years to rebuild. Misleading statements at the hearing might very well extend the time required for TU to convince the NRC staff and the ASLB that Comanche Peak is a safely designed and constructed plant.

6.2 NRC Headquarters Actions including Special Inspections and the Technical Review Team

On March 12, 1984[55], the NRC's Executive Director for Operations (EDO), directed the Office of Nuclear Reactor Regulation (NRR) to manage all NRC actions leading to licensing decisions for Comanche Peak and Waterford. The stated purpose of this directive was to assure the overall coordination and integration of the outstanding regulatory actions and to achieve their resolution prior to a licensing decision. This effort was to encompass all licensing, hearing, inspection and allegation issues. In furtherance of this objective, a Comanche Peak project team was established. Upon its establishment, the team determined their was a need to 1) obtain current information relative to the management control of the construction, inspection and test programs and 2) obtain information necessary to establish a management plan for resolution of all outstanding licensing actions. To obtain this information, NRR, in coordination with the Office of Inspection and Enforcement (I&E) and the Region II and IV Administrators formed a Special Review Team composed of Region II inspection personnel.

6.2.1 The Special Review Team

The Special Review Team conducted its inspection at CPSES from April 3 to April 13, 1984. The review consisted of an audit of significant elements and processes of TU's management control in construction, inspections and testing of systems important to safety. These included:

- Component and material receipt inspection and control.
- Structure, systems, and component fabrication and installation.
- Structure, system, and component acceptance, and preoperational testing.
- Quality assurance and control documentation and procedures governing the above.

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55 Memo from William J. Dircks to Collins, et al, dated March 12, 1984 on Completion of Outstanding Regulatory Actions on Comanche Peak and Waterford (M00212)

The summary conclusions presented in the inspection report were as follows:

> "The teams (sic) findings indicated that the applicants (sic) management control over the construction, inspection, and testing programs is generally effective and is receiving proper management attention. The findings identified three potential enforcement actions ...; two areas of weakness requiring management attention; ... and seven areas where Applicants activities exceeded normal and accepted practice. ... The team also found improvements in the relationship between the current QA/QC management and inspectors which in the past has caused communication problems .... The team believes that the results of this limited review reveal the plant is being built in a safe manner.
>
> "The findings and conclusions of this report of the teams (sic) review should not be construed as resolving any of the issues identified by the ASLB hearings, allegations, or staff concerns of the design adequacy of the plant."

The Potential Enforcement Issues included:

- o ASME record packages were not being maintained in a fire proof container.
- o At least two vendor audits had not been performed within the required time period.
- o Certain pipe supports that had been inspected and accepted were not installed in accordance with design drawings.

The weaknesses noted were:

- o Certain drawing packages issued to the field contained non-applicable DCAs and CMCs, that had been deleted by engineering.
- o Many non-ASME Section 3 drawings contained a large number of DCAs and CMCs (over 300 in some cases) outstanding without being incorporated by revision.

The strengths noted were:

- o The management and craft appear to be competent and the management appears to possess a positive attitude.
- o The QA/QC training program is extensive and comprehensive.
- o The use of a recently established computer system for drawing control and control of design changes.
- o The vendor witnessing program is extensive in its

audits and source inspection of purchased materials.

- o Several instances of use of conservative design practices.

Based on our review, this report provides the following points of interest:

- o In general, the report is complimentary to TU.
- o The report carefully distinguishes between construction adequacy and design adequacy.
- o Except for pipe hangers, which still reflect the problems cited in the CAT inspection report, construction is generally acceptable.
- o While design practices are complimented and considered conservative, the inspection avoids passing judgment on design adequacy.
- o The reference to improved communications between QA/QC management and inspectors makes it clear communications problems existed at an earlier time.

Regarding the last item, the inspection team interviewed a number of QC inspectors and supervisors during the course of the inspection. As noted in Section 5.4.1, the report includes the observation:

> "Many of the inspectors indicated that communications were improving and the assignment of the new site QA manager was a positive step in improving communications. It was clear that some communications problems had existed in the past and rapport between inspectors and their management had been strained previously in some areas."

Since this inspection took place shortly after Mr. Vega replaced Mr. Tolson as Site QA Supervisor, this finding supports the view presented in Section 5.4.1 that during Phase II, the pro-construction attitude of the TU Site QA Supervisor was a major contributor to QA problems at CPSES.

6.2.2 The Technical Review Team

The Special Review Team provided a basis for the development of an NRC management plan for the resolution of all outstanding licensing actions. The purpose of the plan was to ensure the overall coordination and integration of the outstanding regulatory actions at Comanche Peak and their satisfactory resolution prior to a licensing decision by the NRC. In accordance with the plan, a Technical Review Team (TRT) was formed to evaluate and resolve technical issues and those allegations that had been identified. On July 9, 1984, the TRT began its 10-week (five 2-week sessions) onsite effort, including interviews of allegers and TU personnel, to determine the validity of the technical concerns and allegations, to evaluate their safety significance, and to assess their generic implications. The TRT consisted of about 50 technical specialists from NRC headquarters, NRC Regional Offices, and NRC consultants. This staff was divided into groups by discipline; and each group was assigned a group leader.

The topic areas considered by the TRT over the period of its inspection/investigation were:

1. Electrical/Instrumentation
2. Civil/Structural
3. Test Programs
4. Protective Coatings
5. Mechanical
6. Miscellaneous
7. Quality Assurance, including:
   - Quality Control Inspection
   - T-Shirt Incident
   - Inspections of As-Built Pipe and Electrical Raceways
   - Document Control
   - Training/Qualification
   - Valve Installation
   - Onsite Fabrication
   - Housekeeping and System Cleanliness
   - Nonconformance Reports
   - Materials

Following the initial phase of the TRT inspection, the NRC summoned TU management to a September 18, 1984 meeting in Bethesda, Maryland to discuss the findings in the first three areas listed above. These findings, as documented in a report of the same date were as follows:

1) Electrical quality control inspectors were not aware of certain inspection attributes for witnessing the installation of "nuclear heat shrinkable cable insulation sleeves."

2) Inspection reports didn't contain the "witnessing" attribute for splice installation.

3) Lack of cable splice qualification requirements and circuit operability.

4) Drawings and "as-built" cable terminations are in disagreement.

5) Improperly closed NCRs on vendor-installed GE motor control centers.

6) Violations of minimum separation requirements for safety-related cable within flexible conduits.

7) Violation of minimum separation requirements between safety and non-safety cables.

8) Existing TU analysis substantiating the adequacy of the criteria for separation between conduits and cable trays had not been reviewed by the NRC staff.

9) Violation of separation criteria inside control panels.

10) Inconsistent support installation for non-safety related conduits with seismic requirements.

11) Lack of verification documentation for electrical QC inspections.

12) Totally compromised testing and certification programs for QC inspectors.

13) Omission and unauthorized cutting of rebar from reactor cavity.

14) Unauthorized cutting of rebar from the fuel handling building.

15) Questionable concrete strength tests.

16) Questionable "air-gaps" between concrete structures.

17) Inadequate control room design (seismic).

18) Inadequate, incomplete, and unreliable hot functional test procedures.

19) Unreliable Containment Integrated Leak Rate Test (CILRT) results.

20) Use of unqualified craft personnel to perform start-up tests.

As result of this meeting, TU committed to form the Comanche Peak Response Team and the associated Program Plan. The first version of this plan was submitted to the NRC on October 8, 1984.

On November 29, 1984, the TRT issued its second report. This report stated:

1) Due to deficiencies in inspection records and the

apparent lack of inspection criteria, the TRT is not certain whether type (2) skewed welds were inspected properly. This is a generic issue involving many NF supports in various safety-related systems.

2) No evidence existed that anchor bolts were properly installed, and not cut.

3) Piping systems (Main Steam, Aux. Steam and Feedwater) are routed from the Electrical Control Building (seismic Category I) to the Turbine Building (non-seismic Category I) without any seismic isolation.

4) Uncontrolled repairs (plug welds) were made to holes in pipe supports, cable tray supports and base plates.

5) There were inadequate requirements and construction practices for the support of the main steam line during flushing, and for temporary supports for piping and equipment in general. In particular, evaluations to assure the adequacy of temporary supports during flushing and installation were not required.

6) TU failed to adequately review a design change involving the RPVRI support ring (i.e. locating the ring outside rather than inside the insulation) to determine the effect of the change on the annulus cooling flow. As a result, inadequate cooling was provided during the Hot Functional Test of Unit 1.

7) Gaps on the Polar Crane bracket and seismic connections exceeded design requirements.

On January 8, 1985, the Technical Review Team released its third report. This report stated:

1) TUEC failed to periodically assess the overall effectiveness of the site QA program in that there have been no regular reviews of program a[illegible]acy by senior management. Further, TUEC did not assess [illegible]e effectiveness of its QC inspection program.

2) During the peak site construction period of 1981-2, TUEC employed only four auditors, all of whom had questionable qualifications in technical disciplines. Although charged with overview of all site construction and associated vendors, these Dallas based auditors provided only limited QA surveillance of construction activities.

3) Repetitive NCRs were issued that identified the need to retrain construction personnel in the requirements and contents of QA procedures. One corrective action request

(CAR) dealing with inadequate construction training and records remained open for one year. The identical problem was identified in a subsequent CAR, which still had not been closed at the time of the TRT's onsite review.

4) The TRT found many examples of incomplete and inadequate workmanship and ineffective QC inspection in TUEC's evaluation of the as-built program.

5) Some craft workers newly assigned as QC inspectors were in a position to inspect their own work and records. Site management did not view this lack of separation between production and inspection roles as a potential conflict-of-interest.

6) There were potential weaknesses in the TUEC 10CFR 50.55(e) deficiency-reporting system. Applicable procedures did not identify what types of deficiencies constituted significant breakdowns in the QA program, nor how they should be evaluated for reportability to the NRC. Evaluation guidelines for reporting hardware deficiencies lacked clarity and definitive instructions, and the threshold for reporting deficiencies was too high.

7) The TUEC exit interview system for departing employees appeared to be neither well structured nor effective, as evidenced by the lack of employee confidence, limited implementation, failure to document explanations and rationale, and failure to complete corrective actions and determine root causes.

8) The B&R corrective action system was generally ineffective and was bypassed by the B&R QA Manager.

9) The TUEC corrective action system was poorly structured and ineffective.

Based on these findings, the TRT requested additional information from TU to assist the TRT in the evaluation of these issues. The NRC also scheduled a meeting for January 17, 1985, in Bethesda, Maryland to allow TU to ask questions concerning these findings prior to formulating their program plan.

The TRT's evaluation of these issues, and of the allegations received by team members, is presented in supplements 7 through 11 to the CPSES Safety Evaluation Report, NUREG-0797. Some of the conclusions contained in these supplements are described below:

Supplement 7

Electrical and Instrumentation Group

- o Most of the concerns and allegations were raised by electrical quality control (QC) inspectors and were found to be very general, and often without any specific connection between the concern and plant safety.
- o In general, the quality of the E&I installations reviewed by the E&I Group was found to be acceptable, except for those cases which the E&I Group determined to have safety significance. To determine the extent of the generic implication of these concerns, TU is required to conduct further review and inspections.
- o The E&I Group concludes that the problems found with electrical cable terminations, electrical equipment separation and control room ceiling fixture supports, together with the findings concerning inadequate training and qualification of electrical QC inspectors are an indication of a programmatic weakness in QC.
- o The deficiencies identified during the E&I review of both hardware installation and QA/QC-related matters indicate weaknesses in the QA/QC program and are considered in the overall programmatic review by the QA/QC Group.

Test Program Group

- o Except for certain unresolved issues, the testing activities included in the TRT review effort were generally found to have been carried out in compliance with NRC regulations and FSAR commitments.
- o The TRT cannot conclude with reasonable assurance that the document control system problems [identified by the QA/QC group] had no adverse effect on testing activities. Therefore, the TRT will require TU to provide NRC with assurance that all structures, systems, and components were properly and completely tested before it can draw a final conclusion with regard to the testing program.

Supplement 8

Civil and Structural Group

- o Except as noted, the TRT concludes that the civil and structural construction with the scope of the TRT C&S group review effort was adequate and was, for the most part, well documented.
- o Five issues in the civil and structural area still require further action. One case involving reinforcing steel omitted from the reactor cavity wall, and another case of alleged unauthorized drilling of reinforcing steel, require further documentation. TU must also test concrete in place

to evaluate an allegation concerning falsified concrete strength tests. In addition, TU must conduct analyses and inspections to determine whether the separation between buildings is adequate to provide acceptable performance in an earthquake. Finally, there must be a seismic analysis of the suspended ceiling, lighting fixture and nonsafety-related conduit in the control room to demonstrate design adequacy of the ceiling elements. The potential safety implications of this issue for nonseismic structures, systems, and components in other parts of the plant must also be evaluated.

Miscellaneous Group

The TRT found that 9 of the 24 allegations were substantiated, were potentially safety significant, and had generic implications. However, actions taken because of NRC Bulletins, inspections and TU audits/evaluations corrected all but two problems. Therefore, the TRT concludes that 21 of 24 allegations had neither safety significance nor generic implications. The two problems for which TU will have to complete actions and address issues are Miscellaneous Category 2, the gap between the reactor pressure vessel reflective insulation and the biological shield wall, and Miscellaneous Category 11, improper shimming and installation of the polar crane rail support system.

Supplement 9

Protective Coatings

o The TRT evaluation of the protective coatings area revealed may specific deficiencies which render a relatively large percentage of the coatings at CPSES unqualified. However, consistent with the guidelines of the Standard Review Plan [Section 6.1.2], TU has provided justification that debris generated from the failure of all paint in the Containment Buildings under design basis accident conditions will not adversely affect the performance of post-accident fluid systems. Therefore, a determination has been made that coatings inside of Containment Buildings do not need to be qualified. However, based on TU's prior FSAR commitment to provide qualified coatings, the failure of TU to fulfill that commitment indicates deficiencies in the coatings QA/QC program.

Supplement 10

Mechanical and Piping Group

- The staff found that most of the approximately 400 concerns and allegations were either not substantiated or contained insufficient evidence with which to substantiate the alleged concerns. Often, there was no connection between the concern and plant safety. Also, further contact with the individuals raising the concerns often did not provide the required specificity to better focus the allegations. The staff's detailed review of each concern or allegation completely or partially substantiated approximately 60. Five issues evolved from eight substantiated allegations which were of potential safety significance. The staff has requested TU to submit an action plan to address these allegations.

Supplement 11

QA/QC Group

This supplement contains two Appendices: O and P. Appendix O presents the findings of the QA/QC Group for each of the areas listed above. Appendix P assimilates the QA/QC findings of all groups and provides the following overall assessment and conclusions:

- TU senior management was not actively involved in site QA/QC activities.
- The training and qualification of QA/QC, craft, and other personnel were not administered and monitored effectively.
- Design engineering activities were not effective in providing craft and QC personnel with adequate procedures, instructions, and other design documents.
- The control of documents, and subsequently of records, was replete with recurrent deficiencies.
- Some craft personnel appeared to be insensitive to QA/QC concerns at times, possibly because of lack of training, tight schedules, and excessive schedule emphasis by construction management.
- Quality management was lax in its responsibilities to direct and oversee an effective site Quality Program.
- Some QC personnel exhibited repeated lapses in effectively executing their responsibilities for inspection activities.
- The pattern of failures by QA and QC personnel to detect and document deficiencies challenges the adequacy of the QC inspection program at CPSES on a system-wide basis.

TU is currently responding to the findings of the TRT.

7.0 TU Comanche Peak Response Team and Corrective Action Program

7.1 Establishment, Implementation and Evolution of the CPRT Program

7.1.1 Establishment of the CPRT

In response to the TRT's findings and the NRC's requests for information, TU advised the NRC in a letter dated October 8, 1984, that it was establishing the Comanche Peak Response Team (CPRT), and submitted information on how it intended to do this, including a Program Plan and Issue-Specific Action Plans.[1] This was the beginning of the CPRT. More precisely, TU has noted that the CPRT was established at a TU internal meeting on September 22, 1984, by Mr. Spence, President of TU, as documented by Meeting Minutes - Senior Review Team Meeting on 9/22/84 and a memorandum by Mr. Spence on this subject dated 9/24/84. Both of these documents are stated to be in the CPRT Central File.[2]

The CPRT was to develop and implement the Program Plan in response to TRT issues. Within the CPRT, the Senior Review Team (SRT), which reported directly to Mr. Spence, was responsible for approving all work plans and reports. Below the SRT, the CPRT Program Manager was responsible for developing and implementing the Issue-Specific Action Plans (ISAPs). Review Team leaders (RTLs) were to assist the Program Manager. The initial, Revision 0 proposal stated that "root cause", "generic implication", and "collective significance" evaluations would be performed, but provided no details. The SRT was to consist of four TU employees and one contractor (TERA Corporation) employee. The Project Manager was to be John Merritt, Jr., TUGCO's Assistant Project General Manager for CPSES. All six RTLs were from TU or CPSES.[3]

Meetings were held at the NRC offices in Bethesda on October 19 and 23, 1984, at which TU presented its plans for the CPRT and the NRC staff commented on these plans.[4,5] The NRC staff

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1 Letter from Spence, TU, to Eisenhut, NRC, dated 10/8/84, forwarding Rev 0 of Program Plan and Issue-Specific Action Plans for CPRT (M01660)

2 Applicants' Answers to CASE CPRT Program Plan Interrogatories (Set No. 3), 11/7/86, page 2 (M00999)

3 Program Plan and Issue Specific Action Plans, Rev. 0, 10/8/84 (M01660)

4 Transcript of meeting 10/19/84 (M01668)

5 Transcript of meeting 10/23/84 (M01667)

comments included concerns about generic implications of deficiencies, independent verification of results, and QA/QC.

In response to these comments, on November 21, 1984, TU submitted Revision 1 of the CPRT Program Plan and Issue-Specific Action Plans.[6] The most important changes in Revision 1, in direct response to NRC staff comments, were to delete one TU member and add two additional non-TU members to the SRT and to specify that all Issue Team Leaders (ITLs) would be non-TU personnel.

Revision 1 also included more detail on root cause, generic implication and "collective significance" analyses and how they would be incorporated into the ISAPs. This revision also included a provision to "appropriately include consideration" of information presented to the ASLB.[7] The ASLB and other parties were notified a few days later[8] of TU's intent to establish the CPRT, and were provided copies of Revision 1 of the Program Plan and Issue-Specific Action Plans and related correspondence.

In a letter dated November 29, 1984,[9] the NRC supplemented the TRT findings and request for information it had communicated to TU at the September 18, 1984 meeting. The letter pointed out that the TRT investigations/evaluations were still ongoing, that this letter still covered only a portion of the TRT's efforts, and that additional requests for information may be necessary. The specific subjects addressed by this letter were protective coatings, mechanical areas, and two miscellaneous items. The letter noted that the program must address the root causes of each problem and their generic implications and that it should address the "collective significance" of the deficiencies.

This was followed by a third NRC letter, dated January 8, 1985,[10] further supplementing the TRT findings and requested information. An enclosure to this letter provided the TRT's findings resulting from its review of QA/QC allegations. The letter again stated that the TRT's activities were still ongoing, but were nearing

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6 Letter from Spence, TU, to Eisenhut, NRC, dated 11/21/84, forwarded Rev. 1 of Program Plan for CPRT, 11/19/84 (M01662)

7 Rev. 1 of Program Plan for CPRT, 11/19/84 (M01662)

8 Letter dated 11/27/84 from N.S. Reynolds, TU attorney, to Bloch, ASLB, et al (M01663)

9 Letter from Eisenhut, NRC, to Spence, TU, dated November 29, 1984 on Comanche Peak Review (M01632)

10 Letter from Eisenhut, NRC, to Spence, TU, dated January 8, 1985 on Comanche Peak Review (M00187)

completion, and that the TRT's detailed assessment of the significance of all issues examined would be published in Supplements to the NRC's Safety Evaluation Report. The letter made no reference to TU's submittals on the CPRT Program Plan or the Issue-Specific Action Plans. Rather it again requested TU to submit a program plan and schedule, and stated that:

> "This program plan shall: (1) address the root cause of each finding and its generic implications on safety-related systems, program, or areas, (2) address the collective significance of these deficiencies, and (3) propose an action plan from TUEC that will ensure that such problems do not occur in the future. Your actions should consider the use of management personnel with a fresh perspective to evaluate the TRT's findings and implement your corrective actions. Finally, you should consider the use of an independent consultant to provide oversight to your program."

A meeting between NRC, TU and other interested parties took place on January 17, 1985, at the NRC offices in Bethesda, to discuss the TRT findings relating to the Comanche Peak QA/QC Program.[11] Additional meetings were held on February 26, 27 and 28 at the Comanche Peak Nuclear Operations Support Facility near Glen Rose, Texas.[12,13] At these meetings NRC/TRT findings and TU's program for resolving problems relating to the design of piping and pipe supports and the electrical/instrumentation area were discussed. At that time, TU was under the impression that its evaluation of this hardware was "nearing completion," but the NRC staff requested additional information concerning the safety significance of the hardware deficiencies identified.

During this period, the Citizens Association for Sound Energy (CASE) was also reviewing the documents on the CPRT, copies of essentially all of which were being provided to all the parties. On February 7, 1985, CASE, TU and the CPRT met with the NRC Contention 5 Panel to discuss the CPRT Program. At this meeting, Mr. Spence, President of TU, announced that the CPRT would also be investigating <u>design</u> adequacy. CASE also participated in several other meetings with TU and the NRC on the CPRT. As a

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11 Summary of Meeting, by Annette Vietti, NRC dated 1/28/85 (M00532)

12 Summary of Meeting by S.B. Burwell, NRC, dated 3/6/85 (M00143)

13 Summary of Meeting by S.B. Burwell, NRC, dated 3/6/85 (M00533)

result, CASE submitted comments and questions on the CPRT to the ASLB, which both the NRC staff and TU took into consideration.[14]

7.1.2 Independent Assessment Program (IAP)

During this period, an ongoing parallel activity was the Independent Assessment Program (IAP) being performed by CYGNA. This program was initiated as a result of discussions between TU and the NRC staff regarding the need for conducting an Independent Design Verification Program (IDVP) at CPSES. In a meeting with the NRC on December 12, 1982, TU argued that already completed independent confirmation activities obviated the need for an IDVP at CPSES.[15] According to a TU memorandum, the NRC was favorably impressed by the TU presentation and had decided an IDVP was not necessary at CPSES.[16] Before the NRC issued a letter to this effect, however, an NRC Construction Appraisal Team completed its inspection at CPSES. The results of this inspection sufficiently "eroded" the NRC's confidence in the safety of CPSES that it requested TU to propose a program that would restore its confidence.[17] The IAP to be performed by CYGNA was TU's response to this request.

A draft of the report for Phases 1 and 2 of this program was issued November 5, 1983,[18] and the final report was issued on October 12, 1984.[19] Phases 1 and 2 covered design control requirements and the implementation of these requirements for portions of two representative systems - the residual heat removal system and the spent fuel pool cooling system. This report identified a few specific minor problems, but its general conclusion was that, "within the scope of this review, the overall design activities on CPSES are adequate and have been properly implemented".

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14 Letter from Noonan, NRC, to Counsil, TU, dated 8/9/85 (M00559)

15 TU Presentation to NRC on IDVP, 12/10/82. (S00918/CS00190503)

16 Marshall memorandum to Schmidt dtd 3/11/83, Trip Report-NRC IDVP Meeting. (S01308/LV00090533)

17 Ibid.

18 "Final Report - Independent Assessment Program for CPSES (Draft)" CYGNA Energy Services, November 5, 1983 (M01676)

19 "Final Report - Independent Assessment Program of CPSES", CYGNA Energy Services, October 12, 1984 (M00216)

A report on Phase 3 of this program was initially issued on July 16, 1984,[20] and finalized by a document that provided errata and revised pages on November 20, 1984.[21] Phase 3 consisted primarily of a review of the piping and pipe support design in portions of the Component Cooling Water System and the Main Steam System. In Phase 3, CYGNA identified more deficiencies and "items requiring resolution", but it still concluded that it "did not detect any type of programmatic breakdown" on the Comanche Peak project.

CYGNA then started to work on Phase 4 of the IAP which was to be a multi-disciplinary review of the design of a portion of the component cooling water system for Unit 1. The four phases of the IAP were not the result of a coordinated approach to the investigation, but rather, the result of increases in the scope of the investigation as issues arose.

Following a January 10,1985 meeting with the NRC to discuss the IAP, CYGNA sent a letter to the NRC submitting an extensive listing of "open items" and stated, "We are currently in the process of reviewing the basis for closure of Phases 1, 2 and 3 items as well as the overall conclusions."[22] Just one week later, in a letter to the NRC dated January 25, 1985, CYGNA retracted the conclusionary statements in its previous reports pending completion of its entire review.[23] To this date, CYGNA has still not submitted its final report.

Representatives from the CPRT met with CYGNA/IAP personnel on March 14, 1985 to discuss issues CYGNA had observed during its IAP investigation.[24] Additionally, CYGNA sent several

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20 "Final Report - Independent Assessment Program of CPSES (Phase 3)" CYGNA Energy Services, July 16, 1984 (M00229)

21 Errata and revised pages to "Independent Assessment Program of CPSES (Phase 3)", CYGNA Energy Services, November 20, 1984 (M01674)

22 Letter from Williams, CYGNA, to Noonan, NRC, dated 1/18/85 on Open Items Associated with Walsh/Doyle Allegations (M01583)

23 Letter from Williams, CYGNA, to Noonan, NRC, dated 1/25/85 on Status of IAP Conclusions (M01658)

24 Transcript of meeting between CPRT and CYGNA, 3/14/85 (M01657)

"Communications Reports"[25,26,27,28,29] and communicated the bulk of its findings and open items to the CPRT by sending copies of its Review Issue Lists.[30,31,32,33]

In response to a request from the ASLB dated August 22, 1985 for information on CYGNA's practices with respect to communications between it and the CPRT, CYGNA stated:[34]

> "It is Cygna's understanding that the CPRT intends to include all concerns and issues raised by Cygna within the scope of CPRT activities. Cygna does not understand it will be involved in the implementation phase of the CPRT issues response plan.
>
> . . . . .
>
> Cygna understands the resolution of its issues and concerns will be based on subsequent activities of the CPRT in the course of its implementation of its Program Plan. Cygna has been advised that CPRT activities will serve as the basis for closure of both specific Cygna findings and their cumulative effects."

As explained further below, the CYGNA/IAP input into the CPRT is treated as an "external source" by the CPRT.

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25 Communications Report, CYGNA to TU, 3/26/85 (M01678, Attachment C)

26 Communications Report, CYGNA to TU, 3/29/85 (M01678, Attachment D)

27 Communications Report, CYGNA to TU, 4/4/85 (M01678, Attachment E)

28 Communications Report, CYGNA to TU, 6/13/85 (M01678, Attachment F)

29 Communications Report, CYGNA to TU, 7/2/85 (M01678, Attachment G)

30 Review Issue List, 4/4/85 (M01673)

31 Review Issue List, 4/23/85 (M01683)

32 Review Issue List, 6/21/85 (M01684)

33 Review Issue List, 8/13/85 (M01685)

34 CYGNA's Response to Board's Memorandum, September 6, 1985 (M00127)

7.1.3 Draft Revision 2 of the CPRT Program Plan

In accordance with the CPRT Program Plan, a Senior Review Team had been established, which had overall responsibility for the development, implementation and management of the CPRT Program. In response to NRC comments, Revision 1 of the CPRT Program Plan had increased from one to three, the consultant members of the SRT, whose members were then as follows:

Mr. Lou F. Fikar, Chairman of the SRT, Executive Vice-President, Engineering, TUGCO

Mr. Billy R. Clements, Vice-President, Nuclear Operations, TUGCO

Mr. John W. Beck, Manager, Nuclear Licensing, TUGCO

Mr. John C. Guibert, Consultant; Manager, Nuclear Safety & Licensing, TERA Corporation

Mr. Anthony P. Buhl, Consultant; President, Energx Corporation

Mr. John L. French, Consultant; Vice-President, Delian Corporation

Revision 1 of the CPRT Program Plan also listed the specific responsibilities of the SRT, which included, "development of the CPRT Program Plan, and any subsequent revisions thereof". In accordance with this responsibility and in response to comments received from the NRC, the SRT prepared a draft Revision 2 of the CPRT Program Plan and ISAP's, dated 4/19/85. This draft was submitted to the NRC for comment.[35]

The more significant changes from Revision 1 to the draft of Revision 2 were that Messrs. Fikar and Clements were dropped from the SRT, making Mr. Beck the only TU member of the SRT. Also, Mr. Beck was designated chairman of the SRT (which he still is today).

The draft Revision 2 also included a "Charter" for the CPRT, which specified the scope of the CPRT - a big change from Revision 1. The scope was greatly increased beyond the issues identified by the NRC TRT. The draft Revision 2 listed the following sources of concerns to be included in the CPRT review program.

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35 Letter from John W. Beck, TU, to V. Noonan, NRC, dated 4/23/85 (M01661)

- concerns identified by the NRC-TRT

- concerns identified by CYGNA in its independent design verification program for CPSES (IDVP)

- concerns associated with matters currently in contention before the ASLBP No. 79-430-06 OL.

- concerns identified by the NRC that are directly related to the above-mentioned sources of concerns (e.g., SIT, CAT, and Region IV Inspection Reports)

- other concerns that are directly related to the above-mentioned sources of concern and that may be identified by the CPRT itself or that may arise from other sources during the conduct of the CPRT program.

The scope of the CPRT program was further defined to include:

- The CPRT will address the specific concerns identified from the above-mentioned sources, including the logical extension of those concerns based upon its assessment of root causes and generic implications.

- The CPRT will address issues being handled by TUEC in the context of ongoing, routine licensing and inspection & enforcement activities for CPSES, only if those issues are directly relevant to the above mentioned concerns.

- Since Unit 2 is still under construction, CPRT actions address Unit 2 in three ways. First, CPRT activities include completed Unit 2 construction items the same as per Unit 1 activities. Second, current hardware installations and construction activities are incorporating lessons learned from CPRT evaluations in real time. TUEC is responsible for determining where and to what extent Unit 2 incorporates these lessons learned. Third, CPRT will document lessons learned for application to future activities in Unit 2.

- The CPRT will address the above-mentioned concerns as they apply to the operation of Unit 1 and Unit 2. TUEC will be responsible for the evaluation and implementation of the CPRT's recommendations as they apply to future plant operations.

CYGNA/IAP - identified issues, ASLB contentions and other NRC concerns (e.g. SIT, CAT and Region IV Inspection Reports) subsequently came to be called "external source issues", and those identified by CPRT or other TU activities came to be called "internal source issues".

The draft of Revision 2 also expanded the CPRT scope by identifying additional specific objectives with respect to the CPRT reviews of CPSES Design Adequacy and CPSES Quality of Construction, and therefore established new CPRT program elements to address each of these areas. These constituted new Appendices A and B of the draft. The draft acknowledged the "declassification" (resolution) of concerns about the coatings in the plant, as documented in NRC's SSER-9. The draft also included as Appendix C to the Program Plan, Revision 2 of the Issue Specific Action Plans (ISAP's).

In late May of 1985, after the preparation and submission of draft Revision 2, the NRC issued SSER-11 on QA/QC issues.[36] SSER-11 provided the TRT's evaluation of concerns and allegations relating specifically to construction QA and QC at CPSES and an overall summary and conclusions of the QA/QC aspects of issues reported in SSER-7, 8, 9 & 10. (See Section 6.)

7.1.4 Revision 2 of the CPRT Program Plan

TU was submitting revisions of the CPRT Program Plan to the NRC faster than the NRC could review and comment on them. An NRC internal memo dated June 26, 1985, transmitting Region IV comments on the CPRT to the NRC Director of the Comanche Peak Project included a number of very significant comments.[37] Among these was the following:

> "It is important that the NRC expedite the review, comment, and approval of the applicant's plan. Most of the plan is already being implemented and some portions are already completed. The inspection of the implementation of an unapproved plan is not a desirable situation."

Just two days after that memo was written, on June 28, 1985, Revision 2 of the CPRT Program Plan was submitted to the NRC by a letter signed by William G. Counsil.[38] Counsil had just recently

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36 NRC NUREG-0797 Supplement No. 11, May 1985 (M00057)

37 Memo dated 6/16/85 from Denise, NRC Region IV to Noonan, NRC on Comments on the CPSES CPRT Program Plan and Self-Initiated Action (M00185)

38 Letter from Counsil, TU, to Noonan, NRC, dated 6/28/85 (M01574)

been hired by TU as Executive Vice President, Nuclear, from his previous position as Senior Vice President, with Northeast Utilities Service Company, owner and operator of the Millstone Nuclear Power Station. As TU's Executive VP, Nuclear, the position he still holds today, he is in charge of all activities associated with the CPSES. However, the development and implementation of the CPRT Program Plan was supposed to be primarily the responsibility of the SRT. Counsil's transmittal letter to the NRC closed with the statement:

> "We look forward to your review of this transmittal and stand ready to consider your further comments and observations. We encourage frequent interchange and technical discussions throughout the program execution. We suggest that a formal briefing be held at key points in the program and at least every six weeks."

Just two weeks before the submittal of Revision 2, on June 13 and 14, 1985, TU and the NRC met in a public meeting in Arlington, Texas to discuss CPRT activities on design adequacy, quality of construction and QA/QC program.[39] At this meeting TU presented an overview of their Action Plan. They presented what had been requested to date by the NRC and how they were going to fulfill the requests.

Revision 2 does not identify the changes from the previously submitted draft of Revision 2 or Revision 1. A comparison of Revision 2 with the April 19, 1985 draft of Revision 2 indicates that there were no major changes or additions. There were considerable editorial changes, including reorganization of the text, but no major substantive changes. This editing resulted in placing considerable more emphasis on the expanded scope of the CPRT program and in presenting more details on this increased scope. For example, Revision 2 included the following three new Appendices:

Appendix D: CPRT sampling approach, applications, and guidelines

Appendix E: CPRT procedure for the classification, evaluation and tracking of specific design or construction discrepancies identified by CPRT

Appendix F: CPRT interface identification

On the other hand, Revision 2 of the Plan did not include a section on Schedule, as did the draft of Revision 2 and the previous revisions of the Plan. The earlier Revisions did not

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39 Transcript of NRC/TU meeting, June 13-14, 1985 (M01677)

provide much specific information on scheduling. Revision 2 does provide some scheduling information in the individual Action Plans (ISAP's) in Appendix C to the Program Plan.

Attachment 1 of Revision 2 of the Plan, Chronology of Events, states that the Action Plans were revised to reflect insights provided in NRC SSER-11 on QA/QC. Whereas, Appendix B of Revision 2, on Quality of Construction and QA/QC Adequacy Program Plan, states that the CPRT review of SSER-11 would not be completed until August 1, 1985.

7.1.5 NRC Review and Comment on the CPRT

At this time, the NRC staff initiated a more focused review of TU's proposed CPRT effort. In anticipation of the submittal of Revision 2 of the CPRT Program Plan, Vincent Noonan, Director of the NRC Comanche Peak Project Review Group, scheduled a series of meetings to facilitate the NRC review of the plan.[40] One of these involved an NRC contractor, Teledyne Engineering Services, which was helping the NRC staff review the CPRT Program Plan.

Several other internal NRC memos show that the NRC staff was then developing a plan and the organization and staffing to review the CPRT Program Plan.[41,42] Westec Services is identified as another NRC contractor/consultant that would participate in the review. Specifically, the NRC staff was working to write a Supplement to its Safety Evaluation Report on Comanche Peak (SSER), which was to become SSER-13.

In the process, the NRC staff and its consultants were developing "preliminary comments" on the CPRT Program Plan. In general, these comments were favorable about the general concept and expressed intent of the CPRT Program Plan, but expresses many concerns about its details. For example, the NRC staff was concerned whether the Plan includes a mechanism that would assure that all specific issues, including new ones still being identified, would be addressed and that the investigations and resolution of issues would be appropriately coordinated. As a result, the staff was developing another very extensive "request for additional information".[43]

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40 Noonan, NRC, to Shao, et.al., dated 6/27/85 on Texas Utilities Program Plan (M01644)

41 Calvo and Shao, NRC, to Noonan, NRC, dated 7/2/85 (M01645)

42 Calvo, NRC, to Noonan, NRC, dated 7/8/85 (M01646)

43 Shao, NRC, to Noonan, NRC, dated 7/15/85 (M00183)

By letter dated August 9, 1985, the NRC staff sent to TU, "its initial review of the programmatic aspects of those portions of the CPRT Program Plan submitted to date".[44] A 26-page enclosure to the letter provided comments with regard to the programmatic aspects of the Plan; which, as the transmittal letter noted, "must be satisfactorily resolved prior to final staff approval of the Plan". The letter also noted that certain portions of the Plan had not yet been submitted, e.g., the CPRT umbrella QA program. Also, that detailed NRC staff comments on the CPRT Issue Specific Action Plans (ISAPs) would be provided separately in the future.

By letter dated September 30, 1985,[45] the NRC staff sent to TU its "detailed comments" on the CPRT Program Plan. The NRC comments included concerns about sampling methods and requirements, training programs for CPRT personnel, root cause analysis, corrective action and using Unit 1 recommendations for Unit 2.

Within three weeks, TU responded to the NRC staff comments in a 280-page submittal that responded to each concern, on an item-by-item basis.[46] It also committed to revising the Program Plan and ISAPs in accordance with these responses to the NRC staff's comments.

During this period the ASLB had issued a Memorandum and Order in which it stated that it might not accept evidence submitted by the Applicants based on the work of the CPRT. Upon Applicants' Motion for Modification, the ASLB clarified this by a Memorandum and Order stating that the degree of independence of the CPRT would affect the weight of the evidence, and not whether it would be received into evidence.[47] This clarifying Memorandum and Order also reaffirmed that the ASLB believed that the way in which TU management exercised its responsibility for the construction of CPSES is relevant to the compiling of an adequate record about plant quality and, to the extent that the CPRT does not clarify this, the ASLB hoped that the NRC staff would. And, if neither did, then the ASLB would.

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44 Letter from Noonan, NRC, to Counsil, TU, dated 8/9/85 (M00559)

45 Letter from Noonan, NRC, to Counsil, TU, dated 9/30/85 (M01659)

46 Letter from Counsil, TU, to Noonan, NRC, dated 11/22/85 (M01579)

47 ASLB Memorandum and Order, LBP-8-39, October 2, 1985 (M00999)

7.1.6 Revision 3 of the CPRT Program Plan

On January 27, 1986, TU submitted to the NRC Revision 3 of the CPRT Program Plan and Issue-Specific Action Plans (ISAPs).[48] These documents had now grown to fill two large, three-ring binders. Revision 3 includes 7 Attachment sections as well as Appendices A through H, of which Appendix C contains the ISAPs. Missing from this submission were Appendices D and E, the ISAPs on testing and the revised charter of the Overview Quality Team (OQT), which were to be supplied later. Revision 3 identifies changes from Revision 2 by bars in the margins. Significant changes were made to reflect comments from the NRC staff and others and TU/CPRT's own internal reviews of the Program. TU stated that Revision 3 incorporated all the responses to the NRC staff's questions and concerns on Revision 2.

A detailed listing and discussion of the factors that prompted the changes made in the CPRT Program by Revision 3 is provided in a later TU filing with the ASLB.[49]

One of the changes was that two more outside members had been added to the CPRT's Senior Review Team (SRT), so that it now had six members, of which only one, the Chairman, John W. Beck, was a TU employee. The two new members were:

Dr. John H. Buck, Consultant
Mr. Warren E. Nyer, Consultant; President of Nyer, Inc.

The letter transmitting Revision 3 to the NRC also, for the first time, made the following provisions for future changes:

> Future changes to the ISAPs, DSAPs or the Program Plan will be covered as follows:
>
> a) From time to time the implementing procedures require modification. These modifications are included in dated revisions. Current procedures are maintained in the appropriate files and are available for audit at any time.
>
> b) Subsequent to this submittal of Revision 3 of the CPRT Program Plan and its Appendices, any further substantive modifications to these documents will require the approval of the Senior Review Team prior to implementation. A log of approved

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48 Letter from Counsil, TU, to Noonan, NRC, dated 1/27/86 (M00529)

49 Applicants' Answer to CASE CPRT Program Plan Interrogatories (Set No. 3), 11/7/86 (M00999)

changes will be maintained in the CPRT Program Director's Office; and the Program Director will timely notify the Chief, NRC Region IV Comanche Peak Group of any such changes.

c) Any changes to ISAPs or DSAPs not judged by the RTL's to be substantive in nature (e.g., clarification or correction of typographical errors) may be implemented prior to SRT approval with the concurrence of the CPRT Program Director. These changes, when approved by the SRT, will also be included in the log maintained by the Program Director.

Just four days later, on January 31, 1986, TU submitted the revision of Appendix D to the CPRT Program Plan, entitled "CPRT Sampling Approach, Applications and Guidelines".[50] On February 7, 1986, TU submitted the revision of Appendix E, entitled "CPRT Procedure for the Classification, Evaluation and Tracking of Specific Design or Construction Discrepancies Identified by the CPRT".[51] On February 28, 1986 TU submitted most of the ISAPs for the testing area (the III series), which are part of Appendix C of Revision 3 of the CPRT Program Plan.[52] Also on February 28, 1986, TU submitted Figure 2 of Appendix G on the organization and information flow for the Overview Quality Team, which had been inadvertently omitted from the Revision 3 submission.[53]

In general terms, Revision 3 of the CPRT Program Plan committed the CPRT to three objectives:

1. Evaluate and resolve each "External Source Issue".

2. Conduct a Self-Initiated Evaluation of CPSES design adequacy and construction quality.

3. Determine Root Causes, Adverse Trends and Generic Implication of deficiencies and/or deviations identified in the course of its investigations. This will include collectively evaluating results and determining the collective significance, or integrated impact of identified deficiencies.

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50 Counsil, TU, to Noonan, NRC, dated 1/31/86 (M00443)

51 Counsil, TU, to Noonan, NRC, dated 2/7/86 (M00525)

52 Counsil, TU to Noonan, NRC dated 2/28/86 (M00537)

53 Counsil, TU, to Noonan, NRC dated 2/28/86 (M00524)

7.1.7 NRC SSER-13 and Other Comments on the CPRT Program

In May 1986, the NRC staff published Supplement No. 13 to its Safety Evaluation Report on the CPSES, NUREG-0797 (SSER-13).[54] This supplement presents the NRC staff's evaluation of the CPRT Program Plan, as presented in Revision 3 of the Program Plan. The SSER-13 Abstract states that:

> "The NRC staff concludes that the CPRT Program Plan provides an overall structure for addressing all existing issues and any future issues which may be identified from further evaluations, and if properly implemented will provide important evidence of the design and construction quality of CPSES, and will identify any needed corrective action. The report identifies items to be addressed by the NRC staff during the implementation phase."

The operative words here are, of course, "if properly implemented".

The SSER-13 addresses the CPRT Program Plan in three parts- Quality of Construction, Design Adequacy and CPRT Quality Assurance Program - and provides an evaluation for each. Summaries of the items to be addressed by TU (and the NRC staff) during the implementation phase of the Program are provided in the form of two appendices - Appendix B concerning the Construction Adequacy Program and ISAPs and Appendix C concerning the Design Adequacy Program and Discipline-Specific Action Plans (DSAPs). These appendices generally summarize the comments in the staff's evaluation in the body of the SSER. Some of the comments have broad applicability to the program, while some are specific to an ISAP. The SSER does not require a submittal-response to these comments, but states that the NRC staff will review TU's response to them as part of its inspections and audits of the CPRT. The SSER-13 comments will require extensive accommodation by the CPRT Program.

The NRC staff was now in an inspection and audit mode. Results reports from the ISAPs were being submitted by TU/CPRT and were being reviewed by the NRC staff. As a result, additional comments and requests for information were transmitted to TU in the form of letters and inspection reports.[55,56] Some of these

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54 NUREG-0797, SSER-13 (M00059)

55 Letters from Noonan, NRC, to Counsil, TU, dated 4/28/86 (M00159), 5/28/86 (M00409, 6/9/86 (M01670), and 6/20/86 (M00137)

NRC communications either required responses, or TU/CPRT elected to provide a submittal-response to the NRC.[57,58,59] TU/CPRT was also submitting, in rapid succession, what proved to be early revisions (drafts) of Results Reports for individual ISAPs.[60]

TU's May 13, 1986 letter submitting three ISAPs stated that with that submission, Revision 3 of the CPRT Program Plan was complete.[61] However, this was not the final or complete CPRT Program Plan. To address ASLB concerns described in its Memorandum and Order dated December 21, 1984,[62] TU submitted a new ISAP III.a.5, on Preoperational Test Review and Approval of Results.[63] The CPRT Program Plan was still changing and would continue to do so.

7.1.8 ASLB Interactions with the CPRT Program and its Implementation

The ASLB had a considerable impact on the evolution of the CPRT Program. The ASLB still had Contention 5 before it, challenging the adequacy of the QA program and the Construction of the plant. The CPRT had developed into TU's response to Contention 5 and to

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56 NRC Inspection Reports 50-445/86-15, conducted June 1 through 30, 1986, 50-445/86-17, conducted in June and July 1986 of CPRT/TERA QA Program ,50-445/86-18, conducted in May 1986 of CPRT/DAP X, 50-445/86-19, conducted in July 1986 of CPRT/DAPs VIII, IX, and XI, and 50-445/86-22, conducted in July and August 1986 of CPRT Activities (M00045)

57 Letter from Counsil, TU, to Noonan, NRC, dated 7/9/86, on S&W Engineering Evaluation and Resolution of Technical Issues (M00886)

58 Letter from Counsil, TU, to Noonan, NRC, dated 7/23/86, on CPRT Overview Quality (M00167)

59 Letter from Counsil, TU, to Noonan, NRC, dated 7/23/86, on revision of Appendix E of CPRT Program Plan (M01655)

60 e.g., M01196, M00096, M00094, M00105, M00112, M00111, M01525

61 Letter from Counsil/Beck, TU, to Noonan, NRC, dated 5/13/86, submitting ISAPs III.a.1, VII.a.9, and VII.b.1 (M01671)

62 ASLB Memorandum and Order, dated 12/21/84 (M01669)

63 Letter from Counsil, TU to Noonan, NRC, dated 8/11/86, (M00135)

the Board's December 28, 1983, finding that TU had not demonstrated the existence of a system that promptly corrects design deficiencies, and that an independent design review was required.

The ASLB's request for Applicants' statement of Current Management Views established another strong link between the CPRT and the ASLB;[64] because, in its response, TU placed much emphasis on the CPRT program.[65] That document provides an extensive, detailed discussion (74 pages plus attachment) of TU's expectations that the CPRT will resolve all outstanding issues, and the questions on QA/QC in particular.

In a Memorandum dated 4/14/86,[66] the ASLB set forth a Proposed Memorandum and Order that declared its need and intent to be involved in the effort (CPRT Program) to develop a complete record and "not just stand passively by calling balls and strikes". In this regard, the ASLB stated that it would not accept "sketchy results reports" (referring to CPRT, ISAP and DSAP results reports) and established 14 questions that TU would have to answer in conjunction with each results reports.

Another ASLB initiative that directly impacted the CPRT was its Memorandum and Order on the definition of "Root Cause".[67] By this Memorandum and Order, the ASLB encouraged a certain amount of "ambiguity", and resulting breadth in the definition of this term as used in the CPRT Program.

On that same date, the ASLB issued another Memorandum and Order requiring all parties to file periodic reports to keep it abreast of the progress they are making in completing the studies, review and discovery necessary for completing the case.[68] TUts were specifically required to, "give target completion dates for the last CPRT task and for the last corrective-action task in response to the CPRT". TU's first response to this Order was

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64 ASLB Memorandum and Order, LBP-85-16, dated 5/24/85 (M00999)

65 Applicants' Current Management Views and Management Plan for Resolution of All Issues, 6/8/85 (M00999)

66 ASLB Memorandum, Proposed Memorandum and Order, dated 4/14/86 (M01716)

67 ASLB Memorandum and Order (Definition of "Root Cause"), dated 6/6/86 (M00999)

68 ASLB Memorandum and Order (Progress Report and Notice of Available Documents), dated 6/6/86 (M00999)

filed on July 30, 1986,[69] which summarized the status of the CPRT Program: Of the 53 total ISAPs and DSAPs, 2 have been deleted, Results Reports for 7 have been issued and the response to the ASLB's 14 Questions have been provided for one (ISAP: I.a.4). Note that this is the ISAP for which the First Results Report was issued, with which the ASLB and the NRC staff had a lot of problems.

In its Memorandum on "Board Concerns", the ASLB decided to express some of its then current concerns, so that TU could take these into consideration in planning and implementing the CPRT Program.[70] The ASLB's action was stated by the Board to be prompted by its review of TU's recently filed Results Report for ISAP I.a.4 on Agreement Between Drawings and Field Terminations, Revision 1,[71] as well as the CPRT Program Plan and SSER 13. The ASLB's Memorandum expresses the following concerns:

> "Findings in One Area may Affect Study in Another Area -This is a very broad comment, including (again) the depth and breadth of root cause investigations, the size of inspection samples, expanding investigations in or into another area on the basis of discovering discrepancies in a related area, and other similar comments about the breadth and depth of the CPRT Program.
>
> QA/QC For Design and Construction - Expresses concern about how deeply Applicants will pursue identified breakdowns or failures with respect to design or construction QA/QC. Includes a specific concern on ISAP I.a.4 Results Report.
>
> Reliability of Observations - Expresses concern whether the quality observations previously recorded by different observers are sufficiently comparable for statistical analysis.
>
> Staff Concerns - States that the ASLB shares many of the concerns expressed by the NRC staff in SSER-13, especially about preventing a loss of safety margins below requirements."

The ASLB Memorandum specifically states that the parties need not comment on its expressed concerns. TU did respond to these ASLB

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69 Applicants' First Progress Report filed with ASLB, July 10, 1986 (M00999)

70 ASLB Memorandum, LBP-86-20, dated 6/26/86 (M01656)

71 Letter from Counsil, TU, to Noonan, dated ?/4/86 (M01196)

concerns in conjunction with a filing six months later, which is discussed and referenced later in this section.

An ASLB Memorandum on Assistance to the Board, dated August 8, 1986, requested TU to provide it with the following information concerning the CPRT:[72]

> 1. A complete list of the issues that the CPRT is addressing, including QA/QC issues.
>
> 2. For each issue, its source or sources.
>
> 3. The current status of each issue.
>
> 4. With respect to each issue that has been wholly or partially found to be valid, the history, as found in documents and as known to accountable employees and supervisors, of how Applicants knew of that issue over time and how they responded.
>
> 5. The answer to the following question: To what extent are Applicants investigating failure of QA/QC for design or construction on portions of the plant that are now being redesigned or reconstructed and for which the original QA/QC program is consequently no longer directly relevant?[1]
>
> ---
>
> 1 Applicants and Staff appear to be suggesting that such information about quality assurance is not relevant. However, the effectiveness of the QA/QC program is essential to our determining: (a) the extent to which existing breakdowns may cast doubt on the adequacy of portions of the plant that have not been fully reexamined or that cannot be reexamined because of physical obstructions that cannot practicably be removed, and (2) the appropriate remedy with respect to management personnel responsibility for such breakdowns.

The footnote in the ASLB's Memorandum is particularly important, because it indicates the ASLB's concern that the CPRT Program, as then constituted, may not provide all the information the Board believes is necessary.

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72 ASLB Memorandum and Order, dated 8/8/86 (M00999)

In TU's response to the ASLB Memorandum,[73] TU reaffirmed their position that whenever a complete redesign or requalification of a design is performed, there will be little or no investigation by the CPRT of any failures of QA/QC for that design. Similarly for construction QA/QC, TU took the position that when reconstruction is undertaken, investigations of any failures of construction QA/QC would only be performed to the extent necessary to determine the scope of the reconstruction. TU's position is that the CPRT has no responsibility to determine or declare "the appropriate remedy with respect to management personnel responsibility for any QA/QC breakdowns". Rather, the CPRT "is designed to lead to a conclusion that the CPSES facility is adequately designed and constructed and tested (and is therefore eligible to be licensed)."

Just before receiving this response, the ASLB indicated a slightly different but similar concern in another Memorandum and Order, dated October 3, 1986, on CASE Discovery Request of June 27, 1986. The ordered TU to answer the following two Board questions:[74]

1) Will the CPRT review quality control or quality assurance issues generated in audits, reviews, diagnoses, evaluations, consultant reports and in-house audits or other internal reports?

2) to what extent will CPRT examine the adequacy of management response to issues so generated?

TU responded to the ASLB questions in a filing dated November 7, 1986.[75] Put very simply, TU's answers to these question were 1) Yes, and 2) None, but with complicated caveats to both answers.

The evolution and great broadening of the CPRT Program continued to raise questions about the function and need for the CYGNA/IAP review effort. The ASLB took the initiative on this with a Memorandum and Order directing TU to file a statement of their views concerning the present role of CYGNA (IAP).[76] In its

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73 Applicants' Response to Board Memorandum of 8/8/86 (Assistance to the Board), dated 10/6/86 (M00999)

74 ASLB Memorandum and Order, 10/3/86 (M00999)

75 Applicants' Response to Board 10/3/86 Questions (CPRT Scope), 11/7/86 (M00999)

76 ASLB Memorandum and Order, dated 9/9/86 (M00999)

response,[77] TU stated their belief that CYGNA should complete Phase 4 of the IAP and publish a final report, which should set forth CYGNA's views as to whether the activities of the CPRT have, or will, resolve CYGNA's concerns. And further, that a final determination of CYGNA's role in the proceeding should await the issuance of that report. CYGNA subsequently also filed a response to the ASLB's Memorandum,[78] in which it generally agreed with TU and stated that it will complete its investigation (Phase 4), that it will meet with CPRT review teams to discuss its outstanding questions, and that after resolution of all outstanding issues, it will publish its final report, then scheduled for March 1987. CYGNA also stated that it expected to be called upon to testify at the ASLB proceeding.

At a prehearing conference held in Dallas, Texas, on August 18 and 19, 1986, the ASLB again expressed a number of "concerns" about the CPRT Program (approximately 30). TU filed a response[79] not only to these concerns, but also to the concerns the ASLB had expressed earlier in its June 26, 1986 Memorandum.[80]

Page 1 and 2 of TU's response states that:

> "...the ultimate goal of the program is to provide the requisite assurance of adequacy of design and construction for <u>essentially</u> 100% of the safety-related aspects of the facility.[1] No claim has been made that, in its <u>present</u> form, the CPRT Program Plan is necessarily all that will be employed or required to achieve that goal...."*
>
> ---
> [1] Footnote omitted

But, on page 8 the response states that:

> "...It [the CPRT] is designed to lead to a conclusion that the CPSES facility is adequately designed and

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77 Applicants' Views Concerning the Present Role of CYGNA, 10/27/86 (M00999)

78 CYGNA's Response to Board's Memorandum, 11/3/86 (M00999)

79 Applicants' Response to Board Concerns, 12/1/86 (M00999)

80 ASLB Memorandum, dated 6/26/86 (M00999)

constructed and tested (and is therefore eligible to be licensed)..."

The response goes on to address about 40 Board concerns and about 10 CASE statements. According to the responses the concerns listed are unfounded. The responses do not indicate that there will be, or need be, any modification of the CPRT Program Plan to alleviate the concerns. The concerns are "explained away."

7.1.9 <u>The Corrective Action Program (CAP)</u>

In Revision 3 of the CPRT Program Plan the Design Adequacy Program (DAP) was an integral and major part of the CPRT Program. As such, it was to:

- o Conduct investigations of the adequacy of design;
- o Identify individual deviations in the form of Discrepancy Issue Reports (DIRs) for Project resolution;
- o Group DIRs into Issue Resolution Reports (IRRs) for Project evaluations;
- o Provide overview of project corrective action for the identified deficiencies in the pipe and pipe support, cable tray hanger and conduit support programs.

A review by TU in the summer of 1986 of the preliminary results of the DAP investigative phase revealed the findings to be very broad in scope and to involve virtually every discipline. This prompted TU to initiate the Corrective Action Program (CAP).

The DAP evaluation of identified design discrepancies per Appendix E of the CPRT Program Plan was discontinued. The DAP (actually the SRT) did continue its overview activities for certain project corrective actions, per Appendix H. These overview activities were to be documented in Discipline-Specific Action Plan (DSAP) results reports on the following areas;

- o Large Bore Pipe Supports;
- o Cable Tray Hangers; and
- o Conduit Supports.

The significance of the findings identified by the DAP and the effectiveness of the CAP in resolving those findings were to be addressed in the CPRT Senior Review Team's Collective Significance Report.

The CAP is to include a complete design and hardware validation program of the safety-related and certain non-safety related portions of the CPSES. It is to provide "a planned integrated resolution of identified problems rather than attempting to resolve each issue individually".[81]

Note that this reference is dated August 20, 1987. The changes in the CPRT Program, the CAP and other new related programs were not well documented in 1986. This occurred during the next year-long period, and involved a number of public meetings with the NRC and requests for information from the NRC, culminating in TU issuing Revision 4 of the CPRT Program Plan and the referenced letter from Counsil. These public meetings and Revision 4 are discussed in the following section.

The CAP is divided into eleven areas by disciplines and each discipline has been assigned to a company, Stone and Webster Engineering Corp., Ebasco, or Impell, as follows:

Mechanical	SWEC
Systems Interaction	EBASCO
Fire Protection	IMPELL
Civil/ Structural	SWEC
Electrical	SWEC
Instrumentation and Control	SWEC
Large Bore Pipe Supports	SWEC PSAS
Cable Tray Hangers	EBASCO/IMPELL
Conduit Supports Trains A, B, and C > 2"	EBASCO
Conduit Supports Train C$\geq$ 2"	IMPELL
Small Bore Pipe Supports	SWEC PSAS
HVAC	EBASCO
Equipment Qualification	IMPELL

The responsible CAP contractor collected all of the DIRs and IRRs issued by the CPRT DAP that related to its area of responsibility. These were collected into a Generic Issue Report (GIR) for each of the eleven disciplines. These GIRs identified the known issues and provided the planned approach to resolve the issues.

The GIRs and design data such as calculations, drawings, specifications, change documentation, deficiency reports, licensing commitments, FSAR commitments, and correspondence were reviewed by the responsible contractor. Design-related licensing commitments were captured in Design Basis Documents (DBDs) which were developed to identify the bases for the design validation effort. Design documentation, and identified design problems, are then to be reviewed to the design bases to ensure that the design satisfies the licensing commitments. The design

81 W.G. Counsil to NRC, "Comanche Peak Program", August 20, 1987 (M01070)

documentation is either validated as being acceptable, or it is revised to be acceptable. The design validation effort within each of the eleven CAP disciplines is being accomplished and documented in smaller workable packages, design validation packages (DVPs). One of the major activities in the design validation effort is to revise the Engineering Specifications to reflect the validated design, and to include hardware inspection requirements in the specification. This validated design, with required changes identified, is the "final design" with respect to the CPRT program, in that it is to resolve all CPRT design issues.

The only function of the CPRT in the CAP is overview and monitoring by the SRT. This function is discussed further in the next section of this report. The implementation and results of this overviewing and monitoring were to be presented in the CPRT Collective Significance Report.

7.1.10 Public Meetings and Revision 4 of CPRT Program Plan

A public meeting was held between the NRC and TU at the NRC Bethesda, Maryland offices on April 2, 1987.[82] The primary purpose was to discuss the CPRT Program Plan and Corrective Action Program (CAP). Because the NRC had, in February 1987, reorganized to form the Office of Special Projects, which includes the Comanche Peak Project Division, the early part of this meeting was devoted to background and descriptive information on the CPRT, CAP and PCHVP, and their relationship, for the benefit of the new NRC members of this Office. The transcript of the meeting, which includes the viewgraphs shown at the meeting, provides a good summary of the formation, evolution and status of the CPRT Program.

TU's representatives presented the establishment of the CAP, (which had occurred more than half a year earlier) and its relationship to the CPRT. TU maintained that the CAP was to be a 100% verification of critical design parameters at Comanche Peak, which obviated the necessity to continue in certain areas the CPRT Design Adequacy Program. However, the changes to the CPRT Program Plan were represented as minor, and therefore would be documented only in a letter from the SRT to Mr. Counsil - no Revision 4 of the CPRT Program Plan was going to be issued. From the transcript, it is apparent that the NRC staff did not fully understand or accept all this. The NRC staff seemed to be particularly concerned about the apparent loss of third-party objectivity and the documentation of changes in the CPRT resulting from establishing the CAP.

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82 Summary of Meeting Memorandum and Transcript, 4/21/87 (M01679)

At the April 2 meeting, it was decided that another meeting was necessary to further discuss the status of the various CPRT Program efforts underway and other licensing activities for the CPSES. This meeting took place on April 7, 1987, in Dallas, Texas.[83] At this meeting, the CAP was discussed in greater detail, including the status and schedule for each item. TU acknowledged that "major plant modifications" were involved, but said that these were being reported in accordance with 10 CFR 50.55e. TU announced that contrary to what had been said at the April 2 meeting, they were in the process of updating the CPRT Program Plan and that Revision 4, reflecting recent changes, would be submitted in the near future.

Shortly after these meetings the NRC sent a letter requesting additional information and clarification on the subjects discussed at these meetings.[84] By enclosures to a letter dated June 25, 1987, TU responded to the NRC requests.[85] On this same date, TU submitted Revision 4 to the CPRT Program Plan to the NRC.[86] The letter which transmitted Revision 4 states:

> "The revision consists of two formats: first, the current revision of the plan and its appendices which incorporate in-process changes that were made in accordance with CPRT procedures since Revision 3 was published, and, second, forewords to the plan and to Appendix A. The forewords explain how SRT-directed changes in the third-party overview activities have affected Revision 3 and how the comprehensive Corrective Action Program being implemented by TU Electric has obviated the necessity for some of the previously prescribed CPRT-DAP activities.
>
> Appendix C consists only of DSAPs. ISAPs have not been included in this revision inasmuch as Results Reports either have been or soon will be published for each."

Another public meeting was held on July 29 and 30, 1987, in Dallas, Texas, to discuss TU's June 25, 1987 submittals and the

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83 Summary of Meeting Memorandum and Transcript, 5/15/87 (M01680)

84 Letter from Grimes, NRC, to Counsil, TU, dated May 12, 1987 (M01718)

85 Letter from Counsil, TU, to the NRC, dated June 25, 1987 (M01557)

86 Letter From Counsil, TU, to NRC dated June 25, 1987 (M01634)

overall progress of TU's programs.[87] Almost 100 individuals signed the attendance sheet for this meeting, including several representatives from the intervenor, CASE, and the media. In his introductory remarks, Mr. Keppler, then recently appointed Director of the NRC's Office of Special Projects, which includes the Comanche Peak Project Division, said:

> "Since I came on board with this project in March, I have been concerned with the present level of NRC involvement in the Comanche Peak project and in the activities going on, particularly with respect to the plant construction work, the modifications and the reinspection work that have proceeded at rather a strong pace.
>
> I found it difficult to understand the programs that the Utility was undertaking, had undertaken, and I didn't find them to be well defined in the docketing file, and the programs have evolved somewhat with time. So that's contributed to our delay in getting on board.
>
> The objective we had with the May 12th letter was to freeze at this point in time, if we could, Texas Utilities' programs so that the Staff could either approve these programs or require necessary changes to make the programs acceptable to NRC.
>
> This effort, which should have been done a long time ago, would serve as a basis for evaluating the adequacy of your past design and construction verifications and permit confidence that the ongoing reviews will be completed properly. In this meeting the Staff will be seeking clarifications and elaborations of the submittals you have provided so that we can clearly understand your plans, complete the evaluations and establish whether any changes or additions are required." (Page 2 of transcript)

The intervenors, CASE, made some very critical comments about TU's programs at this meeting. The NRC staff noted to TU that if during the course of the meeting they felt that material already submitted could be better clarified with additional submittals, to please do that.

Shortly after this meeting, TU did submit additional information on the CPRT and CAP, and particularly on how these two programs

87 Summary of Meeting Memorandum and Transcript, dated 6/4/87 (M01681)

interrelate.[120] This submittal included, for the first time, a flow chart to show the flow of information and authority/responsibilities within and between the CPRT and CAP Programs. This chart makes it clear that the Post Construction Hardware Validation Program (PCHVP) is part of the CAP. A copy of this chart is provided as Figure 7-1. TU's capsulized description of these Programs and their inter-relation is provided by the Summary section of this submittal:

> Summary
>
> The CPRT investigation of issues and evaluation of findings is essentially complete, and has identified those issues which must be resolved by the project. This investigation and evaluation of findings was a necessary step to determine the nature and extent of problems at CPSES, and it served as vital input to the formulation of the CAP.
>
> The CAP was formulated to address CPRT and other open external source issues. The CAP has three elements: validation of design to licensing commitments, validation of hardware to the validated design, and design reconciliation. TU Electric is confident that the CAP, when implemented, will provide assurance that the design satisfies licensing commitments, and the hardware complies with the validated design. This in turn provides assurance that structures, systems and components with a safety-related function will perform satisfactorily in service.

We note again previous TU statements that the SRT of the CPRT is to overview and monitor the CAP, including the PCHVP, and that the implementation and results of this overview are to be discussed in the CPRT Collective Significance Report. However, as noted earlier, this overview is intended to be almost exclusively a paper review.

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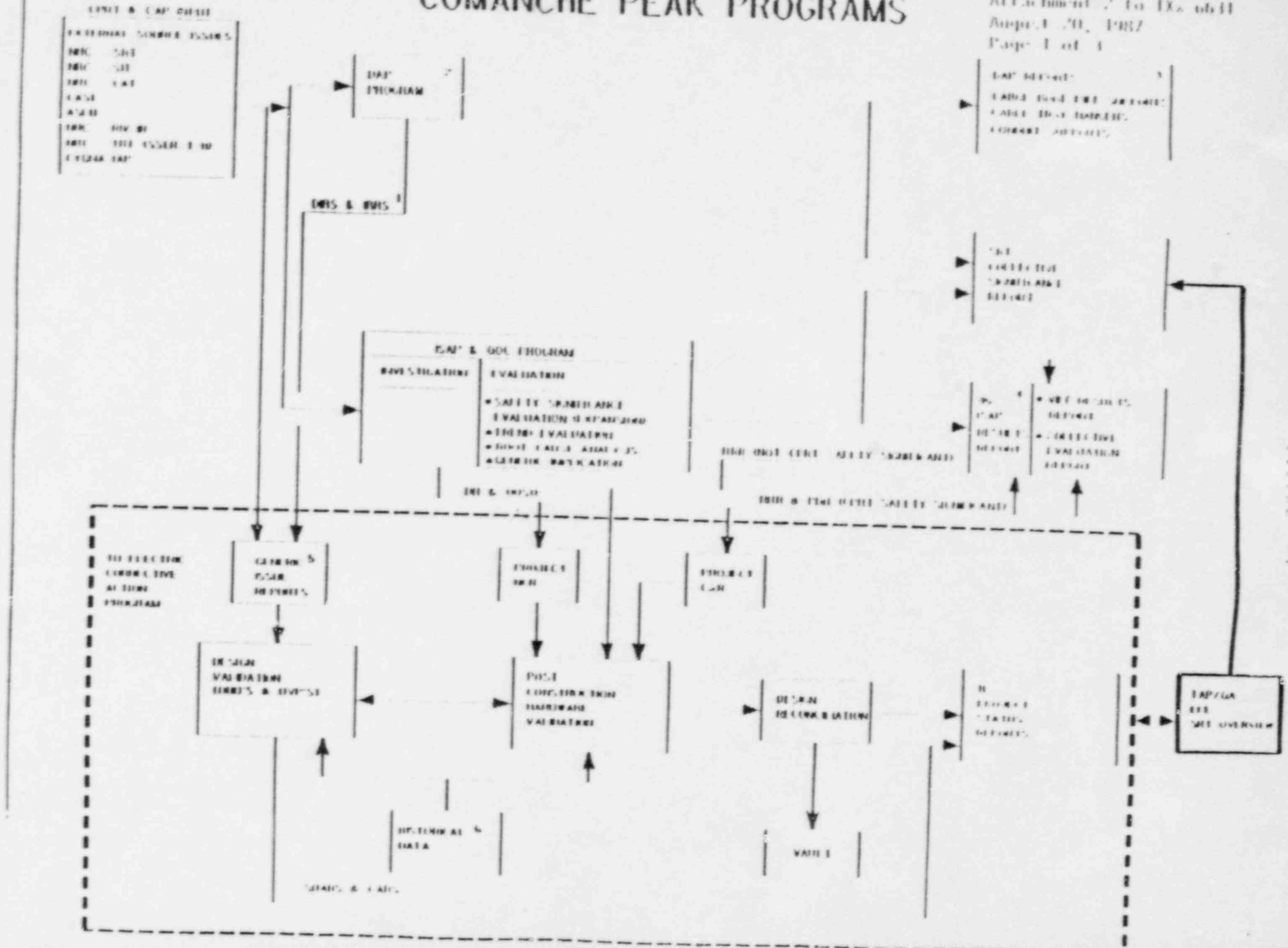
120 Letter from Counsil, TU, to the NRC, dated August 20, 1987 (M01070)

COMANCHE PEAK PROGRAMS

Attachment 2 to TXX-6611
August 20, 1987
Page 1 of 1



7.1.11 Post Construction Hardware Validation Program

The final phase of the CPRT effort is the actual field validation of the As-Built plant hardware and equipment. This effort is described by Mr. Counsil as follows:

> "The Post Construction Hardware Validation Program (PCHVP) is a complete validation of final acceptance attributes for safety-related and selected non-safety related hardware. The revised (validated) erection specifications include hardware inspection requirements for new installations and form the basis for the PCHVP Attribute Matrix. Using input from the QOC program in the form of CARs, NCRs, and CPRT recommendations, and changes identified as a result of the CAP design validation activities, the Engineers will challenge (i.e., evaluate) each final acceptance attribute for acceptability and determine the method to be used to validate the attribute."[121]

7.2 Reports Produced by the CPRT

7.2.1 Project Status Reports

The results of the CAP are reported in eleven (11) Project Status Reports, one for each of the eleven disciplines that were assigned to Stone and Webster, Ebasco, and Impell. The deficiencies identified in these reports can be grouped into three general categories. Any of these can delay the licensing of a plant. The three categories are:

1. Physical Plant Deficiencies Requiring Modification - These are equipment and construction features that are found to be unacceptable and must be reworked or replaced. These generally resulted from faulty design, from design changes that were not approved or available when the installation was made, or simply fabrication or installation not in accordance with the design or procedures. This is the most easily understood category, because faulty QA results in defects requiring modifications to make the plant safe or operable. All of the CAP Project Status Reports reviewed to date identified deficiencies requiring plant modifications.

2. Physical Plant Deficiencies Found to be Acceptable - These are items that are not in accordance with the final design, but upon reanalysis are found to be acceptable "as-is".

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121 W.G. Counsil to NRC, "Comanche Peak Programs", August 20, 1987.

This category, like the one requiring modifications, is the result of inadequate QA, however, in this category analysis is able to show that the condition is acceptable without modification. A deficiency in design can be demonstrated to be acceptable in spite of the errors that have been made. For example, by the use of more precise analytical tools than were used in the original design and analyses; because of margin either intentionally or accidentally included in the original design; or because of good luck. This disposition can only be made after qualified personnel have completed an evaluation of the deficiency. These deficiencies should have been detected by design reviews, design change reviews, or QC inspections and QA surveillances.

Evaluation of deficiencies of this type is the only way to assure the plant was safe or operable. To operate the plant without such analysis, one would have had to gamble with the health and safety of the public and on damaging or destroying the plant. NRC was unwilling to take this gamble and neither was TU's current management.[122]

This type of deficiency may be compared to a situation (with much less severe consequences) that many of us have faced when the "low oil pressure" indicator comes on while driving in an automobile. We are faced with the problem of whether we have a false indication or an engine about to be destroyed. Obviously, the only safe thing to do is to stop the engine and determine the reason for the indicator light being lit. The investigation of the reason for the indication is comparable to the CPRT program. Finding satisfactory oil pressure and no engine damage is comparable to the category of "physical plant deficiencies found to be acceptable." However, finding a failed oil pump is comparable to the category of "physical plant deficiencies requiring modification".

3. <u>Documentation Deficiencies</u> - These are cases where the design is found to be acceptable and the physical plant is found to be in accordance with the design, but the documentation to show this was not completed at the time of design or construction or not retrievable in accordance with the QA documentation requirements. Again the deficiency requires evaluation before this disposition can be made. If the documentation had been maintained in accordance with requirements, no evaluation would be necessary. Until the deficiency is verified to meet design requirements, it could

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122 Applicants' Current Management Views and Management Plan for Resolution of All Issues, June 28, 1985, page 7. M00999.

represent a deficiency requiring modification. It is well established that lacking the documentation necessary to demonstrate by objective evidence that the systems meet applicable requirements is not an acceptable situation from a licensing (NRC) standpoint. Here too, until the CPRT analysis was performed, the actual condition of the plant was just not known.

Examples of deficiencies in each of these categories are discussed Section 7.3. It should be noted that these are only examples to demonstrate that the problem is real and extensive. It is not a comprehensive listing or discussion of these findings. In most cases the recommendations of the action plan teams are still to be implemented. The physical inspection of the as-built item(s) is not yet complete for any of the areas of evaluation. The physical inspections may well identify additional and potentially more serious deficiencies.

The PSRs identify and describe the design and hardware validation activities, and report how the issues were resolved such that licensing commitments have been satisfied. The methodology and results of the corrective actions are discussed in detail. Each report has three appendices.

Appendix A - External Source and CPRT Issue Specific Resolution

Appendix B - Self-Initiated Issue Specific Resolutions

Appendix C - Preventive Action Taken.

7.2.2 Progress Reports

TU's First Progress Report states that:

> "The CPRT does not work to a project schedule in the normal sense in which the term is used. The CPRT Project Director collects and collates information from the CPRT Review Team Leaders ("RTLs") and Issues Coordinators ("ICs") with respect to progress, which information is used by the Project Director and the SRT for planning purposes."

The Progress Report makes some predictions about the completion of Results Reports and the Collective Evaluation Reports. It states that the last report to be issued by the CPRT will be the overall Collective Significance Report for the CPRT Program, which it predicts will be issued in mid-1987. (Revision 0 of that report was recently issued on 2/26/88)

TU's Progress Report includes the statement that:

"This information is provided with certain caveats. These schedules are not the sort of firm schedule the Board may have had in mind when it issued its memorandum; such schedules do not exist and will not be created for the CPRT Program. Some of these dates may slip for a number of reasons including some conscious decisions."

The Progress Report also includes the statement:

"As is set forth in the Program Plan, corrective actions are the province of the CPSES project. Thus, completion of corrective actions is not, except to the extent set forth in CPRT Program Plan Appendix H, a prerequisite to completion of the CPRT program. Similarly, until action plans are completed, no complete catalog of the corrective actions that may be required can be formulated.

As the Board is aware, however, certain corrective actions are presently on-going."

The essence of the reference to Appendix H of the CPRT Program Plan is characterized by the following quotations from that document:[123]

"The CPRT may <u>recommend</u> proposed corrective actions to the CPSES Project; however, the CPSES Project is responsible for the definition of corrective actions.

The CPRT Program Plan also establishes, as a prerequisite for the completion of the CPRT third-party's investigatory activities, that the corrective actions defined by the CPSES Project for all deficiencies and for certain categories of deviations must be acceptable to the CPRT; i.e., the CPRT is satisfied that, <u>when implemented as defined</u>, the corrective actions defined by the CPSES Project will correct the specific non-conforming condition(s) and, if applicable, will preclude the recurrence of similar non-conforming conditions in the future.

As stated in the CPRT Program Plan, corrective actions will be implemented by the CPSES Project. The nature and extent of third-party <u>overview of the actual implementation</u> of the CPSES Project's corrective action plans <u>will vary</u> depending upon the nature of the corrective actions and the third-party's confidence

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123 Rev. 3 of the CPRT Program Plan, 1/27/86 (M00529)

that such actions are being implemented properly. (emphasis added)

o o o o

The CPRT will confirm the adequacy of the CPSES Project's implementation of corrective actions for each CPRT-identified programmatic deviation or deficiency. Such corrective actions are expected to be defined in the form of recommended revisions to CPSES Project policies, programs, and implementing procedures or instructions related to QA/QC or construction processes. CPRT confirmatory activities will be accomplished through reviews of the revised documents that reflect such changes. (emphasis added)

o o o o

The Executive Vice President of TUGCO is responsible for establishing TUGCO's position of any corrective actions for which agreement has not been reached between the CPRT and the CPSES Project and for advising the SRT of TUGCO's intentions."

The ASLB Memorandum and Order required that TU file a Progress Report every two months after the First Progress Report. TU filed the next Progress Report on September 30, 1986 and has filed these periodically since then.[124] These reports, and the

[124] Applicants' Second Progress Report, 9/30/86 (M01697)

Applicants' Third Progress Report, 12/01/86 (M01698)

Applicants' Fourth Progress Report, 2/10/87 (M01699)

Applicants' Fifth Progress Report, 5/18/87 (M01701)

Applicants' Sixth Progress Report, 6/30/87 (M01702)

Applicants' Seventh Progress Report, 8/31/87 (M01703)

Applicants' Eighth Progress Report, 10/30/87 (M01593)

Applicants' Ninth Progress Report, 12/30/87 (M01704)

Applicants' Tenth Progress Report, 3/4/88 (M01705)

NRC staff's periodic Progress Reports[125] serve as a convenient, concise record of the progress and changes in the CPRT Program.

All of these activities are accomplished under the overview of the SRT. The implementation and results of this overview will be discussed in the CPRT Collective Significance Report.

7.3 Corrective Actions Identified by Evaluations

7.3.1 Physical Plant Deficiencies Requiring Modification

Corrective Action Reports identified the following modifications:

TU's validation of the designs for safety-related, large-bore piping and pipe supports (over 2 inch diameter) identified 5,621 pipe supports that require modification - almost half of the approximately 12,020 large bore piping supports considered.[126]

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125 NRC Staff Progress Report and Annotated Bibliography, 8/27/86 (M01687)

NRC Staff Second Progress Report and Annotated Bibliography, 10/27/87 (M01688)

NRC Staff Third Progress Report and Annotated Bibliography, 12/23/86 (M01689)

NRC Staff Fourth Progress Report and Annotated Bibliography, 2/27/87 (M01690)

NRC Staff Fifth Progress Report and Annotated Bibliography, 6/15/87 (M01691)

NRC Staff Sixth Progress Report and Annotated Bibliography, 8/11/87 (M01692)

NRC Staff Seventh Progress Report and Annotated Bibliography, 9/28/87 (M00194)

NRC Staff Eighth Progress Report and Annotated Bibliography, 1/7/88 (M01693)

NRC Staff Ninth Progress Report and Annotated Bibliography, 2/3/88 (M01694)

NRC Staff Tenth Progress Report and Annotated Bibliography, 3/24/88 (M01695)

126 CAP Project Status Report on Large Bore Pipe and Pipe Supports, 11/2/87.

These are only the result of design validation. Field verifications that the piping and pipe supports are in accordance with the design, are ongoing. These field verifications may identify the need for additional corrective modifications.

TU's validation of the designs for safety-related small bore piping and pipe supports (2 inch diameter and smaller) identified 1,896 pipe supports that require modification, almost 1/3 of the 6,630 small bore piping supports considered.[127] Here too, these are only the result of design validation. Field verifications are ongoing and may identify the need for additional corrective modifications.

TU's validation of the designs for safety-related cable trays and cable tray hangers identified the need for approximately 93 cable tray and 874 cable tray hanger modifications.[128] Field verification of the post-construction hardware is still in progress.

TU's validation of conduit supports identified over 9000 modifications that will have to be made in the approximately 30,000 conduit supports larger than 2" that were reviewed. Again, field verification is still in progress.[129,130]

The Cable Tray and Cable Tray Hangers Report states the results of that investigation of the 7,566 cable tray hangers in Unit 1 and Common, 874 hangers required modification. These modifications are in several categories:

- o Member overstresses;
- o Weld overstresses;
- o Member slenderness ratio exceeded;
- o Clamp capacity exceeded;

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127 CAP Project Status Report on Small Bore Piping and Pipe Supports, 11/2/87.

128 CAP Project Status Report on Cable Tray and Cable Tray Hangers, 11/18/87.

129 CAP Project Status Report on Conduit Supports Trains A and B, and Train C Larger Than 2 Inch Diameter, 11/18/87.

130 CAP Project Status Report on Conduit Supports Train C 2 Inch Diameter and Less, 11/11/87.

- o Anchor bolt capacity exceeded.

In addition, there are approximately 93 modifications needed to correct cable tray overstress. Other modifications related to such things as modifications to the cable trays either to add supports or modify supports to redesign cable tray clamp modifications and change the clamp type, or design new or modified cable tray hangers are required. In addition to modifying these cable trays and cable tray hangers, the review required verifying, inspecting and validating documentation for those cable trays which complied with design criteria but had not previously been documented.

The corrective action report covering conduit supports, train C two inch diameter and less, states that there are 105,000 conduit supports in Unit 1 and Common. Of this 105,000 conduit supports, 600 have been identified as requiring modifications. Of the 105,000 supports, 77,000 supports have had their final acceptance attributes validated through the PCHV program.

The Equipment Qualification CAP included:

- o Review of 165 specification and qualification data packages,
- o Review of more than 3,000 original design drawings,
- o Development of 150 environmental equipment qualification summary packages (EEQSPs),
- o Development 500 seismic equipment qualification summary packages (SEQSPs),
- o Validation of the qualification of more than 16,500 equipment items,
- o Resolution of 125 TENERA AIRs, and
- o Development of more than 330 calculations.

This design validation effort determined that relocation, modification and/or replacement of 500 pieces of equipment was required.

TU's validation of the design for safety-related electrical systems resulted in a large number of hardware modifications.[131] Just a few of these are:

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131 CAP Project Status Report on Electrical, 1/15/88. (M01566)

- Two new startup transformers were added.
- Cable sizes for certain power circuits were increased.
- Power and control circuits and protective devices were modified to assure adequate penetration electrical protection, ampacity and short circuit capability.
- Circuits are being modified to add isolation devices between Class 1E and non-Class 1E equipment.
- Damaged equipment and incorrect devices were replaced.
- Lighting circuits are being modified to bring them into compliance with design criteria.
- Battery chargers were modified to assure adequate cooling.
- Electrical terminal blocks that were not environmentally qualified are being replaced.

The CPRT investigations of NRC-TRT findings led to the following modifications:

Potential failure of non-seismic designed components reducing the functioning of seismic Category I systems or components.[132] The entire, original control room ceiling was replaced with one of a completely new design that conforms with NRC Regulatory Guide 1.29 and the Comanche Peak FSAR.

Improper documentation of inspections of electrical butt-splices. This not only substantiated the specific NRC findings, but identified many other deviations in the inspection documentation for butt-splices.[133] As a result, all essential circuits where AMP PIES splices may have been used for terminations or butt-splices were identified and inspected. A number of construction deficiencies were thereby identified which had to be corrected.

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132 CPRT Results Report ISAP: II.d., Seismic Design of Control Room Ceiling Elements, Rev. 1, 10/5/87.

133 CPRT Results Report ISAP: I.a.2., Inspection Reports on Butt-Splices, Rev. 1, 3/27/87.

Separation of flexible conduits and the separation of flexible conduits from exposed cables.[134,135] These investigations and resulting action plans established separation criteria appropriate for the flexible conduit, necessitating reinspection to determine conformance. As result, 34 nonconformances were found that required rework, and reinspections were still ongoing when the referenced reports were written.

Missing barrier inside an auxiliary feedwater control panel and field wiring not being separated by the required distance in another panel.[136] The investigation not only confirmed that the barrier was missing and that wiring in the other panel identified by the NRC violated the separation criteria, it identified over 140 other violations of internal panel separation criteria that required rework. The Review Team for this Action Plan concluded that there had been "inadequate procedures, a lack of effective craft and QC training, and insufficient supervisory emphasis on separation".

Improper shortening of anchor bolts in the steam generator upper lateral supports (restraints). This review not only substantiated the specific NRC findings, but also identified discrepancies in the design of the steam generator upper lateral restraints.[137] This led to a significant reanalysis of the steam generator compartments and a revised design for the steam generator upper lateral connections, which includes the anchor bolts originally in question. This is requiring a major reworking of the restraints in the steam generator compartments in both units. The steam generator upper lateral restraints are Seismic Category I, safety-related components. There is also a lower lateral restraint in each steam generator compartment. These are being reviewed within DSAP VIII of the CPRT Design

134 CPRT Results Report ISAP: I.b.1, Flexible Conduit to Flexible Conduit Separation, Rev. 1, 12/10/86.

135 CPRT Results Report ISAP: I.b.2, Flexible Conduit to Cable Separation, Rev. 1, 12/10/86.

136 CPRT Results Report ISAP: I.b.4, Barrier Removal, Rev. 1, 12/17/86.

137 CPRT Results Report ISAP:V.b, Improper Shortening of Anchor Bolts in Steam Generator Upper Lateral Supports, Rev. 0, 10/21/87.

Adequacy Program. The Review Team for ISAP.V.b concluded that the causes for this problem were:

1. Less-than-adequate installation procedures and instructions due both to the failure of G&H to provide drawings and specification that contained sufficiently detailed instructions to guide installation, and to the failure of construction to develop specific proceduralized guidance for the installation of the SGULs, given the information that they had been provided;

2. Less-than-adequate performance by craft and/or their supervision in that they resorted to practices that were clearly unacceptable even in the absence of specific procedural guidance and that they appeared to have failed to inform their management of obvious problems;

3. Less-than-adequate inspection procedures in that the applicable procedure contained no requirement to verify engagement of bolts in drill and tap blind connections such as were used in the SGUL connections;

4. Less-than-adequate performance of inspections, as evidenced by the fact that documentation of SGUL inspections could not be located; and

5. Less-than-adequate design control program in G&H that permitted the design drawings and specifications to be issued without specific guidance being provided for the installation of the SGULs.

Contributing causes were also identified as follows:

1. Less-than-adequate design control program in G&H that resulted in an inadequate original design concept for the SGUL connections and permitted essential calculations to be missing and to be completed in error, and

2. Less-than-adequate design control at the G&H/Westinghouse interface that results in important design information not being incorporated into design calculations.

The issues identified in this ISAP extended well beyond those expressed by external sources.

7.3.2 Physical Plant Deficiencies Found to be Acceptable

The NRC-TRT identified an issue concerning the omission of reinforcing steel (rebar) from the reactor cavity wall. The CPRT's investigation into this issue determined that rebar was, in fact, omitted from a concrete placement for this wall.[138] The omission occurred because the concrete placement had already been completed when a revision of the applicable design drawing was issued. This occurred even though a similar problem had been identified in 1977 with verification of imbeds, as discussed in section 5.3. The corrective action for that deficiency included preparing procedures to verify readiness to place concrete. A procedure was supposedly in place whereby the Engineer (G&H) was to inform the field via TWX of any pending changes to previously issued drawings, and to follow this up with a Construction Hold Notice (CHN). No TWX or CHN was issued in this case. Analyses performed as part of this action plan concluded that the as-built section of the reactor cavity wall meets the structural and shielding design requirements and is therefore acceptable.

As part of this action plan, other cases of omitted rebar were identified and reviewed, a representative sample of concrete "Pour Cards" was reviewed to determine conformance of as-built rebar and other embedments with design documents, and rebar that had been exposed by chipping concrete as part of another ISAP was inspected and compared with applicable design documents. In each of these efforts, numerous, not-previously-identified discrepancies were found. In all cases, however, "Project evaluation" determined that the as-built condition was acceptable. Even so, these findings demonstrate that the QA Program in effect at the time these reinforced concrete structures were fabricated was not effective. It did not prevent these errors, nor did it identify, document and resolve them. That remained for the CPRT Program to accomplish.

A CPRT review team investigation of onsite fabrication shop activities confirmed the NRC-TRT findings of procedural inadequacies and implementation problems relative to management and inspection controls of onsite fabrication.[139] The review resulted in 32 Deviation Reports being issued. These deviations were all evaluated and determined to have no "safety-significant hardware effect". The review team also concluded, however, that a "lack of appropriate supervisory overview and timely QA monitoring of the inspection records resulted in the placement of unsatisfactory QA documentation in the permanent plant records."

In response to an NRC-TRT identified issue, a CPRT review team investigated whether Project procedures were adequate to control the disassembly and reassembly of valves when this was necessary, and whether valves that had been disassembled were properly

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138 CPRT Results Report ISAP: II.a, Reinforcing Steel in the Reactor Cavity, Rev. 1, 10/6/87.

139 CPRT Results Report ISAP: VII.b.1, Onsite Fabrication, Rev. 1, 2/12/87.

reassembled.[140] Four deviations, not previous identified by the QA Program, were found where valve bonnet assemblies were different from what the records indicated they should be. Follow-up evaluations concluded there was no "safety significance" to these deviations. The review team did conclude that the procedures for valve disassembly/reassembly did not provide adequate control when large numbers of similar valves are simultaneously disassembled -- which had been the case at Comanche Peak. The procedures were therefore revised to provide adequate controls in the future.

A CPRT review team investigated the as-installed quality of Hilti Kwik Bolts (concrete expansion anchors), and the procedures for installation and inspection for them.[141] The review identified 174 deviations, but analyses determined that none of these were "safety-significant". Never-the-less, a large number of these bolts were not installed as intended and the QA Program did not detect and correct this. The review team concluded that both the installation and inspection procedures had "inadequacies".

The CPRT review of the QA/QC documentation for the spent fuel pool liner confirmed the "irregularities" identified by the NRC-TRT in this documentation.[142] The review team found a "number of documentation gaps and inconsistencies in the fabrication records." Evaluation of each of the "substantial number" of deviations identified by the review team indicated that none of these had a "hardware safety significance". However, the review team ended up recommending that the engineer (G&H) conduct another evaluation of the acceptability of the fuel pool liner system. The results of this review clearly demonstrate, that there was not an effective QA program applied to the fabrication of the fuel pool liner.

One of the NRC-TRT findings and subsequent NRC action requirements concerned whether electrical cable terminations in the control room and cable spreading area are in accordance with all current design documents. The NRC-TRT had identified 6 specific cases where cable terminations appeared not to be in accordance with design drawings. TU's review of these specific cases confirmed that, although each one did involve either a drawing error or a termination that was not in accordance with a correct design drawing, none of them was in "functional

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140 CPRT Results Report ISAP: VII.b.2, Valve Disassembly, Rev. 1, 3/18/86.

141 CPRT Results Report ISAP: VII.b.4., Hilti Anchor Bolt Installation, Rev. 1, 5/14/87.

142 CPRT Results Report ISAP: VII.a.8., Fuel Pool Liner Documentation, Rev. 1, 11/4/86.

disagreement with design requirements"[143]. The review identified another 3 cases of drawings and cable tagging errors, but these too were found not to be in functional disagreement with design requirements. These errors had not been identified by the QA program.

A CPRT review team investigated an NRC-TRT identified issue and consequent NRC action requirement concerning the acceptability of type (2) skewed welds on pipe supports designed to ASME Code III Subsection NF.[144] The review team found 12 of a random sample of 60 such welds by Brown and Root contained undersize weld regions. Evaluation of these undersize welds concluded that they were still within ASME allowable stress levels and therefore dispositioned use-as-is. An evaluation of margin based on the measured weld size indicates that it is not likely that any of the type (2) skewed welds in the plant violate ASME limits. The Projects QA Program had not detected that these welds did not meet the established criteria. Brown and Root inspection procedures were revised to minimize recurrence of this problem.

A CPRT review team investigated an NRC-TRT identified issue and consequent NRC action requirement concerning the possible cutting of reinforcing steel (rebar) in the floor slab of the Fuel Handling Building.[145] Cutting of only the topmost layer of rebar had been analyzed and properly authorized for drilling expansion bolt holes to secure trolley rails. This investigation determined that in this case, and in 62 other cases identified by the investigation, holes were drilled into the concrete deeply enough that unauthorized cutting of rebar could have occurred. All cases were evaluated, postulating that the additional rebar was cut, and the structures were found to be adequate. Procedures were revised to establish better controls to minimize the possibility of future occurrences of unauthorized rebar cutting. The Project QA Program had not previously identified any of these cases.

7.3.3 <u>Documentation Deficiencies</u>

The NRC raised concerns about the verification of the compliance of materials and equipment with procurement/design specifications. The CPRT investigation into this question

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143 CPRT Results Report ISAP: I.a.4. Agreement Between Drawings and Field Terminations, Rev. 2, 7/23/86.

144 CPRT Results Report ISAP: V.a, Inspection of Certain Types of Skewed Welds in NF Supports, Rev. 1, 10/22/86 with Errata dated 8/6/87.

145 CPRT Results Report ISAP: II.e, Rebar in the Fuel Handling Building, Rev. 1, 9/2/87.

determined that the original TU QA Program covered construction activities; but "in general did not cover procurement activities."[146]

The CPRT investigated and confirmed the NRC-TRT findings of improperly dispositioned Non-conformance Reports (NCR's) concerning bent electrical terminal lugs. TU therefore re-dispositioned these NCR's to provide adequate justifications for the "use-as-is" determinations. This involved obtaining an "Engineering Evaluation Report" from the supplier of the terminal lugs (AMP), to establish criteria on how much these lugs could be bent or twisted. Using these criteria, all the terminal lugs in question were reinspected and found to be acceptable, except one. In the original dispositioning of NCR's, some of the bent or twisted lugs were replaced. One of these, that was to be replaced had not been replaced; but, the NCR had been closed by the QE (Quality Engineer). This is a "double" discrepancy, that caused the Review Team Leader for this Action Plan to issue a new NCR, which is to be dispositioned by the CPRT QA/QC Review Team.

The NRC-TRT found "a lack of guidelines and procedural requirements for the testing and certifying of Electrical QC inspectors." The NRC action required as a result of this finding increased the scope to all QC inspector training and qualification. The CPRT Review Team for this issue concluded that the procedures for "Training of Inspection Personnel" and "Documentation Within QA/QC Personnel File" did not adequately address the requirements of ANSI N45.2.6 and Regulatory Guide 1.58 and violated Criterion V of 10CFR 50, Appendix B.[147] As a result, the procedures were revised. In trying to determine the root cause for this QA/QC Program Deviation, the Review Team concluded that inexperienced personnel that wrote the original procedures was the primary cause, but that "improper supervision of the work may have contributed to the problem." Furthermore, that "the broader question of whether senior management was remiss in assigning inexperienced personnel to this activity requires further investigation", but that, "this question is beyond the scope of this ISAP and will be addressed during the collective evaluation process."

A CPRT review team investigated an NRC-TRT identified issue on the documentation and review of the Project's established criteria for the separation between rigid conduits and cable

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146 CPRT Results Report ISAP: VII.a.9, Adequacy of Purchased Safety-Related Material and Equipment, Rev.1, 9/18/86.

147 CPRT Results Report ISAP: I.d.2, Guidelines for Administration of QC Inspector Test, Rev. _, 9/4/86.

trays.[148] As a result of this investigation, it was determined that no supporting analysis existed at the time that these criteria were placed in the design and construction documents. It also found that inconsistent assumptions were used in a subsequent G&H simplified analysis to justify the separation criteria. Neither of these were discovered by the QA Program.

There were a number of NRC-TRT findings and consequential NRC action requirements concerning deficiencies in QA/QC procedures and/or documentation. CPRT review team investigations confirmed that each of these findings was at least partially valid and made appropriate changes in procedures and documentation to minimize reoccurrence of these deficiencies.[149,150,151,152,153,154]

7.4 Collective Evaluation Report

7.4.1 Purpose of CPRT

The Collective Evaluation Report indicates that the purpose of the CPRT is "to investigate various issues regarding the Comanche Peak Steam Electric Station (CPSES)."[155] The report continues "The CPRT program consisted of two principal types of activities. First, the CPRT performed investigations to determine the adequacy of various types of programs and hardware at CPSES and make recommendations for corrective actions where required. Second, having concurred with the Project's plans for addressing

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148 CPRT Results Report ISAP:I.b.3, Conduit to Cable Tray Separation, Rev. 1, 3/20/86

149 CPRT Results Report ISAP VII.a.1, Material Traceability, Rev. 1, 5 14/87.

150 CPRT Results Report ISAP VII.a.2, Nonconformance and Corrective Action System, Rev. 1, 5/7/87.

151 CPRT Results Report ISAP VII.a.3, Document Control, Rev. 1, 12/17/86.

152 CPRT Results Report ISAP VII.a.4, Audit Program and Auditor Qualification, Rev. 1, 4/17/86.

153 CPRT Results Report ISAP VII.a.5, Periodic Review of QA Program, Rev. 1, 7/31/86.

154 CPRT Results Report ISAP VII.a.6, Exit Interviews, Rev. 1, 10/29/86.

155 CPRT Collective Evaluation Report, Rev. 0, December 1987, Part II, Page 1 of 6.

these recommendations, the CPRT is overviewing implementation of the corrective actions."

7.4.2 <u>Collective Evaluation Results (CER) Summary</u>

The CER Executive Summary indicates that the report considered "the findings identified in the Results Report for ISAP VII.c and the other ISAPs."[156] Figure 7-2 is a representation of the Comanche Peak Response Team's activities and programs that result in the development of the Project Status Report (PSRs). However, the statistical information used in the report conclusions (Section 2.4) were derived solely from the ISAP VII.c evaluations. (Section 2.2) Also excluded from the Collective Evaluation Report are any evaluations associated with the Design Adequacy Program (DAP) including the Design Quality Assurance Program.[157] Section 2.2 also points out that 73 construction deficiencies, adverse trends or unclassified trends were identified in ISAP VII.c and indicates that "additional reinspections will be performed and corrective action will be taken, thereby assuring the quality of construction of these CWCs (Construction Work Classifications)."

The overall conclusion of the Collective Evaluation is "the CPRT concludes that its program has been sufficient to identify programmatic deficiencies affecting the quality of construction of CPSES, and <u>that upon satisfactory implementation of the corrective action for deviations and findings identified by the CPRT</u>, there will be reasonable assurance that the system, structures, and components of CPSES will meet the <u>significant, safety-related requirements</u> of the October 1985 design (or later applicable design)."[158] (emphasis added)

7.4.3 <u>Inspection Point vs. Item Statistics</u>

As noted, the Collective Evaluation Report relies heavily on the statistical analysis of ISAP VII.c. Section 2.2 of the Executive Summary starts, "The data collected by the CPRT as part of ISAP VII.c provides a sufficient basis for evaluating the overall quality of construction at CPSES."[159] The summary also states "(f)urthermore, the quality was relatively uniform throughout the various disciplines and CWCs. For example, in each discipline, more than 97 percent of the points subject to reinspection were determined to be in compliance with applicable design

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156 CER, Rev. 0, Part I, pg. 6 of 25.

157 CER, Rev. 0, Part I, Section 1.2, Pg. 2 of 25

158 CER, Part I, pg. 13 of 25

159 CER, Part I, Section 2.2, Pg. 8 of 25

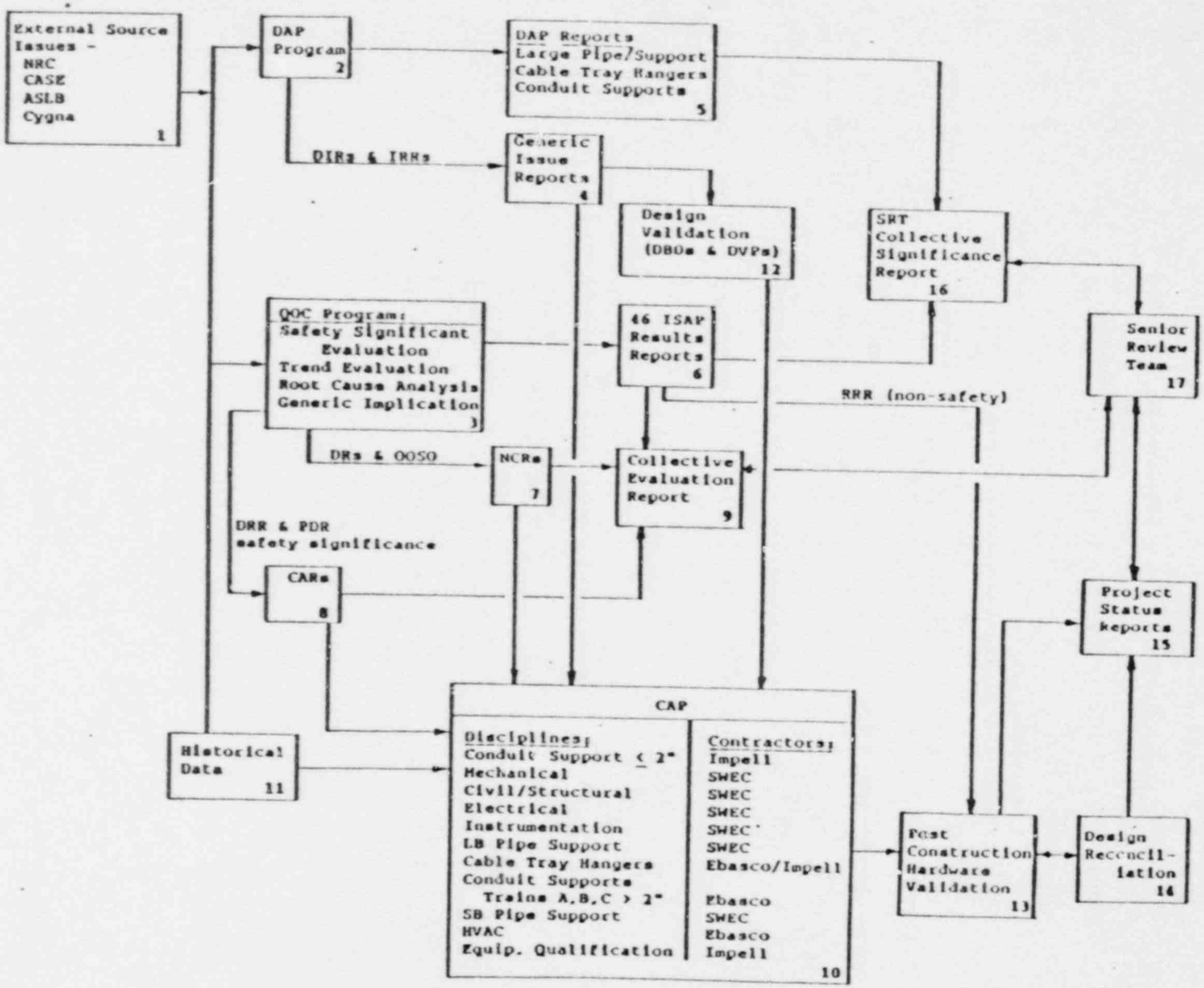

Figure 7-2. CPRT PROGRAMS

requirements."[160] However, the report goes on to discuss the two CWCs (lighting cable and hvac duct supports) that were removed from ISAP VII.c as adverse trends and the 73 construction deficiencies, adverse trends and unclassified trends identified in the ISAP. What is not discussed is that the statistics based on inspection points are not indicative of the true quality of the items inspected. Figure 7-3 of this report, Results of ISAP VII.c Hardware Reinspections, translates the results into a "per item" statistic. Several points are illustrated by Figure 7-3.

First, the 97% conformance rate per inspection point is highly sensitive to inspection point selection. The number of inspection points per item varies from three for the fuel pool liner to 1,250 for field fabricated tanks. HVAC Ducts and Plenums had 893 points per item and 100,000 total inspection points, thereby contributing over 20% of the total inspection point- a conformance rate of 98.6%. When these statistics are re on a "per item" basis, the 112 HVAC Ducts and Plenums represent less than 5% of the population, and there a average 12.21 deviations per item. Other examples c e significant difference in "per item" statistics are so contained in Figure 7-3.[161]

Second, when "per item" statistics are calculated, it is not clear what criteria were used by the CPRT to declare Adverse Trends. Adverse Trends were declared for Lighting Cables and HVAC Duct Supports. The deviations "per item" for these CWCs were 5.96 and 12.18 respectively. Review of Table 7.3 indicates that five other CWCs had deviations per item greater than Lighting Cable: Field Fabricated Tanks (50.37), HVAC Ducts and Plenums (12.21), HVAC Equipment Installation (9.20), Instrument Tubing Supports (6.37), and Pipe Whip Restraints (10.52).

Third, when the percent of items with deviations is calculated, twenty of the 26 CWCs have greater than 10% of the items with significant deviations. Eight have greater than one deviation per item.

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160 CER, Part I, Section 2.2, Pg. 8 of 25

161 Based on information included in Tables 2.1 through 2.4, CER, Rev. 0

FIGURE 7-3. CPSES - RESULTS OF ISAP VII.C HARDWARE REINSPECTION(1)

CONSTRUCTION WORK CATEGORY	NO. OF SAMPLE ITEMS	TOTAL INSPECTION POINTS	INSPECTION POINTS PER ITEM	TOTAL DEVIATIONS	PERCENT INSPECTION POINTS CONFORMING	DEVIATIONS PER INSPECTION POINT	AVERAGE NO. OF DEVIATIONS PER ITEM	AVERAGE(2) NO. SIGNIF. DEVIATIONS PER ITEM
CONDUIT	147	3,000	20	56	98.1%	1.87%	0.38	0.095
CABLE TRAY	102	20,000	196	70	99.6%	0.35%	0.69	0.172
CABLE	374	8,700	23	196	97.7%	[illegible]	0.52	0.131
ELECT EQUIP INST	99	17,000	172	78	99.5%	0.46%	0.79	0.197
INSTR EQUIP INST	167	7,100	43	160	97.7%	2.25%	0.96	0.240
LB PIPE CONFIG	100	6,000	60	120	98.0%	2.00%	1.20	0.300
SB PIPE CONFIG	103	3,700	36	164	95.6%	4.43%	1.59	0.398
PIPE BEND FABR	94	630	7	2	99.7%	0.32%	0.02	0.005
PIPE BOLTED JTS	108	7,700	71	18	99.8%	0.23%	0.17	0.042
PIPE WELDS/MTLS	187	3,000	16	7	99.8%	0.23%	0.04	0.009
TUBE WELDS/MTLS	101	1,500	15	2	99.9%	0.13%	0.02	0.005
FIELD-FAB TANKS	8	10,000	1,250	403	96.0%	4.03%	50.37	12.594
HVAC DUCTS/PLENMS	112	100,000	893	1367	98.6%	1.37%	12.21	3.051
HVAC EQUIP INSTLN	180	50,500	281	1656	96.7%	3.28%	9.20	2.300
MECH EQUIP INSTLN	170	15,040	88	882	94.1%	5.86%	5.19	1.297
CONCR PLACEMENT	154	4,400	29	62	98.6%	1.41%	0.40	0.101
STRUCTURAL STEEL	143	35,600	249	810	97.7%	2.28%	5.66	1.416
CONT & SS LINERS	90	870	10	68	92.2%	[illegible]	0.76	0.189
FUEL POOL LINER	90	250	3	10	96.0%	4.00%	0.11	0.028
LB SUPTS-RIGID	91	21,500	236	330	98.5%	1.53%	3.63	0.907
LB SUPTS-NONRIGID	82	32,000	390	454	98.6%	1.42%	5.54	1.384
SB PIPE SUPTS	78	11,500	147	111	99.0%	0.97%	1.42	0.356
INSTR TUBE SUPTS	140	24,500	175	892	96.4%	3.64%	6.37	1.593
PIPE WHIP RESTR	153	73,700	482	1610	97.8%	2.18%	10.52	2.631
EQUIP SUPPORTS	70	17,000	243	278	98.4%	1.64%	3.97	0.993
CONDUIT SUPPORTS	155	12,900	83	94	99.3%	0.73%	0.61	0.152
SUBTOTAL	3298	488,090		9,900	98.0%	2.03%	3.00	0.750
ADVERSE TRENDS								
LIGHTING CABLE	24	3,900	163	143	96.3%	3.67%	5.96	1.490
HVAC DUCTS/SUPTS	180	31,700	176	2192	93.1%	6.91%	12.18	3.044
SUBTOTAL	204	35,600		2,335	93.4%	6.56%	11.45	2.862
TOTAL	3502	523,690	150	12,235	97.7%	2.34%	3.49	0.873

NOTES:

1. BASED ON TABLES 2.1 - 2.4, CPRT COLLECTIVE EVALUATION REPORT, REV. 0

2. ASSUMES ONE-FOURTH OF DEVIATIONS ARE SIGNIFICANT AND ARE UNIFORMLY DISTRIBUTED OVER SAMPLE. NUMBER WOULD BE SMALLER IF DEVIATIONS ARE NOT UNIFORMLY DISTRIBUTED.

7.4.4 Actual Modifications Reported in Results Reports

The Collective Evaluation Report[162] is a report to the Nuclear Regulatory Commission on the status of compliance with the NRC's requirements. Therefore, the CER is sprinkled with conclusions that "upon satisfactory implementation of the corrective actions..." [163] or "Upon completion of all the corrective actions recommended by the CPRT, including those resulting from collective evaluation, there will be reasonable assurance..." [164]

The actual number of modifications required by the CPRT ISAP reviews is not included in the summary information. However, the CER reports that modifications were required for ISAPs:

I.a.1	Shrinkable Cable Insulation Sleeves
I.a.2	Butt Splices
I.b.2 and I.b.4	Electrical Separation
II.c	Air Gap Between Concrete Structures
VI.a	Air Gap Between RPV Insulation and Biological Shield
VII.b.3	Pipe Supports
VII.b.4	Concrete Expansion Anchors
V.b	Steam Generator Upper Lateral Supports

The Design Adequacy Program was explicitly excluded from the CER. However, deviations identified in the ISAP VII.c inspections that dealt with systems or items being reworked under corrective actions identified in the DAP or CAP were not included in the reported statistics. Therefore, Figure 7-4 was included to give some indication of the modifications required by the design review. Even allowing credit for the items that were identified as modifications to implement recent industry practice, the design review led to modifications of significant portions of the hangers and supports that were subject to the review.

In Supplemental Safety Evaluation Report 14, the NRC provides its first indication of the acceptability of the CPRT program. The report covers large and small bore piping and pipe support activities. In the Staff Evaluation, following a discussion of the deficiencies in the historical QA program Design Change Interface Controls, the NRC Staff states, "(i)n the discussion

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162 CPRT Collective Evaluation Report, Revision 0, December 23, 1987 (M01552)

163 CER, Part I, Page 13 of 25

164 CER, Part I, Pg. 25 of 25

FIGURE 7-4

CPSES- Results of CAP Project Status Reports
Unit 1 and Common

CAP Discipline	Sample Population	No. of Modifications	Less RIP (1) Modifications	No. of Real (2) Modifications	Percent Modified
SB Pipe Supports	6,630	1896	626	1270	19.2%
LB Pipe Supports	12,020	5621	1883	3738	31.1%
Cable Tray Hangers	7,566	874			11.6%
Cable Trays	100% (3)	93			
Conduit Supports Train A,B&C>2"	30,000	8300			27.7%
Conduit Supports Train C≤2"	105000	600			0.6%

1. Recent Industry Practice

2. Modification made because of past practices, no differentiation made between major and minor modifications

3. All cable trays in Unit 1 and common

above on the underlying cause for the piping and pipe support design problems, it follows that a detailed review of all pipe support design, as a minimum, would be required to identify potential design deficiencies."[165] The Staff continues, "(b)ased on the many modifications SWEC has developed for the pipe support designs, the staff has confidence that the design validation process does not cause the same degree of pressure to accept the installed designs which the original architect-engineer may have experienced."[166] The NRC Staff bases its acceptance of the redesign primarily on the "degree to which design changes are being made."[167] The NRC Staff also reserve judgement on the implementation of the Post Construction Hardware Validation Program (PCHVP). "However, the acceptability of the specific attributes to be inspected or excluded from the PCHVP will be reviewed in detail by the staff at a later date."[168]

7.4.5 Implications for the Quality Assurance Program

The CPRT specifically reviewed the historical and current QA programs. The overall conclusions state, "weaknesses were identified in limited areas of the QA Program related to Criteria I, II, V, VII, X, XV and XVIII."[169] These "limited areas" are notably not listed by name. They are:

I.	Organization
II.	Quality Assurance Program
V.	Instructions, Procedures, and Drawings
VII.	Control of Purchased Material, Equipment, and Services
X.	Inspection
XV.	Nonconforming Material, Parts, or Components
XVIII.	Audits

Considering that the Design Criteria were specifically excluded from this evaluation[170], the extent of the deficiencies in the Historic QA Program can hardly be considered limited. In evaluating the reasons for the deficiencies, the CPRT found them

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165 NUREG 0797, Safety Evaluation Report Supplement Number 14, dated March 1988, page 5-3.

166 SSER 14, pg. 5-4.

167 SSER 14, pg. 5-4.

168 SSER 14, pg. 4-14.

169 CER, Rev. 0, Part VI, Pg. 2 of 3

170 CER, Rev. 0, Part VI, Pg. 2 of 3

to be directly related to "lack of nuclear and quality assurance experience on the part of (TU) management and supervisory personnel."[171]

The results of the evaluation in ISAP VII.c are also significant if viewed in the light of the QA Program. The "Inspection Points" for ISAP VII.c were selected to ensure only points that had already been inspected and accepted by QC inspectors were reinspected. Each deviation identified is a criticism of the QA program. While 100% perfection is not expected, a high level of conformance to design requirements for QC accepted items certainly would be. Reviewing the "deviations per item" of Figure 7-3 indicates a system not up to standards as recognized by the CPRT conclusions.

In SSER 14 the NRC identifies the QA Program deficiencies that resulted in the need for a detailed design review. The NRC Staff then relies on the large number of design changes being made as indication that the earlier problems have been corrected. This also indicates an inadequate QA Program.

7.5 Conclusions on CPRT Results

The CPRT relies on the statistics generated by ISAP VII.c to paint a distorted picture of the results of the evaluation. The items being reinspected in other ISAPs were excluded. Remember that the other 46 ISAPs were initiated to address specific areas of concern raised by outside entities and therefore presumably MORE likely to result in deficiencies. Many inspection points were transferred into ISAP I.d.1, Inspector Qualifications, therefore eliminating points that were more likely to have been inspected by an unqualified QC inspector. Finally, two CWCs displaying high deviation rates were removed from the population and declared Adverse Trends, essentially halting inspection of those points for the other CWCs. Therefore, a population that should already have been free of significant error was systematically stripped of any likely source of error, inspected, and then used as the primary basis for statistics.

Even after this culling process, a number of deviations were identified for each item inspected. Seventy-three Construction deficiencies, Adverse Trends, and Unclassified Trends were identified in ISAP VII.c alone. The Executive Summary states, "The approach taken to implement the definition of a construction deficiency would result in the identification of construction deficiencies for items that did not meet code-allowable limits, but that would not have failed under design loading conditions; and for deviations that, if left uncorrected, would not have resulted in a failure of any structure, system, or component to

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171 CER, Rev. 0, Part I, Page 19 of 25

perform its intended safety function."[172] In our review of the ISAP VII.c backup documentation, we found the opposite to be true. A construction deficiency was not declared until all reasonable methods of engineering analysis available to the CPRT review team were exhausted. If the deviation could be shown not likely to result in the failure of a structure or system, even if it did exceed code allowables, then it was declared "insignificant" and removed from the system. Still the evaluation resulted in 73 findings and significant corrective action.

The inconsistency in TU's approach is demonstrated further by the fact that Revision 0 of the CPRT Collective Significance Report was published in February 1988 - before all, or even most, of the CAP is completed.[173] The report acknowledges that the CPRT/SRT overviewing is still going on.

Essentially the same observations can be made about the CPRT Collective Evaluation Report, Revision 0.[174]

Both of these reports present a number of sweeping conclusions, represented to be the "CPRT's", about the adequacy of the CPSES design and construction, yet the CPRT has not yet finished all its assigned functions.

From the point of view of the NRC, this effort combined with the still to be conducted Post Construction Hardware Validation Program may be enough to demonstrate compliance with licensing requirements. What the program results are also demonstrating is that before the CPRT, DAP and CAP, CPSES was definitely not in compliance with regulatory requirements. Significant reevaluation and rework has been required to bring the plant up to its current level of compliance and more is likely prior to licensing.

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172 CER, Rev.0, Part 1, Pg. 4 of 25

173 CPRT Collective Significance Report, Revision 0, February 26, 1988 (M01585)

174 CPRT Collective Evaluation Report, Revision 0, December 23, 1987 (M01552)

8.0 Conclusions on TU Implementation of the QA Program at CPSES

In conducting our review and drawing our conclusions we were careful to evaluate the Quality Assurance program at CPSES from the earliest records of design and construction activities. From this review we determined that the history of CPSES could be classified in three phases, as described in Section 5.2. These are Phase I, Rigorous Application of QA; Phase II, The Cooperative Phase; and Phase III, The Response Team Phase. We concluded that TU management priorities in Phase II were overwhelmingly concerned with completing construction in the most expeditious manner. Part of the result of these priorities was ensuring that the QA organization adopted an attitude of "cooperation" with construction to maintain schedule and hold down costs.

These management priorities were manifested in several ways, but the most significant in terms of QA were replacement of the QA Manager and QA Site Supervisor, dissolution of the Quality Surveillance Committee, and the decision to implement a process to review field generated design changes after the changed design had all ready been constructed (after-the-fact design review.) The new QA management was determined to cooperate with construction to maintain schedule. When deficiencies were noted by internal audits, NRC inspections, or third party reviews, the response of the QA managers was either to fix only the specific deficiency, or if pushed to resolve the growing problems associated with changing designs in the field, to postpone review and resolution until the "final design review and verification."

These practices led to three types of deficiencies: actual hardware deficiencies that had to be reworked; designs that did not meet the applicable requirements but which could be reanalyzed and used without modification; and hardware and designs for which sufficient documentation could not be located and actual measurement and testing of installed equipment and components had to be made to verify that the installed equipment was adequate.

From the point of view of protecting health and safety there are no significant differences between these three deficiencies. Before a nuclear power plant can be operated there must be positive evidence that it meets rigorous safety standards. The consequences of an accident are too great to permit any other approach. Not only must the hardware be correct, but the utility must be able to demonstrate that it is right. By adopting the "after-the-fact" design review, TU intentionally delayed the review and verification of the conformance between the as-built hardware and the design specifications as required by the NRC.

In 1984 the Atomic Safety and Licensing Board required TU to prove that the plant did indeed meet these requirements. The investigations by the NRC, TU and independent contractors led to the formation of the Comanche Peak Response Team. In carrying out the review of design documentation and as-built verifications within the scope of CPRT, TU is finally performing the "after-the-fact" design review that had been promised since 1977. The attendant cost, delay, and rework that is the direct result of this program stems directly from the liability that TU specifically accepted repeatedly in 1977, 1978, 1982 and 1983.

We conclude that TU subordinated the Quality Assurance program to the priority of maintaining project schedules and holding down costs. As a result of this Quality Assurance managers adopted a "cooperative" attitude toward construction and implemented a program of "after-the-fact" design review. The evaluation, rework and delay are attributable to the liability accepted by TU management as a result of the QA approach during the "cooperative" phase.

Appendix A

THE DEVELOPMENT OF NUCLEAR QUALITY ASSURANCE WITHIN THE NUCLEAR INDUSTRY AND ITS DEVELOPMENT AT COMANCHE PEAK

1. THE ROLE OF QUALITY ASSURANCE IN DESIGNING, CONSTRUCTING, AND LICENSING A NUCLEAR POWER PLANT

This Appendix is intended to familiarize the reader with the basic history and concepts of quality assurance and quality control. It is not an in depth treatment of the subject by any means. The appendix discusses the concept of quality assurance, explains the need for quality assurance, and describes the components of a nuclear quality assurance program. To accomplish this task, we define quality assurance and its constituent parts, explain the importance of quality assurance, and describe the development of industrial quality assurance and then more specifically the development of nuclear quality assurance. We then discuss the development of the QA program for Comanche Peak.

A Definition of Quality Assurance

An understanding of quality must start with a definition of the term. The American Society for Quality Control employs the following definition:

> Quality Assurance: A system of activities whose purpose is to provide assurance that the overall quality control job is in fact being done effectively. The system involves a continuing evaluation of the adequacy and effectiveness of the overall quality control program with a view to having corrective measures initiated where necessary. For a specific product or service, this involves specifications, audits, and the evaluation of the quality factors that affect the specification, production, inspection, and use of the product or service.[1]

Note that this definition includes the concept of quality control. Here again, a definition is necessary. The ASQC definition is:

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1 "Glossary of general terms used in quality control." Proposed 1969 Revision, ASQC Standard A3. Quality Progress, July 1969.

Quality Control: The overall system of activities whose purpose is to provide a quality product or service that meets the needs of users; also the use of such a system. The aim of quality control is to provide quality that is satisfactory, adequate, dependable, and economic. The overall system involves integrating the quality aspects of several related steps including: the proper specification of what is wanted; production to meet the full intent of the specification; inspection to determine whether the resulting product or service is in accord with the specification; and review of usage to provide for revision of specification.

The purpose of having quality control is to insure that the processes involved in production are in control and meet the established requirements and specifications. Quality control requires the processing of information provided from inspection and then acting to correct inadequacies in the production process such as incorrect standards, inadequate procedures, or incorrect implementation of procedures. Thus, quality control can be an effective tool for mitigating losses by:

- reducing defective parts which must be scrapped,
- eliminating rework or correction of defective parts of systems, and
- improving the efficiency of inspection resource allocation.

Quality assurance is used to "ensure that each department in the organization carries out its duties towards the achievement of good end-product, and can be seen to have done so."[2] This activity is basically management oversight of quality control and making sure that quality is what it should be. Thus, any management action which can enhance the quality of production by improving the established quality standard or quality control will save resources or will result in a more valuable end-product. The underlying emphasis of this definition is that quality assurance is not an end in itself, but rather, it is only one part of an overall management philosophy.

The Development of Quality Assurance

Although the term was not used until the 1920s, quality assurance or portions of a quality assurance program were in place for years. Pure common sense told early manufacturers to modify the

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2 Nixon, Frank,"Managing to Achieve Quality and Reliability," (New York, N.Y.: McGraw-Hill Book Company, Inc., 1971), p. 201.

manufacturing process or the product specifications when the production process resulted in unusable parts. Prior to World War I, the British airplane manufacturing industry established the first formal system for assuring quality. In 1914, the Aeronautical Inspection Department (AID) of the Royal Flying Corps developed a system for document and process control. AID, as a representative of the customer, defined the requirements needed for AID approval and subsequent purchase. AID insisted not only upon conformance of the final product with specifications, and also required the processes to be conducted in accordance with their requirements. Records of all assembly drawings, processes and standards had to be retained, and any change to these records required AID Inspector approval. Thus, AID established the basic requirements for quality assurance.

Subsequently, in the 1920s Bell Labs formed a Quality Assurance department to ensure economic production of telephone handsets (which were being manufactured at a rate approaching 10 million handsets per year) and to assure customer satisfaction with the quality of the product. Dr. R.L. Jones, the head of this department, defined the duties of the department to be:

- To develop the theory of inspection, statistical methods, and new principles.
- To develop methods of specifying the quality and establishing economic standards of quality of telephone equipment.
- To maintain oversight of the quality of outgoing goods.
- To study the performance of equipment in service and to guide the steps taken to prevent recurrence of trouble.[3]

One member of this department, W.A. Shewhart, succinctly defined the basic tenets of quality assurance:

> The control of quality of manufactured product involves three co-ordinate functional steps: the specification of the aimed-at standard of quality; the production of pieces of product that will be of standard quality; and the determination of whether or not product thus made is of standard quality.[4]

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3 Nixon, Frank,"Managing to Achieve Quality and Reliability," (New York, N.Y.: McGraw-Hill Book Company, Inc., 1971), p. 29.

4 Shewhart, W.A. "Nature and origin of standards of quality.:Bell System Technical Journal, No. 1, Vol. XXXVII, January 1958, reproducing a paper dated 1935.

Thus, the fundamental aspects of quality assurance had been established fifty years ago. Subsequent efforts focussed on the development of quality assurance program components. Many of these early efforts were mainly preoccupied with statistical methods for measuring quality in large scale manufacturing processes, while ignoring the fundamental concept that quality assurance is a goal and esponsibility of the entire organization.

In 1951 with the publication of J.M. Juran's "Quality Control Handbook" and Dr. A.V. Feigenbaum's book "Quality Control" emphasizing the role of management, managers returned to the realization that quality assurance is the responsibility of the entire organization. The U.S. Department of Defense (DOD) reinforced the concept with the publication in 1959 of possibly the most influential treatise on quality assurance. Specification MIL-Q-9858 "Quality Program Requirements" made it incumbent upon defense contractors to have a system for controlling production and documenting quality. DOD did not require a specific organization or method. It specified the elements of an effective program and the information needed to meet the requirements of the consumer, DOD. This document provided a basis for the QA requirements ultimately adopted by the NRC.

Thus, the basic need for quality assurance and its purpose was established early in this century. Later developments reaffirmed the original concept of quality assurance and identified the components needed to achieve the requisite quality and satisfy the requirements of the consumer.

The Development of Nuclear Quality Assurance

Under the leadership of Admiral H.G. Rickover, the U.S. Navy embarked on a nuclear program in the 1950s. Because a system failure could not only handicap or disable a vessel in performing its mission, but could also cause a loss of the vessel and its crew, insuring the safety and reliability the product was a prime concern. Furthermore, this was the first venture into the nuclear field, and a setback could damage this new concept beyond repair. Therefore, Admiral Rickover required standards of quality oversight far higher than had ever been used before. This does not necessarily mean that a nuclear quality assurance program is any different than other industry QA programs. It only means that a nuclear QA program has more exacting standards and specifications to achieve.

In essence, the program employed by the Navy incorporated the same fundamental aspects of quality assurance established by Bell Labs and the British aircraft industry. The definitions for quality control and quality assurance in the previous section also apply to nuclear quality assurance. The major differences with nuclear quality assurance are the extremely high standards that are established both for the specifications of the product and for the quality control and quality assurance efforts. More stringent specifications and more rigorous inspection and testing are imposed. For example equipment necessary for safe operation and shutdown of a reactor is tested in the harshest environments under the greatest stress that could conservatively be expected to occur during the life of the plant.

The quality mission for a nuclear power plant is to produce a safe, reliable, and economical product. The overriding emphasis is on the first attribute, safety, because if there is an accident not only is the product damaged or lost but also there may be loss of life and damage to the surrounding environment. Reliability is in a sense a subcategory of safety. For instance, if the power system fails while a submarine is making a deep dive, the submarine and the men operating it may be lost. Cost definitely takes a back seat to safety and reliability because (a) the consequences of a failure are so severe and (b) a product cannot be economical if it is unsafe or unreliable.

For the nuclear navy this was dramatically and tragically demonstrated in April 1963 when the nuclear submarine, Thresher, was lost at sea. After reviewing the accident the Navy determined that many provisions of the nuclear quality assurance program if applied to critical, non-nuclear systems would improve the reliability (and certainly the safety) of those systems and consequently of the entire submarine. When the transcripts of the hearings held before the Congressional Joint Committee on Atomic Energy were declassified and published, Senator Pastore, Chairman of the Committee, included some telling conclusions in the Foreword.

> Basically, the ship was built to two standards. The standards of design and construction for the nuclear power plant were more stringent than for the rest of the ship. Of particular note is that the technical specification requirements were not greatly different, but that adherence to them was far more strict for the nuclear powerplant than for the rest of the ship.
>
> It now appears that the cost to upgrade our submarine program will be greater than if at the outset the higher standards comparable to those used in the nuclear powerplant had been adopted throughout the ship.
>
> The lesson is obvious. There is no substitute for proper attention to quality of material and workmanship in the first instance. The initial extra costs which may be involved will eliminate much greater additional

> expense later on but much more importantly, it could mean the saving of the lives of the men who man our submarines.[5]

In response to this tragedy the Subsafe program was developed, essentially expanding the concepts and procedures of the nuclear QA program to Balance-of-Plant systems.

Quality Assurance in a Regulated Nuclear Industry

Quality Assurance in the nuclear energy industry differs from other industries for several reasons. First, because a significant quality failure could result in a nuclear accident with potentially serious effects, the U.S. Government required in the Atomic Energy Act of 1954 that all nuclear power plants be built to exacting safety standards developed by the Atomic Energy Commission (later Nuclear Regulatory Commission).[6] Because the Atomic Energy Act also specified that the regulations governing development of nuclear power plants should be "the minimum consistent with achieving the safety goal," the utilities were left to choose the methods that they would use to meet the regulations.

The basic philosophy of the NRC is that the utility constructing and operating a nuclear plant is responsible for protecting the health and safety of the public. The NRC plays a fundamental role in establishing the requirements for the design, construction and operation of these plants. A significant part of the utility's responsibility is assuring that the safety standards established by the NRC are carried out in design and construction of the plant. Therefore, the NRC inspects facility design, construction, and operation to assure that these activities are performed in accordance with approved principals so that the health and safety of the public will be protected. In effect, the NRC acts as a third party to the process.

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5 Transcript of Hearings Held June 23-27, 1963 and July 1, 1964 on the Loss of the Thresher, Congress of the United States, Joint Committee on Atomic Energy, Senator J. O. Pastore, Chairman, December 1964, p. viii.

6 Historical background drawn from the Report, "Improving Quality and the Assurance of Quality in the Design and Construction of Commercial Nuclear Power Plants - A Report to Congress", U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, 03/19/84, Rev. 4, Section 1.3.

Another difference to be considered is that a large construction project, like a nuclear plant, is not subject to the same consumer forces assumed in the development of classic quality assurance program guides like Juran's. Juran defines the basic quality mission to be "meeting the quality wants of specific consumers through specific products."[7] In a large project most activities are not directed at repetitively producing the same product. Therefore, it is not possible for the "consumers" to react to a degradation in the quality. The constructing utility must be aware that poor quality will lead to repair or rework to meet the safety standards set by the NRC. Since this will lead to increased costs, poor quality assurance can lead to a financial impact on the utility when the plant is completed. The utility must therefore be aware that the quality assurance program is a means for management to receive feedback on the quality progress of the design and construction before the economic consequences are too great.

In summary, a quality assurance program, as applied in the manufacturing and construction industries at large, is a management tool which can improve the quality of the final product and reduce the cost of making the final product. Furthermore, quality assurance is the responsibility of the entire organization. In designing, constructing, and licensing a nuclear power plant, an effective quality assurance program can improve the quality of the as-built plant, control the design and construction processes to eliminate costly mistakes requiring rework or reinspection, and provide documentation confirming the quality of the plant. By meeting the first two objectives of the quality mission, reliability and safety, the utility avoids costly rework, correction of problems, and in some cases the loss of the entire power plant. Thus, any improvement in safety and reliability automatically helps in achieving the third goal of producing economic electricity.

Development of the Requirements for Nuclear Quality Assurance for Civilian Use of Nuclear Power

In July 1967, the Atomic Energy Commission (AEC) proposed the first regulation applying to quality assurance. AEC published for public and industry comment Appendix A to 10 CFR Part 50, "General Design Criteria for Nuclear Power Plants." Among the 55 criteria in Appendix A covering plant design, one criterion required a quality assurance program for certain structures, systems and components. Following review, public comments, and

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7 Juran, J.M., "Quality Control Handbook," 2nd ed. (New York, N.Y.: McGraw-Hill Book Company, Inc., 1961), p. 1-4.

subsequent revisions, Appendix A was issued as an effective regulation in February 1971.

Following publication of the July 1967 draft of Appendix A, the Atomic Safety and Licensing Board (ASLB) for the Zion Operating License Hearing noted, in 1968, the lack of AEC requirements and criteria for quality assurance. The ASLB ruled that until the licensee (Commonwealth Edison Company) presented a program to assure quality, and until the AEC developed criteria by which to judge such a program, the hearings would be halted. Following the Board's ruling, the AEC developed requirements and criteria for quality assurance programs and prepared a new regulation, Appendix B to 10 CFR Part 50, requiring licensees to develop programs to assure the quality of nuclear power plant design, construction and operation. In the fall of 1971, 10 CFR 50.34 was modified to require a description in the Safety Analysis Reports of a quality assurance program complying with the requirements of Appendix B.

In Appendix B to 10 CFR 50 the Nuclear Regulatory Commission formally defined quality assurance as comprising:

> ... all those planned and systematic actions necessary to provide adequate confidence that a structure, system or component will perform satisfactorily in service. Quality assurance includes quality control which comprises those quality assurance actions related to the physical characteristics of a material, structure, component, or system which provide a means to control the quality of the material, structure, component, or system to predetermined requirements.[8]

Stated more simply, quality assurance can be described as those actions necessary to assure that a component or system important to safety can perform its intended function. The key word here is safety. A functioning nuclear quality assurance program is necessary to assure the health and safety of the general public.

Appendix B listed 18 criteria that must be a part of the quality assurance program for safety-related systems and components. In developing these criteria, the AEC relied on the experience of the military, especially MIL-Q-9858, the National Aeronautics and Space Administration (NASA), and commercial nuclear projects, as well as the AEC's own nuclear reactor experience. Appendix B was published for comment in April 1969 and implemented in June 1970.

In addition to establishing QA regulations (i.e. Appendices A and

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8 10 CFR 50, Appendix B, Introduction.

B) in the early 1970s, the AEC and industry began issuing guidance that provided acceptable ways of meeting the requirements of the specific regulations. In October 1971, the American National Standards Institute (ANSI) issued Standard N45.2, "Quality Assurance Program Requirements for Nuclear Power Plants." This standard was subsequently endorsed by the AEC in Safety Guide 28 (now Regulatory Guide 1.28) in June 1972. In 1973-1974, the AEC issued three guidance documents, referred to as the Rainbow Series WASH documents, for quality assurance in design and procurement, construction, and operations to help licensees establish QA programs. These WASH documents frequently reference ANSI N45.2. In July 1973, two AEC Commissioners and senior AEC staff participated in a series of regional conferences with utilities to explain the role of quality assurance in designing, constructing, and operating nuclear power plants and the AEC's role in licensing, inspecting, and implementing licensee's quality assurance programs. Since 1970, as the nuclear industry grew, as experience was gained in nuclear regulation, and as the need for such guidance was recognized, many consensus standards and AEC/NRC Regulatory Guides have been developed and published to address various aspects of quality and quality programs. Again, most of these Guides endorse the ANSI standards with minor modifications. All of the ANSI N45.2 Series standards which are commonly applied to the construction of nuclear power plants had been officially issued by 1978 -- after having been available in draft form for one or more years prior to issuance. All of the AEC/NRC Regulatory Guides related to these standards were issued by 1980. Only a few revisions have been made to these standards and Regulatory Guides since their initial issuance.

All of these documents, ANSI and ASME standards, Regulatory Guides, and WASH documents, are only guidance on acceptable methods of meeting the requirements of Appendix B. They describe acceptable methods to achieve the basic, long established objectives of a quality assurance program; they do not describe any new requirements for quality assurance programs. The only requirement is 10 CFR Appendix B, and Appendix B is based on the program developed by the military in 1950s. Therefore, the concept of quality assurance has not changed significantly for over 25 years.

2. Responsibilities and Relationships under the QA Program

This section discusses the general responsibilities of the applicant utility in developing a QA program and the role of the NRC in reviewing the applicant's proposed QA program and the implementation of the program.

Appendix B to 10 CFR 50 states, "The applicant shall be responsible for the establishment and execution of the quality assurance program. The applicant may delegate to others, such as contractors, agents, or consultants, the work of establishing and executing the quality assurance program, or any part thereof, but shall retain responsibility therefor." Clearly this places the responsibility for quality on the applicant. Moreover, as shown in Sections 1.1 and 1.2, the achievement of quality is definitely the responsibility of management, in this case the applicant, and management cannot abdicate that responsibility. In contrast, the purpose of the quality assurance organization is to assure that the defined quality specifications have been met. Therefore, the applicant does not have to be directly involved in a day-to-day fashion in assuring quality but is ultimately responsible for assurance and achievement of quality.

The primary objective of the NRC's program for the [illegible]rance of quality is to provide assurance to the NRC, the pu[illegible] and the Congress that nuclear power plants that are licensed to operate have met the applicable legal requirements and are designed and built in a manner consistent with the health and safety of the public. The NRC achieves this objective by inspecting facility design, construction, and operation (For a thorough description of the NRC's inspection program see Appendix D.). Regarding the quality assurance program of the applicant/licensee, the NRC inspects the program against the requirements of Appendix B and the commitments made by the applicant in its QA program description, Chapter 17 of the Safety Analysis Report.

Following is a general discussion of the applicant's and contractors' roles and responsibilities in developing and implementing a QA program.

2.1. The Development of the QA Program

Two NRC authorizations are required by statute before a utility can build and operate a nuclear power plant:

(1) Before construction may begin, the Company must obtain a Construction Permit from the NRC. The Construction Permit is issued after NRC review of the Company's application which sets forth the principal safety features of the site and the plant.

(2) Before nuclear fuel may be loaded into a completed

nuclear power plant and the plant operated to generate electricity, the utility must obtain an Operating License from the NRC.

The processes involved in obtaining these authorizations are similar. The utility submits an application for each authorization and provides the NRC with a description of the facility and the plans for its operations, and with financial and other required information. This includes a detailed technical analysis of the safety and environmental impact of the facility. Technical and environmental information are submitted in documents referred to as a Preliminary, and later Final, Safety Analysis Report (PSAR and FSAR) and in a separate Environmental Report (ER). Chapter 17 of the Safety Analysis Reports contains the applicant's description of its QA program.

The development of the SAR is the responsibility of the Project Manager of the applicant. Generally, the preparation of Chapter 17 is delegated to the Quality Assurance Manager. In Chapter 17 of the application, the applicant must describe how each criterion of Appendix B will be met.

In preparing this description, the applicant has available a number of guides. The current revision of Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants", describes the requested content and arrangement of the SAR. This document aids the NRC in reviewing the application because it establishes the location where required topics should be addressed and the specific information needed by the NRC. NRC document, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", is used by the NRC staff in reviewing the SAR submitted by the utility. NUREG-0800 is keyed to the format prescribed in Regulatory Guide 1.70 and describes the areas to be reviewed and the NRC acceptance criteria. Chapter 17 of NUREG-0800 provides guidance for the NRC staff review and acceptance of the applicant's QA program. Representatives from the NRC will normally meet with the applicant approximately a year in advance of tendering the SAR to provide a clear understanding of what is expected in the program description and in the implemented program.

The Standard Review Plan (NUREG 0800) is a valuable guide for the applicant in preparing the description of the QA program. Among other items, the document specifies the applicable Regulatory Guides and NRC Regulations. The acceptance criteria include a commitment to comply with the NRC Regulations and the regulatory positions presented in Regulatory Guides. Provided adequate justification is supplied by the applicant, the NRC may accept alternatives providing a level of assurance or protection equivalent to the recommended practice.

The Standard Review Plan specifically states that the requirements of Appendix B to 10 CFR Part 50 apply not only to the applicant but also to its principal contractors such as the nuclear steam supply system (NSSS) vendor, the architect/engineer (A/E), constructor, and construction manager. Therefore, the principal contractors need to have an approved QA program, and the SAR must also describe how their respective QA programs, in addition to that of the applicant, will meet each criterion of Appendix B.

As noted earlier the applicant can delegate portions of the QA program. The Standard Review Plan also includes the acceptance criteria for delegating QA program tasks. Under these circumstances, the applicant must describe how it will maintain responsibility for the overall QA program and how it will evaluate the performance of delegated work. The applicant must also identify the individuals or organizations within its organization responsible for the quality of delegated work.

In summary, the Standard Review Plan provides specific guidance on how to meet the requirements of Appendix B and on what to include in a description of QA program meeting those requirements.

2.2. The Role of the NRC in the Applicant's Development of the QA Program

In addition to meeting with the applicant to explain the NRC's expectations of what an acceptable QA program description should entail and providing QA program guidance documents, the NRC also reviews the QA program description and provides conclusions concerning the applicant's program. The NRC performs its review both prior to docketing the application for a Construction Permit and after docketing the application.

The pre-docketing review of the QA program description places particular emphasis on the areas of organization, QA program, design control, procurement document control, and audit (each of these areas is a criterion of Appendix B). The purpose of a pre-docket review is to ensure the applicant is controlling those activities which are in progress prior to the receipt of a Construction Permit, specifically design and procurement.

The post-docketing review of the PSAR:

> ... covers the QA controls to be applied by the applicant and principal contractors to activities that may affect the quality of structures, systems, and components important to safety. These activities include site testing and evaluation (starting with evaluation of exposed excavated surfaces, determination

of site characteristics, and testing), designing, purchasing, fabricating, constructing, handling, shipping, storing, cleaning, erecting, installing, inspecting, and testing.[9]

The NRC's review of the QA program described in the application for an operating license (the FSAR) does not involve evaluation of the QA program for the design and construction phase; therefore, a description for those activities does not need to be included in the FSAR. However, the applicant is still committed to perform all remaining design and construction activities in accordance with the program described in the PSAR. The NRC review of the FSAR focuses on operational safety. The review covers both the off-site and on-site "...QA controls to be applied to those activities that may affect the quality of items important to safety during the operation, maintenance, and modification of a nuclear power plant."[10]

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9 NUREG-0800, Chapter 17.1, Quality Assurance during the Design and Construction Phases, p. 17.1-2.

10 NUREG-0800, Chapter 17.2, Quality Assurance during the Operations Phase, p. 17.2-1.

3. DEVELOPMENT OF THE COMANCHE PEAK QA PROGRAM

This section describes the evolution of the Comanche Peak QA program. In subsection 3.1, we describe TU's process for developing and submitting the QA plan, including the implementing procedures, and the early interactions between TU and the NRC regarding the plan. Subsections 3.2. and 3.3. describe the QA program for the design and construction phase of Comanche Peak. In these subsections, we focus on the role of TU management and its prime contractors, the Architect and Engineer (A-E), the Nuclear Steam Supply System (NSSS) supplier, and the Constructor and Construction Manager, in the QA program.

3.1. The Development of the QA Program Description Contained in the Comanche Peak PSAR

3.1.1. TU Process for Preparing the QA Plan

The information presently available pertains to TU's development of the QA program description in the Safety Analysis Report. The preparation of Chapter 17 of the SAR is the responsibility of four principal individuals - the Project Manager-Nuclear Plants, the Project Engineer, the Project Nuclear Engineer, and the Manager of Quality Assurance.

The Project Manager-Nuclear Plants is responsible for building and licensing the plant and, therefore, is ultimately responsible for the preparation and submission of all licensing documents. In the area of QA he fulfills this responsibility by providing final approval of Chapter 17 of the SAR. In addition, he is responsible for maintaining the interface between TU and the NRC.

The Project Engineer coordinates the preparation and submission of all licensing documents and supports the Project Manager on licensing matters related to his specific project. The Project Engineer reviews the SAR and either recommends approval by the Project Manager or revision by the responsible engineer.

The Project Nuclear Engineer is responsible to the Project Engineer on all licensing matters, including preparation of licensing submittals, arrangement of licensing meetings, and interpretation of NRC requirements and industry codes. In the development of the QA program description, the Project Nuclear Engineer is only responsible for reviewing the section concerning operational QA; he is not involved in the review of the description of the QA program for the design and construction phase.

The Manager of Quality Assurance is responsible for assuring that the licensing submittals conform to regulatory requirements. He is directly responsible for the preparation of the description of the QA program for the operational phase and the description of the QA program for the construction phase, but only for those activities specifically undertaken by TU. For those activities delegated to its prime contractors, the contractors are responsible for preparing the QA program description to be submitted in the SAR. The Manager of QA does retain responsibility for reviewing the QA program descriptions developed by the prime contractors.

The preparation of the SAR follows a very simple and basic path. First, the Project Nuclear Engineer establishes a schedule for SAR preparation. The Manager of QA negotiates this schedule with the Project Nuclear Engineer and then prepares Chapter 17 of the SAR in accordance with the negotiated schedule and Regulatory Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, and the Standard Review Plan. The Project Nuclear Engineer reviews the application and submits it for approval to the Project Engineer. However, if the description of the QA program applies only to the construction phase of the project, the Project Nuclear Engineer is bypassed in the process, allowing the Project Engineer to receive the document directly from the Manager of QA. The Project Engineer reviews, revises, and approves the document. The document now is sent for review and approval to the Project Manager-Nuclear Projects. Although the Corporate QA Program description and the QA Plan identify the Manager-Nuclear Projects as the recipient and sender of all NRC correspondence, Figure 2.5-1B of the QA Plan[11] shows the Executive Vice President receiving the SAR from the Project Manager. The Executive Vice President then provides final approval and sends the document to the NRC.

Any questions by the NRC concerning the application are reviewed by the Project Manager who then passes the questions along to the Project Nuclear Engineer. Responses to these questions are prepared following the same path described above.

3.1.2. Development of the QA Program Description and Procedures

As described in Section 5.5.4.1.1, on February 15, 1973, NRC personnel held the initial TU Corporate Management Meeting.[12] The purpose of the meeting was to provide TU with a general introduction to the licensing and regulatory process and the NRC's systems. The NRC also explained specific requirements in several areas including quality assurance. The discussion of the

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11 CPSES Quality Assurance Plan, Effective April 25, 1974, p. TUD 00311303.

12 Inspection Report 73-01, February 15, 2973.

Appendix B requirements for a QA program covered:

- o The responsibilities of licensees.
- o Degree of involvement by the licensee.
- o Independence of the QA organization.
- o Involvement in the vendor programs.
- o Audit programs.
- o Programs for corrective actions.
- o Establishment of permanent documentation.[13]

The NRC emphasized the importance it places on QA/QC records in confirming the quality of the plant.

Because design and procurement activities are already underway before the NRC reviews and approves an applicant's description of its QA program in the PSAR, the NRC requires a pre-docketing inspection of the quality assurance program to ensure a satisfactory program is in place.[14] However, this requirement applied only to applications submitted after September 1, 1973, and the TU application was docketed July 20, 1973.[15] Therefore, the NRC performed several inspections prior to issuing a construction permit to determine "whether or not TUGCO had (a) performed the necessary planning and scheduling to assure the timely development and implementation of the quality assurance program, and (b) established and implemented those aspects of the quality assurance program concerning PSAR development, design, and procurement which are consistent with AEC requirements and the status of the project."[16]

The NRC conducted the first such inspection from December 3 through December 6, 1973.[17] The NRC found several deficiencies with the TU QA program and issued a violation. On February 21, 1974, TU issued its response to this report. As a result of the NRC's comments , TU made major revisions to its QA Plan, especially to the Auditing and Procurement Adminstration procedures. The QA Plan now stated that all procedures meet the requirement and intent of the applicable provisions of ANSI: N45.2, N45.2.9, N45.2.11, N45.2.12, and N45.2.13. Also, the Quality Surveillance Committee became responsible for reviewing the management of the QA program and program effectiveness.

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13 Inspection Report 73-01, February 15, 1973, p. 4.

14 NUREG 0800, Standard Review Plan for Safety Analysis Reports, November 1975.

15 Inspection Report 50-445-73-02, January 7, 1974.

16 Inspection Report 50-445-73-02, January 7, 1974, p. 4.

17 Inspection Report 73-02, January 7, 1974.

TU's response closed out many of the expressed NRC concerns; however, the NRC still felt several issues were not satisfactorily addressed.[18] The NRC requested that TU:

- o Change the QA Plan modifiers "applicable provisions of" to clearly state that all activities affecting quality will be in compliance with ANSI N45.2, N45.2.9, N45.2.10, N45.2.11, N45.2.12, and N45.2.13;
- o Revise the correspondence drawing, document, and file control procedure to describe the handling of quality assurance documents; and
- o Assure that all procedures pertaining to the QA Plan, such as minimum job qualifications and training of personnel performing quality work, are included or referenced in the QA Plan.

TU made the appropriate additions and revisions and the NRC closed out these items on June 28, 1974.[19] These were the last concerns the NRC raised prior to the issuance of the construction permit concerning TU's QA Program. However, the NRC still had several concerns over the QA programs of Gibbs & Hill and Brown & Root. The NRC found that G&H's QA policy and procedures were inadequate for the status of the project and QA program documents did not adequately commit to or address the ANSI N45.2 standards.[20] As a result of this finding, G&H made major revisions to its QA manuals including committing to the ANSI standards. This item was closed during by NRC inspections of December 6, 1974.[21]

The NRC also noted in Inspection Report 74-02 that B&R's QA Manual was undergoing revisions because TU found the manual did not sufficiently address the requirements of Appendix B to 10 CFR 50 and ANSI N45.2. TU approved the revisions to the B&R QA Program Manual and the NRC closed this issue in February 1975.[22] This item had the potential for delaying the start of work following the issuance of a construction permit for Comanche Peak. The NRC stated in Inspection Report 74-05 that the B&R QA Program Manual must be approved and issued for use prior to any work to be done under the LWA-2 or a construction permit.[23]

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18 Inspection Report 74-01, March 19, 1974.

19 Inspection Report 74-02, July 11, 1974.

20 Ibid.

21 Inspection Report 74-05, December 16, 1974.

22 Inspection Report 75-04, February 13, 1975.

23 Inspection Report 74-05, December 16, 1974.

B&R was also experiencing problems with the development of their QA/QC procedures. The NRC found a deficiency in Brown & Root's control of changes to and issuance of QA/QC procedures.[24] As a result, TU requested that:

> B&R review their commitments for preparation of written QA/QC and construction procedures, the requirements for such procedures and that they review the preparation schedule for timely preparation. Moreover, the letter requested that B&R schedule and audit of their field operations to assure the QA systems are established and that the required QA/AC [sic] and construction procedures are available prior to the initiation of work activities on any safety related items.[25]

Based on the above corrective actions, the NRC considered the issue resolved in December of 1974.

This section has specifically focused on the early stages of the program to try to establish if the program got started on the right foot or if much of the early work was performed without the use of approved manuals, instructions, or procedures thereby rendering the quality of the work indeterminate in the eyes of the NRC. Obviously, the project did experience problems with the timely development of QA procedures and plans. The design of the plant was approximately 40% complete, according to TU[26], before all of the necessary design control procedures had been issued. Sections 5.3.2 and 5.5.4 of this report present additional discussion of the NRC's views on the Comanche Peak QA program.

Further developments in the QA program are discussed in Sections 3.3, 4.1 and 4.2 of this Appendix.

3.2. <u>The Comanche Peak QA Program</u>

The description of the quality assurance program for Comanche Peak Steam Electric Station is contained in Chapter 17 of the PSAR. This description provides a broad overview of the program. The program is based on two documents referenced in the PSAR-the TUGCO/TUSI Corporate QA Program and the CPSES QA Plan. The <u>Corporate QA Program</u> manual establishes the quality requirements for the project, and the <u>QA Plan</u> interprets these requirements and defines specific procedures, methods, and techniques to meet the quality requirements.

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24 Inspection Report 74-04, November 19, 1974.

25 Inspection Report 74-05, December 16, 1974, p. 10.

26 Inspection Report 74-05, December 16, 1974, p. 5.

The design and construction of the Comanche Peak plant is divided among four principal groups, TU, Gibbs and Hill (G&H), Brown and Root (B&R), and Westinghouse. TU maintains overall responsibility for all activities, including design, procurement, fabrication, and construction, during the entire life of the project. As the A-E, G&H directs and guides engineering, design, and procurement. G&H also performed certain QA/QC surveillance functions. B&R as the constructor and construction manager for the project was the focal point for all construction activities. Westinghouse was the nuclear steam supply system supplier. TU divided the responsibility for quality assurance among each of these groups.

The TU QA program, as understood by the NRC, established essentially three levels for quality assurance and control:

(1) the organization responsible for services, structures, components, and materials shall also be responsible for providing the associated inspection services;
(2) in addition to inspection services, each principal contractor shall provide a surveillance or audit function by an independent organization; and
(3) the applicant [TU] will provide comprehensive surveillance and audit functions including continuous onsite surveillance.[27]

Following is a description of the roles each of these organizations and their respective personnel had in the quality assurance program for Comanche Peak during three separate periods.[28] We chose the periods to be pre 1978, 1978 to 1984, and 1984 to present. The first period encompasses the early development of the QA Program and Plan, the PSAR, and the FSAR. The discussion in this period includes the QA programs of TU and its prime contractors while in the later two periods the discussion focuses primarily on TU's QA program. In 1978, two activities resulted in significant alterations to the structure of the QA Program; TU took over management responsibility of site QA/QC activities, and MAC issued its report on the TU QA program resulting in several modifications to the program. The final period was chosen to coincide with the commencement of the Technical Review Team Inspections and the heating up of the ASLB operating license hearing. These periods roughly correspond to

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27 Comanche Peak Safety Evaluation Report, September 3, 1974, pp. 17-5 through 17-6.

28 This description is based on the information contained in the Comanche Peak PSAR, the CPSES QA Plan and the TUGCO/TUSI Corporate QA Program.

the Phase I, Phase II, and Phase III period, discussed in Section 5 of this report.

3.2.1. Pre 1978[29]

TU

The responsibility for the QA program starts at the top of the TU organization. The President of TUSI authorized the QA program, and thus, committed the organization to a quality program. The Vice President - Design and Construction, who reports to the President, maintains overall responsibility for power plant projects and assures conformance to the established QA program. Although these individuals retain ultimate responsibility for the project, the individuals directly involved in the assurance and achievement of quality are the Project Manager, Nuclear Plants, the Project Engineer, and the Manager, Quality Assurance.

The Project Manager, Nuclear Plants, is responsible for the engineering, design, procurement, and construction of all nuclear plants. The Project Manager assures conformance of TU, contractors, and vendors with the TU and project QA plans. In addition, the Project Manager reviews all licensing applications; therefore, he is responsible for assuring the QA program meets all licensing requirements. The Project Manager reports to the Vice President - Design and Construction.

The Project Engineer is a member of the administrative staff of the Project Manager, Nuclear Plants. The Project Engineer is the technical director and administrator of the plant. He serves in a similar function as the Project Manager but he is only responsible for his specific facility. He identifies the necessary licenses and supervises the submittal of all license applications. In addition, he is responsible for assuring project conformance with the TU and project QA plans.

The Manager of Quality Assurance is responsible for the development, implementation, and surveillance of the TU QA Program and the CPSES QA Plan. With the assistance of his staff and two committees, he monitors the performance of QA activities conducted by TU and its principal contractors, subcontractors, and vendors. The Manager of QA and his engineering staff have the authority to stop work in engineering, design, and construction. He reports on all administrative and technical matters to the President of TUSI and on certain appropriate issues to the Project Manager, Nuclear Projects. This reporting relationship exists in order to isolate the Manager of QA from cost and schedule influences. In addition, the Manager of QA

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29 This corresponds roughly to Phase I, as described in Section 5.2 of this report.

meets with the President and the Project Manager on a routine basis to review the performance of the project QA program and to address future QA plans.

The Design Review Committee and the Quality Surveillance Committee assist in the execution of the QA program. The Design Review Committee serves as an extension of the Project Engineer, who chairs the committee. The committee, in conjunction with the A-E, establishes the design criteria and reviews design criteria for compliance with the required quality, codes, standards, safety requirements, etc. The committee, which includes the QA Manager and other appropriate engineers, meets monthly and reports to the Project Manager of Nuclear Projects.

The Quality Surveillance Committee serves as an extension of the Manager of QA, who also chairs the committee. The committee monitors and audits the QA/QC programs of the A-E, equipment vendors, constructor, and subcontractors. The committee is responsible for assuring the plant is designed and constructed to appropriate quality levels. Each member of this committee is responsible for reporting his evaluation of the program or plan for which he had implementing responsibility. The results of the committee's quarterly meetings are reported through the Manager of QA to the President of TUSI.

<u>G&H</u>
Gibbs & Hill was responsible for providing engineering project management for the overall Comanche Peak Project and design and procurement services for the balance of plant. This included providing licensing support, conceptual design, drawings, specifications, bid evaluation, and QA for design and procurement and QA surveillance of vendors and construction site activities.

The G&H Project Manager directs and guides engineering, design, and procurement for Comanche Peak. He also ensures that QC procedures are complied with and enforced. To meet their quality goals and requirements, G&H maintains a separate QA Department. The department develops detailed QA procedures, audits engineering and design functions, and inspects site work and vendors. The QA Manager heads this department, and he reports to an Executive Vice President.

The QA department contains three subgroups, the Design Review Committee, the Vendor Surveillance Group, and the Site Surveillance Group. The Design Review Group is comprised of senior engineers who review G&H originated design work as well as design documents for systems which interface with G&H systems and are prepared by other outside organizations. The group also audits engineering and design activities. The QA Manager chairs this committee. The Vendor Surveillance Group is comprised of QA engineers and technicians experienced in factory processes, material certification, and welding. This group periodically audits vendors' shops and, if necessary, performs continuous surveillance. The Site Surveillance Group is comprised of technical personnel experienced in construction and QA. This group prepares QA surveillance procedures for erection, fabrication, construction, and installation of safety related equipment. The group also monitors site QA/QC and construction for compliance with quality requirements.

B&R

As the constructor and construction manager, Brown and Root is responsible for assuring the quality of all construction activities. The activities covered by B&R's QA/QC program include field procurement, fabricating, manufacturing, inspecting, cleaning, and testing. The B&R employee responsible for all construction activities is the Project Manager. The responsibility for assuring the plant is constructed to the required quality belongs to the Site Project QA Manager.

The Site QA Manager reports to a B&R corporate QA Manager on issues relating to quality assurance, quality control and personnel administration, and he coordinates with the Project Manager on general project administration and policy. The Site QA organization consists of QC inspection personnel who report to a QC Engineer who in turn reports to the QA Manager. The site QA staff are experienced in the areas of structural, mechanical, welding, electrical engineering, and inspection. The site QA organization is accountable to the corporate QA group and also to TU's Site Surveillance Group.

The B&R site QA organization has the responsibility and the authority by documented procedures to:

(1) approve various phases of work before actual work is initiated,
(2) prohibit the use of materials, equipment or components that do not conform to requirements,
(3) stop any work not being done in accordance with plans, procedures, or specifications, and
(4) require the removal of faulty construction with prior approval from the QA manager.[30]

The corporate QA Manager has the responsibility for vendor surveillance, audits, and shop inspection.

Reports of the QA activities of B&R are sent to the TU QA Manager and the B&R Senior Vice President for Power Engineering and Construction. Audit results are sent to TU, B&R, and G&H management.

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30 Comanche Peak Safety Evaluation Report, September 3, 1974, p. 17-14.

Westinghouse

Westinghouse was responsible for designing, engineering, manufacturing, and delivering two nuclear steam supply systems (NSSSs). In addition to assuring the quality of these activities, Westinghouse also was responsible for design verification in this area.

The Westinghouse quality assurance program is included in the PSAR by reference to the Westinghouse Topical Report WCAP 8370, "Quality Assurance Plan Westinghouse Nuclear Energy Systems." Because of its extensive experience as a NSSS supplier, Westinghouse functioned somewhat independently from the other prime contractors. However, there is interaction between the A-E and Westinghouse because the NSSS, along with the turbine generators, form the basis for the final plant design.

The Product Assurance Department of Westinghouse Pressurized Water Reactors Systems Division has the responsibility for developing quality control requirements and procedures for the NSSS and assuring these requirements and procedures are followed. The Product Assurance Department is on the same organizational level as other major departments within this division, and its manager reports directly to the Division General Manager. The department contains two groups: (1) the Product Assurance Systems Group which is responsible for records management and quality and reliability engineering and (2) the QA Group which is responsible for internal and external QA surveillance.

Westinghouse maintains three levels of control to evaluate its QA program.

> At the first level, process audits are conducted by Nuclear Energy Division and by other divisions to assure functional areas are adequately considered. At the second level is the WNES [Westinghouse Nuclear Energy Systems] QA Committee, providing WNES management assurance that QA policies and practices of the division result in products and services that meet safety and reliability requirements. At the third level is the Headquarter's Quality Control Staff, organizationally independent from the Westinghouse Power Systems Company reporting directly to Westinghouse corporate management on the effectiveness of the QA programs of all divisions in the corporation.[31]

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31 Ibid., p. 17-12.

3.2.2. 1978 to 1984[32]

As a result of TU taking over technical management of site QA/QC from B&R[33] (except for activities under the jurisdiction of ASME Section III) and the issuance of the MAC Report on the TUGCO QA Program Audits[34], the QA Program underwent several changes.

As a result of these changes, the TUGCO Executive Vice President and General Manager maintained ultimately responsibility for the entire QA program. He was to monitor program activities and effectiveness by reviewing audit reports, inspection reports, design reviews, and briefings with the Manager, QA. TU divided the responsibility for the actual quality of the project among three entities, the Design Review Committee, the QA Division, and the Project Management Office.

The Project Management Office coordinates and controls all engineering, procurement and construction activities and maintains direct responsibility for control of project cost and schedule. This department ensures that all project activities are conducted in accordance with the quality requirements. The TUSI General Manager along with a contracted General Manager head this office. There is also a CPSES Resident Manager who retains the above responsibilities with regards to site activities. The General Managers report to the TUSI Executive Vice President.

The responsibilities of the Design Review Committee did not change. The committee, in conjunction with the A-E, establishes the design criteria and reviews design criteria for compliance with the required quality, codes, standards, safety requirements, etc. The Chairman of the Committee is the Manager, Nuclear Services. Other members include the Manager, QA, the General Superintendent, and the TUSI Project General Manager.

The Manager, QA, heads the QA Division. The only significant change to his job function involves the dissolution of the Quality Surveillance Committee which the QA Manager previously chaired. TU incorrectly disbanded this committee, in response to comments made in the 1978 MAC Audit Report that TU management should be more routinely involved in problem resolution. TU revised the FSAR to incorporate this change and stated that henceforth management attention will be maintained by not less

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32 This corresponds roughly to Phase II, as discussed in Section 5.2 of this report.

33 Letter from R.J. Gary (TUGCO) to J.G. Munisteri (Brown & Root), January 3, 1978.

34 Management Analysis Company Report on the TUGCO QA Program Audit, May 17, 1978.

than quarterly meetings of the Manager, QA, and the TUGCO Executive Vice President and General Manager.[35] The Manager, QA, also meets on a regular basis with the Project Manager, Nuclear Plants, and the TUSI Project General Manager, and supervises the Resident QA Engineer at G&H's offices in New York and the CPSES Site QA Supervisor.

The Resident QA Engineer at the G&H New York offices was responsible for assuring implementation of the QA function at G&H. He had stop work authority and maintained final approval authority over all technical aspects of G&H QA activities.

The Site QA Supervisor implemented the QA program at the site. His responsibilities included writing QA procedures, training site QA/QC personnel, and evaluating program effectiveness. In 1978, he also became responsible for the technical supervision of site QA and QC in all areas except ASME Code Work, which was still B&R's responsibility. The TUGCO/G&H staff and B&R Site QA & QC Managers assisted him in these activities. The change in 1978 came as a result of TU taking over this responsibility from B&R.

For technical and administrative supervision of ASME Code work and for administrative supervision in all other areas the B&R Site QA & QC Managers reported to the B&R QA Manager. For technical, non-ASME work, they reported to the TUGCO Site QA Supervisor. The TUGCO QA Manager resolved disagreements between B&R Site QA and QC Managers and the TUGCO Site QA Supervisor.

Although the FSAR was never revised to state that the CPSES QA Plan was no longer in use, the QA Plan seems to disappear from existence during this period. ATLIS and ASPEN do not have any entries for the QA Plan during this time period, or if they do, the actual document produced is the Corporate QA Program Manual. Furthermore, the Lobbin Report, issued in 1982, comments on the nonexistence of a QA Plan for Design and Construction.[36]

It is not clear what prompted the assumed elimination of the QA Plan. The 1978 MAC audit report commented on the complex and confusing array of documents describing and defining the QA Program for Comanche Peak, the CPSES SAR, the Corporate QA Program Manual, the CPSES QA Plan, and the QA Manuals for the prime contractors. TU's response to the MAC Report states that the QA Plan is being revised but makes no mention of eliminating

35 Final Safety Analysis Report, Amendment 4, January 31, 1979.

36 Review of the Quality Assurance Program for the Design and Construction of the Comanche Peak Steam Electric Station, F.B. Lobbin, February 4, 1982.

the document.

The change in management responsibility for site QA/QC is another possible reason for the elimination of the document. TU may have decided to produce separate implementing procedures now that they have site QA/QC management responsibility. In 1978 the first distinct QA procedures, which are separate from the QA Plan, appear. The procedures, however, appear to be drawn directly from the QA Plan with little or no modifications.

3.2.3 1984 to Present[37]

The ASLB hearings and the resulting investigations, the TRT inspections, SRT inspections, etc., mark the beginning of the final stage of QA program evolution. The documents describing the QA program are the QA Program Manual and the QA Plan. (The QA Plan reappears with Revision 5 to the Plan dated 7/31/84.) The QA Plan is a vastly different document than the Plan issued in 1977. The new Plan consists of 21 sections with the first 18 addressing the criteria of Appendix B. Each section consists of approximately one paragraph stating that procedures will be prepared to address the specific criterion and may also describe two or three specific topics or activities the procedure will address or include. This Plan is in marked contrast to the earlier Plan which contained 4 sections, Organization, Project Engineering, Site QA Construction Surveillance, and Auditing, comprised of detailed procedures. The QA Plan is now approximately 50 pages while earlier versions were in excess of 400 pages.

The Corporate QA Program Manual was also trimmed (in 1982 we believe) from 140 pages and 9 sections to less than 30 pages and 2 sections with 2 appendices. The new sections are Introduction and QA Program and the appendices are Corporate Organizations and Corporate Organization Activities. This manual basically serves to describe the responsibilities of the senior TU officials active in the QA program.

The Project Management group's responsibilities are similar to those previously described; it is only the titles of the positions that have changed. The group has responsibility for design, construction, procurement, and modification of CPSES, and for maintaining cost and schedule control of the project. The Vice President Engineering and Construction, who also serves as the CPSES Project General Manager, heads the Project Management group, and he reports to the TUGCO Executive Vice President,

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37 This corresponds roughly to Phase III, as discussed in Section 5.2 of this report.

Nuclear Engineering and Operations. The V.P. Engineering and Construction is located at the site and he assures compliance of design, procurement, and construction activities with the quality requirements. His staff includes Directors of Engineering, Projects, and Construction.

The QA Division was and is responsible for development, assurance of implementation, management, and surveillance of the QA Program for design and construction. In 1984 the QA Division consisted of the Manager, QA, the Supervisor QA Services, and the Supervisor Vendor Compliance who are located at the home office in Dallas and the Supervisor Quality Engineering, the Site QA Manager, and the Brown & Root Project QA Manager who are located at the site. The responsibilities of the Manager, QA, were similar to those described previously. He now reports to the V.P. Nuclear Operations for review and evaluation of QA program effectiveness. All of the above identified members of the QA Division, except for the B&R QA Manager, report directly to the Manager, QA. The B&R QA Manager reported to the TU Site QA Manager for activities other than ASME III work.

The responsibilities of the Supervisor QA Services included:

- o Determining the adequacy of proposed corrective actions,
- o Maintaining the QA Plan and Chapter 17 of the SAR,
- o Verifying TUGCO-Dallas QA personnel training,
- o Reviewing and evaluating codes, standards, regulations, and regulatory guides for applicability to the project, and
- o Preparing 10 CFR 50.55e reports.

The responsibilities of the Supervisor Vendor Compliance included:

- o Surveillance of hardware during manufacture and
- o Performance of final release inspection before shipment.

The responsibilities of the Supervisor Quality Engineering included:

- o Assisting QA Services on technical audits,
- o Providing statistical expertise in reviewing sampling programs,
- o Reviewing purchase orders for inclusion of the appropriate QA criteria,
- o Developing site QA/QC procedures and instructions,
- o Training site QA/QC personnel, and
- o Reviewing design and engineering packages for major modifications.

The responsibilities of the Site QA Manager included:

- o Supervising site QA/QC and surveillance,
- o Assisting the Manager, QA, in the development and

implementation of the CPSES QA Plan for design, engineering, and construction, and
- Coordinating site QA/QC functions.

Subsequently, in 1986, the structure of the QA Division was changed. A QA Division was formed and was headed by a Director of QA. Reporting to the QA Director are a Manager, QA, a Manager, QC, and a Manager, Operations QA. All three of the Managers are located at the CPSES site. The Director, QA, has ultimate responsibility for all quality related activities. Among his responsibilities are:

- Developing the QA Program and Plan,
- Establishing means for implementing indoctrination and training program,
- Defining responsibilities of his personnel, and
- Providing regular QA program activity updates to the Senior Management Overview Committee.

The Director reports to the Vice President, Nuclear Engineering and Operations.

The Manager, QA, is responsible for verification of overall conformance to the QA Program and Plan. His specific responsibilities include:

- Performing audits,
- Developing the QA Plan and Chapter 17 of the SAR,
- Verifying training of TUGCO-Dallas QA personnel,
- Interpreting industry codes, standards, regulations, etc., for their applicability to the project,
- Performing and coordinating surveillance of construction and hardware during manufacture,
- Preparing surveillance procedures,
- Reviewing proposed corrective actions,
- Reviewing procurement documentation for appropriate QA criteria, and
- Evaluating QA program effectiveness.

The Manager, QC, implements the QA Plan and provides technical supervision of site QC efforts in all areas excluding ASME Code work, which is the responsibility of B&R. His responsibilities include:

- Developing procedures to assure the implementation of site QC activities,
- Assisting in the development of the QA Plan for site construction and engineering,
- Assisting in evaluation of site QC effectiveness,
- Supervising the site Construction Quality Engineering staff, and
- Training site QC personnel.

The Manager, Operations QA, has no direct responsibility for design and construction; therefore, a discussion of his role is beyond the scope of this report.

3.3 Interface Control between and within TU and Its Prime Contractors

A large construction project, such as a nuclear power plant, involves many contractors, vendors, and designers. When one of the organizations involved exchanges information with another it is said to have an interface with the other organization. In many cases the output of one organization (such as a design drawing completed by Gibbs and Hill) is the input to another organization (such as to Brown and Root for construction of the system). The information flows both directions when the output is not sufficient without explanation or revision. It is extremely important for the constructors, engineers, and licensing personnel to have current information, drawings, etc. For example, the A-E cannot design much of the main steam system without knowledge of the design specifications for the NSSS. Therefore, a system for controlling interfaces is necessary to insure that the cognizant vendor, contractor, and TU personnel receive adequate and accurate information. Furthermore, there needs to be a system to monitor these interactions. To accomplish this task, TU established with each of its contractors a division of responsibility covering all phases of the project and identified individuals responsible for coordinating all external interfaces. Table A3-1[38] shows this division of responsibility and identifies organizations responsible for surveillance.

As Table A3-1 displays, the TU Project Manager of Nuclear Projects is responsible for controlling all interfaces between TU and its contractors. The Project Manager is thus responsible for document control for all entities which have an engineering or design function. Accordingly, all prime contractor engineering documents are to be received by TU, reviewed, distributed and superseded in accordance with procedures approved by the Project Manager. In addition, the Project Manager is to provide similar controls for all external correspondence. The TU Manager of QA is responsible for monitoring this activity for conformance with the established controls and for reporting any deficiencies in

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38 Table 6-1 is a reproduction of Table 2.1 of the TUGCO/TUSI Corporate QA Program Manual, Revision 0, August 1, 1973.

implementation or effectiveness. As shown by Table A3-1, similar responsibilities are established for interface control for the other prime contractors. In addition, TU has secondary responsibility for surveillance of contractor control of interfaces.

Table A3-1
INTERFACE CONTROL AND QA RESPONSIBILITY
(TUSI and Prime Contractors)

Organizations	Interface Type	Interface Control Responsibility	Interface Surveillance Primary	Interface Surveillance Secondary
TUSI	Internal	TUSI-PM	TUSI-QA	
GH	Internal	GH-PM	GH-QA	TUSI-QA
W	Internal	W-PM	W-QA	TUSI-QA
BR	Internal	BR-PM	BR-QA	TUSI-QA
TUSI-GH	External	TUSI-PM	TUSI-QA	
TUSI-W	External	TUSI-PM	TUSI-QA	
TUSI-BR	External	TUSI-PM	TUSI-QA	
TUSI - Consultant	External	TUSI-PM	TUSI-QA	
GH-W	External	GH-PM	GH-QA	TUSI-QA
GH-BR	External	GH-PM	GH-QA	TUSI-QA
W-BR	External	TUSI-PM	TUSI-QA	

Legend:
- PM - Project Manager
- TUSI - Texas Utilities Services Inc.
- GH - Gibbs & Hill
- BR - Brown & Root
- W - Westinghouse

4. STAFFING AND TRAINING OF THE QA FUNCTION AT COMANCHE PEAK

4.1. PSAR Commitments for Qualification and Training of QA Personnel

The only TU commitments in the PSAR in the area of QA personnel and training are in the PSAR description of the QA program. The PSAR lists the required qualifications for only three key individuals -the TUSI QA Manager, the Gibbs and Hill (G&H) QA Manager, and the Brown and Root (B&R) Corporate QA Manager. The minimum qualifications for each follow:

TUSI QA Manager

- o Minimum of 10 years experience in design, construction or operations of power plants,
- o College degree in an engineering discipline (BS minimum),
- o Demonstrated ability to manage people and projects,
- o Knowledge of QA requirements for nuclear plants, and
- o Registered Professional Engineer.

G&H QA Manager

- o Engineering degree,
- o Minimum of 10 years of engineering experience,
- o Prior responsible control of the QA program for essentially the entire design, engineering, procurement, and construction phases of at least one nuclear power plant, and
- o Minimum of 5 years of experience in nuclear and power quality assurance activities.

B&R Corporate QA Manager

- o College degree in an engineering discipline from an accredited university, college or technical institute,
- o 10 years engineering of quality control experience,
- o Technical, supervisory, and management experience in field of QA/QC, and
- o Demonstrated administrative and management effectiveness in implementing a quality assurance program.[39]

Neither the CPSES QA Plan nor the Corporate QA Program contain any additional qualification requirements; however, the CPSES QA Plan, as it existed in 1975, does describe the training required for QA personnel.

The QA Plan states that the Manager, Quality Assurance, was responsible for developing and implementing a program for

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39 CPSES Preliminary Safety Analysis Report, Amendment 5, April 5, 1974.

training QA personnel. The Manager, QA, held QA training sessions, made reading and study assignments, and authorized seminar and training attendance. The training would cover as a minimum:

- o 10 CFR 50, Appendix B,
- o Industry codes and standards,
- o NRC Regulations and Regulatory Guides,
- o Chapter 17 of the PSAR and FSAR,
- o Corporate QA Program, and
- o CPSES QA Plan.

The QA Plan stated that this training must be completed within two years after employment as a member of the QA organization. During the training period, the Manager, QA, determined the activities that a QA employee could perform.

As discussed in section 3.1, TU revised the QA Plan in 1978 to be a much more general manual which no longer addressed specific activities such as indoctrination and training of QA personnel. These activities were now to be covered by specific procedures. The procedure describing minimum training requirements was issued on May 30, 1978. This procedure, "Training of Inspection and Testing Personnel," Rev. 0, did not differ greatly from the requirements previously described in the QA Plan. The responsibility for training now rested with the TU Site QA Supervisor. The Site Supervisor was also responsible for administering examinations; however, the procedure did not identify a requirement for examinations. The procedure also mentioned that on-the-job training must be under the direct supervision of a qualified inspector, but again, the procedure does not detail what on-the-job training is required.

Although the current training procedure, Revision 22, dated August 21, 1986, is much more prescriptive about documentation requirements, the basic requirements of the procedure have not changed tremendously since 1978. The procedure does describe in much greater detail the process for creating an examination, passing examination grades, and specific on-the-job training inspection activities. Revision 4 to the procedure did include one significant change - training must be completed within sixty days of employment. In addition, although the title of the position responsible for the training program changed throughout time, the responsible individual was always the head of the TU site QA/QC staff. Many of these changes were made in response to NRC findings.

The only other significant change to the training and qualification procedure was in the area of qualification requirements for inspection personnel. Revision 10 to the procedure, issued November 4, 1981, defined three categories of inspection personnel as described in ANSI N45.2.6. The categories were and still are Level I, Level II, and Level III. As the level increases the qualifications and the capabilities of the inspection personnel increase. Basically, a Level I can perform inspections, examinations, tests, etc. In addition to having all the capabilities of a Level I person, a Level II person is capable of planning, supervising and evaluating inspections, and a Level III person is also capable of evaluating the adequacy of specific inspection, testing, and training programs. Later, the procedure distinguishes one more category, an Administrative Level III person. This person administers the CPSES QC program and is identified as the QC Manager Site. He also has general Level III capabilities.

In addition to defining the capabilities of these three levels of inspection personnel, the procedure also defines the minimum qualification requirements for each level. The requirements depend upon an individual's education and experience in equivalent inspections, examinations, or testing activities. Basically, a Level I person needs six months of related experience and a high school diploma; a Level II person needs one year experience as a Level I; and a Level III person needs six years of satisfactory performance as a Level II. These requirements vary for different levels of education.

4.2. Evaluation of Staffing and Training

Information on staffing levels is still being developed. Preliminary findings indicate very few TU personnel were involved in the site QC and surveillance efforts. It appears most of the individuals involved in these efforts were provided by B&R, EBASCO and G&H.

Appendix B

REGULATION OF NUCLEAR POWER PLANTS AND SOURCES OF REGULATORY REQUIREMENTS

1. NRC Regulatory Responsibility

The NRC has four principal statutory missions: (1) To assure the protection of the public health and safety; (2) to protect the common defense and security against diversion of strategic special nuclear material and sabotage of nuclear facilities; (3) to preserve environmental values and cost benefit analysis of alternatives; (4) to prevent the creation or maintenance of situations inconsistent with the anti-trust laws. This report is concerned only with the first item, regulatory requirements issued to assure the health and safety of the public. Although environmental considerations are dealt with in the same NRC proceedings which address public health and safety considerations, the quality assurance program associated with the environmental monitoring program is not discussed in this report and was not the subject of our evaluation.

2. NRC Regulatory Process

Two NRC licenses are required in connection with a nuclear power plant:

(1) Before construction may begin, the Company must have an NRC Construction Permit, issued after detailed NRC review of the Company's application setting forth the principal safety features of the site and the plant. The Comanche Peak construction permit was issued in December 1975.

(2) Before the nuclear fuel may be loaded into the reactor core of a completed nuclear power plant and the neutron chain reaction initiated, the utility must be issued an NRC Operating License. This is based on a detailed NRC review of the design of the facility and analysis of its safety in normal operation, upset conditions, and postulated accidents. TU has not yet received an operating License for Comanche Peak.

The two processes are similar. The utility applies for the license and provides, besides financial and other information, detailed technical analysis of the safety and environmental impact of the facility in a Safety Analysis Report and an Environmental Report. These are documents of several thousand pages, containing detailed technical descriptions of the relevant parts of the facility and detailed technical analysis of the safety and environmental impacts of the plant.

The NRC staff with its consultants performs technical reviews of the utility's Safety Analysis Report and Environmental Report. These reviews typically take a couple of years. The results are embodied in NRC staff reports entitled Safety Evaluation Report and (Draft and later Final) Environmental Impact Statement.

The utility reports and the NRC staff evaluation reports are both supplemented during the review process. Before issuing its Safety Evaluation Report, the NRC staff will have engaged in a dialogue with the utility, asking many questions and requesting additional information. The utility will furnish the needed additional information in the form of amendments to its Safety Analysis Report. Similarly, after the issuance of the initial NRC staff Safety Evaluation Report, additional reviews by the staff and other bodies, and additional information, are incorporated and reviewed in several supplements to the Safety Evaluation Report.

By law, each application to construct or operate a nuclear power plant must be reviewed by the statutory Advisory Committee on Reactor Safeguards (ACRS), a committee of up to 15 technical experts who are not full-time members of the NRC staff. The result of the ACRS review is contained in the committee's report to the Chairman of the Nuclear Regulatory Commission.

In parallel to these technical review, the application in also reviewed in a quasi-judicial proceeding by an Atomic Safety and Licensing Board. This is required by law for all Construction Permits and all contested Operating Licenses. Other, non-contested Operating Licenses are decided by the NRC staff without a hearing. Parties to the quasi-judicial proceeding are the utility, the NRC staff, and any organization or member of the public whose interest might be affected by the issuance of the license. The proceeding is conducted by a three-member board. The parties to the proceeding present testimony and are cross-examined. If there are no matters in controversy, the Board determines whether (1) the application and the record of the proceeding contain sufficient information and (2) the review of the application by the Commission staff has been adequate. The ultimate issues is whether the public health and safety will be adequately protected and the environmental review and cost-benefit balancing have been adequately conducted. Where matters are in controversy, either between the utility and the NRC staff, or between the utility and intervenors, the Board will decide the matters in controversy. The result of the Board's decision deliberations is embodied in the Initial Decision issued by the Board. If there is no appeal, the Initial Decision becomes the NRC ruling.

The Commission routinely appoints an Atomic Safety and Licensing

Appeal Board to review the Initial Decision and hear any appeals by parties to the proceeding. There is also a procedure for appeals to the Commission, or commission review on its own initiative of any Licensing Board or Appeal Board decision.

The final decision of the NRC, as the result of Appeal Board or Commission orders, can be appealed to the Federal Courts for judicial review.

The result is issuance, conditioning, or denial of the Construction Permit or Operating License sought by the utility.

3. Sources of NRC Regulatory Requirements

Throughout this report, we use the term "Regulatory Requirement" to mean all of the prerequisites and conditions imposed by the Nuclear Regulatory Commission (commissioners, boards, and staff) on the utility in connection with a nuclear power plant. We intend "requirement" to be a generic term, including laws, regulations, orders, standards, guides, etc. -- the various forms in which the requirements are actually stated. We also included both formally and informally imposed conditions. Our intent is to use a practical definition: If the utility was required by the NRC to do it, it was a regulatory requirement, regardless of whether the NRC had the legal right to make the utility do it. We are not offering a legal opinion regarding nuclear regulation. Instead, we recognize the practical, realistic conditions faced by an applicant seeking the permits and licenses from the NRC that are necessary to operate a nuclear plant. All the requirements that we discuss are in written form.

Some requirements are in the form of a written regulation, guide, or other generally applicable "requirements" document (see below). Alternately, some Comanche Peak requirements are set forth in NRC staff letters to TU, stating staff positions. Still less formal were statements of staff positions in meetings between the NRC staff and representatives of TU. These positions were recorded in Meeting Reports routinely prepared by the staff for all meetings with utilities seeking licenses.

The ultimate basis for the NRC regulatory requirements is a series of Federal statutes that has established the program of Federal regulation of nuclear power in the United States. These include the Atomic Energy Act of 1954, as amended, the National Environmental Policy Act of 1969, and provisions included in the annual authorization and appropriation bills related to the operation of the Nuclear Regulatory Commission. These often contain new statutory requirements compelling or forbidding the NRC to do some specified act. There are other laws with less direct effect on the programs discussed in our report, such as the Nuclear Waste Disposal Act, The Clean Air Act, and others.

The regulations of the Nuclear Regulatory Commission are contained in Title 10 of the Code of Federal Regulations. Chapter 1, Parts 0-199, contain the regulations enacted by the NRC to implement the legislative mandate (Chapters II, III, and X contain the regulations of the U.S. Department of Energy.) The principal safety requirements for nuclear power plants are contained in the following parts of the regulations: 20, Standards for Protection Against Radiation; 21, Reporting of Defects and Noncompliance; 50, Licensing Production and Utilization Facilities; 51, Licensing and Regulatory Policy and Procedures for Environmental Protection; 55, Operator's Licenses; 70, Domestic Licensing of Special Nuclear Material; 73, Physical Protection of Plants and Materials; and 100, Reactor Site Criteria.

These regulations have the force of law. They are adopted an amended only by a formal rule-making procedure that includes public notice and opportunity for public comment. Occasionally, public quasi-judicial hearings are held on the subject of an existing or proposed regulation or amendment. A regulation can be, and has been, challenged in the Federal Courts. Most have been upheld; however, in the famous Calvert Cliffs case, [Calvert Cliffs Coordinating Committee, Inc., et. al. v. U.S. Atomic Energy Commission, 146, U.S. ATP. D.C. 33, 449 F. 2d 1109 (1971)] the predecessor of the present Part 51 was invalidated by the Court as inconsistent with the National Environmental Policy Act.

The language of the regulations is often general and sometimes cryptic. Without additional guidance, translating them into detailed plant design and operation is not always an easy or fully defined task. For this reason, the NRC has long had other documents which purport to give guidance to utilities and to members of the NRC staff regarding what the regulations really mean. Some examples of classes are these regulatory guidance documents are listed below.

- Regulatory Guides: Each of these documents sets forth what the NRC staff and the ACRS believe the regulations require in some particular area. Many, but by no means all of the guides reference a code or standard promulgated by a professional society or the American National Standards Institute. Some of these guides endorse the whole standard; others endorse some portions of a standard or establish other requirements in addition to those of the standard. There are currently about 150 regulatory guides in Division 1, Power Reactors Guides are adopted by the NRC staff with the concurrence of the ACRS, following notice to the public and the nuclear industry and opportunity for comment.

- NRC Standard Review Plan: This is a voluminous document (over a thousand pages), organized according to the outline of the Standard Format and Content for Safety Analysis Reports. For each section of the Safety Analysis report, the Standard Review Plan identifies the NRC organizations having principal and support review roles, lists the areas to be reviewed and the acceptance criteria. Attached to many sections of the Standard Review Plan are Branch Technical Positions. These provide guidance in many ways similar to that of the regulatory guides, but their adoption is a less formal process not always involving ACRS concurrence of public notice and comment.

- NUREG Reports: These are technical documents issued by the NRC. Besides reports of technical research results, Safety Evaluation Reports, and other policy documents, some NUREG reports include regulatory guidance in technical areas. For example, proposed resolution of generic issues and Unresolved Safety Issues are reported by the NRC staff in NUREG reports.

- Codes and Standards: These are documents developed by industry groups, professional societies, and the American National Standards Institute. They play an important role in establishing specifications and requirements. As stated earlier, some NRC regulatory guides adopt individual codes or standards as NRC regulatory guidance. In fact, the NRC regulations (Part 50, Section 50.55a) require conformance to the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code and certain other identified codes and standards. Still other codes and standards are referenced by utilities in writing specifications for plant design, materials and purchased equipment.

- The NRC Office of Inspection and Enforcement: This organization issues information notices, circulars, and bulletins. These contain information obtained from the NRC inspection program. Some of them set forth requirements for action by the utilities as a result of the problems uncovered in the inspections at various plants. Several such documents are referenced in the discussions of regulatory requirements in our report.

- NRC Staff Positions: In reviewing the Comanche Peak license application, the NRC staff took positions that the Company was required to make changes in the plant design and other programs related to the construction of Comanche Peak. These were case-specific regulatory requirements for Comanche Peak.

Even though all of these documents do not have the formal status as regulations or laws, they have the practical effect of requirements, so we have called them requirements. In fact, there is a certain amount of give and take to the licensing review process. Individual reviewers, members of the NRC staff and consultants to the staff, develop opinions as they review single applications. The managers in the NRC staff see a larger picture, including the reviews of many applications and also the results of inspections, operation of many plants, and results from the research programs of the NRC and the nuclear industry.

Besides the more formal processes such as the development of regulatory guides and the Standard Review Plan, there is also the day to day development of positions in individual cases. The result is an exchange of formal questions from the NRC staff to the utility, and utility responses in the form of amendments to the Safety Analysis Report. As part of this process, the NRC staff takes positions on what is required on the part of a utility in order to bring a plant into conformance with the requirements of the regulations and the guidance provided by these various other documents.

There is also the opportunity for the utility informally to disagree with the staff. In addition, there is a formal appeal procedure for utility representatives to present their point of view to NRC staff management. The ACRS sometimes plays a role in resolving differences between the NRC staff and the industry or individual utilities. In principle, it is possible for the utility and the staff to bring such a disagreement into a formal licensing proceeding before the Atomic Safety and Licensing Board, and to ask the Board to make the decision. We do not believe that this has ever happened.

The reality is that the utility wants the license. The utility perceives delay in obtaining a license to be so expensive that compliance with almost any NRC staff position is cheaper for the utility than fighting it. There are plenty of examples of the staff accepting a utility's point of view and changing its requirements on individual cases. This happened during the Comanche Peak review, and it happened in most licensing reviews because the NRC staff also has an interest in completing the reviews and issuing the licenses. The fact is that the NRC staff almost always wins if the Company doesn't persuade them to change their minds. As a result, all of the "guidance" documents- guides, Standard Review Plans, Branch Technical Positions, individual case requirements - effectively become regulatory requirements that must in the end be implemented by the utility. That is the reason why we have lumped all these documents together as "requirements," a term which we use in its dictionary sense to mean the things that TU practically had to do to get licenses for Comanche Peak

Appendix C

A REVIEW OF THE TU AUDIT PROGRAM AT CPSES

1. Introduction

A systematic audit program was recognized as an integral part of the overall QA program by TU in Section 9 of its "Corporate Quality Assurance Program" (Revision 0, 1973, at SC0045). The Manager of Quality Assurance was given responsibility for the administration and implementation of the program to audit TU and its prime contractors. The Manager of QA would also be responsible for reviewing and approving the audit plans and procedures of the prime contractors, who were in turn responsible for auditing their immediate subcontractors. Those subcontractors were similarly responsible for auditing their first level of subcontractors, and so on.

The definition of an audit:

> "A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence, that applicable elements of the quality assurance Quality Assurance program [sic] have been developed, documented and effectively implemented in accordance with specified requirements. An audit does not include surveillance or inspection for the purpose of process control or product acceptance."
>
> [Source: Guidance on Quality Assurance Requirements during the Construction Phase of Nuclear Power Plants, AEC, Pg. 2, Draft 3-Rev 4, 2/22/74.]

The regulatory requirements for audits:

> "A comprehensive system of planned and periodic audits shall be carried out to verify compliance with all aspects of the quality assurance program and to determine the effectiveness of the program. The audits shall be performed in accordance with the written procedures or check lists by appropriately trained personnel not having direct responsibilities in the areas being audited. Audit results shall be documented and reviewed by management having responsibility in the area audited. Followup action, including reaudit of deficient areas, shall be taken where indicated."

[Source: NRC, Criterion XVIII of Appendix B to 10 CFR 50: Audits, Pg. 533.]

The Manager of QA was designated by the Corporate QA Program as responsible for developing an "overall Audit Plan" at the beginning of the project. According to the Corporate QA Program, this Audit Plan was to provide a minimum audit frequency (emphasis in the original) of semi-annually for internal audits; annually for the architect-engineer (Gibbs & Hill); annually for the NSSS supplier (Westinghouse); semi-annually for the construction manager (Brown & Root); and so on. More frequent audits were to be justified by any of six criteria as necessary to assure "quality".

Our review focuses on TU's QA auditing of the design and construction of Comanche Peak project, of Gibbs & Hill, and of Brown & Root. From 1978 through 1985 there were approximately 120 audits of design and construction, 25 audits of Gibbs & Hill, and 10 audits Brown & Root. These audits are designated by prefixes TCP-, TGH-, and TBR- respectively, and assigned a sequential number as suffix.

1.1 TU Audit Program of the Comanche Peak Project

The TU Series of design and construction QA audits of the Comanche Peak project from 1978 through 1984 are denoted as audits TCP-1 through TCP-123. This series of audits was started after TU assumed responsibility for the overall technical management of the QA/QC functions for the CPSES (See Paragraph C 1.3).

As can be seen from table C 1-4 only three audits were conducted in 1978 and three in 1979. TCP-6 was conducted in December 1979 and January 1980 of site engineering activities. Although too few audits were performed to cover all activities as required, significant problems were identified. e.g. TCP-6(12/17/79-1/21/80) identified 22 findings in the area of design review/design change and procedures. During a reaudit (7/21-8/7/80), 23 additional findings were made primarily in mechanical engineering. No procedure had been developed for safety related small bore piping (2" and under), inadequate documentation of design reviews on small bore piping and no evidence that design reviews were being performed on changes to previously verified designs. Additionally, seven findings were made in the area of large bore piping. During the course of the audit TU issued a STOP WORK DIRECTIVE.

A reaudit of the small bore piping program was performed September 22-23, 1980. Each reaudit used the checklist from TCP-6 along with the findings from the previous audits as a guide for conducting the reaudit. A second reaudit was performed January

19 through February 16, 1981 in order to close all of the open items from TCP-6 and the TCP-6 reaudits. Reaudit #2 listed 5 open items where commitments were either incomplete or not started, 11 new findings, 3 concerns, and 5 observations. TCP-6 reaudit #3 was conducted August 10-19, 1981 and all items were closed. There were five items where corrective action was incomplete. These were written up as corrective action requests and put into the corrective action system. Therefore after over 18 months the audit findings were closed out by identifying the corrective action to be taken, not by verifying that the corrective action had been either implemented, or had been effective in preventing recurrence of the problems. TCP-6 Followup audit #2, dated March 24, 1981, summarized its findings as follows:

> "TCP-6 Follow-up Audit Number 1 identified the absence of a design control program for 2" and under (small bore) pipe support design. A program was subsequently established and work performed in this area since implementation of the program was found acceptable. However, a commitment to implement a backfit program on small bore pipe support designs done prior to the program has not been complied with. As stated in TU response logged CPPA-6610, dated September 25, 1980, TU committed to starting the backfit program estimated at a 30,000 man hour effort, by November 3, 1980 and completing it by February 13, 1981. As of the start of this audit, January 19, 1981, the backfit effort had not begun.
>
> In addition, another violation of Appendix B Criterion V was identified in the Pipe Support Design Group. Design change activities were being conducted in the absence of an established design change control program and involved personnel whose minimum training requirements to approve field change requests (referred to as Component Modification Cards or CMCs) had not been met. This problem was brought to immediate attention of TU management who issued a Stop Work Order in this activity until the deficiency was corrected. The deficiency is still being identified for the purpose of addressing work done prior to the audit.
>
> As identified in detail in the report, instances were seen where design change requests are being approved without due consideration of their impact on earlier design work. We acknowledge TU intent to perform both initial calculations and independent verification after the CMC's are implemented as appropriate. We strongly recommend to TU management that it require supporting calculations or justification prior to approval of design change requests for those changes that violate

design criteria such as Hilti Bolt Spacing on design length requirements.

The audit report also identifies inaccuracies in a listing of hangers in areas with 2-inch architectural topping. This problem was reported to the NRC under 10 CFR 50.55(e). An initial commitment was made via ;our report TXX-3171 to complete the evaluations and corrective action by January 1, 1981. This commitment was subsequently revised via TXX-3247 dated December 22, 1980, to complete this project by August 1, 1981. As of the audit, a procedure for this work had not been generated. The responsibility for doing the evaluations had not been clearly defined in that confusion existed as to who was responsible for evaluating the 2-inch and under hangers.

This audit is also identifying problems in the area of fire protection hanger design. The design records generated while these designs were being done by the Pipe Support Design Group-Field Engineering should be reviewed by responsible TU management. Calculations are in such a state that they need to be redone in a legible, orderly manner, traceable to the component.

As demonstrated by the deficiencies identified, and by the list of problems identified by Grinnell in their letter CPPM-80-175 Revision 0, dated February 10, 1981, there is a need for design control emphasis in the fire protection hanger design activity.

It is the observation of the audit team that significant backlogs exist in the above areas. Issuing less than thoroughly reviewed engineering work adds to the existing backlogs. Even though the adverse cost and schedule impacts caused thereby are not the responsibility of QA, we are concerned that accelerated "back-end" efforts to clear the backlogs under time constraints could make design verification extremely difficult."

As addressed above in the discussion of TCP-6, TU policy was to perform both initial calculations and independent verification after the CMC's had been implemented. Paragraph 4 addresses the ineffective corrective action program. The last paragraph addresses TU policy on releasing less than thoroughly reviewed engineering work and alerts management to the problems this policy may create. This is also a further warning to management regarding the risks of the TU policy on after-the-fact design review. Proper management overview and assessment would have recognized the significance of the findings in TCP-6 and reaudit #1. Reaudit #2 was performed one year after TCP-6, yet corrective actions on many of the findings were incomplete, and no one had been clearly assigned responsibility for evaluating the small bore pipe hangers.

An evaluation of audit reports reveals that findings were not treated as generic or indicative of problems with the QA program. e.g. Although training and indoctrination problems were identified by TU during audits TGH-1, 2, 6, and 24 of G&H, TBR-3, 4, 6, 7 and 8 of B&R, and CPSES audits TCP-56, 72, 74, 75, 77, 90, and 122, there is no evidence that these findings were treated programmatically. Therefore the problem persisted in different parts of the CPSES program through the end of 1984. Another example is "design problems", TU identified design problems in audits TGH-1, 2, 3, 4, 6, 7, 9, 11, 13, 18, and 20 of G&H, TBR-2 and 3 of B&R, and TCP-4, 6, 18, 27, 32, 33, 43, 47, 74, 75, and 95, again there was no objective evidence (during Reaudit #2 the same type of problems were identified in Mechanical Engineering as were identified in Electrical and I&C during TCP-6) that these findings were treated programmatically.

Table C 1-1

Summary of CPSES Audits by TU Classified by Subject of Audit

SUBJECT	YEAR						
	78	79	80	81	82	83	84
ASME Activities	1				39	79,83	97,101 115, 109
Material Control	2	5	9	25	48		92
Design Review/ Design Change		4,6	6,18	27	32,33 43,47	74,75	107
Electrical Const.		5	12	29	41	69,78 85	100 121
Pipe & Pipe Support		6	6,13		38,39 47,50 52	64,76 70	112, 115
Site QC		7			36	76	
EQ			8		31,55		96
F-P			11	27,29	54,58	62,77	94,98
Damage Study			14,17	22	45,58	77	104
I&C Constr.				21	35	63	100, 118
Mechanical Constr.			13		37	67,79	101, 120
Document Control				23	40,46 51	68,84	99, 106, 113
Protective Coatings			15	24	30,42, 53	89	
Records Management				26			

NCR/Corrective Actions		28	56	87	111, 117
AQ-Built Verification			57,59	50,70	110
Rad Waste Management				66	
Construction Turnover				2, 80,88	95, 103, 105, 108, 110, 122
Training			36,56	90	
Weld, Cadwelding, & Concrete Testing	3 10,15				
Procurement	8	22	34,46	65	93
Commitments		19,20			
Control of M&TE			44	81	119
TU Engineering			49	61, 73, 82,86	96, 102, 114
PSI					91

Table C 1-2

TU Audits of CPSES, Number of Findings by Audit

Audits	Date	Findings	Concerns	Comments
TCP-1	3/20-23/78	11		
TCP-2	6/26-30/78	6		
TCP-3	9/7-13/78	2		
TCP-4	4/10-12/79	0	2	
TCP-5	8/27-30/79	2	5	
TCP-6	12/17/79-1/21/80	22		7
TCP-7	12/26-28/79	3	3	
TCP-8	2/11-3/13/80	10		
TCP-9	3/24-4/1/80	7	6	
TCP-10	4/28-5/2/80	0	2	
TCP-11	4/28-5/1/80	0		
TCP-12	5/20-6/5/80	5	6	
TCP-13	6/16-7/7/80	11	2	
TCP-14	8/20-21/80	1		7
TCP-15	10/6-8/80	1		1
TCP-16	POSTPONED			
TCP-17	10/28-29/80	1	3	
TCP-18	12/2-4/80	5	1	1
TCP-19	3/31-4/1/81	0	1	
TCP-20	4/20-27/81	0	4	
TCP-21	5/11-21/81	5	2	

TCP-22	8/3-7/81	1	1	4
TCP-23	9/21-25/81	1	3	
TCP-24	9/14-18/81	1	1	1
TCP-25	9/21-25/81	2		
TCP-26	10/5-8/81	1		1
TCP-27	11/10-12/81	2	3	1
TCP-28	11/16-19/81	1		4
TCP-29	11/30-12/4/81	5	2	
TCP-30	1/25-28/82	3		
TCP-31	1/25-29/82	2	1	
TCP-32	2/8-11/82	4	1	
TCP-33	2/10-17/82	4	3	
TCP-34	1/18-29/82	3		
TCP-35	3/8-12/82	1		
TCP-36	3/8-12/82	2	1	2
TCP-37	3/15-19/82	1		
TCP-38	4/13-14/82	0		
TCP-39	4/19-23/82	0		
TCP-40	4/26-29/82	3		
TCP-41	5/3-6/82	0		
TCP-42	5/10-13/82	0		
TCP-43	5/17-20/82	5	3	
TCP-44	6/22-24/82	1	1	
TCP-45	6/29-7/2/82	3	4	3
TCP-46	7/6-9/82	1	2	2
TCP-47	8/3-5/82	4		

TCP-48	8/16-19/82	2	1	3
TCP-49	8/30-9/3/82	4	1	3
TCP-50	9/13-17/82	1		
TCP-51	9/13-17/82	3		2
TCP-52	9/27-10/1/82	5	5	2
TCP-53	9/28-10/1/82	1	1	
TCP-54	10/11-14/82	0	3	
TCP-55	10/18-21/82	4		
TCP-56	11/8-12/82	5	3	
TCP-57	10/25-27/82	0	1	
TCP-58	11/25-12/1/82	1	1	
TCP-59	12/15-17/82	2	5	1
TCP-60	CANCELLED			
TCP-61	1/4-7/83	4		
TCP-62	1/4-7/83	2	1/17-21/83	3 2
		1 TCP-63		
TCP-64	1/24-28/83	2		1
TCP-65	1/31-2/4/83	0		
TCP-66	2/7-3/22/83	6	2	
TCP-67	2/21-25/83	2	1	
TCP-68	3/21-24/83	3	3	
TCP-69	3/28-31/83	0	1	
TCP-70	4/4-8/83	2	1	
TCP-71	CANCELLED			
TCP-72	4/25-29/83	2	2	

TCP-73	5/9-13&27/83	10	8	1
TCP-74	6/6-10/83	6	3	1
TCP-75	6/20-24/83	6	2	
TCP-76	6/27-7/1/83	4	4	
TCP-77	7/5-8/83	8	5	
TCP-78	7/11-15/83	7		
TCP-79	8/1-5/83	1		
TCP-80	8/15-26/83	4	1	3
TCP-81	9/6-8/83	2	1	
TCP-82	9/6-9/83	1	1	3
TCP-83	9/26-30 10/3-4/83	8	5	
TCP-84	10/11-14/83	8	3	
TCP-85	10/3-7/83	1		2
TCP-86	10/17-21/83	4	11	3
TCP-87	10/24-11/1/83	8	6	
TCP-88	10/31-11/15	2	2	
TCP-89	10/31-11/4/83	0	1	2
TCP-90	11/8-11/83	0	3	4
TCP-91	1/23-27/84	0	1	
TCP-92	1/9-13/84	1	2	2
TCP-93	1/9-13/84	2	1	1
TCP-94	2/6-10/84	0		
TCP-95	2/20-3/22/84	5		1
TCP-96	2/20-23/84	1		2
TCP-97	3/5-9/84	2		
TCP-98	3/20-28/84	2		2

TCP-99	3/26-30/84	6	4
TCP-100	4/2-6/84	2	
TCP-101	4/2-5/84	2	2
TCP-102	4/9-12/84	0	
TCP-103	4/23-5/4/84	7	3
TCP-104	4/30-5/4/84	3	6
TCP-105	5/29-6/13/84	5	2
TCP-106	6/11-16/84	3	
TCP-107	6/18-22/84	1	
TCP-108	7/9-20/84	0	
TCP-109	7/16-20/84	7	
TCP-110	7/30-8/8/84	1	
TCP-111	8/13-17/84	3	
TCP-112	8/20-24/84	1	6
TCP-113	8/8-10/84	2	3
TCP-114	9/4-7/84	5	
TCP-115	9/17-21/84	0	
TCP-116	CANCELLED		
TCP-117	11/12-15/84	2	1
TCP-118	11/12-16/84	0	
TCP-119	11/13-21/84	0	1
TCP-120	11/26-30/84	0	
TCP-121	12/3-11/84	2	
TCP-122	12/17-27/84	1	5
TCP-123	12/14-17/84	3	

1.2 TU Audit Program of Gibbs & Hill

The TU series of audits (1974 - 1985) of Gibbs and Hill, the architect-engineer on the project, are denoted as audits TGH-1 through TGH-25. TGH-1 was conducted in January 1974 and was a comprehensive evaluation of Gibbs and Hill's QA program. There were 52 findings in the report, some very significant. The report summarized their major concerns as follows:

> "Areas of major concern to TU are as follows:
>
> 1. Although the CPSES project activities were stated to be approximately 15% complete, conceptual and preliminary design work is in progress, the PSAR and some amendments have been submitted, and preliminary procurement activities have begun, the implementation of Quality Assurance activities to date appears to have been minimal. In our judgement, QA must be implemented, as applicable, early in the design and procurement phase, and not wait until after initial issue of approved design and procurement documents
>
> 2. Gibbs and Hill personnel were not adequately familiar with, nor committed to, applicable requirements of AEC's "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Power Plants" (The Gray Book) issued in July, 1973. The series of AEC regional conferences on this subject emphasized the need for early development and implementation of design and procurement activities, as well as providing applicable standards and additional AEC guidance on quality assurance."[1]

It is obvious from this report that the QA program had not been fully developed and implemented; that key personnel had not been trained and indoctrinated in QA, even though design and procurement activities were in progress.

It is difficult to understand why TU did not issue a "Stop Work Order" to force Gibbs and Hill to develop and implement its QA program in the areas where quality related work was in progress.

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1 Audit Report No. TGH-1, dated February 15, 1974. (S00461/CS00041052)

TU conducted two re-audits, one in August and a second in September 1974, to resolve the 52 findings (34 on the QA manuals and 18 on implementation). In the re-audit of August, 13-15, 1974, TU summarized two of their findings as follows:

> "... No design review has been done on accident analysis calculations which are the basis for many designs that have been essentially complete in this respect for as much as six months. Calculations on subcompartment pressure differentials during LOCA, the results of which have been given to the structural group for inclusion into drawings for release to Brown & Root by October 1974 have not been checked or independently reviewed."[2]

TU stated in their cover letter to Gibbs & Hill on August 26, 1974 which transmitted the report of the first re-audit that:

> "During the AEC's post audit discussion, we were advised of the importance of resolving the outstanding deficiencies in the Gibbs & Hill quality assurance area at least six weeks prior to our ACRS hearing, at which time the AEC plans to re-audit TU to determine what their position will be on these hearings. The ACRS hearings are scheduled for the week of October 7, 1974. Failure to resolve the Gibbs & Hill deficiencies prior to six weeks before the hearing date could possibly result in adverse testimony by the AEC staff which could conceivably delay our construction permit..."[3]

During the second re-audit in September, these two items were closed out after TU verified that the design review and calculations had been done. There was no mention of how the program was corrected or if this design input was given to the structural group for inclusion into drawings for Brown & Root, therefore it appears that TU was more interested in closing out the 52 findings prior to the ACRS hearings, rather than having Gibbs & Hill adequately correct its QA program.

Despite the programmatic problems identified during TGH-1, the overall QA program was not audited again until TGH-20 (See Table C 1-3 and C 1-4) was conducted in December 1982. TGH-20 was a follow-up audit on INPO's findings during their evaluation of Gibbs & Hill's QA program in July 1982.

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[2] Re-audit Report No. TGH-1, dated August 26,1974, Summary 3 (S00457/Cs00040969)

[3] Letter from P.G. Brittain, TU, to A. Matiuk, G & H, dated August 26, 1974, TGH-419 (S00457/CS00040969)

TABLE C 1-3

Summary of Gibbs & Hill Audits by TU QA

Subject	YEAR 1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
QA Program	1	3	4						20		22	24
QA Organization	1											
Procedure Implementation	2	3	4	5		12		17		21	23	25
Audit Followup	1*	2*		5	7,8 9	10,11	14, 16	17	18,20	21	22	
Design/Design Change				5	7,8 9	12	15		18,19 20		22 23	24 25
Dallas Office				6	7	11						
IEEE Quals							13,16	17	18			
Damage Study							16	17	19			
IE Bulletins								17				
Drawing Control									18		22	24
Gibbs & Hill Audits										21		
NCR's												

Note: Number Refers to TU Audit Report Number (TGH-1 thru 25)
1* Two Re-audits Conducted to Close Out Findings
2* One Re-audit Conducted to Close Out Findings

TABLE C 1-4

TU Findings in Audits of G&H

Audit	Date	Findings	Concerns	Comments	Unresolved Items
TGH-1	1/15-17/74	52			
TGH-2	12/9-12/74	28			
TGH-3	12/16-18/75	12	2		
TGH-4	10/4-8/76	10	4		
TGH-5	3/28-4/1/77	2	3		
TGH-6	9/15-16/77	6			
TGH-7	1/23-27/78	3			13
TGH-8	5/23-26/78	3			
TGH-9	12/5-8/78	7			
TGH-10	5/15/79	0		2	
TGH-11	6/21-22/79	0	2	1	
TGH-12	12/11-14/79	4	2		
TGH-13	4/15-18/80	5	2		4
TGH-14	6/10-13/80	0			1
TGH-15	9/30-10/3/80	0			2
TGH-16	12/9-12/80	1			1
TGH-17	6/9-12/81	4			
TGH-18	2/2-5/82	5	1	2	
TGH-19	7/13-16/82	1	2	3	
TGH-20	12/7-10/82	2	2	4	
TGH-21	7/26-29/83	6	5		
TGH-22	5/15-18/84	0		2	

Audit	Date	Findings	Concerns	Comments	Unresolved Items
TGH-23	8/20-24/84	3			
TGH-24	6/12-13/85	2			
TGH-25	8/9-11/85	0			

Table C 1-3 illustrates the number and subject matter or primary focus of TU QA audits of Gibbs & Hill from 1974 thru 1985. An examination of this table reveals that while most activities have been audited, audits of certain activities have not been performed on a regular basis or in the case of Gibbs & Hill nonconformance reports, not been performed at all, and the area of internal audits was audited only once in 1983. A review of the reports of these audits suggest that these audits were often of limited scope e.g. significant parts or all of audits 7, 8, 9, 10, 11, 14, 16, 17 and 20 are devoted to follow-up and close out of previous findings.

Table C 1-3 also reveals that TU audit focus was more on compliance (as revealed by the number of audits of procedure implementation and the lack of QA program audits) than evaluating the QA Program effectiveness of Gibbs & Hill (No review of Gibbs & Hill NCR Process or internal audits until 1983). Between 1976 and 1982 no audits were made of the QA Program content, changes in the regulatory requirements or implementation of changes in the SAR.

Table C 1-4 reveals that a large number of problems were identified during QA program audits TGH-1, 2, 3 and 4. Two reaudits were conducted in order to close out the findings of TGH-1 and one reaudit to close out the findings of TGH-2. TGH-3 findings reveal that the civil/structural area was still not reviewing design calculations prior to incorporation into design documents.[4] The problem was first identified in January 1974 (TGH-1), and had not been resolved as evidenced by the civil/structural finding in TGH-3 (December 1975). Training and indoctrination were identified initially in TGH-1, yet the problem still existed as late as TGH-6 (September 1977) in another part of the G & H program. A number of design change and design change review problems were identified in TGH-1, yet during TGH-9 (December 1978) I & C diagrams were found being reviewed using outdated revisions of flow diagrams. The audit responses and the re-audits reveal that the large number of findings were resolved

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[4] Audit report TGH-3, dated January 15, 1976 (S00646/CS00040843)

by changing of procedures and implementing program changes. By January 1977 the same type of program problems began to appear again. e.g. TGH-9 on design change and design change reviews and TGH-6 findings on training and indoctrination. This time frame corresponds roughly with Phase I and Phase II of Section 5.2. This condition persisted until NRC made a finding on TU's corrective action system for the audits in 1983.[5]

1.3. TU Audit Program of Brown & Root

The TU Series of audits (1974 to 1986) of Brown and Root (B&R), the project construction manager, are dencted as audits TBR-1 through TBR-11. TBR-1 through TBR-8 were performed while B& R was in charge of all construction QA/QC. By letter R. J. Gary, TU to J. G. Munisteri, B&R, date January 3, 1978 (TBR-414), TU assumed full responsibility for the overall technical management of QA/QC functions for CPSES except for those activities under the jurisdiction of the ASME Code, Section III, Division 1. Brown and Root retained responsibility for technical management of the ASME Code work and personnel administration for CPSES activities. TBR-9 through TBR-11 audits were performed subsequent to the change in QA/QC functions.

Table C 1-5 and C 1-6 reveal there were a large number of findings throughout B&R's QA program. A review of the reports (TBR-1 through TBR-8) indicates most findings were significant, and that the QA program had not been fully developed and implemented as late as 1977, e.g., TBR-8 was an audit of the vendor surveillance program at the Houston Home Office of B&R. Findings indicate that some procedures had not been developed, some procedures were not being followed and some inspectors were performing inspections that they were not qualified to perform. A STOP WORK ORDER was issued at the conclusion of the audit by TU.[6] Committed corrective action on TBR-5 (3/18/76) had still not been completed at the conclusion of TBR-8 (7/27/77.)

TU audited B&R ASME activities in TCP-1,[7] shortly after TU took over B&R QA site activities, but did not audit ASME activities again until TCP-39 (four years later)[8], even though B&R had lost

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5 NRC Inspection Report No. 50-445/83-18

6 Letter D.N. Chapman, TU, to T.H. Garon, B&R, dated July 29, 1977 (S00291/CS00480714)

7 Audit Report TCP-1, dated May 11, 1978 (S00185/CB00080806)

8 Audit Report TCP-39, dated May 12, 1982 (S00215)

its N-Stamps because of a survey,[9] conducted by an ASME Survey Team, October 12-14, 1981. Table C 1-6 reveals that TU did not audit B&R Houston QA/QC functions again until 1983. These facts support the conclusions reached in Section 5.3. (Note this time frame is the middle of Phase II identified in Section 5.2.)

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9 Letter from J.A. Russo, ASME to R.J. Vurpillat, B&R, dated November 23, 1981 (S00012/EH00221609)

Table C 1-5

TU Findings in Audits of B&R

Audit	Date	Findings	Concerns	Unresolved Items
TBR-1	6/6/74	6		
TBR-2	3/25-27/75	12		25
TBR-3	9/22-24/75	32		
TBR-4	3/15-17/76	5		
TBR-5	3/18/76	5		
TBR-6	12/7-8/76	4		
TBR-7	1/8-22/77	9	2	
TBR-8	7/25-27-77	16		
TBR-9	11/7-8/83	1	2	
TBR-10	12/12/84	0	2	
TBR-11	6/11-12/86	2		

Table C 1-6

TU Audits of Brown & Root by Subject Area

Subject	Year							
	74	75	76	77	83	84	85	86

QA Program	1	2		7,8			
Followup on Prior Audits	1*	2*	4,6	7,8		10	
Procedure Implementation		3	6				
QA Records			4				
Houston Office			5,6	8	9	10	11
Audits by B&R			6		9	10	11
Vendor Surveillance				8			

Note: Numbers refer to TU Audit Reports (TBR-1 through TBR-11)
1* Refers to TBR-1 Reaudit
2* Refers to TBR-2 Reaudit

1.4 Conclusions

(1) Design
An evaluation of Tables C 1-1 through C 1-6 reveals that the number and subject matter of TU audits were very limited until 1982 (this is one of the findings of the Lobbin Report). Between 1978 and 1982, 29 audits were conducted on the CPSES project. During 1982, 30 audits were conducted, but only 66 findings were made compared to the 126 were made in the 29 audits prior to 1982. The number of findings in themselves don't indicate depth but the significance of the findings do (e.g. TCP-1, 6, 8, 13, 18, & 21, TGH-1, 2, 3, 4, 6, 9, & 13, and TBR-1 through 8.)

The findings in the design area identified problems all along and foreshadowed problems to come. Following is a sequence of audit findings in the design and design change area:

TGH-1 January 1974

- #5 No design reviews of calculation checking have been conducted.
- #17 No procedure to translate requirements into design documents.
- #17-30 Design Control Problems.

TGH-2 December 1974

- #11 Work starts and sometimes completed before the design and engineering change order was signed.
- #13 Design description document not prepared for design work in the Civil/Structural Area.
- #19 Documentation on design review.

TBR-2 March 1975

- #2 & 3 Field design change request problems.

TBR-3 September 1975

- #17 Conflicting procedures on field design changes.
- #18 No QC surveillance of field design changes.

TGH-3 December 1975

- #1 Design description not being prepared in the mechanical area.
- #2 Calculations not always approved by civil before incorporation into design drawings.
- #5 Civil/Structure drawings issued before fully design reviewed.
- #6 Design review of specifications sometimes performed after purchase order is issued.
- #8 General lack of timeliness of design reviews.
- #9 Design review of calculations are not always completed prior to incorporation into drawings being issued for construction or fabrication.

TGH-4 October 1976

#4 Design review comments resolved 7 weeks after specification accepted by Vendor.
Concern #3 Seismic requirements of Spec. 2323-MS-10 did not reflect the correct design bases.

TGH-5 April 1977

#1 Design reviews of specs not reviewed for compliance with PSAR.

#2 Two examples of inadequate design reviews.

TGH-6 September 1977

#3 No procedure for interface between G & H site, Dallas and N.Y. offices.

#6 No procedure to set criteria for field changes to be reviewed in N.Y.

TGH-7 January 1978

#2 Inadequate interface procedures for design review of DC/DDA's.

TGH-8 May 1978

#3 Misclassification of equipment supports anchoring and equipment tagging on structural drawing. Interface problems.

TCP-6 January 1980

No Design Control Program for Pipe Hangers. See Section C 1-1

TCP-12 May 1980

#2 No procedure to incorporate design changes arising from G & H termination drawings.

#5 DCA not complete, cable & cable termination card not in agreement.

TCP-12 Followup April 1981

#2 Asbuilt condition did not conformed to cable connection card.

TCP-13 June 1980

#2 Six valves not installed as per drawings. No NCR or DC completed.

#4 Bolts not as per drawing.

#10 Gang hanger not re-analyzed.

#11 8 out of 11 hanger CMCs not design reviewed.

TGH-15 October 1980

Unresolved #1 No interface on CMCs between TU, G&H and Westinghouse.

TGH-4 October 1976

#4 Design review comments resolved 7 weeks after specification accepted by Vendor.
Concern #3 Seismic requirements of Spec. 2323-MS-10 did not reflect the correct design bases.

TGH-5 April 1977

#1 Design reviews of specs not reviewed for compliance with PSAR.

#2 Two examples of inadequate design reviews.

TGH-6 September 1977

#3 No procedure for interface between G & H site, Dallas and N.Y. offices.

#6 No procedure to set criteria for field changes to be reviewed in N.Y.

TGH-7 January 1978

#2 Inadequate interface procedures for design review of DC/DDA's.

TGH-8 May 1978

#3 Misclassification of equipment supports anchoring and equipment tagging on structural drawing. Interface problems.

TCP-6 January 1980

No Design Control Program for Pipe Hangers. See Section C 1-1

TCP-12 May 1980

#2 No procedure to incorporate design changes arising from G & H termination drawings.

#5 DCA not complete, cable & cable termination card not in agreement.

TCP-12 Followup April 1981

#2 Asbuilt condition did not conformed to cable connection card.

TCP-13 June 1980

#2 Six valves not installed as per drawings. No NCR or DC completed.

#4 Bolts not as per drawing.

#10 Gang hanger not re-analyzed.

#11 8 out of 11 hanger CMCs not design reviewed.

TGH-15 October 1980

Unresolved #1 No interface on CMCs between TU, G&H and Westinghouse.

Unresolved #2 No interface on CMCs between G&H, cable tray supports, pipe hangers, and HVAC etc..

TCP-18 December 1980

#1 No procedures for design review of CMCs in the Pipe Support Group. CMCs being appr i without supporting calculations. TU manageme accepts the liability of approving field design changes without supporting documentation.

#3 Design interface between engineering groups involved in hanger declassification was not adequately defined.

#4 Errors identified in design review documentation.

#5 Inadequate interface between Field Engineering and Technical Services to resolve design questions during design review of CMCs.

TCP-27 November 1981

#2 Design reviews performed without authority.

Concern 1b Procedure did not address design review.

TGH-18 February 1982

Concern #1 The majority of DCA/CMCs have not been incorporated into the Master Index.

TCP-33 February 1982

#2 No procedure for design control of unique systems.

TCP-43 May 1982

#1 Engineering did not send design info to Pipe Support Engineering in controlled or documented manner.

#4 Drawings checked and approved by unauthorized personnel.

#5 Calculation packages were reviewed which did not have accept ble data or retrievable calculations.

TCP-47 August 1982

#1 Design review did not address 19 questions of ANSI N45.2.11.

#3 Design revi w packages transmitted without suitable controlling method.

TCP-52 September 1982

#1 Procedure did not address the interface between the Stress Analysis Group and Pipe Support Engineering.

TGH-20 December 1982

Concern #1 from TGH-18, Problems with DCA documentation.

#1 Use of mark-overs, Whiteout and correction tape on change verification checklists (Repeat from TGH-19).

#2 Three of five DCA's restatused as approved without adequate supporting documentation.

TCP-74 June 1983
- #1 No controlled method to identify corrections by a CMC.
- #2 Procedure allows design changes to be made by a Field Modified Hanger Sketch without a CMC or DCA.
- #4 No procedure to control CMCs/DCAs against as-built verified hangers.
- #6 Personnel instructed to review only those DCAs which are most important.

TCP-95 February 1984
#s 1,2,3,4 & 5 As-built deviations.

TCP-103 May 1984
#s 1,3,4 & 5 As-built deviations.

A review of this sequence of audit findings reveals design/design change problems were identified from the first audits in 1974 through 1983. The programmatic changes which needed to be made to correct the CPSES project programs were never adequately made. Then in 1984, the results that could have been predicted from the inadequate corrective actions to audit findings, show up in the form of As-Built deviations in the hardware. These problems were a result of conscious decisions on the part of TU management (e.g.TCP-6 findings revealed, design change activities were being conducted with no design change control program and design change requests were being approved without due consideration of their impact on earlier design work. See Section C 1.1.) The audit report acknowledges TU intent to perform both initial calculations and independent verification after the design changes were implemented. Finding #1 in TCP-18 found no procedures for design review of CMCs in the Pipe Support Group and CMCs were being approved without supporting calculations.[10] In response TU management accepted the liability of approving field design changes without supporting documentation.[11] This practice was not stopped until 1985,[12] after the TRT final report was issued.

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10 Audit Report TCP-18, December 18, 1980 (S01003/PT00802122)

11 Office Memorandum, CPPE Response to TCP-18, dated February 4, 1981 by M.R. McBay and J.T. Merritt Jr. (S01005/PT00802145)

12 Office Memorandum from J.T. Merritt, TU, dated January 21, 1985 (S01940/CB0014)

An indication that only the problem that was identified during a specific audit was addressed rather than the generic implication of the finding is shown by the findings on design interface: TGH-6 #3, TGH-7 #2, TGH-8 #3, TGH-15 Unresolved Items 1 & 2, TCP-15 #s 3 & 5, TCP-43 #1, and TCP-52 #1, all identified interface problems in one way or another on the CPSES Project between 1976 and the end of 1982.

The lack of adequate information being passed between the design groups coupled with all of the identified problems with design changes and design reviews simply set the stage for the Design Adequacy Program of the CPRT.

(2) Corrective Actions

Unlike the design/design change audit finding trail, the corrective action audit trail is almost nonexistent. A glance at tables C 1-3 and C 1-6 reveals that G&H and B&R corrective action programs were never audited by TU. A review of Table C 1-1 reveals that the first NCR/Corrective Actions audit of CPSES was TCP-28. An examination of that audit report reveals that only one minor deficiency was identified along with four comments. The area was not audited again until TCP-56, one year later. During this audit only one concern and one comment were identified in the area of NCR administration. TCP-87 conducted during October and November 1983, appears to be the first audit of any depth of the NCR/Corrective Action Program at CPSES, but this was very late in construction. The bulk of construction was completed in Unit 1 by this time, many allegations were being made, and the ASLB was raising questions about design and as-built conditions of the CPSES project. Therefore the TU Audit Program was ineffective in identifying problems in the NCR/Corrective Action Programs at CPSES.

(3) Training

a. Gibbs and Hill (G&H)

A review of Table C 1-3 reveals that Training and Indoctrination (T&I) was never the subject of an audit of G&H but training and indoctrination was examined along with other subject material During TGH-1, findings were made[13] that there was no description of training and indoctrination in the Project Guide or the Project Procedures Manual, no formal T&I had been provided and a draft of the QA T&I Program had been written but it had not been reviewed by management or implemented even though the Project Design and Procurement activities were reported to be 15%

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13 Audit Report TGH-1, dated 2/15/74 (S00461/CS00041052)

complete. During TGH-2, findings were made[14] that a list had not been provided to QA of personnel required to attend QA seminars, QA seminars had not been held twice per year and T&I records were not being kept on QA engineers. These two audits appear to have corrected the G&H's program on T&I. However during TU's audit of the Dallas office of G&H[15], a problem surfaced again in the finding of no personnel T&I records. In June 1979,[16] almost two years later, this problem with records or documentation of T&I was still carried as an open item. Two minor record problems were identified during 1985,[17] otherwise the audit reports reveal that G&H resolved all of their major problems prior to 1976 and only minor record problems were identified after that time.

b. Brown and Root (B&R)

A review of Table C 1-6 reveals that T&I was not the subject of an audit of B&R, however T&I was examined along with other subject material. One finding in 1975 identified that document control center (DCC) personnel had not been properly trained and indoctrinated.[18] During the next audit,[19] the personnel identified in TBR-3 had been trained or retrained but two new employees had not. During 1977, three findings on the certifications, T&I of QC inspectors and one improperly certified QC inspector were identified.[20] Also in the same year[21], a finding was made where QC inspector training and qualification requirements had been downgraded to below acceptable levels. This was the last TBR Audit before TU assumed responsibility for the site B&R QA Program Management (See Section 5.4.2). The above facts or findings reveal there were continuing problems with training, indoctrination, and "certification of QC inspectors" during the time that B&R managed the CPSES Project QA Program.

c. CPSES

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14 Audit Report TGH-2, dated 12/19/74 (S00451/CS00040900)

15 Audit Report TGH-6, dated 9/19/77 (S00632/CS00040726)

16 Audit Report TGH-11, dated 6/29/79 (S00602/CS00040503)

17 Audit Report TGH-24, dated 9/6/85 (S00547/CS00040074)

18 Audit Report TBR-3, dated 10/20/75 (S00727/RL09480906)

19 Audit Report TBR-4, dated 4/16/76 (S00182/CS00480570)

20 Audit Report TBR-7, dated 6/2/77 (S00285/CS00480656)

21 Audit Report TBR-8, dated ?/29/77 (S00166/CS00101483)

An examination of Table C 1-1 reveals T&I was not the subject of an audit until TCP-36, however, T&I was sometimes audited with other subject material e.g. Finding #17 in TCP-6 documents widespread lack of documentation for T&I in Electrical, I&C, and all phases of Mechanical Groups of Site Engineering.[22] During Follow-up Audit No.2, no T&I records on 2 of 4 persons authorized to approve field changes.[23] Thus a year later the T&I problems had still not been corrected. The issue was closed out in Audit Report TCP-6 Follow-up #3.[24] This is a clear case where the identified problem was fixed but the problem was not treated as a generic one and the overall problem was not fixed. In three audits, (TCP-36,56, and 90), findings indicate that the T&I program was good with the exception of some minor record and documentation problems. We question the depth of these audits, e.g. in TCP-56, finding #2 identified 12 QC inspectors where there was no objective evidence to show that these QC inspectors had received T&I in certain procedures, while other records certified the same QC inspectors to inspect using these procedures. There should have been a followup to find out if these inspectors were qualified to perform these inspections and if not, had they actually been performing these inspections. This type of followup would have identified possible problems in as-built conditions.

(4) Document Control

B&R was assigned responsibility of receiving design and construction records from Westinghouse, G&H, and Vendors and maintaining a document control system until such records were turned over to TU. An examination of Table C 1-6 reveals that document control was never the subject of an audit of B&R by TU. A review of audit reports show that this area was not completely neglected. Audit TBR-2 findings identified[25] a lack of some procedures, inadequate procedures, incomplete records, inadequate control of reproduction of control documents, and that the DCC vault had <u>not been constructed.</u> During the next Audit[26], nine new findings were made in the same areas identified in TBR-2 plus some approved procedures had not been implemented, some logs were not being kept, fire protection in the central file storage was

22 Audit Report TCP-6, dated 2/6/80 (S00188/CS00101339)

23 Audit Report, TCP-6 Follow-up #2, dated 3/24/81 (S00199/CS00101202)

24 Audit Report, TCP-6 Follow-up #3, dated 9/4/81 (S00202/CS00101180)

25 Audit Report TBR-2, dated 4/14/75 (S00957/PT00692527)

26 Audit Report,TBR-3,dated 10/20/75 (S00727/RL09480906)

deficient, and training of DCC personnel was deficient. During Audit TBR-4,[27] findings indicate that the records system still had not been fully developed, procedures for handling and storage of QA records in the construction vault were not developed, security at the vault was inadequate, and two newly hired DCC personnel had not been trained. Even at this early stage of construction, a trend of repeat findings can be seen. The next audit at the Houston offices[28] found more repeat findings; inadequate implementation of procedures, records not being handled consistent with procedures, and inspection packages not being obtained from the site DCC. During TBR-6 [29], the only finding in this area was that all of the corrective action on TBR-5 findings were incomplete (eight months later), and the items were carried as open items. TBR-8 [30] was again conducted at the Houston offices, the findings indicate that the office files were not up to date, the vendor surveillance group was not on distribution for design drawings, and the item identified in TBR-5 on the inadequate implementation of procedures on collection, storage, and handling of QA records was still open (15 months later). At this time this series of audits ended, the CPSES series of audits started and the audit findings were similar to the previous ones. Between 1977 and 1985, at least 15 audits identified at least 25 findings in the area of document control[31]. Since the findings of the TBR audits are representative, the trend indicates that this area was never brought under control. Some of the later findings were more significant (.e.g finding #1 of TCP-23, the auditor examined 169 controlled drawings and identified 105 problems, many findings where the wrong revisions were on file, and some where design changes were not incorporated into drawings.)

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27 Audit Report,TBR-4, dated 4/16/76 (S00182/CS00480570)

28 Audit Report,TBR-5, dated 4/6/76 (S00279/CS00480601)

29 Audit Report, TBR-6, dated 1/3/77 (S00282/CS00480624)

30 Audit Report, TBR-8, dated 7/29/77 (S00166/CS00101483)

31 TU Office Memo to file by Susan Palmer, dated 5/14/85, Subject, Document Request GS-6 (S02046)

Appendix D

Overview and Statistical Analysis of the NRC Inspection Program at CPSES.

This appendix presents an overview and analysis of the 304 NRC Comanche Peak inspection reports listed in Table D-1. Six reports within the range of report numbers listed in the table (73-01 to 86-29) have actually been issued but are not presently on hand.[2] Efforts have been initiated to obtain these reports.

A brief analysis of the data contained in the reports has been performed to determine if any conclusive patterns could be identified that would direct attention to specific areas of interest. Data considered in the analysis included the year of the inspection; the type of inspection - e.g. construction, radiation protection, etc.; the number and types of adverse findings identified by the NRC inspectors; the number of inspection hours spent on the inspection (where available); whether the inspection was routine or in response to allegations; and the names of the inspectors performing the inspection.
Because the physical quality of a plant is determined primarily by the quality of its design and construction, this analysis was limited to NRC inspections that addressed these areas. For convenience, these will be referred to as Construction Inspections. This focus is appropriate to the present instance because it is mainly through a breakdown in construction quality that a project manager can jeopardize the licensability of the facility and find it necessary to undertake expensive and time consuming major corrective action programs. Of the 304 NRC inspection reports listed in Table A-1, 218 have been classified as construction reports. These 218 reports form the core of the present analysis.

The number of construction inspections performed per year is shown in Figure D-1 for both routine and reactive inspections. For the purpose of this review we have defined reactive inspections as either inspections or investigations performed in response to allegations of improper construction activities. Routine inspections, on the other hand, are inspections performed in accordance with established NRC inspection plans. Examination of this Figure shows a low level of inspection activity during 1973 and 1974, with a sharp jump in inspection activity beginning in 1975. The increased activity beginning in 1975 correlates well with the beginning of construction in 1975 following issuance of the CPSES Construction Permit in December 1974. After 1975, the number of inspections is seen to increase gradually, in step with the increased pace and breadth of

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2 NRC inspection report numbers used in this report will be the number assigned for CPSES unit 1.

construction. Also increasing over this period, however, is the number of reactive inspections - reaching a temporary peak of eight reactive inspections in 1979. After 1980, the number of routine inspections is significantly smaller, but the number of reactive inspections continues to be significant. The large number of reactive inspections in 1982 and 1983 is attributed to the opening of the ASLB hearing in December 1981 and the airing of a number of allegations at those hearings.

A single NRC inspection may involve one hour of inspection time or hundreds. Therefore, the number of inspections conducted is only one aspect of NRC inspections. To the extent data are available, Figure D-2 shows the variation of inspection hours per year over the course of the project. (No data are available from the CPSES inspection reports prior to 1977; the data for 1977 and 1986 are very fragmentary and some important data are not included in the 1978-85 reports.) Figure D-2 shows that although the number of inspections appears to have decreased after 1980, the annual resources expended for construction inspections between 1982 and 1984 was much higher than in earlier periods. One obvious conclusion is that many more hours were expended per inspection. An equally obvious conclusion is that much more inspection effort was needed to resolve the numerous questions concerning plant quality raised at or in connection with the ASLB hearing. Figure D-2 also shows the number of hours the NRC spent during this period inspecting activities other than construction. These data are included to illustrate why it is necessary to differentiate between different types of inspections when performing an analysis of this type.

Figure D-3 shows the variation in the number of NRC construction findings per year over the course of the project. We have used the term "finding" instead of "violation" to provide a more uniform yardstick than provided by the NRC. This is necessary because sometimes the NRC will cite each unique violation individually, and on other occasions, will group the unique violations as "examples" under a single violation. Our listing simply defines each unique violation as a finding regardless of the manner in which the citation was drafted by the NRC. One of the notable features of Figure D-3 is the fairly large number of findings in 1973. These findings derived from a single inspection and related to numerous problems with the quality assurance program prior to issuance of the Construction Permit, but at a time when plant design was well underway. As for 1974, although no formal citations were issued that year,[3] several concerns related to quality assurance were carried as Unresolved

3 For simplicity, a finding resulting from inspection report 74-XX, will be referred to as a 1974 finding regardless of the date of issue of the inspection report.

Items[4] and closed out just prior to issuance of the Construction Permit. We note there are a very low number of findings in 1981. Based on the data for adjacent years, the number of findings appears to be outside the bounds of normal variation. We also note an unusually large number of findings in 1985 and 1986. A preliminary review of the citations issued in 1986, however, suggests that based on the problems identified by the TRT, the NRC inspectors during this period were being much more thorough in their assessment of design and constru tion practices.

Figure D-4 presents the previous data in a slightly different form such that the number of construction inspections per year and the number of findings from those inspections are presented in adjacent columns. Inspection of the Figure shows that between 1975 and 1983, the number of findings was typically somewhat smaller than the number of inspections -- that is, not every inspection identified violations. After 1983, however, it is seen the number of findings exceeded, and in some cases greatly exceeded, the number of inspections.

As noted earlier, measurements in units of numbers of inspections do not necessarily reflect the actual resources applied to the task. The actual resources expended per finding are shown in Figure D-5. (Note: Because data concerning inspection hours are missing from many inspection reports, only those reports providing inspection hours were included in preparing Figure D-5.) As can be seen, wide variations in the inspection hours per finding occurred. If the period from 1978-80 is considered a norm (with roughly 140 hours per finding), a huge divergence is seen in 1981. In this year, although the number of inspection hours was slightly reduced, only two findings were identified--thus producing an index of about 700 hours per finding, or five times the norm. In contrast, the construction inspection hours for 1982-84 were 1.5 to 3 times those of the reference period, but were only a one-third to one-half as effective in terms of hours per finding. Finally, in 1985-86 the index again changes dramatically to a level of 45-60 inspection hours per finding. Little importance should be attached to these numbers, however, because during this period Region IV started to not include the number of inspection hours expended in the reports of the inspections.

The final area analyzed was the distribution of inspection findings amongst the eighteen criteria of 10 CFR 50, Appendix B. It should be noted that during the construction of a nuclear plant, the great majority of the violations written by the NRC are written as violations of Quality Assurance requirements as

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4 The NRC definition of an Unresolved Item is an item for which additional information is needed in order to determine if it is a violation of regulatory requirements.

described in 10 CFR 50, Appendix B. In addition, the violations are typically written against one of the 18 criteria in Appendix B. Our experience indicates any tabulation of these violations by criterion cited, will show the majority are written against Criterion V, Instructions, Procedures and Drawings. This should not be unexpected since Criterion V states, in part:

> "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

Thus, any activity identified by an NRC inspector that is not being performed in accordance with the applicable procedure is likely to be cited against Criterion V. In addition, Criterion V provides a basis for a citation when a procedure should exist but does not, or when a procedure is demonstrably inadequate. In the final analysis, practically every violation is the result of failure to follow some procedure or regulation. Thus, conceivably, practically all violations could theoretically be written against Criterion V.

The distribution of violations at CPSES follows this pattern, with more than half the total number violations cited against Criterion V. To provide a more useful picture of the distribution of violations between criteria, we have subdivided the CPSES Criterion V findings into three subgroups:

- o The first group consists of those findings based on the absence of a required procedure, or use of an inadequate procedure. Findings falling in this group are designated V-A.

- o The second group consists of those findings involving failure to follow a procedure applicable to one of the criteria in Appendix B, such as a design control procedure (Criterion III), a document control procedure (Criterion VI), a procurement procedure (Criterion IV), etc. In these cases the finding was reassigned from Criterion V to the criterion applicable to the functional area.

- o The third group consists of those findings involving failure to follow a procedure that is not addressed by one of the criteria in Appendix B. These are typically construction procedures, such as concrete preparation and placement, and mechanical and electrical installation. Since welding is specifically addressed by Criterion IX, Control of Special Processes, findings related to welding were assigned to Criterion IX.

Based on application of the above process to findings originally cited against Criterion V, and the NRC inspector's classification for other findings[5], the results are shown in Figure D-6.

Inspection of Figure D-6 shows that despite the distribution of some of the Criterion V findings to other criteria, Criterion V (consisting of V-A and V-B) still leads all others. Indeed, both Criteria V-A and V-B individually are more numerous than any of the other categories. The other criteria were cited as follows:

Criterion		Occurrences
X	Inspection	24
III	Design Control	16
IX	Control of Special Processes	14
II	Quality Assurance Program	10
XV	Nonconforming Materials, Parts, or Components	9
VI	Document Control	7
XIII	Handling, Storage and Shipping	7
XVI	Corrective Action	7
VII	Control of Purchased Material Equipment and Services	6
XVII	Quality Assurance Records	6
XVIII	Audits	5
IV	Procurement Document Control	3
I	Organization	2
XIV	Inspection, Test and Operating Status	2

From the foregoing it is concluded the six areas where deficiencies were identified by the NRC most often at CPSES were as follows:

- o Compliance with construction procedures
- o Lack of or inadequate procedures
- o Inspection activities, including qualifications of QC inspectors
- o Design Control
- o Control of Special Processes, including welding
- o Administration of the Quality Assurance Program

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5 In a very few instances, the inspector's classification was changed when it was considered appropriate. For example, in Inspection Report 81-02, a second violation of piping installation procedures was changed from Criterion V to Criterion XVI, Corrective Action because the procedures to prevent recurrence had been ineffective.

Analysis and Evaluation of the Project Management Services Provided by Texas Utilities in the Construction of the Comanche Peak Steam Electric Station

Tex-La Electric Cooperative of Texas, Inc.
Brazos Electric Power Cooperative, Inc.

February 15, 1988

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I. INTRODUCTION

Case No. 86-6809-A, Texas Utilities Electric Company vs. Tex-La Electric Cooperative of Texas, Inc., Texas Municipal Power Agency and Brazos Electric Power Cooperative, Inc., regarding various issues surrounding the Comanche Peak Steam Electric Station, is pending before the 14th Judicial District Court of Dallas County, Texas. This report is intended to cover the areas Nowell E. Rush of Ernst & Whinney will address in testimony presented in this case and a brief description of the basis for the conclusions we have reached.

The remainder of this report consists of two chapters. Chapter II presents our overall conclusions regarding the performance of Texas Utilities (TU) as a project manager for the construction of the Comanche Peak Steam Electric Station (CPSES). Chapter III presents the results of our evaluation.

II. OVERALL CONCLUSIONS

The role of the project manager in any large steam electric station construction project is difficult and complex. The project manager is charged with the responsibility of coordinating the available resources in order to meet the objectives of quality, schedule, and cost. A nuclear steam electric station construction project presents the project manager with an even more difficult task because of the more stringent requirements to which a plant owner commits so that the quality of the resulting plant will ensure the public safety.

At the Comanche Peak Steam Electric Station, Texas Utilities has failed in several key aspects of its project management responsibilities and that these failures have resulted in the inability of the company to receive the approval of the Nuclear Regulatory Commission (NRC) to license and operate the plant. An experienced and qualified project manager would not have allowed these failures to occur. An experienced project manager would have ensured that the project could demonstrate that a safe and reliable plant had been built.

TU simply failed to implement good management processes and, more critically, failed to heed the many warning signals it received throughout the life of the project. Those signals indicated that the systems TU had put in place in key and fundamentally important areas had inherent weaknesses and needed to be corrected. In many cases the identified deficiency was either ignored, discounted, or "corrected" in an ineffective manner. Warning signals came from a number of sources, including the NRC, outside consultants, and TU's own audits, and in the form of significant incidents taking place at the project. Good project managers understand and heed such signals so that underlying problems can be corrected. TU failed to do this.

Without a doubt, the responsibilities of the project manager at Comanche Peak, as at all nuclear power plants built in the 1970s and 1980s, posed a very difficult and challenging task. The technical requirements of a nuclear plant are extremely complex given the myriad of systems related solely to nuclear safety and the added complexity of other systems dictated by the need to ensure safe nuclear operations. The difficulty of the project manager role is exacerbated by the need not only to construct a quality, safe plant but to develop and maintain the documentation necessary to demonstrate this quality and safety. Notwithstanding these difficulties, a nuclear power plant construction program must meet and accomplish these challenges. Many utilities in the United States have successfully accomplished these project management challenges and today have safe and operating nuclear power plants. These utilities have been able to meet, and demonstrate that they have met, all their commitments to the NRC and other regulatory bodies.

Our analysis and evaluation of the company's project management performance was structured to determine what aspects, if any, have led to the inability of the Comanche Peak Steam Electric Station to be licensed and to determine if those elements should have been avoided. Our review initially focused on the fundamental duties of project management. These basic responsibilities include the necessity to establish management processes that direct and control the activities of many organizations and people. Our analysis indicates it was the failure of the Company to implement and control some of these key management processes that has directly contributed to the inability to license this plant and to the massive review and correction program currently underway.

As demonstrated in this report, we found that the Company had repeated failures in several key project management areas including:

- Procedure control and compliance
- Design control process
- Document control
- Training, indoctrination and certification of QA/QC personnel.

These management processes, while important in any major construction project, are of paramount importance in a nuclear construction project. The control of the design process, the effective use of procedures and the control of project documents are necessary to ensure that the plant is built to meet all safety requirements and that the project manager can demonstrate that these safety requirements have been met. Thus, the role of QA/QC personnel is unique and extremely important on a nuclear construction project because they are one of the critical links to ensure that safety requirements are met and can be demonstrated to have been met. Consequently, the unique role they play dictates that certain elements such as training and certification must be in place for them to fulfill their all important role.

The NRC requires that nuclear plant licensees commit to maintaining effective procedural controls through the development and maintenance of written procedures. Those procedures serve as standards to which the licensee is held accountable on future audits and, ultimately, for licensing. They play an important role in assuring the reliability and safety of a nuclear power plant and in being able to demonstrate that fact to the NRC. Procedures are used to control the design and construction of a power plant by defining acceptable methods for accomplishing specific tasks and defining the acceptable or expected results of those tasks. As is demonstrated in this report, the procedure control and compliance process at CPSES broke down and was not able to achieve completely its intended purpose. In spite of frequent signals and warnings given to TU that this process had widespread weaknesses, there is no evidence to indicate that the company ever understood the severity of the problem nor took the appropriate steps to make fundamental corrections. TU's inability or unwillingness to ensure the establishment of required procedures, maintenance of those procedures, and compliance with those procedures and to take adequate corrective actions in response to identified deficiencies is a failure of TU to fulfill a key project management responsibility.

In order for a complex project such as a nuclear plant to be designed and constructed, the activities of large, diverse organizations must be properly controlled and coordinated. Fundamental to this process is the task of adequately defining the technical design criteria and ensuring adherence to these criteria through the production of detailed design drawings and specifications that accurately reflect the "as-installed" condition. This process for controlling design and engineering documents must include measures to ensure that the final product satisfies the licensee's commitments, safety criteria specified by regulatory agencies, applicable codes issued by professional technical associations, and sound engineering principles. The result of this process is a safe and reliable plant.

It is the responsibility of the project manager to control the design process and the associated documentation in order to demonstrate that the plant can be operated safely. Our analysis indicates that TU did not assume adequate control of the design process and, consequently, failed in its responsibility as project manager. As in procedure control, there were indications throughout the course of this project that there were weaknesses and failures in this management process. TU responses, however, were neither broad nor comprehensive enough to correct the deficiencies that ultimately led to the December 1983 finding by the Atomic Safety Licensing Board that TU did not demonstrate the existence of a system that promptly corrected design deficiencies and led the ASLB to suggest the need for an independent design review.

A project manager must implement a document control process that effectively disseminates information among the various engineering, construction and project management areas so that construction and design are coordinated and that configuration control is maintained. The Company's project management approach to and implementation of the document control process at Comanche Peak did not satisfy its obligations in this area. TU's actions failed to meet or satisfy the NRC requirements regarding document control and consequently TU has been unable to obtain an operating license for the plant. There were clear indications that this process was not implemented in a way that would accomplish its intended purpose. TU appears to have attempted modifications and corrections to the document control system but they too failed to correct the problems that existed. A project manager with nuclear experience would not have allowed this to occur nor would it have tolerated its continued existence over any extended period of time. TU allowed the situation to continue uncorrected until well into the project life. We believe that this is a significant failure on the part of TU in discharging its project management responsibilities.

The importance of the QA/QC function on a nuclear power project cannot be overstated. Licensing ultimately relies on the QA/QC function to help demonstrate that all safety requirements have been met. Its importance has long been recognized by the utility industry and the NRC. One of the major requirements of ensuring that the QA/QC area is fulfilled successfully is the training, indoctrination and certification of the personnel that play crucial roles in demonstrating the safety of a power plant project. Various industry standards exist that identify the minimum standards acceptable for training, indoctrination and certification. TU and the rest of the nuclear industry commit to those standards as part of their nuclear power program. Our review found that numerous examples existed at CPSES of unacceptable staffing, inadequate qualification or problems with training of QA/QC personnel. Repeated instances such as these led to the NRC's Technical Review Team finding in 1985 that " . . . TUEC's training and certification program lacked the programmatic controls to ensure that the requirements in 10CFR50 Appendix B were achieved and maintained." Clearly the project manager on a nuclear construction project has the responsibility of ensuring that the requirements in 10CFR50 are achieved. Further, at CPSES, the project manager is the same party who committed to the NRC that it would meet that standard.

Given our conclusions regarding the failures of Texas Utilities as project manager, the question arises of how a utility that has successfully constructed fossil fuel power plants can experience failures so fundamental to the successful completion of this project. We believe that a major underlying problem at CPSES was the lack of nuclear industry experience within the senior project team. Based on the organization and experience records reviewed to date, it is clear that prior to 1984 senior project management personnel lacked significant levels of nuclear industry experience. Significant experience was not brought to the project until 1984 and later, well after it was recognized that CPSES had serious problems. This lack of experience by the senior project managers was exacerbated by the selection of an architect/engineer and construction manager that also had only limited previous nuclear construction experience.

A lack of nuclear experience can have serious consequences on a nuclear construction project. This fact is supported by findings of the Nuclear Regulatory Commission Office of Inspection and Enforcement. NUREG-1055, issued in 1984, stated that the failure to include adequate nuclear construction experience on the project team was a major factor in project management failures. It stated that:

> The principal conclusion of this study is that nuclear construction projects having significant quality-related problems in their design or construction were characterized by the inability or

failure of utility management to effectively implement a management system that ensured adequate control over all aspects of the project. Each of the major quality-related problems cited . . . was related to breakdowns or shortcomings in the implementation of the project's quality assurance programs; however, the quality assurance program's deficiencies had as their root cause shortcomings in corporate and project management. At several projects, breakdowns in the quality assurance program were part of larger breakdowns in overall project management, including planning, scheduling, procurement, and oversight of contractors.

There are two major corollary findings associated with management capability and effectiveness. First, in today's environment, prior nuclear design and construction experience of the collective project team (defined as the architect-engineer (A/E), nuclear steam supply system manufacturer (NSSS), construction manager (CM), constructor and owner) is essential, and inexperience of some members of the project team must be offset and compensated for by experience of other members of the team. Each member of the project team should assume a project role consistent with its prior nuclear experience and not overstep its capabilities. A false sense of security growing out of prior success in fossil plant construction led several first-time utilities into underestimating the complexity of nuclear design and construction. This miscalculation resulted in the assembly of a project team that lacked the requisite experience, background, and management capability, individually or collectively, to successfully design and construct a commercial nuclear power plant without the development of significant quality problems. Although prior nuclear design construction experience of the collective project team appears necessary for future plants, it is not sufficient to assure the completed construction of a quality nuclear plant. . .

Although it is necessary that each team member assume a project role commensurate with its capability and prior experience for project success, it is not sufficient. Prior nuclear construction experience of the utility owner is particularly helpful, although not mandatory if the corporate entities comprising the rest of the project team are sufficiently experienced and if the utility and the other members of the project team assume project roles consistent with their respective levels of nuclear experience. However, the utility is ultimately responsible for the project, and it cannot delegate its management and oversight responsibilities to others. This thought was summarized well by the Deputy Administrator of one of the NRC regional offices:

> It is essential that a utility undertaking the construction and operation of a power reactor facility have strong project management capability within its own organization to enable independent owner direction and assessment of overall management and assurance of quality of the project.

Another essential characteristic of a successful nuclear construction project is an understanding and appreciation of the complexities and difficulties of nuclear construction by top corporate management that manifests itself in a project management approach that includes adequate financial, organizational, and staffing support for the project; good planning and scheduling; and close management oversight of the project and the project contractors. Other factors contributing to project success include strong management commitment to quality and support for the quality program that starts at the top of the corporate structure and flows down through project-level management to first-line supervisors and foremen; involvement of top corporate management in the project; commitment of resources sufficient to complete the project in a quality manner; careful selection of key project staff; an atmosphere that encourages looking for problems and solving them; an openness to ideas for improvements; effective project interfaces; and understanding of the symptoms of poor management practices; use of the quality assurance program as a management tool, rather than as a substitute for management; and an understanding of the role, mission, and constraints of the NRC.

Nuclear construction is sufficiently different from and more complex than fossil construction that fundamental changes to utility's corporate structure and project approach may be necessary to successfully complete the project.

It is clear that many of the problems experienced on the CPSES project are similar to those discussed in NUREG-1055. While TU lacked nuclear experience and chose to hire major project team participants that also lacked significant nuclear experience, that it in no way relieves TU of the responsibility it assumed to ensure that project management duties were fulfilled in appropriate ways. TU could have hired personnel with strong nuclear experience, as other utilities did, or could have sought the assistance of outside consulting firms that provide this type of expertise, as other utilities did. TU, however, did not bring in experienced nuclear personnel at the senior project manager levels until it was clear that CPSES had problems so pervasive that the plant could not be licensed and a remedial program of reinspection, reanalysis and rework had to be performed. TU simply failed in this aspect of its project management role.

Project managers also recognize that there are key points in time during projects when management must reevaluate its own project management performance. TU apparently did not do so. For example, when TU elected to adopt an "at-risk" design approach, it should have ensured that it had the appropriate systems in place to support such a process and that it was capable of managing the project under that approach, assuming that such an approach was otherwise permissible. Instead, TU allowed already weak management systems to suffice even when warned as early as 1978 by an outside consultant that "the current site DC DDA system of after the fact coordination of design changes with the original designer provides a significant risk of design error . . ."

Similarly, in the early 1980's, it was clear that the NRC was beginning to scrutinize quality assurance activities at power plants more closely. The problems experienced at the Zimmer Nuclear Power Station and at the Midland Nuclear Power Station prompted many nuclear project managers in the industry to perform a self-evaluation to ensure that existing management processes would meet this closer scrutiny. If TU had performed such a self-evaluation, it would have been clear that the management processes evaluated in this report had significant weaknesses that had to be corrected. Consequently, we can reach no other conclusion but that Texas Utilities failed to exercise properly its project management responsibilities in certain key areas. That failure has led to completion delays, the inability of TU to obtain a license for this plant and the necessity to perform an ongoing program of reanalysis, redesign and rework of significant portions of the plant.

III. EVALUATION OF PROJECT MANAGEMENT

The role of the project manager on a nuclear construction project is extremely important. Virtually all commercial nuclear projects built during the 1970s and 1980s experienced, throughout their life, changes pertaining to project management organization, philosophy and function. These changes were due at least in part to the evolving complexity and extended lengths of the projects themselves. Project managers often adopted increasingly complex administrative controls, systems and organizations to address the challenges facing the nuclear industry and to ensure that the necessary safety requirements were met to ensure the construction of a safe plant.

The owner's project management role should be clearly defined early in the project. Due to the hundreds of complex functions required to complete a nuclear project, the role defined by the owner must be consistent with its own internal capabilities and experience. Assumption of project management responsibilities requires the owner to develop the expertise, resources and administrative controls necessary to execute the role properly. Throughout the 1970s and 1980s, utilities often chose to expand their project management roles and responsibilities in an attempt to maintain control of their nuclear projects. Project management at Comanche

Peak began in the early 1970s and continued to evolve to an arrangement in which the owner, Texas Utilities, assumed responsibility for the majority of project management functions associated with commercial nuclear construction.

This chapter presents the results of our review of Texas Utilities' project manager role in the construction of the Comanche Peak Steam Electric Station. Based on the information evaluated to date, we have identified five areas in which events and activities demonstrate fundamental flaws in TU project management:

- Procedure Control and Compliance
- Design Control Process
- Document Control
- Training, Indoctrination, and Certification of QA/QC Personnel
- Relations with QA/QC Employees.

The following sections present our results for each of these areas.

PROCEDURE CONTROL AND COMPLIANCE

Overview

Procedures have two basic purposes in a nuclear construction project. The first purpose of procedures is to outline an acceptable method for accomplishing a task. The second purpose is to define the acceptance criteria, or expected result, of the task. Through procedures it is possible to control the methodology employed in accomplishing a task, and communicate the expected result.

For procedural controls to work effectively, certain criteria must be satisfied. Among the most significant is the need for procedures to be clear and unambiguous. Procedures must also incorporate the pertinent technical requirements and clearly define when and where to perform the steps in relation to other activities. A good procedural control program will establish records to measure adherence to procedures. Even with the above criteria satisfied, the program will not work unless controls are established to assure that personnel using the procedures are sufficiently trained both technically and procedurally.

Procedural controls are commonly used in commercial, industrial, and even office environments. They are of paramount importance in nuclear power applications because of their role in assuring the reliability and safety of a nuclear power plant. The NRC has mandated effective procedural controls by requiring that licensees develop and maintain written procedures, which then serve as the standards to which the licensee is held accountable on future audits and, ultimately, for licensing.

To appreciate fully the specific importance of procedural controls in a nuclear power plant construction project, it is important to understand the magnitude of such a project. During the construction phase, up to 5,000 personnel can be employed at a site. In addition there may be several thousand off-site engineering and technical personnel directly involved with a project. These people possess widely ranging skills and are also subject to a high turnover rate. Obviously, all of the discrete activities performed by these personnel must be coordinated to ensure that technical requirements are ultimately translated into a safe and reliable operating unit. This is a situation that demands a well managed, procedurally controlled program to ensure that the necessary interfaces are established and that requirements are adequately documented and accomplished.

Adequate procedures serve as evidence that the plant has been designed and built in accordance with requirements. The onus is on the licensee to prove the quality of the plant. Without the documentation that procedures provide, proving the quality of design and construction would be expensive (i.e., repeating design checks and inspections) and in some instances perhaps impossible (i.e., verifying concrete mixes, weld root passes, the size of embedded rebar). This documentation forms the base for the NRC Safety Evaluation Report (SER). Ultimately, the granting of an operating license may hinge on the adequacy of documentation.

TU's procedural controls were deficient throughout the project. The NRC, third party consultants, and TU itself identified procedures that were not written, maintained, or properly distributed. Further problems were found with corrective actions regarding procedures. As late as 1985, the NRC's Technical Review Team (TRT) reported that the TU QA program was weakly implemented and that TU lacked the commitment to implement an effective QA program due in part to construction and inspection procedures in some areas that were "inadequate, contradictory, uncontrolled, or nonexistent." In addition to the numerous procedural deficiencies cited in Appendix P to Supplemental Safety Evaluation Report (SSER) 11, which presents the TRT's assessment of TU's QA/QC program, SSERs 7-10 further describe procedural deficiencies in the Civil and Structural, Protective Coatings, Electrical and Instrumentation and Test, and Piping and Mechanical areas. These reports were by no means the first indications to TU that there were procedural problems at all levels.

Facts

The following facts are based on our review of the documentation and testimony obtained thus far. These facts form the basis for the conclusions contained in this report.

Establishment of Required Procedures. In numerous instances throughout the project's life, TU management failed to ensure that necessary procedures were established. TU committed to providing these procedures in a timely manner in its Preliminary Safety Analysis Report (PSAR) and Final Safety Analysis Report (FSAR). In addition, the 18 criteria set forth in 10CFR50 Appendix B, and the requirements established by the American National Standards Institute (ANSI), stipulate that proper procedures be developed and maintained.

In the early years of the project, problems with procedures focused on the quality assurance program. As the project progressed, the evidence includes instances in which construction or engineering procedures were missing or inadequate. If these deficiencies had been isolated, their effect on the overall ability of TU to ensure that the plant is licensed could be minor. However, deficiencies of the same nature reoccurred over a span of years and thus are symptomatic of a failure by TU to manage the Comanche Peak project competently.

For example, TU was repeatedly cited for a lack of procedures to establish and define authorities, duties, and responsibilities of QA, Engineering, and Construction personnel. A 1973 NRC Inspection Report (73-02) found that Comanche Peak was in violation of Criterion I of Appendix B to 10CFR50 because neither the TU Corporate Quality Assurance Program nor the Comanche Peak Quality Assurance Plan (QA Plan) clearly established the duties of TU's QA Engineers. During a 1975 inspection, an NRC inspector noted that the Brown & Root QA/QC Manual for Nuclear Project (Brown & Root Manual) did not clearly establish and delineate in writing the duties and authorities of the site QA/QC supervisory staff. In the same inspection, it was found that the specific duties and responsibilities of TU's and Gibbs & Hill's QA staffs were not clearly set forth in the QA Plan.

In response to the inspection, Ashley (Brown & Root) informed Caudle (TU) that a draft of a procedure for the Brown & Root QA organization would be written by July 14, 1975. The procedure would establish the "authority and duties of supervisory positions." However, NRC Inspection Report 75-07 dated June 11, 1975 reported that no procedure yet existed to describe the authority and duties of Brown & Root site QA personnel. In addition, the QA Plan still did not address the duties and responsibilities of the site QA Supervisor and the QA group. Roughly two years after being cited for a procedural deficiency, TU still had not corrected the deficiency and the item remained unresolved.

Although by 1978 procedures delineating duties and responsibilities were eventually established, the findings in a report that year by Management Analysis Corporation (MAC) included an observation that current activities of TUGCO personnel were not consistent with the authority delegated to Brown & Root and Gibbs & Hill in the PSAR and the QA Plan. Also, the MAC report found that the authority delegations in the QA Plan were not consistent with those in the procedures. In a July 11, 1978 internal response to the MAC report, written by R. J. Cary and L. Fikar to P.G. Brittain, it was agreed that the QA Plan and procedures were complex; therefore, the Corporate QA Plan was currently under study with the goal of streamlining it.

In 1979, TU management reorganized its QA program. The major reorganization effort, described in NRC Inspection Report 79-18, included several changes in personnel assignments, organizational structures, and staff functions. At the time of the inspection report, TU was supposedly in the process of making the necessary changes to procedures to reflect the changes in functions and responsibilities. However, NRC Inspection Report 79-26/27 reported that the procedures had not in fact been changed to reflect existing functional responsibilities. When QA Audit TCP-6 was performed in 1980, several deficiencies were again noted in which procedures were inadequate to define the responsibilities in the organization.

In addition to the NRC inspection reports and TU internal audits, personnel at Comanche Peak gave clear signals to management that they were unsure of their duties, authorities and responsibilities. Any efforts made by TU management to streamline the QA Plan and procedures were apparently not perceived as effective by QA/QC personnel, as indicated in a series of interviews conducted in October of 1979. The concerns expressed by personnel in the interviews included uncertainty over who had authority over QC personnel and uncertainty over the duties and responsibilities of QC personnel. Although management eventually responded to the concerns expressed in the interviews and conducted follow-up interviews, it is significant that by 1979, QA/QC personnel were still uncertain about their duties and responsibilities.

Procedural deficiencies related to defining duties and responsibilities again surfaced in 1981. NRC Inspection Report 81-10 reported that no TUGCO operations procedures had yet been issued to address responsibilities and activities for instrument installations following the turnover to TUGCO by TU.

Nearly a full decade after first being cited by the NRC for a lack of procedures defining duties, authorities, and responsibilities, TU was told by an outside consultant that responsibilities remained unclear. In a 1982 report commissioned by TU, F. Lobbin recommended that a hierarchical system of policies defining objectives and responsibilities should be developed. The fact that duties and responsibilities were not yet clearly defined and understood by personnel at this late date in the project raises doubt as to the quality of management and work performed in prior years. TU management either ignored the signals it was given by the NRC and its internal audit program or it failed to respond to warning signs effectively.

Another example of recurring procedural deficiency is the failure to establish procedures for the regular review by TU management of the adequacy of the QA Program. An NRC Inspection Report in 1973 (73-02) reported that Comanche Peak was in violation of Criterion II of Appendix B to 10CFR50 because the Comanche Peak QA Plan did not contain procedures for management review of the status and adequacy of the QA Program. Over ten years later, in 1984, the NRC served TU with a Notice of Violation for this same procedural deficiency. NRC Inspection Report 84-32 described the deficiency as a failure to regularly review the adequacy of the QA Program, which is in violation of 10CFR50 Appendix B, as well as commitments made by TU in the PSAR and FSAR. TU did not establish procedures to review the adequacy of the construction QA program nor did it appear to have done so in prior years. Subsequent to this NRC inspection, the NRC Technical Review Team (TRT) issued a report in 1985 that concluded that the QA program was weakly implemented and that TU lacked the commitment to implement an effective QA program due in part to a lack of procedures to require regular reviews by senior management.

These examples of failure to establish required procedures are only a few of the incidents which occurred throughout the life of the Comanche Peak project. Procedural deficiencies also occurred in such areas as vendor surveillance, document control, QC inspection, and QA review of design documents. The primary significance of these deficiencies are the far-reaching implications the lack of necessary procedures can have on other aspects of the project such as training and indoctrination, document control, design change control, and the QC inspection program. Viewed collectively, these deficiencies point to a failure by TU management to ensure that its commitments to establish effective procedures are fulfilled and, on a broader scale, a failure to demonstrate the plant conforms to safety requirements.

Maintenance of Adequate Procedures. In addition to its failure to ensure that required procedures were established, TU management failed to ensure that those procedures were adequate to provide clear, current and consistent direction to QA/QC and craft personnel. Numerous instances indicated a lack of control over the proper maintenance of project procedures. Specific inadequacies include obsolete procedures, improper distribution of procedure manuals, confusing or unclear procedures, and incomplete or inconsistent procedures. The following incidents taken from NRC inspection reports, internal TU audit reports and third-party reports illustrate the failure by TU management to maintain effective procedures.

A 1973 NRC Inspection Report (73-02) pointed out several inadequacies including: (1) the QA Plan was not clear on the duties and responsibilities of QA Engineers, (2) the Corporate QA Plan committed to procedures in compliance with Criterion V, however the project QA Plan did not contain the necessary procedures, and the implementing procedures for the QA Plan for the audit program did not address ANSI requirements. NRC Inspection Report 74-02 found that the Brown & Root manual was deficient in that it did not contain detailed requirements that reflect the criteria in Appendix B to 10CFR50.

NRC Inspection Report 74-04 identified additional problems with Brown & Root's procedures. The report found that Brown & Root on-site construction procedures had not yet been fully developed. In response to similar deficiencies identified in internal audit TBR-1, TU stated that Brown & Root's Construction department had no apparent control over the preparation of construction procedures. An NRC inspection early in 1975 found the Brown & Root QA Manual to be further deficient in that the manual did not contain references to other Brown & Root QA/QC manuals in use, nor was it clear as to the manual's functional application to Comanche Peak. This deficiency was noted as unresolved in NRC Inspection 75-02 in late 1975. Problems with control over the development of Brown & Root procedures culminated in a January 28, 1975 letter from Schmidt of TU to Whitford of Brown & Root concerning the Brown & Root QA/QC Manual. Schmidt expressed his concern that there was a lack of control in the development of the Brown & Root QC Procedures Manual and other QA documents and that careless errors had been made in the procedures manual.

The problems were apparently not solved. NRC Inspection Report 75-12 reported that the inspector found difficulty in determining the manner in which Brown & Root identified, reviewed, accepted/rejected, and documented nonconforming items. NRC Inspection Report 76-03 reported that the appropriate QA procedure was revised in response to the deficiency.

By 1977, TU had been given numerous signals that many of the procedures for QA/QC and construction and engineering were not effective. MAC's 1977 review of Brown & Root found that the Comanche Peak procedures poorly defined the process for release of design documents. The 1978 MAC report prepared for Comanche Peak found that the QA Plan and procedures were not consistent and that the procedures were complex and difficult to maintain. Interviews of QA/QC personnel in October of 1979 revealed a concern about inadequate training on procedures and identified a need for additional training. Follow-up interviews conducted in 1980 indicated improvements; however, procedures were still thought to be confusing. Both series of interviews should have sounded alarms to TU management that procedures were neither clear nor effective.

The reorganization of the Comanche Peak QA program in 1978 included the assignment of additional qualified personnel to QA Engineering to provide more explicit direction in QA/QC procedures and instructions. Unfortunately, TU failed to follow up its effort with the appropriate changes to procedures. An NRC Inspection Report in late 1979 (79-26/27) identified numerous instances of inappropriate and obsolete procedures. A review of TU and Brown & Root manuals identified at least nine procedures that had been obsolete for two or more months. A Notice of Violation was assessed on TU because the situation was not in compliance with Criterion V of Appendix B to 10CFR50. Similar deficiencies were again identified by an internal audit (TCP-6), the results of which were issued in early 1980.

Thus while it appears that TU management attempted to solve some of the specific problems related to procedural inadequacies, the underlying, generic problems continued. Management pushed for a 1982 fuel load while its procedures for design, construction, and quality assurance remained unclear and ineffective.

Deficiencies continued to be identified in the period subsequent to 1982, further demonstrating a need for a reevaluation and clarification of procedures. Audit TCP-36 performed in early 1982 examined site QA/QC personnel training and identified a need to provide additional clarification of actual practices set forth in training procedures. In 1983, the NRC Construction Appraisal Team (CAT) issued its report which identified, among numerous other deficiencies, problems with improperly qualified welding procedures in the HVAC area. Also, NRC Inspection Report 83-23 identified several problem areas in need of attention that demonstrated a lack of procedural control and outdated procedures. QA Audit TCP-74, performed in

1983, identified several procedural deficiencies, one of which involved a lower tiered procedure that did not satisfy commitments of upper level documents in that it allowed design changes to be made without issuing a Component Modification Card (CMC) or Design Change Authorization (DCA). The audit also found that there were no programmatic controls to address and control the issuance of CMCs/DCAs against as-built verified hangers.

Audit TCP-87 found additional procedures that did not meet requirements. These procedures described activities in the areas of Piping Deviation Record Forms and corrective action requests, responses and follow-ups. Audit TUG-49 discovered that the independent review of Non-Conformance Reports (NCRs) by QA personnel was not provided for in the appropriate procedure. Two years later, NRC Inspection Report 85-18 found that the Design Change Control procedure still did not provide for the necessary review by and coordination of design interfaces.

These repeated occurrences of procedural deficiencies relating to the reporting of nonconforming items and corrective action are particularly significant in light of the numerous warnings given to TU management over the years. For example, while performing an aggregate study in early 1976, independent consultant Joseph Varela warned that the present system of handling NCRs was vulnerable and could cause future problems with the Atomic Safety Licensing Board (ASLB) that would prove to be embarrassing and costly. Also, the results of both the MAC study performed for Brown & Root in 1977 and the MAC study performed in 1978 for TU expressed concerns about the control of the nonconformance and design change systems.

Had TU management understood and been sensitive to the problems brought to its attention by these third parties, the NRC, and its own internal auditors, it would have made an attempt to discover and resolve the root cause of the problems. Clearly, ensuring that the procedures governing these activities and others were effective and complete would have been a logical step in solving its problems. However, the evidence in the years subsequent to the various warnings given to it suggest TU management chose otherwise.

Assurance of Adequate Compliance with Procedures. Viewed collectively, incidents identified over the years of the Comanche Peak project demonstrate that TU management experienced problems in assuring proper compliance with project procedures by QA/QC and craft personnel. Reoccurring construction deficiencies and inadequate inspections provide evidence that the procedures were not being followed and TU was not taking effective corrective action to resolve the deficiencies in procedure compliance. Specifically, reoccurring incidents were identified that involved failures to follow procedures in training, QA/QC, document control, engineering and construction. Failure to adhere to procedures over a wide range of activities throughout the project life compounds the effect. This compounding complicates TU's ability to demonstrate the installed plant's compliance with safety requirements.

As early as 1976, TU was given adequate warning that adherence to construction procedures was a problem. In an internal Brown & Root memo (January 26, 1976) to Munisteri, Gamon discusses Schmidt's (TU) dissatisfaction with the large number of construction deficiencies given the level of activity at the plant thus far. Nearly ten years later and after numerous incidents of failures to comply with construction procedures, the topic of discussion in an Operations Review Committee Meeting on January 13, 1984 was the results of QA Status Report 83-07, which showed a large number of deficiencies attributable to a failure to follow procedures. In a follow-up meeting, it was announced that the number of incidents of noncompliance had been declining in the past month, and close analysis could uncover no explanation for the large number of incidents that had taken place earlier.

In 1985, the Technical Review Team (TRT) found a series of incidents involving failures to adhere to training and certification procedures further illustrating the failure of TU management to ensure proper implementation of procedures. QA Audit TBR-5 conducted in 1976 found that Brown & Root procedural requirements were not always adhered to, specifically in the area of certification and examination requirements. In 1980, QA Audit TCP-6 found that procedures for indoctrinating engineering personnel had not been followed. Another audit in 1982 identified problems with following training procedures. The audit discovered that QA procedures were not adhered to for the training and certification of inspection personnel. Finally, in 1986, TU was given a Notice of Violation by the NRC for failing to follow procedures for the training of inspectors.

Following procedures to maintain and control the appropriate documentation also proved to be a reoccurring problem for Comanche Peak. In 1978, TCP-2 identified a failure by QC Inspectors to follow the procedure which required inspectors to maintain the necessary data. The IE inspector conducting NRC Inspection 81-15 determined that QC inspectors were not satisfying the records requirements of procedures. Also, the documentation for checklists had not been completely filled out as per the appropriate procedure. In the NRC Inspection 83-18, the Construction Appraisal Team (CAT) identified instances where Brown & Root procedures for document control were not followed. NRC Inspection Report 83-40 and QA Audit TCP-68 both identified failures to follow procedures for document control.

Failures to follow procedures relating to maintaining and controlling the proper documentation continued to occur. In a response to NRC Inspection Report 85-07, TU stated that the failure to follow procedures was due to the failure by personnel to properly prepare design documents, as well as inadequate control of safety-related work. The report issued by the Technical Review Team reiterated these findings. The specific significance to this particular management failure can be better understood by examining the findings presented in the document control section of this chapter.

When the failures to comply with all of these types of procedures are viewed collectively, they point to a larger breakdown in the QC inspection program. Had the QC inspection program been effective, the deficiencies resulting from failures to follow procedures would have been detected by the inspectors. Although instances in which inspection procedures were either inadequate or not adhered to were identified throughout the project, it was not until late in the project that the effectiveness of the inspection program was challenged.

NRC Inspection 83-23 found numerous examples in which the inspection program did not detect failures to meet construction requirements. In addition, results of the Construction Appraisal Team (CAT) inspection in 1983 demonstrated a breakdown in the fabrication, installation, and inspection of the Heating, Ventilation and Air Conditioning (HVAC) systems. These HVAC systems provide more than personnel comfort in nuclear power plants. Some of these systems serve safety-related functions including control of radioactive particles in the plant air, cooling for safety-related equipment, and allowing for control room habitation under certain accident conditions. The CAT report also concluded that TU's QA program did not ensure that certain HVAC equipment was installed and inspected to the latest design documents. Finally, in 1985, the TRT found numerous examples of ineffective QC inspections, demonstrating a failure by inspectors to follow procedures and/or inadequate inspector training. By 1986, TU could no longer deny that the QA program, and specifically the inspection program, had not been effective.

The preponderance of evidence illustrating numerous deficiencies in the establishment of, maintenance of, and adherence to Comanche Peak procedures supports TU's own admission that the QA program was not reliable to ensure a safe plant. The failure by TU management to ensure procedural compliance and adequacy contributed to the larger problems afflicting the QA/QC program.

Corrective Action in Response to Procedural Deficiencies. The three types of failures previously discussed were exacerbated by a fourth failure by TU management. TU management failed to ensure that adequate corrective action in response to procedural deficiencies was performed. For failures related to the development and maintenance of procedures, inadequate corrective action can result in both improper disposition of the specific item and recurrent deficiencies. The proper response to deficiencies in procedural compliance is two-fold. First, a disposition for the specific deficiency is required. Typically, a decision is made to rework the item or accept it "as-is". Secondly, a determination of the cause of the deficiency is made. Corrective action is then taken to ensure deficiencies do not recur.

Several specific findings in which adequate corrective action was not performed illustrate the overall trend with respect to this failure by TU management. The findings include examples of untimely responses, reoccurring deficiencies, ineffective corrective action and improper closeouts of deficiencies.

One example of a failure to respond promptly to and resolve a procedural deficiency involves control over the Brown & Root procedures. QA Audit TBR-1 examined Brown & Root project construction-related activities and identified several deficiencies concerning Brown & Root procedures. Two months later, in the reaudit of TBR-1, all items from the original audit had been closed. However, NRC Inspection Reports 74-04, 74-05, 75-01 and 75-02 all reported unresolved items related to Brown & Root construction and QA procedures. Following completion of revisions to the Brown & Root QA Program Manual and TU approval, NRC Inspection Report 75-05 considered the matter of the Brown & Root QA Program Manual closed. Unfortunately, the same or similar deficiencies related to Brown & Root's procedures continued to be identified throughout the next several years, as evidenced in the inspection reports and internal audits. In addition to failing to respond and resolve the deficiencies in a timely manner, it is evident that the measures that were instituted by TU were ineffective.

Another example demonstrative of inadequate corrective action relates to the effectiveness of TU's responses to procedural deficiencies for training and certification. TU was cited for deficiencies concerning training procedures early in the project. A 1973 inspection report found that the QA Plan did not contain procedures for the necessary training of personnel. In response to deficiencies identified in NRC Inspection Report 75-10, TU proposed corrective action which included additional classroom training of craftsmen and supervisors on the correct procedures and specifications. QA Audit TBR-5, performed in 1976, identified further deficiencies related to training and certification. The audit found that procedural requirements were not always adhered to specifically with regard to certification and examination requirements.

Following the reorganization of the QA program in 1979, NRC Inspection Report 79-18 reported that the position of Brown & Root QC Supervisor had been filled with an experienced person to improve the training and motivation of personnel. Additional personnel also were assigned to provide more explicit direction in QA/QC procedures. It appeared as if the necessary corrective action was being implemented. However, the series of interviews with QA/QC personnel conducted in late 1979 revealed dissatisfaction with the training on procedures. The follow-up interviews in 1980 continued to include concerns about confusing procedures, thus demonstrating that the actions taken by TU were neither effective nor complete.

This trend was further substantiated by the findings of QA Audit TCP-6 in 1980, which identified failures to follow procedures which were designed to ensure that Engineering personnel were aware of procedures. Two years later, QA Audit TCP-36 discovered that QA procedures were not adhered to for the training and certification of inspectors. The TRT Report issued in 1985 identified numerous deficiencies in the QC program due in part to failures to follow inspection procedures. Finally, the NRC assessed TU with a civil penalty in 1986 for failing to follow procedures for the training of inspectors. This series of findings relating to the development and maintenance of procedures for training and certification, as well as adherence to these procedures, is significant because it illustrates the ineffectiveness of TU's responses and the results of its failure to ensure adequate corrective action.

A third example of a failure by TU to ensure adequate corrective action for procedural deficiencies involves the development of vendor surveillance procedures. QA Audit Report TBR-5, issued on April 16, 1976, first identified that vendor surveillance procedures had not yet been developed by Brown & Root. Brown & Root responded to the deficiency by scheduling issue dates for the procedures. TU, however, notified Brown & Root on June 14, 1976 that the issue dates were not timely and that seven procedures were not addressed. TU's actions up to this point were reasonable in demanding a prompt and complete resolution by Brown & Root.

However, over six months later, the reaudit of TBR-5 (Appendix A to TBR-6) found that corrective actions had not been adequately implemented for the open items identified in TBR-5. Specifically, vendor surveillance procedures had not been completed or issued. Brown & Root immediately responded to the audit announcing that quality surveillance procedures had been rewritten and would be issued by January 26, 1977. TU found Brown & Root's response to be acceptable. Again, six months later, QA Audit TBR-8 identified as an open item the failure to complete and issue vendor surveillance procedures. By the end of 1977, the deficiency still remained open, over a year and a half after it was originally identified in TBR-5.

TU's handling of this incident is demonstrative of an overall failure to correct deficiencies properly.

A fourth example which illustrates a failure by TU to initiate effective corrective action relates to a deficiency identified in QA Audit TCP-18. The report, which was issued in late 1980, found that no measures had been established in the Pipe Support Design Group (PSDG) for the design review of Component Modification Cards (CMC), thus resulting in CMCs being approved without the supporting calculations. TU responded to its own internal audit by saying that "TUSI management accepts the liability of approving field design changes without supporting documentation." The deficiency remained open and eventually TU committed to issuing engineering instructions for the design review of CMCs in the PSDG. However, it was not until over a year later that TCP-47 finally verified that the corrective action had been implemented and the deficiency had been closed.

Conclusion

The failure to ensure adequate development of, maintenance of, and adherence to procedures, combined with TU's failure to ensure adequate resolution of these deficiencies, is only one of the many factors contributing to the breakdown in the effectiveness of TU's management of the Comanche Peak project.

The sheer magnitude of incidents reported and problems identified in procedure control and compliance is evidence that TU was not discharging its project management responsibilities in an acceptable manner. The weakness of TU's approach to procedural matters was identified early in the project and often thereafter. However, in spite of the clear signals received TU, it was never able to take effective control of its management of procedures. Its inability or unwillingness to establish required procedures, to maintain procedures, and to take adequate corrective actions in response to identified procedural deficiencies is one demonstration of TU's failed approach to project management. This failure was identified by the TRT and SSER 11 as contributing significantly to TU's inability to obtain an operating license.

DESIGN CONTROL PROCESS

Overview

In order for a complex project such as a nuclear plant to be designed and constructed, the activities of large, diverse organizations must be properly controlled and coordinated. Fundamental to this process is the task of adequately defining the technical design criteria and ensuring adherence to these criteria through the production of detailed design drawings and specifications that accurately reflect the "as-installed" condition. This process for controlling design and engineering documents must include measures to ensure that the final product satisfies the licensee's commitments, safety criteria specified by regulatory agencies, applicable codes issued by professional technical associations, and sound engineering principles. The result of this process is a demonstrably safe and reliable plant.

The techniques that the project manager and the A/E typically use to accomplish this task focus on establishing three important management processes. First, a process must exist to require managers, engineers, and technicians to incorporate the requirements into the design criteria. Second, a process must exist to provide independent design reviews which verify that the design criteria are met by the detailed design. Finally, because unforeseen difficulties such as space constraints, interferences, or changes in vendor equipment can warrant changes to the design (i.e., "as-built" conditions) a comprehensive control system must exist to verify that such conditions are documented and that the plant, "as-built," satisfies the original design criteria.

The process that ensures that "as-built" conditions are incorporated in the design is essential to project management's ability to demonstrate the safety of the completed plant. This process, typically referred to as "configuration control," requires close coordination between engineering and construction personnel.

Design control is particularly important in a nuclear power plant project for several reasons:

- Nuclear plants must successfully integrate the complex technical issues of the various engineering disciplines and distinct support systems onto a single comprehensive plant design
- Design deficiencies identified during construction and testing must be effectively resolved
- Technically complex mechanical, electrical and structural components must be successfully integrated into operating systems
- Requirements to ensure the operation and safe shut-down of the plant under postulated accident conditions must be fulfilled.

Certain events which have occurred demonstrate that TU's project management in this critical area was inadequate and failed to meet the standards TU was obligated to meet as a result of its contractual commitments, safety requirements and prudent management practices.

For instance, in its December 1983 decision, the NRC's Atomic Safety Licensing Board found that the NRC should not proceed with issuing an operating permit for CPSES because of deficiencies in the management process that TU used to control the development of detailed design documents. In its decision, the ASLB found that "TU had not demonstrated the existence of a [management] system that promptly corrects design deficiencies and has not satisfactorily explained several [technical] design questions . . ." An April 1983 report by an NRC Construction Appraisal Team (CAT) noted that there were various methods used by TU to address and resolve certain nonconformances in the plant's design. The CAT report concluded "the design change process at CPSES is complex, and at times, cumbersome." The resulting implication of the CAT's inspection is that the process was ineffective. The same CAT inspection team concluded that the process used to control the development of drawings and specifications at CPSES was not adequate to ensure that the resulting design produced and constructed was safe.

Throughout the history of this project TU was given clear warnings that the design control process it employed had not functioned effectively, and in fact, appeared to deteriorate until TU management focused on this area in 1984. TU's inability to resolve these problems is particularly troubling when considered in the context of TU's adoption of an "at-risk" approach to the design process. (The at-risk concept is addressed below in the section entitled Control of the Field Design Process). Such an approach in and of itself should have mandated a control program that was more tightly run than the program TU employed.

Facts

The following facts are based on our review of the documentation and testimony obtained thus far. These facts forms the basis for the conclusions contained in this report.

TU's performance as manager of the design process exhibited significant weaknesses, particularly a lack of control of the process itself and over field design changes. It is not any one incident that leads to this belief, but rather it is the number of incidents identified, the repetitive nature of the problem, and the apparent inability of TU to resolve its difficulties or to address the root cause of the problem. When taken as a group, these facts paint a picture of a project manager who either failed to anticipate problems, failed to address problems as they arose and were brought to its attention, or took actions that were inadequate or inappropriate to resolve design control problems.

Establishment of a Comprehensive Design Control System and Assurance of Procedure Compliance. The original project concept for the review of the design documents was contained in the Project Guide, which was in effect from the inception of the project in 1974 until about 1983. During the time the Project Guide was used to control the design process, numerous instances of serious violations, inconsistencies, and disregard of the established design development practices were documented. As early as 1974, TU's own staff concluded that sections of the Project Guide "conflicted with Gibbs & Hill's own internal procedures" for development of the design, detailed drawings and specifications. In addition, TU also discovered that other guidelines contained in the Project Guide were not being followed. For instance, TU discovered in its QA audits that Gibbs & Hill's procurement process for CPSES equipment was not adequately defined and documented. Specifically, a TU QA audit concluded in 1974 that Gibbs & Hill had not completed any internal design reviews of the preliminary plant drawings by that date. At that time the design for the plant was already 15% complete. This deficiency indicated that many of the fundamental technical decisions affecting the extent to which the design of the plant met safety requirements had already been made but the impact of the decisions had not been assessed. Although the TU reports often recommended action to correct the problems, TU never exercised its responsibility as project manager to see to it that the problems were resolved.

Similar problems were identified in later reviews of Gibbs & Hill's design development practices and Gibbs & Hill's interface with TU's engineers. In 1975, the NRC found that TU's management methods for accomplishing corrective action or identifying deficiencies in designs were not resulting in the actual accomplishment of their intended purpose. TU's own QA audits of Gibbs & Hill gave similar indications. As a result of these audits, Gibbs & Hill acknowledged that compliance with its internal procedures for processing design changes, internal distribution of design and vendor drawings, and the designation of safety-related plant systems as such on design documents were not being followed. In 1976, more detailed inspections of procedural compliance performed by the NRC (NRC Inspection Report 76-08) found TU to be in violation of 10CFR50, Appendix B, Criterion V. In at least three of the limited number of areas examined, NRC inspectors found drawings whose distribution and updating were not controlled by Gibbs & Hill and Brown & Root according to QA requirements and that Gibbs & Hill and a subcontractor had failed to incorporate approved design changes into design specifications and work procedures according to requirements. During the same time period, a management review of the design deficiency review and resolution process demonstrated that changes were needed to increase control over the process. The review concluded that TU's process of resolving NCRs could expose it to licensing risk before the ASLB.

In a separate report in 1978, MAC found that the "system of after-the-fact verification of design changes provided a significant risk of design error." In addition, MAC found that the Design Change/Design Deviation Authorization (DC DDA) system was in noncompliance with 10CFR50

Appendix B and ANSI N45.2.11. The TU internal response to the MAC Report's findings was disagreement with both of the points above. As a result, the design change system was left unchanged. The consultant found further that the process was poorly defined, with a multitude of methods for initiating changes in controlled drawings and that this resulted in a process that was difficult to comprehend, maintain and keep consistent. In 1980, 1982, and 1983, similar instances of failures to ensure that adequate procedures were followed to provide effective design control were also noted. The findings show that the root cause of the problem was never adequately addressed and certainly never resolved.

The Project Guide did not contain any provisions for verifying that internal TU departmental review of Gibbs & Hill designs met applicable NRC or industry standards. It was not until 1983 that TUGCO Nuclear Engineering began to issue procedures directed at this problem. The first of these procedures covered processing design change orders and associated paperwork. Shortly thereafter, TU's own auditors disclosed that a continuing pattern of noncompliance with even these newly adopted procedures existed. The audits also disclosed that the newly issued procedures contained internal contradictions and needed revisions. In 1983, the ASLB found that TU's design control system was deficient and suggested that an independent design review be conducted. Again, in 1984 a Special Review Team reported that deficiencies still existed in the area of configuration control. Thus, more than 10 years after the project started, and more than three years after the plant was initially to have been on line, TU still had not achieved control of the design process. Similar problems relating to violations of the design control procedures were again disclosed in 1985.

At about that time, TU's internal audits also found that internal procedures for maintaining the integrity of computer programs used in making design calculations had not been followed, resulting in the incorporation of unauthorized changes into these programs. TU internal audits also found that specifications for equipment had not been properly reviewed and approved in advance of the specifications being adopted.

Control of the Field Design Change Process. As early as 1974, TU knew of problems with Brown & Root's drawing and specification distribution system. TU's own auditors noted that procedures that were in place were not being followed and that the required quality assurance oversight of the resolution of field design changes was ineffective. Although the timely resolution of field design changes was not critical to the project schedule at the early stages of the project due to the limited number of changes, it was to become so as the project neared completion.

By 1976, Brown & Root had obtained the results of a study that examined the overall process of resolving Design Deficiency Reports (DDRs). The study recommended that extensive changes be made to the system that was in place, and noted that unless the changes recommended were made "the ASLB might hold up licensing because of the problems" associated with the process then in place. Brown & Root took no issue with those findings and committed to make changes in its internal procedures to enhance the verification of enforcement of its procedures. Notwithstanding such promises, by 1977 TU was still finding that the previously identified problem existed and that "a majority of the previously identified corrective actions" had not been implemented. In 1977 TU began to make significant changes in the overall process of field design changes.

In 1977, in response to construction delays caused by the lack of timely engineering response to construction problems, TU directed that Gibbs & Hill approve construction NCRs prior to the approval and design review by Gibbs & Hill's engineering department. Gibbs & Hill warned TU that this policy decision exposed the project to the risk of backfitting.

This policy decision marks the beginning of TU's implementation of an "at-risk" design approach. This approach requires careful administrative control of the design documentation. The administrative controls must ensure (1) that the most current design documents are used to install and verify the installation; (2) that design change documents, which reflect the "as-built" condition, are independently verified to the same extent as the original design; and finally, (3) that modifications which are required to correct deficiencies in the design detected in the independent verification process are implemented in the field.

In 1978, as part of a more extensive review of TU's management. MAC concluded that the at-risk approach of design control contained significant consequences for QA monitoring of CPSES work and that the problems might lie with the elements of design control affected by the at-risk approach which were subject to QA plan requirements. Specifically, MAC concluded that TU's present system of managing the control of field design changes might not meet CPSES' own QA plan and the plant's PSAR. Thus, this approach exposed CPSES to fundamental licensing risks. Fundamentally, the TU approach to design control was one that permitted "after-the-fact" design review. The inherent risk of such an approach is the exposure to rework if the original design does not "prove out" in the design review process. The potential impact of rework on project cost and schedule must be evaluated when such an approach is undertaken.

Given the early point in the project's life that this policy was adopted, the volume of design changes typically incurred in a project this size, and the number of vehicles provided to effect a design change, the approach required a major commitment of administrative resources to control the design successfully.

Conclusion

Taken as a whole, these findings show that TU did not ensure that adequate control of the design process was provided. Moreover, TU chose to pursue an at-risk design approach without establishing an effective control system to track and detect design deficiencies.

Design control is a critical area in the construction of a nuclear power plant. An experienced, competent project manager would have recognized the criticality of this area and assumed a level of control significantly beyond that demonstrated by TU during the course of this project.

DOCUMENT CONTROL

Overview

The document control process used on a nuclear construction project must effectively disseminate information between the various contractors and project site areas. If project management fails to satisfy its role in the control of document flow or allows the flow of information between necessary groups to deteriorate, the integrity and safety of the design and construction of the project can become unverifiable to the NRC.

Craft and QA/QC personnel must have the most current drawings and procedures for construction and inspection activities. The obvious consequences of a failure to maintain current documentation in the field are construction and inspection deficiencies. Construction and QA/QC inspections may in fact be adequate but the plant may ultimately not be licensable if project documentation is not sufficient to demonstrate this adequacy to the NRC. In nuclear construction, any doubt about whether construction is consistent with approved design specifications presents two options. Either construction must be reworked to ensure conformance with design, or engineering must evaluate, verify, and approve the as-built conditions as acceptable. Both of these options represent negative cost and schedule impacts.

At the outset of the project TU assumed an approach to design review and document control that is common in the industry. However, in response to developing circumstances, TU in 1977 adopted an at-risk approach to design and construction. The at-risk approach imposes additional burdens on the document control process and on the design change control process.

Not only must the document control process control the flow of information from engineering to construction, but it must also control the flow of as-built design information back to engineering. Based on the as-built design information, engineering must verify and approve the safety of construction and update the plant design documentation. Having elected an at-risk approach, TU should have realized that an increased level of effort would be required to meet its document control obligations.

TU management's approach to and implementation of the document control process at Comanche Peak did not satisfy its obligations or the requirements necessary to obtain an operating license. Evidence of failures in the document control process was found in the dissemination of drawings and procedures. Incidents reported throughout the life of the project, and the findings of various regulatory and outside consultants support certain conclusions about the overall impact on the project of TU's failure to manage Comanche Peak's document control process properly.

Facts

The following facts are based on our review of the documentation and testimony obtained thus far. These facts form the basis for the conclusions contained in this report.

Project management at the CPSES site was repeatedly cited for its failure to ensure that relevant drawings and updated procedures were available to construction and inspection personnel. TU practices in this area were inconsistent with sound project management and contrary to commitments made by TU in the PSAR and FSAR.

For instance, TU had received repeated signals that the Comanche Peak project QA program had difficulties in disseminating documents. NRC Inspection Report 73-02 reported that in violation of Criterion II of 10CFR50, Appendix B, most of the QA Plan manuals used to manage the project contained only two or three procedures although five procedures were reported to be fully implemented. Remarkably, the QA Plan did not contain a procedure implementing the requirement that documents be distributed to and used at the locations where the quality-related work is being performed.

NRC Inspection Report 75-06 noted that a Brown & Root QA manual assigned to a member of the Brown & Root field staff was observed to be outdated. Brown & Root responded that procedure revisions were being sent to the site Document Control Center for distribution and that Brown & Root would provide each holder of controlled documents computer printouts of up-to-date revisions and require periodic file verification. Brown & Root believed that those changes would resolve the identified problem.

In 1977, a report commissioned by TU and issued by Management Analysis Corporation (MAC) found that in violation of Criterion III, 10CFR50 Appendix B, the system used to control the release of design documents was poorly defined in Comanche Peak procedures.

The next year, a TU QA audit (TCP-1) described a situation where in spite of a QA commitment to establish procedures to ensure that the latest approved drawings were available and used at work stations, drawings at pipe fabrication work stations were not the latest versions. Therefore, in addition to violating regulatory commitments relating to document control, as-built pipe at this work station was fabricated using outdated design specifications.

Procedures were still missing or not yet approved by 1981, after TU had already applied for its operating license. As reported in Inspection Report 81-10, the NRC inspector found that no TUGCO procedures had yet been issued regarding instrument installations, to address the responsibilities, activities and documentation requirements of the operating utility (TUGCO) after release and turnover of the safety-related instrument systems, subsystems, and components by the construction utility (TU).

NRC Inspection Report TCP-65, issued in 1983, identified several procedural deficiencies relating to the control of design documents. First, no check-out/check-in control was being implemented and the corresponding design change documents were not being maintained at the same location as the drawings. In a second deficiency, numerous documents were found at issue stations that were not current or adequately controlled. Finally, a controlled drawing, which was not stamped with any identification, was found lying in the parking lot. Each of these deficiencies is indicative of ineffective control over design documents.

Also in 1983, the NRC CAT Team identified problems with drawing control that made it difficult to ensure that certain equipment was installed to the latest design documents. J.B. George, the Project General Manager, expressed a similar concern at that time, recognizing that corrective action had to be taken. Shortly after the CAT report was issued, an internal TU memo reported that corrective action had been taken in response to the problems. The current document control method was revised by replacing it with "satellite" Document Control Centers (DCCs).

In a follow-up response to QA Audit TCP-68 in 1983, the auditors recommended a refresher course in document control procedures. Further, approximately two months later, QA Audit TCP-74 found additional deficiencies in the control of design documents.

TU QA Audit Report TCP-84 was issued on November 15, 1983. It listed eight deficiencies and three concerns about the CPSES Document Control Program but concluded that the stated deficiencies were minor and did not affect the overall effectiveness of the CPSES Document Control Program. The auditor stated that the revised TU system was in its infancy and should be reevaluated when it is more mature. The deficiencies included the lack of document control procedures, inadequate assurances that access to controlled documents was limited to authorized individuals, incorrect revisions of drawings at work stations and failure to monitor the Document Control Center (DCC). Some of the identified problems were however significant in that they were system-wide deficiencies that required program corrections to prevent reoccurrence.

As late as 1984, the operating instructions used to control the DCC satellites, those offices in which document flows occur, were withdrawn by TU because TU's procedures did not conform with established Brown & Root procedures.

The evidence gathered on site by the Technical Review Team (TRT) of the NRC reveals that the document control system at the Comanche Peak site was neither effective nor consistent in its provision of documents for construction practice and records. The Document Control Center (DCC) satellites, which were phased in between February and August 1983 to improve document handling, were found to be issuing incomplete or inadequate document packages to craft personnel. Examples of the types of document control problems identified by the TRT in 1984 included:

- Drawings released to the field were not current
- Drawings and specification changes were not current
- Design documentation packages were incomplete
- DCC did not provide the satellites with up-to-date drawings and document revisions
- Drawings hanging from an open rack, which had no checkout control, were available to craft and QC personnel
- Design change logs were inaccurate
- Design documents were not always properly accounted for in DCC
- Current and superseded copies of design documents were filed together
- Satellite distribution lists were inaccurate
- Discrepancies existed between drawings at the satellites and those in the DCC
- Some drawings were missing from the satellite files
- Telephone request for design documents resulted in the issuance of documents that bypassed the controlled distribution system.

Project management failed to ensure that revisions to site drawings and procedures were complete and up to date. In fact, project management appears to have not understood the serious consequences of poor document control in terms of cost, scheduling and verification of construction quality.

Another problem that existed in this area was that, contrary to the CPSES QA Plan, there was no formal QA/QC interface with the package flow control group, which is required for proper document control. This deficiency was noted by TU itself in Audit Report TCP-106. Almost concurrently, it was also discovered that some drawing packages had non-applicable Design Change Authorizations (DCA) and/or Component Modification Cards (CMC), or contained non-ASME drawings with a large number of unincorporated revisions.

In SSER 11, the TRT group concluded that "although many of the document control inadequacies have been corrected, the implications of past inadequacies on construction and inspection have potential generic significance which has not yet been fully analyzed by TUEC."

Conclusion

Overall we believe that TU management did not do an acceptable job of implementing the document control process at CPSES. This is another critical area that can have, and has had, serious implications. As a result of inadequate document control, TU was unable to provide documentation to satisfy NRC licensing requirements. Partially as a result of this failure, TU failed to receive an operating license for CPSES.

TRAINING, INDOCTRINATION AND CERTIFICATION OF QA/QC PERSONNEL

Overview

The NRC long ago recognized that nuclear power was a complex technology requiring specialized activities and processes in order to properly design, construct and operate a safe nuclear facility. One of its major mandates was to require training, indoctrination and certification of the specialized activities critical to safety. The Nuclear Industry interpreted this requirement in two ANSI standards--N45.2-6 "Indoctrination, Training and Certification Requirements During the Construction Phase of Nuclear Power Plants," and N18.1, "Qualification and Training Requirements for Operating Nuclear Power Plants." TU and the rest of the nuclear industry adopted those standards as part of their nuclear power program. The two ANSI standards not only identify minimum standards for indoctrination, training and certification, but also provide for auditing the training program and the maintenance of training records.

Training, indoctrination and certification take many forms at the nuclear construction site. Indoctrination is an activity that all new employees undergo to understand the project's goals and priorities. It also conveys basic information regarding administration, safety, work rules and the project's expectations of the workers.

Training is an activity performed by the company to develop or polish employees' skills which facilitate their performance of normal, specialized, or complex tasks. Most project managers have recognized the critical importance of training to ensure that employees perform even the most basic of skills well. Good training practice not only ensures quality, safety and employees satisfaction in a job well done, but also lowers costs by reducing rejects, scrapage and rework.

Certification is an extension of the training program in that it recognizes the level of proficiency attained and sets up minimum standards or criteria necessary to attain a particular level. A good certification program also helps promote quality, safety, lower costs and employee satisfaction.

Training, indoctrination and certification can occur within all functions and levels at a nuclear power plant. For example, most nuclear projects have general indoctrination and training programs regarding QA requirements and administrative processes for all employees on the project. Often, projects will hold special training programs for employees who work with especially complex activities or procedures. In other cases, the NRC requires training and certification programs for specialized processes important to safety such as non-destructive examination (NDE), pressure vessel welding, cad-welding, and others. In all cases where training, indoctrination, and certification affects a safety-related activity, the required training is specified and the project manager is required to maintain records of the individuals trained along with quality records of the activity performed.

Due to the safety requirements regarding training as well as the industry's general acceptance of its importance in positively affecting quality, safety and cost, E&W expected to find well developed indoctrination, training and certification programs in place with strong evidence of training records management. However, at CPSES numerous examples, particularly in the QA/QC area, of insufficient staffing and of inappropriately trained personnel working in areas and functions critical to safety were found. Audit findings of poorly developed training programs at times during the project when such programs should have been fully operational were also reviewed. We found reports of improperly maintained or missing training records and documentation. Individually, these items may not be critical or fatal but they do reflect training program deficiencies. When reviewed collectively, however, we believe they point to an overall failure on the part of TU project management to recognize the system-wide nature of these problems and to comprehend the impact these problems had on its ability to demonstrate the quality of systems important to safety.

Facts

The following facts are based on our review of the documentation and testimony obtained thus far. These facts form the basis for the conclusions contained in this report.

Staffing of QA/QC Functions and Qualifications of Personnel. Signals of inadequate staffing and personnel qualifications were available to TU throughout the life of the project. An early signal of certification problems came in a TU self-audit in April of 1976, when TU identified that Brown & Root procedural requirements were not always adhered to, specifically concerning certification and examination requirements. Nine months later, TU found that the corrective action for this deficiency was not adequately implemented. Over one year after the first audit identifying this problem, Brown & Root had not yet remedied the situation. As project manager, TU had the responsibility to see that certification and examination requirements were met in all levels of the organization.

Maintaining a qualified QA/QC staff, and specifically inspectors, was a recurring problem for TU. In 1975, TU recognized that considerable effort would be required to maintain control of the Brown & Root QA program and fulfill QA staffing needs. TU was aware at this early time of the need for improved QA staff qualifications. Independent consultants MAC, in May 1978, and Lobbin, in his first report issued in February 1982, identified continued deficiencies in inspector qualifications. In a 1984 NRC memo, the list of open issues included unqualified QA/QC supervisory personnel. Despite TU efforts to hire more qualified inspectors, the problems persisted. By 1985, TU had still not solved the problem identified almost nine years earlier. Even at that late date, the NRC's TRT identified seven inspectors with questionable qualifications. Similarly, they stated that "[d]uring the peak site construction period of 1981-2, TUEC employed only four auditors, all of whom had questionable qualifications in technical disciplines." In 1986 the NRC issued a Notice of Violation and civil penalty based on TRT findings, stating that TU failed to ensure that QC inspectors were properly qualified and certified. The NOV also cited the numerous deficiencies found by the TRT in the site inspector qualification and certification program. Thus, a problem first identified by TU itself in 1975 resulted in an NOV more than ten years later.

Lack of previous experience was a qualifications problem found across reporting levels as well as functions, including management, construction, and start-up. For example, in 1976, Brown & Root identified the inexperience of TU upper management, and specifically the inexperience in nuclear matters of then-Project Manager Schmidt and then-QA site Supervisor Milam, as potential problems at CPSES. In a report submitted to TU in 1982, an outside consultant stated that the overall low level of nuclear experience was "the prime contributing factor to other areas of concern," he had. His concerns included the experience levels of construction personnel and qualifications of QC inspectors. Lack of nuclear start-up experience was later identified as a problem, further broadening the functional areas affected.

Provision of Necessary Training Documentation. Management documents, such as the QA Plan and procedures, are used by project management to ensure that requirements are met. As is any project manager of a nuclear construction project, TU was required by the NRC to produce a QA Plan that met certain outlined plans for the project, including those for training. TU committed first in its PSAR and later in its FSAR to meet the requirements set out by 10CFR50 and ANSI, including requirements concerning the proper procedures for training QA/QC personnel. Throughout the life of the project, the NRC, independent consultants, and TU itself found that TU was remiss in meeting these requirements.

For instance, in 1973 the NRC included in its Inspection Report 73-2 that the QA Plan did not include the necessary training procedures. In 1974, the NRC more specifically identified the need for revision of TU's QA Plan regarding "Indoctrination and Training of Personnel" so that it would provide at least the minimum training required. TU identified further procedural problems on the project in a 1977 audit of Brown & Root, finding that procedures found lacking in 1976 were still not available. In 1978 the MAC Report identified that the QA Plan and procedures did not completely address the eighteen criteria of 10CFR50 Appendix B, notably those relating to this area. In 1982, TU identified the need for clarification of procedures for training of inspection personnel. The Comanche Peak Review Team (CPRT) in 1984 examined two procedures, "Training of Inspection Personnel" and "Documentation Within QA/QC Personnel Qualification File" and found both to be deficient. Thus, even at that late date, the inspector certification program was found not to be in compliance with safety requirements. The CPRT concluded that "lack of experience of involved individuals likely contributed to the preparation of inadequate procedure revisions." Project management simply did not, over a significant period of the project, have in place the procedures necessary for successful execution of the QA function.

Training and Training Documentation. Again, as in qualifications and procedures, TU had many indications throughout the project that its training programs required improvement. The problems however persisted and eventually resulted in an NRC Notice of Violation in 1986.

Through the late 1970s and early 1980s, TU identified in its internal audits and audits of Brown & Root that training of QA/QC personnel was inadequate or could not be verified. Further, in repeated SERs and SSERs, the NRC discovered training deficiencies. Specifically, they noted deficiencies in the inspector testing and certification program, identified instances of craft not properly trained on specific procedures, and noted an instance of craftsmen receiving inadequate instructions. In 1982, Lobbin found in his second report that certain training programs were not well-defined. Also in 1982, a Systematic Assessment of Licensing

Performance (SALP) report issued by the NRC found that TU failed to properly indoctrinate and train personnel performing activities affecting quality. The following year, an NRC Construction Assessment Team report identified further inadequacies in inspector training. The NRC's Technical Review Team stated in their 1985 report that "TUEC's training and certification program lacked the programmatic controls to ensure that the requirements in 10CFR50, Appendix B were achieved and maintained." This deficiency resulted in a 1986 Notice of Violation and civil penalty.

After repeated demonstrations of problems with the program, TU should have known that unless it took effective corrective action, its training program would not satisfy safety requirements or its PSAR and FSAR commitments. Consequently, TU would not be able to demonstrate that a safe plant had been built.

Conclusion

Training, indoctrination and certification are important aspects of nuclear project management. Experienced managers readily recognize the need to devote time resources and attention to this area. TU, however, either never understood this requirement or chose not to take the steps necessary to meet the needs presented by this area.

RELATIONS WITH QA/QC EMPLOYEES

In 1984, EG&G Idaho, Inc. issued a report commissioned by the NRC which reviewed allegations of employee harassment at the CPSES site. The report explained that:

> Organization climate is essentially a perceptual phenomena. . . . Elements such as task requirements, the nature of interfaces, relationships among co-workers, the quality of supervision, the amount and nature of communication, and the equity of the reward system are all important in influencing the perception of the total climate.

The organizational climate at any work site can have a profound impact on the ability of personnel to function effectively. Major construction projects tend to be rigid, hierarchical organizations, where potential sources of conflict are institutionalized. For example, at a nuclear construction site, the inherent nature of the relationships between the crafts people and the QC inspectors clearly has the potential to be adversarial. Crafts focus on maintaining production schedules and may often view quality control personnel as obstacles to meeting those schedules. A nuclear construction site organization is particularly vulnerable to the effects of low employee morale because of the potential negative impact on the quality and safety of the ultimate product.

Project management must be aware of the impacts that organizational climate and morale can have on both the quality of the work performed and the productivity of the personnel involved and must commit the resources, time and attention necessary to minimize employee relations difficulties so they do not escalate to the point that the work product suffers. This need to maintain a positive organizational culture is not unique to the nuclear industry. Every large construction project, including fossil fuel projects, necessarily contain the potential for conflicts leading to worker dissatisfaction and low morale.

Given Texas Utilities' past construction experience, this is one area in which particularly competent project management could be expected. Instead, evidence was found of an environment of worker discontent and of management's inability to overcome effectively the problems that existed in the area of management relations with personnel in the QA/QC function. We found evidence that TU's management style created a tense and stressful atmosphere, and that TU's reactions to problems relating to employee morale were, on occasion, ill-conceived and counterproductive.

The NRC investigated employee relations at the project in 1979 (79-15). The NRC concluded that although major organizational changes undertaken in 1978 had strengthened the QA/QC program, the repeated allegations concerning construction problems at Comanche Peak suggested a morale problem attributable in part to communication problems between the workers and supervisors. In 1985, Appendix P to SSER 11 reported that the Technical Review Team found that the employee relations problems in the QA/QC area had resulted from conditions which had existed for a significant period of time prior to 1984. The TRT determined that TU senior management had not been actively involved in the site QA/QC activities and that design engineering activities had not been effective in providing craft and QC personnel with adequate procedures, instructions, and other design documents. It further found that some craft personnel appeared to be insensitive to QA/QC concerns possibly because of lack of training, tight schedules and excessive emphasis on construction schedules by construction management personnel. The review team noted that quality management was lax in its responsibilities to direct and oversee an effective site quality control program.

In light of the vital service QA/QC provides to management in ensuring that a nuclear facility is safe and can be demonstrated to be safe, TU management's attitude towards QA/QC personnel needs was surprising.

One particular incident highlights management's attitude towards QA/QC personnel matters. Several workers arrived at the site wearing T-shirts emblazoned with the phrase "Comanche Peak Nitpickers--We're in the Business of Picking Nits." In reaction to this, QC supervisors segregated those QC inspectors from the general workforce, alleging that they had been guilty of disruptive behavior. Then without authority or permission, QC supervisors proceeded to search those inspectors' workplaces. An investigation of the incident by TU revealed that the QC inspectors wore the T-shirts as a sign of unity rather than an attempt to disrupt work at the site. A subsequent investigation by the NRC revealed that TU's investigation had been done in a superficial manner. Whether or not TU's investigation revealed the true state of affairs, a reaction to employee behavior that includes sequestering of inspectors and a search of their workplaces is hardly typical of a work environment in which morale is high and cooperation is encouraged. Such a reaction could only serve to perpetuate a climate of low morale and discontent.

The T-shirt incident was recognized by the NRC in a May 1986 Notice of Violation (NOV) as an "unwarranted over-reaction by CPSES management that was reasonably likely to dissuade QC inspectors from reporting safety concerns." Also included in the NOV was an early 1983 incident of intimidation involving a QC inspector at CPSES. A former Brown & Root QC inspector alleged that she was instructed by her supervisors to sign off a number of liner plate travelers which the inspector believed were inadequately documented. Interestingly, recent depositions revealed that certain key upper management personnel were unaware of this incident.

The management reaction to the "T-shirt incident" is particularly surprising in that TU had been clearly warned that there were morale problems and concerns in the QA/QC area in a series of interviews conducted on site in 1979 to address problems identified in a TU internal audit. The interviews were conducted with site civil QC inspection personnel, QA administrative personnel, QA/QC site surveillance personnel, site protective coatings QC personnel, site QC receiving inspectors, site QC test lab personnel, QA/QC staff personnel, site electrical QC personnel, site NDE personnel, site QC documentation personnel, site instrumentation QC personnel and site mechanical personnel. Virtually everyone interviewed voiced some concerns about training, documentation, management, communication or other major problems. The diversity of the group interviewed and the views expressed is certainly an indication of the extent and complexity of the site problems TU was experiencing.

For instance, QA/QC personnel expressed the opinion that, instead of supporting their vital function, management was too production oriented. They stated they had been informed that documentation they produced needed to be only 90% complete. They also felt that there had been inadequate planning and coordination of their function to allow them to do quality work. As a result, work load and program effectiveness suffered. The interviews also revealed that some QC personnel felt that their supervisor was unqualified. They pointed out that the supervisor in question lacked control of the group and that in their opinion his decisions were based on personal opinion rather than on valid inputs. They expressed concerns that the supervisor's knowledge of the specific job they were doing appeared to be marginal and that the supervisor's verbal instructions were disrupting the group's ability to work as a unit.

One concern that was expressed in the interviews by the QC personnel that should have been particularly disturbing to TU as a project manager was that some personnel did not know whether Texas Utilities or Brown & Root was in charge of the QC Department. Quality control personnel noted that there were no job descriptions and consequently they did not understand their job scope, duties, responsibilities or authority. Providing that type of information to a workforce is basic to any personnel management process and its absence here, in this critical area, was quite surprising.

Another cause of low employee morale expressed by quality control personnel was management's propensity to issue too many verbal instructions, some of which were in conflict with specifications, procedures or code requirements as the personnel understood them. QC personnel felt particularly insecure in those situations because they believed that management would not support them if and when conflicts arose.

Yet another source of quality control personnel discontent related to basic employee relations matters such as questions concerning pay scales, promotional opportunities and their perception that doing a competent job would be counterproductive to their personal career objectives.

There were other signals of potential morale problems in the QA/QC area in the periods following the interviews. For example, there were allegations of harassment throughout the period. While EG&G Idaho, Inc., found that in general, management responded appropriately to the individual allegations, it concluded that "if management were to deal with the general pattern as well as isolated symptoms in order to improve the relationships between superiors and subordinates and to build a good strong working relationship among QA, QC and the crafts, then appearances or perceptions of intimidation might be significantly reduced."

Based on the information reviewed, we conclude that management had weaknesses in the working environment that TU created for QA/QC personnel that were counterproductive to the construction of a safe and licensable nuclear facility.

DAMAGES TO

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

AND

TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.

RELATED TO PARTICIPATION IN

COMANCHE PEAK STEAM ELECTRIC STATION

REPORT OF

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February, 1988

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Report of
Whitfield A. Russell

I. INTRODUCTION

This report presents the findings of a study of monetary damages suffered by Brazos Electric Power Cooperative, Inc. ("Brazos" or "BEPC") and Tex-La Electric Cooperative of Texas, Inc. ("Tex-La") as a consequence of, among other things:

1. the excessive cost and delayed commercial operation of the Comanche Peak Steam Electric Station ("Comanche Peak" or "CPSES"); and

2. Texas Utilities' failure to deliver low-cost power from CPSES.

Brazos' excessive construction expenditures have been approximately $187,000,000. Tex-La's excessive construction expenditures have been approximately $86,000,000. Both figures are stated as of year-end 1988. These damages are based on inservice dates as represented by TU to Brazos and Tex-La at the time they bought into the project. Brazos' cost of replacing power not available from Comanche Peak (expressed in 1988 dollars) has been $32,618,539 through December 31, 1987, and is expected to reach $45,594,202 through 1989, the most recently forecast completion date provided by the plant's majority owner, Texas Utilities. Tex-La's cost of replacing power not available from Comanche Peak has been $32,631,874 through year-end 1987 and is expected to reach $41,122,120 through 1989.1/ If Comanche Peak is cancelled at year-end 1989, Brazos' cost of replacing its output will reach $205,258,551 through 2018; Tex-La's cost of replacing its output in the event of cancellation will reach $133,241,037 through 2020. Grand totals of both construction-related damages and replacement power costs are $392,331,004 for Brazos through 2018 and $129,505,986 for Tex-La through 2020. See Table 2 and Table 3.

Brazos and Tex-La have filed suit against Texas Utilities Electric Company ("TUEC") in connection with Plaintiffs' participation in TUEC's Comanche Peak.2/

Comanche Peak is a 2,300 MW nuclear project originally scheduled by TU for commercial operation in 1980 (Unit 1) and 1982 (Unit 2). In June 1979, Brazos Electric Power Cooperative signed the Joint Ownership Agreement ("JOA") with TU for a 3.8% share of Comanche Peak (87.4 MW). At the time Brazos signed the JOA, the inservice date for Unit 1 was 1981 and for Unit 2 was 1983. Tex-La signed the JOA in December, 1980 and closed on its final share of 2 1/6% of the project in May 1982. At that time, Unit 1 was expected in service in 1984 and Unit 2 in 1985.

1/ These results are stated assuming a judgment is rendered in 1988. If the judgment is rendered after 1988, the payments must be adjusted for the time value of money.

2/ Brazos and Tex-La are defendants in TUEC's original suit for a Declaratory Judgment although the three nominal defendants are in fact seeking damages through a counterclaim. Accordingly, we refer to Brazos and Tex-La as Plaintiffs herein to reflect the substance of the lawsuit.

Although Plaintiffs were led to expect power from Comanche Peak beginning in 1981, the estimated inservice date for Unit 1 is now sometime after 1989. Expenditures have exceeded several previous estimates, and estimates of completion costs have increased steadily from approximately $1.7 billion (at the time Brazos signed the JOA) to the latest completion cost estimates of $5.46 billion (TU Annual Report for 1985) and $6.7 billion (the Wall Street Journal in December, 1986). These most recent estimates are already obsolete by TU's admission; TU has stated that it expects to make a new estimate shortly. The history of TU's delays and cost overruns is summarized in Table 1. Although TU's method for calculating plant costs uses different capital costs than does that of the co-owners, thereby understating total Comanche Peak costs, it is useful to compare the sequence of cost estimates and estimates of commercial operating dates TU has made over the years.

The estimates shown in Table 1 do not reflect the entire cost escalation at Comanche Peak because they do not reflect the fact that TUEC's customers are paying a rate of return plus income taxes on a portion ($1,286,067,000 since 1984) of the Construction Work in Progress or "CWIP" associated with Comanche Peak. This accounting practice is referred to as putting CWIP in the rate base. TUEC customers have paid $254 million in 1985 and in 1986, and $233 million in 1987 as a consequence of having Comanche Peak CWIP in the TUEC rate base. Thus, published estimates of completion cost mask a major hidden cost of delay, a cost that mounts with each day of delay.

Brazos contracted for Comanche Peak entitlements in June, 1979 based upon TU's representations as to the estimated completion dates (1981 and 1983) and completion costs ($739/KW) at that time. Tex-La's acquisition of a 2 1/6% share of Comanche Peak became final in May 1982. At that time, estimated completion dates of 1984 and 1985 were in effect and TU's representations as to the estimated completion cost was $1,454 per KW.

II. SUMMARY AND ORGANIZATION OF DAMAGES

Damages are defined as the difference between (i) the actual costs the minority owners have incurred and can be expected to incur ("Case A") less (ii) the lower costs the minority owners would have incurred in the past and would incur in the future if their entitlements to Comanche Peak had been available when they should have been ("Case B")[3]/. A slightly different formulation will define damages in a cancellation or rescission scenario.

Not only do the co-owners not have a projected date for the completion of Comanche Peak with which to compute damages, the

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[3]/ Costs incurred by the co-owners to date in "Case A" are a matter of record. Costs which should have been incurred, Case B, are also known. Damages cease accruing when the plant goes in service; however, without an inservice date, damages are not precisely calculable. TU has withdrawn its last forecast of a completion date and an estimated completion cost. TU's December 31, 1987 Long-Term Peak Load and Resource Forecast (a document filed annually at the Texas Public Utilities Commission or TPUC) states:

> "The attached forecast is predicated upon the projection that commercial operation of Comanche Peak Unit 1 will be achievable in early 1989 and that commercial operation of Comanche Peak Unit 2 will be achievable in late 1989. In November, 1987, it became apparent...that the early 1989 projected date for commercial operation of Comanche Peak Unit 1 is no longer achievable..."

co-owners have no real basis on which to project that Comanche Peak will enter service at all. Accordingly, damages have been calculated under two sets of assumptions for the actual, or Case A, scenario. One assumption is that the units enter service in 1990, and the second is that the units are cancelled. Assuming rescission is the remedy, Brazos and Tex-La will receive their payments back with interest.

Damages result first from construction cost overruns (including interest costs) as a consequence of TU's failure to complete Comanche Peak within budget and on time. Additional damages such as the higher cost of replacement energy and capacity, flow from TU's failure to complete the units. Other types of damages have not been considered.

For purposes of calculation and discussion, two major subcategories of damages are defined:

1. DAMAGES FROM CONSTRUCTION DELAYS AND COST OVERRUNS

These damages are the amount by which the funds laid out for the construction of the actual Comanche Peak plus interest have exceeded the amounts that should have been laid out plus interest.

The magnitude of these damages is highly sensitive to the inservice date as shown below:

DAMAGES FROM CONSTRUCTION
DELAYS AND COST OVERRUNS
FOR THE PERIOD ENDING
SEPTEMBER 30, 1987

INSERVICE DATE	BRAZOS	TEX-LA
1. January 81/January 83	$166,000,000[4/]	
2. January 84/July 85		$64,800,000
3. January 85/July 86	$51,000,000	$47,200,000
WITH INTEREST THROUGH 12/31/88		
4. January 81/January 83	$187,000,000	
5. January 84/July 85		$85,900,000
6. January 85/July 86	$72,000,000	$68,300,000

4/ Using the alternative August 1, 1981 inservice date for Unit 1, damages for Brazos are $162,000,000.

2. DAMAGES FROM LOST POWER SAVINGS

Tex-La and Brazos have experienced additional damages attributable to lost savings in capacity and energy costs. This category of damages arises from the fact that co-owners have had to generate or purchase high-cost energy that should have been displaced by low-cost energy from Comanche Peak. The replacement energy for Brazos has come from its generators and other utilities. Brazos has purchased capacity from the Texas Municipal Power Pool in 1986 and 1987, and those capacity purchases are projected to increase substantially in the years ahead. Replacement power damages have been calculated for Brazos for the period to date and separately for the years after 1987 through 2018.

It is important to recognize that as part of the arrangement to acquire a share in CPSES, Brazos and Tex-La had to agree to restrictions governing interstate operations, making the buying or selling of power and energy interstate (i.e., outside of ERCOT) essentially impractical. This constraint on interstate purchases precludes interstate purchases of replacement power for Comanche Peak. This disability, which is insisted upon by TU, added to the cost of delays in that each co-owner was limited to ERCOT sources of replacement power.

Damages to Brazos for replacement power are shown on Table 2.

Tex-La has purchased capacity from TU to replace capacity unavailable from Comanche Peak.

In addition, Tex-La has experienced damages related to the fact that TU would have reflected the costs of its own share of Comanche Peak in its rates.

TABLE 2

BRAZOS DAMAGE SUMMARY

REPLACEMENT ENERGY PLUS ADDITIONAL PURCHASE COST

	FOR 1981/1983 START-UP	FOR 1985/1986 START-UP
THROUGH 12/31/87	$ 32,618,539	$ 5,783,216
THROUGH 12/31/89	$ 45,594,202	$18,758,879
THROUGH 2018	$205,258,551	$64,769,074

GRAND TOTALS

CONSTRUCTION COST OVERRUNS PLUS REPLACEMENT POWER COST

	FOR 1981/1983 START-UP	FOR 1985/1986 START-UP
THROUGH 12/31/87	$219,690,992	$ 77,924,284
THROUGH 12/31/89	$232,666,655	$ 90,899,947
THROUGH 2018	$392,331,004	$136,910,142

Replacement power damages arise from the fact that in connection with placing CPSES in service, TU (i) would have changed its rates to Tex-La for firm power that Tex-La would continue to purchase from TU, (ii) would have begun purchasing Tex-La's share of Comanche Peak at a profit to Tex-La and (iii) would have commenced offering several types of services that it does not now offer separately to Tex-La. These services include installed reserves (Reserve Capacity), spinning reserves, partial requirements service (Supplemental Power & Energy) and backup energy.

Damages to Tex-La for replacement power are shown on Table 3.

These calculations represent my best judgments which were necessary in the absence of complete data. Data for a more precise calculation is in the control of Texas Utilities. TU has taken the position that it need not provide substantial quantities of that essential information which information is uniquely within TU's possession and control. In light of TU's position, I have calculated approximate damages based on publicly available data. TU's refusal to provide essential data coupled with its inability to project a completion date and completion cost for CPSES have substantially impeded my calculating a precise amount of damages.

TABLE 3

TEX-LA

REPLACEMENT ENERGY

PLUS ADDITIONAL PURCHASE COST

	FOR 1984/1985 START-UP	FOR 1985/1986 START-UP
THROUGH 12/31/87	$32,631,874	$ 21,078,168
THROUGH 12/31/89	$41,122,120	$ 31,820,587
THROUGH 2020	$38,565,551	$ 28,893,020

GRAND TOTALS

CONSTRUCTION COST OVERRUNS PLUS REPLACEMENT POWER COST

	FOR 1984/1985 START-UP	FOR 1985/1986 START-UP
THROUGH 12/31/87	$118,572,309	$ 89,364,834
THROUGH 12/31/89	$127,062,555	$100.107,253
THROUGH 2020	$124,505,986	$ 97,179,686
CANCELLATION		$219,181,472

TABLE 1

HISTORY OF COMANCHE PEAK COST INCREASES AND DELAYS OF INSERVICE DATE

DATE OF COST ESTIMATE	CAPITAL COST ($/KW)
March 31, 1975	333
March 16, 1976	429
October 29, 1976	600
March 20, 1978	739
July 22, 1980	972
October 26, 1981	1,454
January 24, 1985	1,984
November 20, 1985	2,374
November 25, 1986	3,300

DATE OF INSERVICE ESTIMATE	INSERVICE DATES: UNIT ONE	UNIT TWO
March 19, 1973	1980	1982
October 29, 1976	1981	
February 7, 1977	1981	1983
July 22, 1980	1982	1984
October 26, 1981	1984	1985
December 22, 1983	1985	1986
January 24, 1985	Early 1986	Mid-1987
November 20, 1985	Mid-1987	End 1987
January 31, 1986	August 1, 1988	
November 25, 1986	Early 1989	Summer 1989

III. ALTERNATIVES FOR CALCULATING DAMAGES

Damages are intended to give Plaintiffs what they bargained for. In the case of Comanche Peak, Brazos bargained for two nuclear units, one to be placed in service in 1981 and another to be placed in service in 1983. Brazos was led to expect completion costs of $739 per kilowatt for those completion dates. At the time Tex-La closed on the acquisition of a 2 1/6% share in May, 1982, Tex-La was led to expect Unit 1 in January 1984 and Unit 2 in July 1985. TU itself stated in 1984 that Unit 1 was complete. I have calculated damages based on both (i) the promised inservice dates for each of Brazos and Tex-La and (ii) the date at which the Company declared Unit #1 complete.

Determining damages which flow from the contested actions of a defendant is quite straightforward, at least in concept. First, one hypothesizes the events which would have unfolded if the contested actions had never happened. Once the alternative sequence of events is hypothesized, one sums the costs which Plaintiffs would have incurred under the hypothesized scenario and compares those costs to the higher costs incurred, or estimated to be incurred, in real life. The difference is damages.

I first calculated damages for historic periods because those damages are "locked in". In other words, historic damages require no forecasts of CPSES completion dates, revised TU expansion plans, or forecasts of completion costs, load growth, fuel prices, etc. Most of the data essential to calculating historic damages are known. However, a precise quantification of historic damages is not possible at this point. Data essential to the quantification are being withheld by TU.

INSERVICE DATES

Calculating reasonable costs requires that Brazos and Tex-La select reasonable inservice dates and a stream of reasonable payments to TU. The amounts and sequencing of the reasonable payment stream are essential ingredients in determining AFUDC or capitalized interest charges. One must know the amount and timing of each capital expenditure for a reasonable plant and then accumulate interest on that stream of expenditures to arrive at a total "reasonable" cost.

TU's estimates of the reasonable payment stream associated with several inservice dates have been found, but for other inservice dates, data are very sketchy.

For Brazos, the earliest reasonable inservice dates for Comanche Peak Units 1 and 2 are January 1981 and January 1983. The first recital in the Joint Ownership Agreement identifies the years 1981 and 1983 as the point in time when each respective unit was "expected to go into service" and page 17 specifically refers to January 1981 and January 1983 as best effort dates for timely completion of the units. TU documents dating from 1977 give January 1981 and January 1983 as the then-current official expectation.

A December 28, 1979 letter from Mr. L. F. Fikar of TU Services, Inc., to Brazos submits an estimate "...for closing with Brazos for the Comanche Peak Joint Ownership Agreement in accordance with Paragraph 2.02 of the Agreement." It indicates a commercial operating date of August 1981 for Unit 1 and January 1983 for Unit 2 and provides an estimated stream of payments for TU and Brazos with nuclear fuel payments separately specified.

For Tex-La, I have calculated damages using inservice dates of January, 1984 and July, 1985. These are the inservice dates in effect when Tex-La closed on its 2 1/6% share of CPSES.

For each inservice date to be studied, Tex-La and Brazos must hypothesize what would have happened to each of the elements of its costs and operations and to the costs and operations of TU in order to determine damages. As noted previously, this has proven difficult because of TU's refusal to provide essential data and to update its estimates of actual completion costs and completion dates for CPSES.

ASSUMPTIONS FOR CALCULATING DAMAGES

Three sets of inservice dates have been considered for damage calculations:

1. 1981 for Unit 1 (January or August) and January 1983 for Unit 2 (Brazos only);

2. January, 1984 for Unit 1 and July 1985 for Unit 2 (Tex-La only); and

3. January 1985 for Unit 1 and July 1986 for Unit 2 (Tex-La and Brazos).

The 1981/1983 inservice dates are the dates that TU represented in 1977 and 1979 were reasonable and on which Brazos relied when signing the JOA. Those dates appear in the first "Whereas" clause of the JOA.

The 1984/1985 inservice dates were in effect when Tex-La finalized the acquisition of its share.

The 1985/1986 inservice dates are those which were in effect in 1984 when TU declared that Unit 1 was complete. This is the scenario for which the most data is available.

In an effort to comply with the deadline for submission of this report, I have made calculations assuming inservice dates for which data is publicly available. Although damages resulting from these calculations might be different if based on more precise data for the 1985/1986 inservice date and on now-unavailable data for the other inservice dates, the methodology has been developed in considerable detail. If TU provides the necessary data on its own system, I shall make the alternative calculations. The only elements of Brazos' and Tex-La's damages that are not included herein are those which TU's own conduct has made impossible to provide.

IV. DAMAGES FROM CONSTRUCTION DELAYS AND COST OVERRUNS

Both Brazos and Tex-La have stopped advancing money to TU for Comanche Peak construction. Thus, as time goes on, construction cost damages will increase by the amount of accrued AFUDC until the units are placed in service. As noted previously, the direct damages expressed in 1988 dollars are:

CONSTRUCTION COST DAMAGES [5]

INSERVICE DATE	TEX-LA	BRAZOS
January 1981/January 1983		$187,000,000
January 1984/July 1985	$85,900,000	
January 1985/July 1986	$68,300,000	$ 72,000,000

A. METHODOLOGY

Damages were calculated by subtracting the cost of a reasonably priced Comanche Peak from the actual costs incurred by each of Brazos and Tex-La. Brazos' and Tex-La's actual payments to TU and detail of financings from the Federal Financing Bank ("FFB") were readily available. If either co-owner borrowed an amount greater than needed to meet its payment commitments to TU and meet its quarterly interest obligation on previous financings,

5/ These damages do not include internal Tex-La or Brazos costs, such as costs related to this litigation, nor do they include other elements of damages discussed elsewhere in this report and by other experts.

the excess funds were placed in the bank. The interest earned by these accounts was used to reduce costs.

Amounts borrowed from the Federal Financing Bank were adjusted to match the co-owners' requirements for the reasonable plant. AFUDC and interest earned by the bank account were recalculated under the reasonable scenarios.

The actual and reasonable damage simulations were done using computer programs called DAMAGEA2.FOR (Brazos) and DAMAGEA3.FOR (Tex-La). Brazos' actual payments were modeled from the original buy-in in 1979 through the final payment in May 1985 with interest added through September 30, 1987. Tex-La's actual payments were modeled from the buy-in in 1982. AFUDC for both was calculated through the final payment in May 1986 to a cutoff in September 1987. Two plant simulations were done. Payments to TU for Unit 1 and AFUDC were modelled from the original buy-in through the projected commercial operation date of Unit 1. The simulation for Unit 2 covered the period from the buy-in through the projected in-service date of Unit 2.

Because we do not have an inservice date for the future (and because TU has not provided an estimate), I cannot yet determine those future damages, but I shall do so as soon as the information is provided. We have considered every dollar of expenditure in excess of those dollars which should have been expended to be damages. For damages expected to be incurred in future periods, Brazos and Tex-La will determine those future damages, but those calculations cannot yet be made.

V. REPLACEMENT POWER DAMAGES

A. Brazos

Brazos is a member of the Texas Municipal Power Pool and uses gas and oil in its generating units. Brazos buys firm power from the San Miguel lignite plant and buys power from TMPP and other utilities. Had CPSES been in operation in 1981, Brazos would have displaced the power it generated and purchased with the output of CPSES and would have made additional sales to other utilities. In 1986 and 1987, Brazos would have bought less firm capacity from TMPP. Brazos actually bought 162.6 megawatts at a cost of $18,000 per megawatt-year in 1986 and 159 megawatts at the same rate in 1987. Brazos' replacement power damages are:

DAMAGES FOR REPLACEMENT POWER

(1981/1983 INSERVICE DATE)

YEAR	REPLACEMENT ENERGY	REPLACEMENT CAPACITY	LESS TRANSMISSION	NET DAMAGES
1/81-7/81	$ 1,348,200		$ 305,900	$1,042,300
8/81-12/81	$ 963,000		$ 218,500	$ 744,500
1982	$ 2,110,000		$ 524,400	$1,585,600
1983	$ 6,712,000		$1,048,800	$5,663,200
1984	$ 5,688,000		$1,048,800	$4,639,200
1985	$ 5,383,000		$1,048,800	$4,334,200
1986	$ 325,000	$1,573,200	$1,048,800	$ 849,400
1/87-7/87	$ 792,000	$1,573,200	$1,048,800	$1,316,400
8/87-12/87	$ 565,714	0	$ 0	$ 565,714
THROUGH 1988	$23,886,914	$3,146,400	$6,292,800	$20,740,514

NET PRESENT WORTH IS $31,070,000.

METHODOLOGY

Brazos' replacement power damages were determined through the use of a computer program named PCOST which measures the impact of C manche Peak energy upon Brazos (and the Texas Municipal Power Pool (TMPP)). The PCOST technique involves simulating the marginal production costs, hour by hour, for the TMPP system. To accomplish this, the program commits and dispatches gas-fired generating units for the TMPP members (Brazos and TMPA) collectively and individually both with and without the Comanche Peak energy. The simulations, which are replications of historical (i.e., without Comanche Peak) operations, are referred to as Case 1 studies. Simulations which include Comanche Peak generation are termed Case 2 studies. Each case study includes three scenarios -- (1) the TMPP system comprised of TMPA and Brazos, (2) Brazos generating to meet its own needs and (3) TMPA generating to meet its own needs. For each hour of the period the program produces six estimates of the marginal production costs on all or a part of the TMPP system.

The program begins with the native loads for each pool member, reduces the pool load by the fixed energy schedules (hydro generation, lignite generation and, when appropriate, Comanche Peak generation), adjusts for the off-system transactions and then commits and dispatches the gas-fired generating units to meet the system load and reserve requirements. If the estimate of gas-fired generation exceeds the residual load, the model attempts to resolve this by first reducing the off-system purchases and then reducing the lignite generation. If there is no feasible solution at that point, the model will report any remaining energy as "excess generation."

An integral part of the modeling system is the internal calculation of intrapool energy transactions. The value of intrapool transactions is based upon a concept of shared benefits (primarily based upon split savings but with a recognition of the intertemporal problems associated with minimum loads and other non-traditional costs related to load carrying responsibilities). By comparing costs in the stand-alone scenario within each case for each of the members to their respective costs in the combined system scenario, an estimate of the relative hourly costs of production is obtained. This estimate reflects not only relative instantaneous production cost differences within a given system configuration but also reflects differences attributable to the various generating unit configurations between the scenarios.

Once the model has calculated the internal cost of production for each case, a comparison between the cases is performed. The result of this comparison is the estimate of the impact of the Comanche Peak generation on the system cost of production.

B. Tex-La

For purposes of calculating replacement power damages, Tex-La's situation is different from that of Brazos. First, Tex-La has no generation that it can displace with the output of Comanche Peak. Instead, Tex-La would use its Comanche Peak entitlement to displace purchases from TUEC.

Second, Tex-La has executed an Entitlement Assignment Agreement under which it would have sold to Texas Power & Light ("TP&L", now merged into TU) the entirety of its interest in each Comanche Peak unit during the first year of each unit's commercial operation and would have recaptured its interests in each unit in blocks over the subsequent seven years as follows:

Annual Period	Percentage Assigned To TP&L (TUEC)
First	100%
Second	90%
Third	80%
Fourth	70%
Fifth	[illegible]%
Sixth	50%
Seventh	25%
Eighth	25%

The sellback of capacity is made under a split-savings formula which yields a profit to Tex-La. As compared to an arrangement in which Tex-La would absorb the entirety of each unit in a single step, the Entitlement Assignment Agreement should stretch out the impact of CPSES costs on Tex-La's ratepayers, reduce the rate shock to Tex-La and, as compared to Brazos, increase the period of years over which Tex-La experiences damages. Whereas replacement power costs diminish sharply for Brazos when CPSES goes commercial, Tex-La will be growing into its entitlement for eight years.

The Entitlement Assignment Agreement also provides for Tex-La to purchase standby power, installed reserves and spinning reserves.

Third, Tex-La relies upon TUEC for a large portion of its power supply, and Comanche Peak would have affected the rates Tex-La paid to TUEC. At year-end 1986, TUEC's net utility plant in service (original cost less depreciation) was $4.84 billion. Reflecting the completion cost of Comanche Peak in TUEC's rates would have changed Tex-La's costs, even assuming that a substantial portion of TUEC's investment in Comanche Peak were excluded from rate base. Therefore, an important part of calculating damages for Tex-La is determining the impact of Comanche Peak and the Entitlement Assignment Agreement upon the rates TUEC charges Tex-La.

Elements of Tex-La's
Replacement Power Cost Damages

Tex-La would have realized positive damages from:

1. Displacing capacity purchases from TUEC;

2. Losing the profit on sales of Comanche Peak capacity back to TUEC during the delay;

3. Displacing energy purchases from TUEC.

Tex-La would have incurred the following types of additional costs as a result of CPSES entering commercial service:

1. Backup energy costs to the extent CPSES operated at less than 100% capacity factor;

2. Spinning reserve charges;

3. Installed reserve charges;

4. Transmission charges;

5. Possibly increased costs on Tex-La's continuing purchases from TUEC. This appears to be a relatively neutral factor that adds to damages if rates are set on the basis of low rates of return prevailing in recent years. This factor reduces damages if a 15.6% rate of return is used. FERC's generic rate of return has

ranged from 14.4% in 1985 to 11.6% in mid-1986. Thus, this factor can be expected to have a slight positive influence on damages.

The net effect of these factors is shown in Table 4 (following) for CPSES inservice dates of January 1, 1984 for Unit 1 and July 1, 1985 for Unit 2. Note that these inservice dates are a year earlier than those used for the revenue requirement calculation.

TABLE 4

TEX-LA REPLACEMENT POWER AND RESIDUAL PURCHASES

(1984/1985 IN-SERVICE DATES)

YEAR	DISPLACED PURCHASES PLUS CHANGE IN RATES	LESS TRANSMISSION $1.00/KW/M	PLUS PROFIT ON SELLBACK	LESS COST OF CPSES ENERGY	NET DAMAGES
1984	$ 276,084		$ 3,016,000	0	$ 3,292,084
1985	$ 5,490,639	($ 29,900)	$ 2,941,000	($181,738)	$ 8,220,001
1986	$ 5,829,389	($ 74,751)	$ 3,017,000	($649,220)	$ 8,122,418
1987	$ 5,023,115	($ 134,552)	$ 2,737,000	($897,083)	$ 6,728,480
	$16,619,227	($ 239,203)	$11,711,000	($1,728,041)	$26,362,983

NET DAMAGES ESCALATED AT 9.5% (1988 DOLLARS) = $32,631,874.

DAMAGES ON POWER PURCHASED FROM TU

Both Tex-La and Brazos buy power from TUEC. Brazos buys power from TU at delivery points remote from Brazos' main system under wholesale rates established by the TPUC. The study assumes that Brazos would continue to purchase all this power from TUEC and that Tex-La would displace a portion of its purchases with CPSES.

The data available for recalculating such rates to reflect TU's addition of a "reasonable" CPSES is very limited. In addition, the process of recalculating rates is very elaborate and time-consuming. Accordingly, I have determined the effect on TU's rates to Brazos and Tex-La of adding CPSES only for the alternative inservice dates of 1985 for Unit 1 and 1986 for Unit 2. The same calculation will be made for Brazos for the 1981/1983 inservice dates and for Tex-La for the 1984/1985 inservice dates.

This calculation involved tabulating the kilowatts and kilowatthours (called the "Billing Determinants" or "BD's") bought at dozens of delivery points for the time periods in question. The recalculated rates were then applied to the historical BD's.

THE 1985/1986 SCENARIO

In order to calculate how the costs of power which Tex-La and Brazos would continue to purchase from TU would change, I had to recalculate TUEC rates. One important step in this process is to quantify the amount by which TU's revenues would have to change if CPSES entered service. For the 1985/1986 inservice dates, I have calculated the revenue requirement beginning in 1985 assuming the following significant attributes:

1. Unit No. 1 in service on January 1, 1985, at a direct cost of $1,604,724,000, AFUDC of $426,036,000 and a total plant in service of $2,030,760,000. These are the costs of TUEC's share only.

2. Unit No. 2 in service on July 1, 1986, at a direct cost of $981,947,362, with AFUDC of $300,512,638 and a total plant in service of $1,282,460,000. Again, these are the costs for TUEC's share only.

3. TU's total cost with AFUDC is $3.313 billion in mixed dollars through 1987 as projected by TU in its SEC Form 10-K for 1983.

4. The schedule of TU's direct cash outlays to be as shown in the January 12, 1984 TU document given to the co-owners. That forecast was in effect in 1984 when Unit 1 was declared complete. Total dollars shown on that document exceed those in the 1983 10K because AFUDC was imputed to the shares of the co-owners.

5. Comanche Peak energy costs are taken from a budget for Comanche Peak prepared in anticipation of commercial operation in January 1985 for Unit 1 and July 1986 for Unit 2. It reflects some costs and energy production in 1984 in connection with test energy.

Total TUEC revenue requirements were calculated for each calendar year using adjusted actual or projected cale'.ar year expenses and an average rate base determined by dividing beginning of year and end of year balances by two. Thus, 1987 is the first year reflecting complete Comanche Peak Unit 2 expenses in the revenue requirements study.

Two alternate return on equity assumptions were used to give a range of revenue requirements given different future rates of inflation. A 15.6 percent return on equity, allowed by the Texas Commission in TUEC's last rate case, Docket No. 5640, was used as the upper bound. A 12 percent return on equity was used as the lower bound. The "Benchmark" rate of return on common equity determined by the FERC since 1985 has ranged from a high in mid-1985 of 14.44 percent to 11.20 percent for the period February through April 1987. The current "Benchmark" rate of return is 12.27 percent.

Insofar as the available data permitted, an attempt was made to replicate the ratemaking treatment adopted by the Texas Commission in TUEC's last rate case, Docket No. 5640, with the following two major exceptions:

For determining income taxes allowable, the Commission denied the deduction of imputed interest expense related to Investment Tax Credit ("ITC") financed rate base because of uncertainty regarding IRS policy on this matter. Since the rate case, permanent regulations have been issued by IRS which sanction this method. Therefore, it is assumed that the Commission would allow ITC "interest synchronization".

AFUDC on new additions had been calculated assuming the Commission would not allow continuing CWIP in rate base after 1986. If both Comanche Peak units were in service by that time at a reasonable cost and TUEC was projecting slowed construction programs for its lignite units because of the decline in its load forecasts, it is unlikely TUEC could justify including CWIP in rate base as a necessary step to protect its financial integrity. A reduced amount of CWIP has been included in the 1985 and 1986 rate bases which was estimated to be consistent with the AFUDC calculations for the estimated Unit 2 and actual non-Comanche Peak CWIP during that period.

The in-service dates and construction expenditures for the major production additions, with the exception of Comanche Peak are consistent with the TUEC Long-Term Peak Load and Resource Forecast filed by TUEC with the Texas Commission.

Additions to Transmission, Distribution and General investments for 1987 through 1989 are projected based on TUEC's projected construction expenditures for these categories in its 1986 Form 10-K with an annual 5 percent escalation of the average additions for three years after 1989. AFUDC has been added assuming an average one year construction schedule.

Comanche Peak capital improvements and betterments, fixed operating and maintenance expenses, taxes and insurance have been projected using data from the May 20, 1987 Operating Expense/ Budget Forecast adjusted for the earlier in-service dates assuming an annual inflation rate of 5 percent.

Lignite and Oil and Gas capital improvements and betterments were estimated based on the average production plant additions from 1982 through 1986 when there were no major additions adjusted for an assumed 5 percent annual inflation.

Decommissioning costs were projected based on a 1983 TUEC projection used by the Commission Staff in a 1985 Comanche Peak rate impact study. We received on January 20, 1988, a more complete description of this study which shows the Unit 2 costs approximately $2 million per year below the cost level currently reflected in our study. According to the Texas Staff, no more current study exists although the assumptions in the 1983 study are out-dated. The 1983 study assumes an internal fund and no current tax deductions.

Comanche Peak is assumed to have a book plant life of 30 years pursuant to a TUEC data response in Docket No. 5640. The book depreciation rates approved in Docket No. 5640 for the other functional categories have been used.

Because of the lack of data responses, approximations have been made of the percentage of AFUDC in existing plant-in-service, Investment Tax Credit amortization and other key parameters affecting the return, depreciation and income tax calculations.

In addition, more information is required in order to accurately project lignite and nuclear fuel rate base and income tax components.

The last step was to allocate costs to the wholesale class and, then, to design a new rate for wholesale power, using allocated costs as revised.

The cost allocation process was based on the methods and relationships reflected in TUEC's Rate WP in Docket No. 5640. Production and transmission rate base are allocated using an average and excess non-coincident peak process. Wholesale class allocation determinants were held constant relative to the other TUEC rate classes, except to reflect Tex-La's acquisition of a share of Comanche Peak, under the terms of the Power Supply Agreement between TU and Tex-La. Tex-La's share of CPSES, as used in the cost allocation and rate design process, reflects the Entitlement Assignment Agreement and produces a different wholesale production allocator for each change in the share of the station for which Tex-La receives capacity credit.

Distribution investment and other rate base items are allocated using the relationships between classes from Docket No. 5640.

The customer allocator reflects the inter-class relationships from Docket No. 5640 and holds the "number" of wholesale customers constant while reflecting the increase in customers for other TU rate classes as reflected in the revised cost of service.

Allocation of expenses is also based on the methods and class relationships used in Docket No. 5640. Fuel and variable production expense are allocated on the basis of energy. Fixed production expense and transmission O & M expense are allocated using the production allocator. Expenses reflecting customer accounts, customer service, and Administrative & General costs are allocated based on the class relationships in Docket No. 5640.

Rates are designed using actual TU load growth in 1985 and 1986 and a 6% growth rate for all subsequent years. Rates as designed track the relationships between wholesale cost of service, divided into the demand, energy, and customer components reflected in Docket No. 5640, and the revenues collectable from the demand charge, High Voltage credit, and energy charge which resulted from that proceeding. The revised HV credit tracks TU's relative net transmission service investment, as allocated to the wholesale class. The revised demand and energy rates reflect the fixed, variable, and customer components of the cost of service allocated to the wholesale class, maintaining the cost/revenue relationships demonstrated in Docket No. 5640.

COMPARISON OF TUEC
CURRENT ELECTRIC SALES REVENUES
WITH
REVENUE REQUIREMENTS WITH COMANCHE PEAK IN-SERVICE

1/1/85 and 7/1/86

($000)

	1985	1986/1987	
Adj. Actual Revenues[1/]	4,091,877	3,795,249	
	5.31¢/kwh[3/]	5.26¢/kwh	
Revenue Requirements with Comanche Peak (15.6 ROE)	4,512,984	4,190,247[2/]	4,094,173
	6.40¢/kwh	5.80¢/kwh	5.46¢/kwh
Difference (15.6% ROE)	421,107	394,998	
	.59¢/kwh	.54¢/kwh	
% Increase	10.2%	10.3%	
Revenue Requirements with Comanche Peak (12% ROE)	4,298,321	3,961,707[2/]	3,874,545
	6.10¢/kwh	5.49¢/kwh	5.17¢/kwh
Difference	206,444	166,458	
	.29¢/kwh	.23¢/kwh	
% Increase	5.0%	4.4%	

1/ Alcoa/Sandow Revenues and over/under recovery of fuel costs removed.

2/ Average Rate Base method used for calendar year and thus only one-half year of Unit 2 expenses are included.

3/ Revenue Requirements and KWH sales exclude Alcoa/Sandow.

VIII. CANCELLATION

If TUEC cancels one or both CPSES units, or if the units do not come on-line, each co-owner will begin planning for replacement resources from the date of cancellation. This will increase damages beyond the levels calculated previously because each co-owner must expend funds on replacement power that it would not have expended if Comanche Peak had entered service. Additional damages associated with cancellation equal (i) the added cost of the replacement capacity plus (ii) the difference between the cost of replacement energy and the cost of CPSES energy. A fuller explanation of the cancellation scenario will demonstrate why this formulation for additional damages is correct.

Damages for any scenario in which a nuclear plant enters service do not include the cost of a reasonable plant but, rather, are limited to a co-owner's expenditures in excess of a reasonable plant's cost. This is proper in that the co-owners bargained for the cost of a reasonable plant, and when the nuclear plant enters service, they obtain the benefit of their bargain:

low-cost energy. Thus, at any point in time after the originally projected inservice date, damages are net of the cost of the reasonable plant.

In the cancellation scenario, the co-owners obviously do not receive the benefit of their bargain. They will have none of the capacity they would have had from the reasonable plant starting with the date of cancellation and ending with the termination of the originally-planned useful life of CPSES. Thus, all expenditures for replacement capacity on and after the date of cancellation through the useful life of the reasonable CPSES should be added to damages incurred through the date of cancellation.

In addition to replacement capacity, the co-owners will have to obtain replacement energy. Unlike the case with capacity, damages previously calculated do not include a cost for future CPSES energy costs. Therefore, I have determined the difference between the projected post-cancellation cost of CPSES energy and the cost of replacement energy.

An equivalent calculation would be to calculate damages based upon returning to Brazos and Tex-La (i) the entirety of their capital investment in Comanche Peak (because they would not be getting power or energy from the plant) less (ii) the cost to Brazos and Tex-La of having to purchase substitute capacity and energy in the future. I have not used this alternative calculation because it is simpler to calculate the additional damage cost of post-cancellation replacement power.

Additional costs of post-cancellation replacement power fall in different categories for Brazos than for Tex-La. Brazos is assumed to replace its cancelled entitlement with purchases from the Texas Municipal Power Pool through 1989 (at which time TMPP reserve capacity becomes insufficient to supply Brazos' deficiency) and then switch to a combustion turbine for capacity. TMPP would remain the source of energy at a price equal to the cost at which Brazos could produce the energy at its Miller Plant.

At Brazos' isolated delivery points, Brazos is assumed to pay a post-cancellation rate for wholesale power different from those used in the scenarios comparing reasonable inservice dates to unreasonable inservice dates. Prior to cancellation, damages are the same at isolated delivery points as they were in comparing a reasonably priced CPSES to an unreasonably priced CPSES. This is merely the differential between the costs of the actual rate now being charged and the rate with Comanche Peak in service. After CPSES is cancelled, a different rate is assumed.

For Tex-La, replacement power for the cancelled entitlement is deemed to come from TUEC. For power that Tex-La would continue to purchase from TUEC in any event, Tex-La is assumed to pay a capacity rate based on a newly planned system redispatched to reflect the absence of Comanche Peak.

I have calculated damages for both Brazos and Tex-La using the inservice dates at which Comanche Peak was supposed to come on-line when they purchased into the plant and also the inservice dates at which TU stated Unit 1 and Unit 2 would be ready to operate, assuming it were licensed. I have not carried out complete calculations based upon TU's intervening projected inservice dates, although obviously, these calculations could be made. The calculations would follow the methodologies described in the report.

RESCISSION

In the event of rescission, Tex-La and Brazos will be refunded all of their expenditures, plus interest.

Comanche Peak Licensing Delay

A Report to
Brazos Electric Power Cooperative
Tex-La Electric Cooperative of Texas

Victor Gilinsky
15 February 1988

CONTENTS

I. INTRODUCTION

The operation of Comanche Peak Unit 1 has been delayed because Texas Utilities[1] could not obtain the requisite operating license from the Nuclear Regulatory Commission. The agency, which oversees safety at commercial nuclear power plants, normally licenses a qualifying plant for operation when construction and pre-operational testing are completed. In this case, near the end of construction the NRC found deficiencies in design and construction to a degree that caused the NRC to doubt the project's fundamental compliance with federal safety regulations in a number of important areas.

The NRC mandated extensive reinspections and reviews by the Company. By the NRC's recent account to Congress, the deficiencies discovered through these efforts have led to corrective actions that include "in many cases, actual physical

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[1] Various Texas Utilities Company entities participated in the construction of Comanche Peak. Texas Utilities Electric Company (TUEC) is a subsidiary of Texas Utilities and holds a majority interest in the Comanche Peak Steam Electric Station (CPSES). Texas Utilities Generating Company (TUGCO) is the operating division of TUEC with overall responsibility for engineering, design, procurement, construction, and quality assurance. Texas Utilities Services, Inc. (TUSI), whose management overlapped with that of TUGCO, performed various functions for TUGCO. For the sake of simplicity, I shall refer to the utility and its various subsidiaries as Texas Utilities, TU, or the Company.

The other major participants in the engineering and construction were Westinghouse, which engineered and manufactured the nuclear reactor and associated steam supply system; Gibbs & Hill, which provided engineering and other services for the balance of the plant; and Brown & Root, which did the constructing.

hardware changes and reconstruction."[2]

The remedial design and construction will add substantially to the owners' costs, as will the costs of the associated delay. As of January 1988, the Company does not project commercial operation of Unit 1 until after the summer of 1989.[3] Unit 2 is similarly affected and delayed. It is still unclear how much work will be required to bring the plant into conformance with federal nuclear safety regulations. It is therefore impossible to predict with any confidence the ultimate cost of the remedial work and delay.

The delay should be measured from at least early 1985, which is the date the Company gave to the NRC in 1986 for the physical completion of the plant.[3] This allows a generous amount of time -- about 120 months -- to complete the plant (most plants which were built in parallel with Comanche Peak took about 110 months).

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[2]NRC Quarterly Status Report to Congress (3rd quarter 1987), submitted by NRC Chairman Zech to Chairman Bevill of the Subcommittee on Energy and Water Development, Committee on Appropriations, U.S. House of Representatives, 13 November 1987.

[3]"Utility Again Pushes Back Start-Up of Comanche Peak," Wall Street Journal, 2 December 1987, p. 58. The story mentions that TU is reviewing its $6.7 billion cost estimate for both units and expects to announce a new figure early in 1988. In a 25 November 1987 filing with the Securities and Exchange Commission (Form 8-K), the Company stated it "does not believe that the licensing process can be completed in time for commercial operation of Unit 1 until after the summer peak of 1989..."

[3]29 January 1986 Letter, William G. Counsil to Harold R. Denton, the NRC's Director Of Reactor Regulation. The Company was seeking an extension of its construction permit, which it had allowed to lapse through an oversight.

At issue is whether the minority owners,[4] who relied on the Company's performance as Project Manager, should share these additional costs. This report, prepared for Brazos Electric Power Cooperative and Tex-La Electric Power Cooperative of Texas, examines the reasons for the Company's failure to receive operating authorization from the NRC.

The first part of my report is organized as follows: Chapter II describes the NRC licensing process and examines the nature of the Company's responsibilities for designing and constructing a nuclear power plant. A nuclear utility is responsible not only for building a plant which complies with all applicable NRC safety regulations but also for demonstrating such full compliance to the NRC safety experts. There are strictly prescribed means for doing this, which the large majority of plants have followed, with the result that they have gained the confidence of the safety regulators and have received their operating licenses upon project completion.[5]

Chapter III briefly discusses the basic nuclear safety concerns to make clear the reason for the NRC's demanding nuclear design and construction standards.

Commercial nuclear power plants, even more than other technologically complex industrial projects, require a formal system of work discipline. Chapter IV describes the unusually demanding quality assurance (QA) standards the NRC established

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[4]Texas Municipal Power Agency (6.2%), Brazos Electric Power Cooperative (3.8%), and Tex-La Electric Power Cooperative of Texas (2 1/6%).

[5]During 1984 and 1985 the NRC granted operating licenses to 18 nuclear power plants.

for the nuclear industry in 1970. These mandate working within the boundaries of approved paths, and carefully checking and rechecking work to sharply limit the possibility of errors. The utility building the plant is responsible for insuring that all the participants -- architect/engineer, constructor, equipment vendors, and subcontractors -- adhere to the quality assurance plan approved by the NRC as a condition of the construction permit. The NRC's confidence that the plant's detailed design and construction incorporate an adequate safety margin and that the plant is eligible for licensing stems in large part from the utility's formal undertaking that all the work was performed in accordance with those procedures for assuring quality.

The NRC inspections can be viewed, in large measure, as a check of the utility's system of quality assurance and of the records that system generates. Violations of procedural or document requirements (which some people try to minimize as "paper" problems) are breaks in the system of control and are no less real than hardware problems. It is the "paper" trail which records the configuration of equipment, and whether the right materials were used and prescribed methods followed. The records are essential for tracing later problems, or dealing with changes in equipment. The "paper" is, so to speak, the plant's pedigree. Without it, you don't know what you have.

Chapter V describes the sequence of nuclear power plant design and construction and how the Company departed from the usual design practices. The Company's managers disregarded the generally followed approaches to designing and constructing nuclear power plants. When extensive changes had to be made, they tried to short-cut the process by releasing drawings for use by the construction crews before all the necessary quality checks had been completed. The Company assumed that the quality approvals would be forthcoming in the end and that only a limited amount of rework would have to be done. Unfortunately, so many changes were required -- tens of thousands -- that the entire system of design change was overwhelmed, with the result that it became impossible to tell whether structures and equipment had been designed and built to the appropriate standards. By deliberately postponing key quality checks on design and construction until after the plant was built, the Company set itself up for a 'balloon payment' in terms of safety inspection which it was unable to meet. Eventually, many errors in design, construction and rework were discovered.

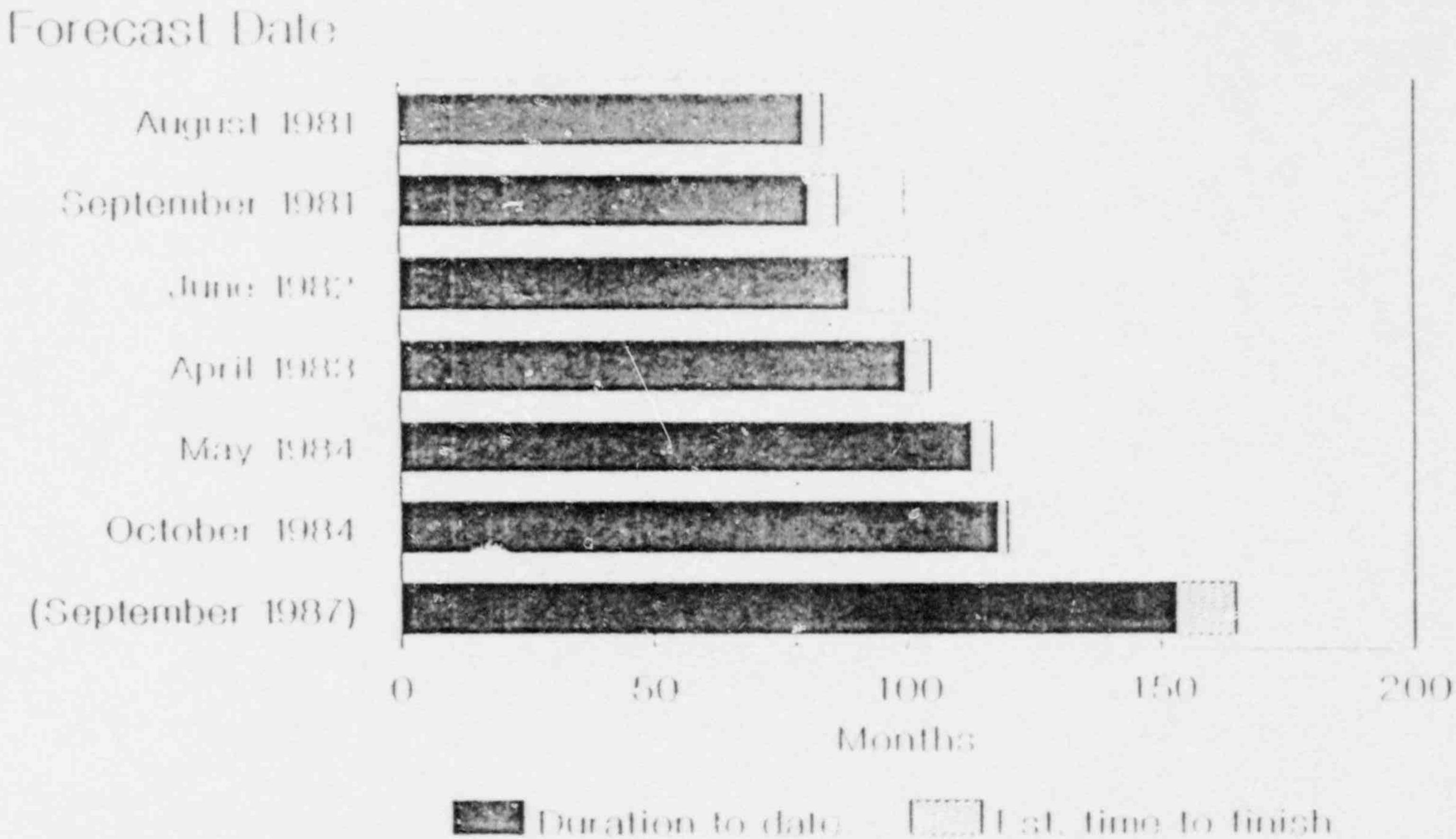
The second part of the report, Chapters VI, VII, VIII, and IX, presents the history of the project's interaction with the NRC -- in short, the view of Comanche Peak from the vantage point of the safety regulators. The discussion relies principally on NRC documents, or other public documents available through the NRC.

It needs to be said that the project showed signs of managerial failings before it ran afoul of the NRC relatively late in the construction sequence. The project already had a long history of delays and of missing one completion date after another. While most nuclear projects suffered from overly optimistic planning, Comanche Peak was in a class by itself in the lack of realism of its forecasts. The Company never seemed to have a clear idea of what remained to be done.

As the accompanying chart shows, after about mid-1981 TU seems to have continually thought it was within several months of completing the plant. (The solid part of each bar indicates the time elapsed between the start of construction and the date of the forecast. The gray addition represents the Company's

Comanche Peak Unit 1 Fuel Load

TU Forecasts Overly Optimistic



Data taken from Bevill Reports/draft

estimate of th. additional time required to finish all work necessary for fuel load.)

Chapter VI covers the period up to mid 1982, when the Company's relations with the NRC were mainly with the regional inspectors (based in Arlington, Texas), who regulated with a relatively light hand.

Chapter VII covers the 1982-1983 period during which witnesses before the NRC Licensing Board raised significant design and construction safety questions. These were initially dismissed by the regional NRC inspectors. But the administrative judges on the NRC Licensing Board were unconvinced and on 28 December 1983 issued a major decision which found the Comanche Peak design to have been carried out in violation of NRC regulations on quality assurance. Chapter VIII covers the 1984 period when the headquarters NRC staff -- through the Technical Review Team -- became more deeply involved in inspecting the plant to resolve outstanding issues. By the end of the year, the NRC staff's initially favorable view of Comanche Peak (as represented in hearing testimony) had been reversed.

The NRC is on the whole a sympathetic partner in the plant's licensing and will hold up the process only if it is impossible to resolve important safety questions. However, a nuclear constructor that departs from the usual design methods, fails to carry out a sufficiently strict regime of checking and correcting the quality of work, and fails to maintain adequate and easily auditable records -- and all these elements are present in this case -- is on a risky course.

In January 1985 the Company postponed plans for the near-term operation of Unit 1, and turned its attention to the

Comanche Peak Response Team (CPRT) program, the name given by the Company to its effort demonstrate the plant's compliance with NRC regulations. Chapter IX covers the subsequent period during which the Company hired new top managers and continued remedial programs. Those programs are still underway.

All of the safety problems will have to be resolved to the satisfaction of the NRC. Moreover, given its past failings, the Company will to have to go to further considerable pain and expense, beyond what would normally be the case, to regain the confidence of the NRC sufficiently to receive an operating license. The NRC Licensing Board, which has yet to conduct a hearing on the adequacy of design and construction following the remedial program, stated that on the basis of its earlier findings it would assume that Comanche Peak's original quality control and quality assurance programs for both design and construction had broken down, and would require "careful proof" whenever these program are relied on to justify the plant's adequacy.[6]

In February 1988 the Company was in the process of submitting eleven project status reports, which are to be a basis for NRC review and a hearing before the Licensing Board.

Chapter X presents an overall assessment of the sources of the delays encountered by the project. Chapter X also deals with whether the Company was justified in relying on the NRC regional inspectors' favorable ratings of the project.

The Company was not aided by the lax approach taken by NRC Region IV, the least effective regional office in the NRC

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[6]Memorandum and Order (Litigation Schedule), 18 November 1987.

system, which was responsible for the day to day regulatory supervision of Comanche Peak. However, the Company knew that the NRC's inspections were really only audits of its performance and it should have known -- and was so informed by both the NRC and its own consultants -- that it, not the NRC, was responsible for assuring the quality of design and construction.

If nothing else, the Company had to know by 1981 that, following the highly publicized disclosures in 1978-81 of serious breakdowns in quality assurance at a number of plants, the NRC was demanding a much higher standard of design and construction performance than it had previously. The Company should have been ensuring the high quality of its work and preparing to demonstrate strict conformance with NRC regulations. Instead it gambled on getting by with bare compliance.

At the root of the Company's difficulties was its managers' near-total inexperience with commercial nuclear power -- be it nuclear design, construction, or operation -- and their failure to comprehend the technical and managerial demands of a commercial nuclear project. The Company compounded its problems by hiring relatively inexperienced contractors for design and construction.[7] And, unfortunately,

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[7]Gibbs & Hill had worked on several nuclear plants abroad but had designed only one U.S. nuclear plant -- Ft. Calhoun, a small (480 megawatt) plant owned by the Omaha Public Power District. Comanche Peak was G&H's only ongoing U.S. nuclear project.

Brown & Root had constructed one nuclear plant -- the Brunswick plant for Carolina Power & Light -- before getting involved with Comanche Peak. B&R was acting as architect-engineer and constructor of the South Texas plants (Houston Lighting & Power), but that was an unsuccessful effort which culminated in B&R's replacement by Bechtel.

the Company managers did not have the good sense to stay alert to signs of trouble, to face problems squarely, and to get experienced help when they needed it. They ignored or brushed aside criticism from both outside and inside the project organization. In 1978, outside management auditors informed the Company that its design practices did not meet NRC requirements and provided a "significant risk of design error"; the Company was told by its top QA managers that they disagreed with the design practices in question; yet the practices were continued.[8] Given the Company's approach to the project and its lack of experience with commercial nuclear power, I do not believe that TU could have built a plant which could have withstood serious NRC scrutiny without fundamental changes in the Company's management.[9]

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[8]Management Analysis Company, "Texas Utilities Generating Company Audit Report," Appendix A.

Deposition of Mr. B.R. Clements taken in this proceeding on 15 December 1987, volume II, page 94.

[9]It is also doubtful that without such management changes the Company could have met any of its completion forecasts. This includes the projected completion dates which the Company gave to the minority owners when they joined the project: Brazos and TMPA, which entered into contracts with TU in 1979 were given a commercial operation date of January 1981 for Unit 1; Tex-La was given a 1982 commercial operation date for Unit 1 when it signed an amended contract with TU in December 1980.

Even if the NRC had not looked carefully at the plant and TU had managed to obtain an operating license in 1985, there is little assurance that the plant would be operating today. Deficiencies in documentation of equipment qualification were found in 1985 at TVA's Sequoyah plant, which had been operating since 1980, which threw into question the adequacy of safety equipment. The Sequoyah plant has been shut down (as of January 1988) since then while efforts are made to bring it into compliance with NRC requirements.

It has now brought in new top management for the nuclear program and virtually all of the managers responsible for the original design and construction have been moved aside -- a point the Company has emphasized. At a 2 April 1987 meeting with NRC staff, Mr. William Counsil, the Company's top nuclear official, who joined the Company in 1985, remarked "the three officers sitting in this room from TU Electric had nothing to do with the original design or QA, QC, period, nor did any of the department heads who are here with me today." Unfortunately, these changes in Comanche Peak leadership came late.

My conclusion, after examining the basic NRC inspection and licensing records and some Company and third party documents, is that TU failed to meet its responsibilities to design and construct the plant with the requisite degree of care and in accordance with required procedures and safety standards. Because of its inability to demonstrate to the NRC that the plant had been designed and built in conformance with the regulations, the Company's management is responsible both for the failure to obtain an operating license and for the consequent delay in operations, at least since early 1985.[10]

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[10] I have not examined whether the plant should have been completed and operating even earlier.

II. THE NRC'S SAFETY LICENSING PROCESS AND THE COMPANY'S RESPONSIBILITIES

To understand why Comanche Peak failed to receive NRC operating authorization, it helps to know something about the NRC inspection and licensing system. The licensing review is not a single review, but a series of reviews conducted by various branches of the NRC. All parts of the review have to be completed satisfactorily by the utility before its nuclear plant can be put into operation. I will describe briefly the agency's organization and practices, as well as the hierarchy of laws, regulations, regulatory guides, and license conditions that govern design and construction of nuclear plants.

The NRC was formed in 1975 to assume the safety functions of the Atomic Energy Commission. The agency is headed by five commissioners. The Chairman, acting through an Executive Director for Operations (EDO), supervises a staff of over 3,000 at its Washington headquarters and in five regional offices, one of which (Region IV) is in Arlington, Texas. The agency's organic statute is the Atomic Energy Act of 1954, as amended.

A. NRC's Broad Statutory Safety Mandate

Because of the universal concern about nuclear plant safety, and the complex nature of the subject, Congress gave the NRC an extraordinarily broad mandate. The Act leaves the basic safety standards to the agency's discretion.

Applicants for licenses must supply such information as the NRC deems necessary to find that the activity "will provide adequate protection to the health and safety of the public".[11] The NRC is to issue licenses to persons "who are equipped to observe and who agree to observe such safety standards to protect health and to minimize danger to life or property as the Commission may by rule establish...".[12]

B. The Broad Safety Standard of NRC's Rules

The NRC's own rules also express the safety standard in broad terms. The NRC may issue a construction permit (CP) if, among other things, there is "reasonable assurance that...the proposed facility can be constructed and operated at the proposed location without undue risk to the health and safety of the public".[13]

In a similar vein, the rules specify that an operating license (OL) may be issued upon a finding, among other things, that the facility has been built "in conformity with the construction permit...the Act, and the rules and regulations of the Commission" and that there "is reasonable assurance (i) that the activities authorized ... can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the

[11]Atomic Energy Act, Section 182.

[12]Act, Section 103.

[13] Section 50.35(a) of Title 10 of the Code of Federal Regulations.

The NRC's regulations are contained in volume 10 of the Code of Federal Regulations (CFR). The regulations cover administrative matters, adjudicatory and licensing procedures, and the substantive standards applicable to the possession and use of nuclear materials and to the construction and operation of nuclear facilities.

regulations in this chapter"[14].

Elsewhere, the regulations speak of "reasonable assurance that the applicant will comply with the regulations in this chapter...and that the health and safety of the public will not be endangered".[15] Finally, issuance of the license must not "be inimical to the...health and safety of the public".[16] Everyone involved with the agency is clearly on notice that the agency has left itself broad discretion in the application of the law.

More detailed technical regulations cover the design, construction, and operation of nuclear plants. The bedrock of these are the fifty-nine General Design Criteria[17] which have been essentially unchanged since 1971. These are also phrased in fairly broad terms. For example, Criterion I requires that the parts of the plant "important to safety" be designed, built and tested "to quality standards commensurate with the importance of the safety functions to be performed." The term "important to safety", and its near equivalent "safety-related", are key terms of art which define those aspects of a project to which NRC requirements apply.

Additionally, "structures, systems, and components important to safety":

shall be designed to withstand the effects of natural

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[14]10 CFR 50.57(a)

[15]10 CFR 50.40(a)

[16]10 CFR 50.40(c)

[17]10 CFR Part 50, Appendix A.

> phenomena such as earthquakes.[18] [and]
>
> shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.[19]

Another example of the broad sweep of the design criteria is the criterion which deals with emergency cooling:

> A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant...Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that...the system safety function can be accomplished...[20]

The details of how to satisfy a particular General Design Criterion are usually spelled out in more specific regulations. For example, the requirement for a comprehensive quality assurance system (GDC 1) is spelled out in a section entitled "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", known as "Appendix B."[21] I will discuss it in detail in the next chapter. What is relevant for this overview is that a hierarchy of other NRC staff-approved documents, which are not formally adopted regulations, spell out accepted means of satisfying the individual provisions of regulations (in this case, Appendix B). These "regulatory guides" may lack the formal status of regulations but as a practical matter they are requirements all the same.

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[18] Ibid., General Design Criterion 2

[19] Ibid., General Design Criterion 3

[20] Ibid., General Design Criterion 35

[21] 10 CFR Part 50, Appendix B.

These guides may incorporate industry standards, such as those established by the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), or the American Welding Society (AWS), which are usually more detailed than the basic NRC documents.[22] A utility applying for a license will typically commit itself, in the Safety Analysis Report that is part of its application, to implement these industry standards in the manner outlined in specific regulatory guides. The utility will thereby meet the NRC staff's interpretation of the regulation being addressed. For example, Regulatory Guide 1.64 (Revision 2, June 1976), dealing with "Quality Assurance Requirements For the Design of Nuclear Power Plants", states that:

> The requirements and recommendations for establishing and executing a quality assurance program during the design phase of nuclear power plants that are included in ANSI N45.2.11-1974 ["Quality Assurance Requirements for the Design of Nuclear Power Plants"] are acceptable to the NRC staff and provide an adequate basis for complying with the pertinent quality assurance requirements of Appendix B to 10 CFR Part 50....

The important thing to remember is that following the regulatory guides is the means of satisfying the regulations which has already been reviewed and accepted by the NRC staff. Use of other approaches is permissible in principle but risky in practice as they will take time to review and may not gain approval.

The NRC staff review follows a Standard Review Plan, a several-thousand-page document, which specifies the areas of

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[22]These standards are developed and controlled by committees of industry and independent experts.

review, the staff acceptance criteria, the review procedures, and the findings the staff reviewers have to make. The various sections contain the following statement:

> Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used by the staff in its evaluation of conformance with Commission regulations.

Any utility applying for a license that chooses to proceed along different lines, or to use unfamiliar hardware solutions (as TU was to do in the area of pipe supports), understands that it will have to justify the unconventional approach. Taking the NRC staff into unfamiliar regulatory territory risks lengthy reviews and delayed approvals. The simple reason is that the issues are often complex and the safety stakes high. Changes in one reactor system often affect many others. The safety reviewers are understandably more comfortable with designs they have seen and reviewed in detail before.

C. The NRC Licensing Process: Application and Staff Review

Federal law provides for a two-step licensing process -- a utility must obtain a construction permit to start building, and it must have an operating license before it loads nuclear fuel into the reactor after construction is completed. A utility's application consists mainly of a multi-volume Safety Analysis Report which describes how the design conforms with safety regulations. The Company's statements in such reports on procedures to be followed in design and construction (at the CP stage) and in operation (at the OL stage) are binding commitments.

At the CP stage, when the design is in a preliminary stage, this report is known as a Preliminary Safety Analysis Report (PSAR). It is important to stress that when such reviews were done --it has been some years since the NRC has received a PSAR for review -- the NRC licensing staff did not review the actual engineering design, which had hardly been begun at that stage, but rather the design outlines and the engineering methods to be applied.

At the OL stage, when more of the design details are available, the corresponding applicant's document is called a Final Safety Analysis Report (FSAR). An NRC staff review is again conducted by the agency's technical staff, principally in the Office of Nuclear Reactor Regulation (NRR). The work of the individual reviewers in the various technical branches is coordinated by a licensing Project Manager who is assigned full-time to the licensing case. The staff's conclusions are presented in a Safety Evaluation Report (SER). The SERs embody the agreement arrived at between the NRC staff and the utility during the course of the staff's review. It should be understood that -- with some exceptions -- the NRC staff OL review is still not at the level of detail of the construction drawings.

TU filed its PSAR with the AEC on 20 July 1973, and on 17 October 1974 received a "Limited Work Authorization," which permitted a certain amount of site preparation. Comanche Peak's construction permits were issued literally in the last days of the AEC, on 19 December 1974, exactly a month before the AEC was dissolved and its regulatory responsibilities transferred to the newly-created NRC.

The staff SER on the construction application made clear that the Company's own inspectors had the lead role in assuring quality. By comparison, the AEC inspectors were assigned a minor role: they would "perform such additional inspections as may become necessary to examine the current status of the constructor's quality assurance program and the implementation of the overall quality assurance program for the Comanche Peak nuclear project."[23]

Four years later, when enough of the detailed design was completed and construction was well underway, the Company filed its FSAR (27 February 1978). After a preliminary check, the Comanche Peak OL application was docketed on 24 April 1978, and the NRC staff review began.

In recent years, in part to accommodate pressures for more rapid licensing, the staff has taken to publishing the SER, covering resolved issues, at the earliest possible date and has left the thornier questions to be resolved in Supplementary Safety Evaluation Reports (SSERs) issued at a later time. Matters as to which the staff and applicant have not yet agreed are referred to as "open issues." The NRC staff's safety evaluation of the Comanche Peak OL application was published in such a series of volumes, the first appearing in July 1981.

D. Advisory Committee on Reactor Safeguards

The NRC staff's conclusions described in the SER are further reviewed on a selective basis by the NRC's Advisory Committee on Reactor Safeguards (ACRS), a statutory body of fifteen senior experts in various scientific disciplines. The ACRS is required by law to write a public comment on each application. A 29 July 1981 letter from NRC Chairman Palladino

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[23] Safety Evaluation of the Comanche Peak Steam Electric Station Units 1 and 2, Docket Nos. 50-445 and 50-446, USAEC, 3 September 1974, page 17-17.

to Congress states that the ACRS held off its review of Comanche Peak because of the number and significance of safety items left open in the SER. The ACRS meeting was held in November 1981.

As a practical matter, a favorable ACRS letter to the Commission on an application is a prerequisite for moving on to the hearing before the Licensing Board. In addition to the usual boilerplate approval, the Comanche Peak ACRS letter observed "there is a significant lack of hands-on experience with large commercial nuclear power plants..." The ACRS endorsed the NRC staff requirement that TU augment its operating staff with experienced persons.[24]

E. Licensing Board

At the construction permit stage, a three-member NRC Licensing Board of administrative judges is required by law to conduct a public hearing to review the staff's work. Members of the public may participate, with the right to cross-examine witnesses on issues in which they have an interest. However, none did in the Comanche Peak hearing.

At the operating license stage, a hearing is held only if it is requested by interested members of the public. The participants must advance relevant contentions which have to be approved by the Licensing Board. The hearing covers only these contentions. (All other issues are dealt with by the NRC staff.) In recent years the Commission has strictly circumscribed the Board's discretion to raise questions on its own motion.

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24 17 November 1981 Letter, ACRS Chairman J. Carson Mark to NRC Chairman Palladino.

Notice of a public hearing on the Comanche Peak OL application was published on 5 February 1979.[25] A 28 June 1979 Licensing Board Order stated that timely petitions had been received from the State of Texas and three citizens' organizations, including Citizens Association for Sound Energy (CASE), which were arrayed against the Company and the NRC staff.

A licensing case does not go to hearing until the NRC staff is satisfied with its review of the Company's FSAR and with the amendments to the Report which grow out of the Company-staff discussions and negotiations. The amended FSAR and the SER and SSERs embody the settlement of the outstanding issues between the applicant and the NRC staff. This means that in the hearing the NRC staff (which is represented by NRC staff lawyers) typically supports the Company's position on essentially all questions. (In contrast, in most other regulatory commission proceedings the public staff and the applicant present rather different positions for the commissioners to judge.)

The Comanche Peak Board ultimately determined that the various quality assurance and quality control (QA/QC) contentions advanced by the intervening parties could be encompassed by the following very broad contention, which was known as Contention 5:

> The Applicants' failure to adhere to the quality assurance/quality control provisions required by the construction permits for Comanche Peak, Units 1 and 2, and the requirements of Appendix B of 10 C.F.R Part 50, and the construction practices employed...have raised substantial ques-

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[25] 44 Fed. Reg. 6995

> tions as to the adequacy of the construction of the facility. As a result, the Commission cannot make the findings required by 10 C.F.R. 50.57(a) necessary for issuance of an operating license for Comanche Peak.[26]

The future of Comanche Peak turned on this contention. (A number of contentions dealing with other issues were also admitted but were subsequently dismissed.) In December 1983 the Board resolved this issue, as it related to the design process at Comanche Peak, in favor of the intervenors. In other words, the Board found that the plant had not been designed in accordance with the regulations. However, over the

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[26]Section 50.57(a) lists six basic findings which must be made before the issuance of an operating license. The first of these is:

> (1) Construction of the facility has been substantially completed, in conformity with the construction permit and the application as amended, the provisions of the Act, and the rules and regulations of the Commission.

(Other findings cover plant operation and the technical and financial qualifications of the utility.) TU has recently argued before the Licensing Board that it need not make this finding. ASLP Special Prehearing Conference, 2 November 1987, transcript. (Company counsel, in commenting on licensing cases, told the Board: "There is nothing in there that says you have to make that finding." Transcript p. 24985.) TU is arguing that all that is necessary for a license to issue is that the Board make the third finding:

> (3) There is reasonable assurance (i) that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations in this chapter.

TU's counsel, Mr. Eggeling, argued further that Appendix B was not on the same footing as other regulations and that "one who fails and has deficiencies in Appendix B does not, it seems to me, violate the regulations within the meaning of that section [50.57(a)(1)]." Transcript p. 25027.

objection of the intervenors, the Board allowed the Company another opportunity to make its case.

The Licensing Board's decisions can be appealed to a three-member Appeal Board and, ultimately, to the NRC commissioners themselves.

When the hearing is concluded with a favorable Licensing Board decision, the Board authorizes the NRC staff to grant an operating license when all other (non-contested) safety issues have been resolved to the staff's satisfaction. The actual license is issued by the staff. Since 1980, by Commission rule, such staff authorizations have been restricted to initial testing at below five percent power.

F. Commissioners

Since the accident at Three Mile Island, the NRC commissioners have retained the authority to grant a full power license. They vote in public after a briefing by the NRC staff. If the current practice is continued by the present Commission, the Commission will have to vote on any grant of full power authorization for Comanche Peak, which, if the Company's plans hold up, would likely come no earlier than in 1989. Until then, the case will be in the hands of the staff and Board. Occasionally, the Commission takes formal review of certain issues raised before the Licensing or Appeal Boards but such adjudicatory excursions have become increasingly rare.

The Commissioners' involvement with a case prior to their OL review is limited because their role as judges bars them from discussing the substance of the case with the NRC staff, which is a party in the hearing, outside the context of the adjudicatory hearing. The commissioners' main awareness of

Comanche Peak during the early 1980s was through its appearance on lists, prepared for Congress, of the status of plants which were thought to be near to completion and licensing.

G. Bevill Reports

Throughout this period the NRC was reporting on Comanche Peak's progress (and that of other plants) to the House Appropriations Subcommittee on Energy and Water Development. The Subcommittee Chairman, Congressman Tom Bevill, regularly accused the agency of needlessly holding up licenses and threatened to reduce its budget, which the Subcommittee controlled, unless the agency was more forthcoming.

Beginning in 1980 the Commission prepared for the Subcommittee a periodic licensing status report, known as the "Bevill Report," on plants under construction. Right from the start there were arguments over which construction completion dates -- the utilities' or the NRC's -- to use in estimating future licensing "delay." The utilities objected to use of forecasts by NRC's Caseload Forecasting Panels[27] (which turned out to be less optimistic, but more accurate). By putting forth overly optimistic construction completion dates, and making it appear that the NRC would soon be holding up a plant ready to operate, utilities pressured the NRC to hurry reviews and hearings.[28] Optimistic schedules also helped the utilities in their dealings with bankers and public utilities commissions.

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[27]These forecasts helped to guide the assignment of NRC's sorely pressed reviewers. The panels included NRC's experts on construction scheduling.

[28]Many utilities whose construction was slipping behind schedule tried to mask that fact in order to hold their place in the NRC licensing review queue.

Fairly early on, the Commission decided to accommodate the industry and the House Appropriations Subcommittee by working to the utility schedules. These were optimistic, but none more so than TU's consistently unrealistic forecasts for Comanche Peak. These made it appear that if the NRC staff and Board did not finish their work quickly they would hold up Comanche Peak's operation -- at considerable cost. The effect was to put additional pressure on the NRC safety reviewers and their managers to wind up their work.

The NRC's own construction completion estimators consistently believed TU's forecasts were overly optimistic. This judgment was based mainly on material (reinforced concrete, piping, electrical cabling) installed and the rate at which plant systems were being tested for operation. A hard look at safety issues would have come up with an even more pessimistic assessment.

H. NRC Inspectors

The NRC's regulations are enforced in the field by the agency's inspectors and investigators both during construction and during operation. The inspectors' job is not to set standards but to determine whether the NRC requirements have been met. These inspectors are mainly based in the five regional offices and at the plants themselves. The regional office which supervises Comanche Peak is Region IV. (It was my view, and I believe a generally prevalent one, that Region IV was for many years the weakest NRC regional office.) Since the TMI accident, resident inspectors have been assigned to all operating reactors and those under construction. Comanche Peak has generally had two such inspectors.

NRC inspection reports, of which there may be several dozen per year for a particular site, are public documents. If the inspectors find violations of regulations, the agency issues a Notice of Violation. There are five violation levels (I-V) with "I" being the most serious. Violations at levels III and higher are usually accompanied by civil penalties which range from tens to hundreds of thousands of dollars. (Violations higher than level III are extremely rare.) Overall, Region IV took an easy line with Comanche Peak when it came to violations.

The NRC occasionally conducts intensive special inspections using Construction Assessment Teams (CAT) which include inspectors from regions other than the one directly responsible. Such a CAT inspection was conducted at Comanche Peak during January-March 1983 with the participation of headquarters staff, and a report issued in April 1983. The results were mixed. The body of the report contained important criticism, but it was moderated in the cover letter transmitting the report to the Company.

The regional inspectors issue more or less annual NRC Systematic Assessment of Licensee Performance (SALP) reports which provide an overall evaluation of each project. These grade the utility in a number of areas. The grades are Category 1, 2, and 3, with "1" being the best. On the whole, Comanche Peak received grades which were satisfactory or better on these reports, although the detailed report discussions suggest Region IV was being generous in its conclusions.

Before loading of nuclear fuel into the reactor vessel is authorized, the inspectors give the plant a final pre-operational check. Should any safety concerns be expressed at this time by plant employees, as sometimes happens, they are quickly examined. These are especially important if they come from the project's own inspectors and if they suggest that the project's quality control and assurance systems -- on which the NRC places great reliance -- did not function properly. usually the issues are resolved promptly, if necessary by a NRC special team assembled for the purpose.

I. Investigators

The job of the NRC inspectors is to check that hardware and procedures are in compliance with requirements. Another NRC office, the Office of Investigation, investigates possible wrongdoing an the part of licensees or applicants. This office does not seem to have played a major role in this case, but another NRC investigatory office was involved in an important way. The Office of Inspector and Auditor, which investigates improper activities on the part of NRC staff, was called in by a commissioner to investigate charges that Region IV management pressured NRC field inspectors to go easy on Comanche Peak.

The results appeared in a November 1986 OIA report which was highly critical of Region IV. It concluded that Region IV managers established "a higher than normal threshold for assessing violations" at Comanche Peak and "downgraded" recommendations from inspectors. Reports critical of the Company were routinely delayed and modified on the basis of post-inspection submissions from the Company. The Region IV inspection program of quality assurance at Comanche Peak was judged "inadequate" by the OIA report. The charges were aired at a Senate Governmental Affairs Committee hearing on 9 April 1987. The NRC staff played down these findings, but in July

1987 major personnel changes were made in Region IV.[29]

J. Special Review Team and Technical Review Team

Because of the mounting problems in the way of Comanche Peak licensing -- the Board's unfavorable December 1983 decision and the increasing numbers of allegations of safety deficiencies -- and also because of the lack of confidence at NRC headquarters in the ability of Region IV management to cope with the situation, additional special inspection teams were set up to inspect Comanche Peak, and to assess and resolve the problems to clear the way for licensing. This team approach

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[29]On 19 August 1987, the NRC released the November 1986 OIA report (86-10) together with NUREG-1257, a March 1987 staff report of the "Comanche Peak Report Review Group," and an April 14 memorandum on the report's recommendations from the staff's Executive Director to the commissioners. The carefully-hedged staff report concluded that none of the issues identified in OIA Report 86-10 as instances where the plant inspectors' findings were softened by Region IV managers, or where Region IV failed to carry out inspections, was significant in terms of "direct adverse impact on plant safety." That is, NUREG-1257's authors did not think the particular TU procedural violations at issue, or Region IV lapses, necessarily translated into hardware problems.

A close reading shows the staff report conceded OIA's main points -- that Region IV managers had softened inspectors' findings and that there were gaps in the Region IV inspection program. The difference was that NUREG-1257's authors generally supported Region IV management actions, and they thought the Region IV inspection gaps were "for the most part" compensated by later special headquarters inspections. Appendix C (pages 10-11) makes this claim seem strained. It lists "NRC inspection procedure line items," applicable to Comanche Peak, for which there was no record of completion by Region IV. The areas listed include program for handling 10 CFR Part 21 (deficiency) reports, Reactor Vessel and Internals QA Review, Geotechnical/Foundation Activities, Electrical Components and Systems, Instrumentation Components and Systems, Fire Protection and Prevention, Containment Structural Integrity Test, Containment Penetrations (Mechanical), and Inservice Inspections.

had previously been used successfully to resolve a broad range of issues in advance of licensing at the Waterford plant, also in Region IV. As the NRC 1984 Annual Report put it:

> Assigning dedicated task groups to resolve problems is an innovation for the NRC which is proving effective in upgrading licensing efficiency and eliminating unnecessary delay.[30]

The Comanche Peak team inspections included the Special Review Team in early 1984 and the larger (fifty-person) Technical Review Team in the latter half of 1984. The unfavorable results of the TRT inspections led the top NRC headquarters licensing officials to conclude that Comanche Peak could not be licensed without extensive reinspection and reanalysis.

In February 1987, in a highly unusual move, the NRC created an Office of Special Projects to deal with its most troubled projects: Comanche Peak and those at TVA, all of which had been shut down by failures to comply with regulations. This office combines both licensing and inspection authority for these projects. Its first head was James Keppler, formerly the Region III Administrator, and a well-regarded NRC official. He has since resigned and been replaced by Stewart D. Ebneter.

K. Who Is Responsible for Safety?

In view of the broad safety role of the NRC, and the NRC regional inspectors' failure to spot the problems at Comanche Peak (and in fact their favorable rating of the project), it is natural to ask whether TU can reasonably be held to account for failing to identify the problems on its own. In short: to what extent can a utility rely on NRC approval or acquiescence as a

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[30] NRC 1984 Annual Report, p. 44.

vindication of its efforts? And more generally, who is responsible for safety -- the utility or the government?

I will deal with these questions in the last chapter. But, in brief, both the utility and the government have responsibilities for public safety, but they are different responsibilities.[31] The government is responsible for setting the rules and enforcing them. The utility is responsible for conducting itself in accordance with the rules and for protecting the public safety. An analogy with driver safety may be helpful: the government sets the standards for obtaining drivers' licenses and monitors highway speeds, but each licensed driver is responsible for his or her safe driving. It would not be an acceptable defense, when caught speeding on a particular stretch of road, to say that previous patrols had not enforced the rules.

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[31] Shortly after the Three Mile Island accident, General Public Utilities (GPU), the owner of the plant, filed a claim for over $4 billion against the NRC under the Federal Tort Claims Act, arguing that the NRC had negligently failed to warn it of defects in the plant and that NRC had negligently issued an operating license to TMI-2. The Commission found the claim without merit and at odds with the regulatory framework of the Atomic Energy Act which places primary responsibility for the proper construction and safe operation of nuclear facilities on the licensees. The Commission also noted that in prescribing standards, it does not certify to the industry that the standards are adequate to protect its equipment or operations.

The District Court denied the Government's motion to dismiss in November 1982. However, in September 1984, the Third Circuit reversed and ordered the case dismissed (745 F.2d 239 (1984)). In so doing the Court said:

> It is the burden and responsibility of the applicant to demonstrate the adequacy of its application. The Commission's obligation is to assess the application according to what the agency determines is significant from the standpoint of health and safety.

In February 1985 the Supreme Court declined to take review of the case.

The government <u>is</u> responsible for setting standards commensurate with the dangers involved in the particular regulated activity. In the case of nuclear power, the standards are understandably high.

III. WHY NRC'S SAFETY STANDARDS ARE SO DEMANDING

Comanche Peak was tripped up by its failure to meet NRC's strict design and construction standards. The response of the Company, at least initially, seems to have been that while the plant may not have met the precise requirements, it was good enough. Even as late as 1985, Mr. J. B. George, the then-Comanche Peak Project General Manager, in speaking of the pipe supports (which must, among other things, resist the maximum earthquake thought possible at the site), told the NRC staff:

> there may be a few errors made in that process, by the sheer magnitude of the supports that were there. But we think -- I think, as the general manager of the project and having had interface with these people and being on-site through the years, the systems are good and certainly the plant will be safe under any earthquake conditions that we've experienced.[32]

To understand why such general assurances are not good enough, it will be helpful to explain the safety concerns that underlie the need for a strict system of federal safety regulation and the need for special attention to high quality of design and construction by the utility. Why, for example, the need for high quality welds and checking and rechecking? Why all the documents?

This look will take us briefly into hazards associated with possible release of radioactivity from the reactor core and the NRC's "defense in depth" philosophy of reactor safety. The need to maintain cooling of the reactor core under all circumstances dictates making sure reactor coolant piping does not break or leak in the first instance, and making sure

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[32]Transcript, Company meeting with NRC staff, 10 January 1985.

emergency cooling is available if needed. The supports of the safety-related piping systems -- which figure prominently in Comanche Peak's troubles -- are obviously critical. They must withstand all possible loads and therefore must be engineered and installed carefully. All sorts of seemingly inconsequential plant details (even paint on the inside of the reactor building) can affect the course of an accident and must be examined. More obvious concerns are fires and adequate separation between safety systems to assure that redundant safety systems will not be incapacitated by the same event. It will help to start with a word about how reactors work.

A. How Reactors Work

A nuclear power reactor uses the heat released by nuclear fission to produce steam which powers an electrical turbine-generator. In more detail, a reactor of the type built at Comanche Peak, a Westinghouse pressurized water reactor (PWR), works as follows.

The reactor core contains about 100 tons of uranium fuel in the form of cylindrical uranium oxide pellets in long vertical rods. These are enclosed in a several-hundred ton steel pressure vessel through which water at high pressure is continually pumped in the closed "primary" circuit. The water serves two functions: it slows down neutrons and thereby helps to maintain a chain reaction, and it removes the heat of the reaction. The water, at a temperature of about 600 degrees Fahrenheit and a pressure of about 2250 pounds per square inch, flows through heavy stainless steel piping to four large vertical steam generators (which also weigh several hundred tons each). There heat is transferred through the thin walls of thousands of tubes to a lower pressure "secondary" closed water circuit in which steam is generated. The primary water leaving the steam generator is pumped back to the reactor vessel to be reheated by the nuclear reaction.

The steam in the secondary circuit is used to spin turbines which power an electric generator. This is the business end of the power plant. The turbines' spent steam is collected in a condenser and returned to the steam generator to once again gain heat from the primary circuit and repeat the cycle.

B. The Safety Problem

Uranium would be just another fuel for making steam if it were not for the extremely dangerous radioactive substances that are formed within the fuel as the uranium is consumed. The overriding object of nuclear safety is to keep the fuel's radioactivity -- the source of danger -- inside the power plant under all circumstances, including accidents involving breaks in the cooling system. The reason this is not a simple matter is that the core is very hot to begin with and that the radioactivity in the fuel continues to generate heat even after a reactor is shut down (that is, after the fission chain reaction is stopped). The reactor core's heat must be removed quickly or it will destroy the metal rods encasing the fuel and release their dangerous radioactive contents.

The radioactivity diminishes from its initial level fairly quickly but it nevertheless persists for long periods at levels that require continued cooling of the reactor core. In the absence of any cooling, the heat would ultimately melt the ceramic uranium oxide pellets. A 100-ton puddle of melted uranium oxide at the bottom of the pressure vessel would melt through and fall onto the reactor building ("containment") floor. What would happen after that is conjectural and would depend, in any case, on the detailed construction of the containment. It is important, however, to understand that containments, however formidable they may appear, are not designed to deal with this contingency. Should large amounts of radioactivity escape the reactor's containment, the radioactivity could cause enormous harm to people and property.

C. Multiple Barriers to Radioactivity Release: "Defense in Depth"

The safety philosophy embodied in the NRC regulations seeks to reduce to a very low level the probability of such serious accidents involving multiple equipment failures, and to rely on consecutive barriers to keep the dangerous radioactive substances away from people and the environment should accidents occur. These barriers include the pressure vessel around the reactor's uranium fuel and the piping of the primary loop. As the containment is not designed to ride through the worst accidents, the safety emphasis is on avoiding such accidents in the first place by assuring adequate supplies of emergency cooling water for the reactor core under essentially all circumstances.

D. Emergency Cooling Systems

The NRC approach relies on redundant (that is, parallel) and diverse safety systems to provide reliable protection. For example, parallel identical emergency core cooling systems, with independent power supplies, are installed so that one of them can cool the reactor fuel in the event the other fails. Diverse and physically separate means of cooling are employed to minimize the chance that some common flaw (in design, construction, or maintenance) affects all units of identical pieces of equipment. For example, emergency cooling for the fuel is available from both pump-driven systems and from large tanks held under pressure.

The safety-related piping -- which includes the primary circuit piping and the separate emergency cooling piping -- and the pipe supports which keep it in place, are obviously critical to maintaining the flow of cooling water to the core. Equally important are the electrical cables, and cable trays and conduits (in which the cables run), and their respective supports, which link the instruments and switches in the control room to the vital safety pumps and valves. Electrical cables to independent safety systems must also be adequately separated from each other and protected so that one failure cannot simultaneously defeat all backup safety systems.

E. Seismic Protection

The plant's designers are required to ensure that earth tremors do not damage equipment essential to safety. The buildings, equipment, and equipment supports necessary to shut down the reactor and keep the fuel from overheating must be able to withstand and operate through the maximum earthquake ("Safe Shutdown Earthquake") thought to be possible at the site. This requires adequately strong structures and supports, and qualified equipment. For example, each of the thousands of pipe supports and restraints for safety-related piping must be designed and analyzed for seismic response. This is extraordinarily exacting and time-consuming work, but it needs to be done properly to ensure safety systems will function as intended.

In part because of its limited resources, the NRC has not usually checked the design calculations, even on an audit basis. Its checking has been limited to ensuring that the appropriate engineering methods are used. The agency has relied heavily on the integrity of utility and contractor work and records. When doubts have arisen about the accuracy of calculations, especially since the discovery of design errors at the Diablo Canyon plant in 1981, the utility has been required to have independent consultants check the work, and the NRC has on occasion itself retained such consultants.

The seismic standard imposed on Comanche Peak -- a maximum ground acceleration of 0.12 of gravity -- was not a particularly demanding one. It was in fact very nearly the lowest for a plant built in this country. The standard was also unchanged from the start of the project so it should have been accommodated easily in the design and construction. By contrast, Southern California Edison's San Onofre Units 2 and 3 had to meet a standard more than five times as high. The difference in terms of the demands placed on the structures and equipment, and the consequent cost, is very large.[33]

F. Equipment Must Be Qualified for Accident Conditions

Plant owners are also required to demonstrate that their safety equipment will continue to operate under conditions of high temperatures, humidity, and radiation so that the initial phases of an accident will not incapacitate equipment needed to cope with it. Without adequate documentation of test results or analyses, one simply does not know whether the plant's safety systems will be able to perform during an accident. To speed issuance of the construction permit, TU undertook to qualify the Comanche Peak safety equipment in accordance with

[33]San Onofre 2, which like Comanche Peak started construction in 1974, completed construction and loaded fuel in 1982 and started commercial operation in mid-1983.

IEEE standard 323-1974, which was issued in 1974. TU seems to have seriously underestimated what complying with this standard would entail.[34]

G. Fire Protection

Special measures must also be taken both to prevent fires and to limit the damage which can be done by a fire inside the plant, particularly to the electrical control cables of safety equipment. This became a major concern after the 1975 fire at Browns Ferry which destroyed many of the plant's control cables. The guiding principle is to make sure that a single fire cannot incapacitate both a piece of safety equipment and its backup at the same time. To accomplish this, the control cables for parallel safety systems are installed sufficiently far apart, or are separated by suitable fire barriers, to insure that a fire in one bundle of cables will not simultaneously affect the other set of cables.

H. Quality Design and Construction

To guarantee that the plant will meet the specifications of the design, a very high level of quality is required in construction. The magnitude of a nuclear project and the associated risk demand a very formal and elaborate system of quality control (the actual checking of the work done) and a strict system of quality assurance (the audit system for determining that the quality control checks are working as

[34]Material received in discovery, p. 2343, draft paper on IEEE 323/344 Impacts, February 5, 1985.

designed).[35] This quality oversight involves careful recordkeeping and controlling who-does-what to a degree not found in any other form of large construction.

[35]The NRC also uses the term "quality assurance" to denote the whole system to achieve quality, so that in this sense quality control is a component of quality assurance. (See 10 CFR Part 50, Appendix B.) I will use this sometimes imprecise terminology because it is so common.

IV. NRC-MANDATED QUALITY ASSURANCE FOR DESIGN AND CONSTRUCTION

Quality control and quality assurance are the terms used to describe the systems for documenting and checking safety-related work at each plant. They are vital tools of technical and management control to ensure that safety-related work is done properly and that errors are caught.

A. Structure of the QA System

The overall quality standard is set forth in the first General Design Criterion:

> Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.[36] (Emphasis supplied)

The basic quality requirements are stated in Appendix B to 10 CFR Part 50, which was issued by the AEC in 1970. These requirements apply to "the safety-related functions" of structures, systems, and components that "prevent or mitigate the consequences of postulated accidents that could cause undue

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[36] 10 CFR Part 50, Appendix A, Criterion 1.

risk to the health and safety of the public." The activities which are covered include "designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling and modifying" the facility. This AEC/NRC approach to quality assurance was well-defined by 1974-5.

An outline of Appendix B gives an idea of its comprehensive coverage of the quality assurance program:

I. Organization
II. Quality Assurance Program
III. Design Control
IV. Procurement Document Control
V. Instructions, Procedures, and Drawings
VI. Document Control
VII. Control of Purchased Material, Equipment, and Services
VIII. Identification and Control of Materials, Parts, and Components
IX. Control of Special Processes
X. Inspection
XI. Test Control
XII. Control of Measuring and Test Equipment
XIII. Handling, Storage, and Shipping
XIV. Inspection, Test, and Operating Status
XV. Nonconforming Materials, Parts, or Components
XVI. Corrective Action
XVII. Quality Assurance Records
XVIII. Audits

Design control, which became one of the central issues in the Comanche Peak licensing case, comes first in the Appendix B sequence of project functions. Criterion III states that:

> Design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. The verifying or checking process shall be performed by individuals or groups other than those who performed the original design, but who may

be from the same organization....

Design _change_ control -- which is where Comanche Peak departed from the usual way of doing things -- receives special emphasis in Criterion III:

> Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design unless the applicant designates another responsible organization.

The point is that design changes during construction should not defeat the original design quality.

Almost all the nuclear plants in this country were built using the "fast track" system under which major components were ordered and construction started before much detailed design had been completed. This approach makes numerous changes in design almost inevitable. Under these circumstances it is especially important to control changes in design to the same degree as the original design. That means keeping close track of the changes and making sure the constructors, start-up testers, and quality inspectors are working with up-to-date, approved, and checked drawings. Accurate documentation is needed not only to show that the plant meets NRC requirements but also to ensure that the operators understand the detailed plant configuration, and to enable future changes to be made with a clear understanding of the "as-built" condition of the plant.

One of the chief sources of Comanche Peak's problems is the failure to rigorously control design changes. The Company seems to have consciously adopted an informal approach to design changes in which design checks required by Appendix B were postponed and construction changes were made on an "at risk" basis.[37]

The system to assure construction quality can be thought of as working on several levels. The first level is that of the worker (usually employed by a contractor) who inspects his own work to ensure that it conforms to the design and specifications. At the second level, a quality control inspector (usually employed by the same contractor) reviews the work done and signs off on the appropriate control documentation. The third level of company review, the quality assurance audit inspection (conducted sometimes by the contractor but always also by the utility) is supposed to check whether the worker and quality control inspector are doing their work properly. Normally, the inspector at this level reviews quality control records and a sample of the work done at the lower levels. Another level of review is performed by the NRC, which does an audit of the system documents and some equipment inspections to ensure that the entire quality control and quality assurance system is functioning properly.

Appendix B to Part 50 of the NRC regulations requires prompt identification and correction of problems. Criterion XVI specifies that:

> Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and

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[37]An unsigned draft paper, "Change Paper Design Verification", dated 20 December 1984, apparently prepared either by a Company official or by a consultant to the Company, provides an illuminating insight into the shortcuts TU used after about 1978 in the design verification process, and what went wrong. Material received in discovery (PT0024). This is discussed in a later chapter.

> corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management.

The interpretation of this part of the rule figured prominently in argument before the Licensing Board. Apparently because of the "at risk" approach it had taken, the Company argued before the Board that this Criterion -- insofar as it called for "prompt" correction -- did not apply to design.[38] The Board's rejection of this argument is discussed in Chapter VIII.

Significant deficiencies must also be reported promptly to the NRC. Section 50.55(e) of the regulations requires the holder of a nuclear power plant construction permit to notify the NRC of each deficiency found in design and construction which could adversely affect the safe operation of the plant and which represents (i) a significant breakdown in the quality assurance program, (ii) a significant deficiency in the final design, (iii) a significant deficiency in construction, or (iv) a significant deviation from performance specifications.

As mentioned earlier, the NRC's approach is to review only a very small fraction of the work done and already inspected by

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[38]This is the Board's characterization of TU's position as expressed in the Board's 28 December 1983 Memorandum and Order (Quality Assurance for Design). The Board cites TU's proposed finding that "Appendix B does not address inadequate designs but rather addresses the conformance of installed hardware and the inspection thereof to the design." Memorandum, p. 2. TU sought reconsideration in a 17 January 1984 motion, claiming that the Board had misunderstood the Company's arguments. The Board denied reconsideration, rejecting TU's new characterization of its earlier statements.

the project inspectors. (There are usually only two full-time NRC inspectors at a site which may employ 5,000 workers.) The conceptual basis for this approach is that if the NRC does find deficiencies, it will examine a larger sample of similar items. If this expanded sample reveals no additional errors, the defects are judged to be isolated occurrences. However, if the expanded sample yields additional deficiencies in inspected work, the natural conclusion drawn is that the licensee's quality assurance system was not working properly. The NRC inspection is then intensified until the NRC is satisfied that the extent of the problem has been ascertained and that the causes have been eliminated. If the problem cannot be handled in this fashion because of limitations on NRC resources, one or more independent firms are called in to conduct a broader and more detailed review. This is of course what has happened at Comanche Peak.

The entire quality assurance system depends upon an accurate and complete chain of Company and contractor records which show what work was done, what materials and equipment were used, who did the work, and who checked it. Without such records, it is impossible to go back and determine whether the plant meets safety standards without a detailed reinspection of the hardware. In most plant areas, it is possible in principle to go back and reinspect one hundred percent of the work done, although this approach is prohibitively expensive if applied to many systems. In some areas, however, such as reinforced concrete where the placement of reinforcing steel may be in question, the original work is usually no longer accessible, and subsequent inspections are not feasible as a practical matter. When problems surface in one area and it appears that because of inadequate records the company cannot reconstruct what was done, the NRC doubts about equipment adequacy may understandably extend to other parts of the plant.

Almost all violations of NRC requirements are, in practice, identified as violations of Appendix B requirements. The regulatory system assumes that some mistakes will be made during the course of construction and, indeed, does not impose penalties on the utility merely for making an error. However, the purpose of NRC's Appendix B requirements is to provide a safety net by assuring that quality inspections will detect mistakes, which can then be corrected. Therefore doing something incorrectly and not catching that error in the course of quality inspections may entail a penalty.

To take one example of the QA responsibilities a utility building a plant accepts, consider the controls on welding, which are covered by Criterion IX of Appendix B:

> Measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

In referring to "applicable codes," this section sweeps up a hierarchy of more specific requirements and, in effect, incorporates them into the NRC regulations. For example, the project constructors have to qualify the specific (safety-related) welding procedures -- that is, the types of welds, of which there may be several dozen, which will be used on the project -- in accordance with the welding codes of the American Society of Mechanical Engineers (ASME) and the American Welding Society (AWS).

An actual safety-related field weld is checked by both the welder and the inspector and carries with it an elaborate pedigree which covers materials, procedures, and results. A comprehensive and effective recordkeeping system must be in place both to make sure that the work and checks are done properly, and to be able to demonstrate this to the NRC. The documents are also necessary to permit checking the material content, the welding procedure, and the welder and inspector of a particular weld should these ever be called into question in the future. Confidence in the integrity of tens of miles of pipe and thousands of pipe and cable tray supports important to safety depends on the proper functioning of this system of quality assurance.

B. Increased NRC Emphasis on QA after 1981

On the whole, in the pre-Three Mile Island era, NRC construction inspection was relatively light. It was rare, for example, for fines to be imposed for construction violations. The underlying notion was that the utility was expected to build correctly and that it was proceeding at its own risk: if plant design or construction were found to be deficient during the final pre-operation licensing checks, the federal regulators would not authorize operation.[39] In the meantime, since there was thought to be no immediate health and safety threat, there was thought to be no pressing need for closer NRC

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[39]The agency cited the Supreme Court for approval of this doctrine. In Power Reactor Development Co. v. International Union of Electrical, Radio, and Machine Workers, 367 U.S. 396 (1961), the Court held, in effect, that the Commission need not make definitive findings of safety of operations until the end of construction. The Court said that the utility was on notice that "it proceeds with construction at its own risk, and that all its funds may go for naught....It may be that an operating license will never be issued."

inspection.[40] There was never any question, however, about the utility's responsibility for ensuring proper construction, whether the NRC inspected or not.

The agency later decided in the post-TMI period that it could not rely to such a great extent on the pre-operation inspections because it was difficult to find all the deficiencies at that point, and sometimes too late to make corrections. The heavy pressures on the reviewers to permit operation of a completed plant made it difficult to thoroughly review problems that arose at that stage. In short, many construction safety issues could not realistically be left for a last-minute NRC check. Moreover, as the NRC inspectors started to look at plants more closely after the 1979 accident, they found evidence that management attention to quality at a number of sites was deficient. Problems emerged with the quality of concrete at Marble Hill in 1979, and with material quality and welding at Zimmer in 1981, both of which were eventually abandoned as nuclear plants. Poorly compacted subsoil and sinking buildings eventually led to the same result at Midland. Extensive quality problems were also found at Houston Lighting & Power's South Texas project in 1980, three years before Comanche Peak ran into serious problems with the NRC. TU does not seem to have paid heed to this nearby warning despite the similarities in the two cases -- an inexperienced utility, an inexperienced contractor (Brown & Root, in both

[40] The Licensing Board's 12 December 1974 Initial Decision authorizing grant of Comanche Peak construction permits picked up the AEC staff's proposed language which makes clear the agency is looking to the Company's QA programs to assure "safety related structures, systems, and components will be designed, constructed, installed, inspected, and tested in accordance with...Appendix B..." The Commission's inspectors will perform "such additional inspections as may be necessary..."

cases), and a weak regulatory office (Region IV).

A pivotal event in this sequence was the discovery in 1981, immediately after the plant had received an operating license, that a serious design error had been made at the Diablo Canyon plant. This discovery, and the consequent public and Congressional criticism of NRC effectiveness, more than anything else marked an important turning point for the NRC in the area of design and construction quality. Diablo Canyon's operating license was suspended and the plant was required to undertake an extensive review and rework program to requalify for a license. Since then plants have routinely been required to present the results of a design review by an independent reviewing organization in order to qualify for an operating license.

The NRC 1981 Annual Report describes the Commission's Policy and Planning Guidance and mentions that the NRC staff:

> will encourage industry to be more aggressive in verifying the quality of each plant during design, construction, and operation, and will also review NRC activity in promoting quality assurance and propose a plan for upgrading quality assurance programs throughout the agency early in 1982...

C. QA as a Basic Management Tool

NRC's 1984 report, Improving Quality and the Assurance of Quality in the Design and Construction of Nuclear Power Plants,[41] mandated by Congress, discussed the factors that

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[41] NUREG-1055, May 1984. The NRC Authorization Act for fiscal 1982-1983 directed that the NRC "shall conduct a study of existing and alternative programs for improving quality

separated successful projects from unsuccessful ones. Its conclusions are particularly applicable to the case of Comanche Peak. The report stressed the tie between good management and quality assurance:

> The principal conclusion of this study is that nuclear construction projects having significant quality-related problems in their design or construction were characterized by the inability or failure of utility management to effectively implement a management system that ensured adequate control over all aspects of the project. Each of the major quality-related problems cited in Chapter 1 was related to breakdowns or shortcomings in the implementation of the project's quality assurance programs; however, the quality assurance program's deficiencies had as their root cause shortcomings in corporate and project management. At several projects, breakdowns in the quality assurance program were part of large breakdowns in overall project management, including planning, scheduling, procurement, and oversight of contractors.[42]

The report went on to stress the importance of experienced management:

> There are two major corollary findings associated with management capability and effectiveness. First, in today's environment, prior nuclear design and construction experience of the collective project team (defined as the architect-engineer (A/E), nuclear steam supply system (NSSS) manufacturer, construction manager (CM), constructor, and owner) is essential, and inexperience of some members of the project team must be offset and compensated for by experience of other members of the team....
>
> It is clear in retrospect that some utilities granted CPs [construction permits] under previous standards would not,

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assurance and quality control in the construction of commercial nuclear power plants."

[42]Ibid., p. 2-2.

> based on the same qualifications, be granted a CP in today's regulatory environment without substantial personnel and organizational improvements in experience levels and management approach.[43]
>
> A common thread running through each of the four [problem] projects was a lack of prior nuclear experience of some key members of the project team...[44]

The report used the Palo Verde plants as an example of what could be accomplished by an inexperienced utility with the proper attitude:

> Palo Verde is the first nuclear project of Arizona Public Service (APS). From the project's outset, senior APS management felt strongly that nuclear construction was sufficiently different from fossil construction that it would have to be managed differently. The utility did not have previous nuclear experience as a corporation, but it recruited a technically capable core group of project personnel with prior nuclear construction and A/E [architect/engineer] experience, reorganized the corporation to create a separate division dedicated to the nuclear construction project, and contracted for extensive applicable corporate and individual experience in each of the key project organizational roles of A/E, CM [construction manager], and constructor. (p. 3-16)

By contrast, TU, which had no commercial nuclear experience at all, did not hire managers with such experience, and hired key contractors with little commercial nuclear experience in the United States.[45]

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[43]Ibid., p. 2-2.

[44]Ibid., p. 3-3.

[45]Initially, despite its inexperience, the Company seems to have been more attentive to quality assurance requirements than its contractors. In 1975, Gibbs & Hill claimed it was due an increased fee to compensate for the "significantly more demanding" NRC QA requirements as spelled out in ANSI N45.2.11. H.C. Schmidt, TU's Quality Assurance Manager, disputed this

The report also emphasized the importance of treating quality assurance as a valuable aid in doing good work rather than as just another regulatory box to check:

> Other factors that contributed to major construction quality problems in the past include...some licensees' failure to treat quality assurance as a management tool, rather than as a paperwork exercise or, conversely, as a substitute for their own management involvement.[46]

The report pointed out that:

> Some managers would treat the requirements as just a hurdle to be crossed. This perception leads management to focus not on the intent of the program, but on its details, e.g., a written manual, an independent QA manager, layers of procedures. Some managers honestly felt they had met their responsibilities when they had

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claim in a memorandum on 18 August 1975. He pointed out that at the date of the TU/Gibbs & Hill contract the contractor's QA program document "did not fully comply with Appendix B requirements." (Original emphasis.) He cited the AEC's July 1973 announcement that stated "these new regulatory procedures (earlier implementation of Appendix B requirements) are not additional requirements for utility applicants. They are, rather, intended to assure that all applicants have complied with the Commission's QA regulations which already exist (Appendix B)." (Original emphasis.) Mr. Schmidt added:

> The basic problem here, in my judgment, was that G&H did not really have a good appreciation of Appendix B requirements, partially because the Ft. Calhoun station [G&H's only prior U.S. project] which they designed and built was well along in design and construction prior to the issuance and implementation of Appendix B.

[46] QA Report, p. 2-3.

attended to such details.[47]

The authors stated that "one consistent study finding was that shortcomings in quality assurance program implementation were linked to shortcomings in project management, and vice versa".[48] When one considers the complexity of building a nuclear power plant, and the potential consequences of deficiencies in design or construction, it is apparent that the failure to carry out the quality assurance program wholeheartedly and rigorously is a sign of poor management. The Comanche Peak project's weakness in this area was an important factor in its inability to qualify for an operating license.

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[47]Ibid., p. 3-23.

[48]Ibid., p. 3-23.

V. DESIGN AND CONSTRUCTION ON A FAST TRACK: CONTROLLING DESIGN CHANGE

Before getting into the record of TU's relationship with the NRC during Comanche Peak's early construction it will be helpful to say a few words about the basic "fast track" nuclear power plant design and construction sequence followed by nearly all nuclear projects. A brief account of the Company's handling of "design change control" is also important background to the failure to obtain NRC operating approval.

In order to speed the projects, utilities using the "fast track" approach (which included almost all the utilities building nuclear power plants) ordered major equipment and began construction before much of the detailed plant design was available. Inherent in the fast track approach are many changes in the design as construction proceeds and interferences (or desirable improvements) are discovered. Because the original engineering design was typically done quickly -- not far ahead of construction -- all construction interferences and system interactions could not be anticipated. And, of course, the builders in the 1970s and 1980s also had to accommodate changes mandated by new safety requirements. Because of the complexity of a nuclear power plant, the high level of coupling between plant systems, and the high standards to which the work has to be done, such design changes, if not properly controlled, could overwhelm a nuclear construction project. Effective design change control was therefore key to a successful nuclear power plant project. It is an area where experience and strong management count heavily.[49] The

[49]many project designers built large models of the plants to be constructed in order to aid in identifying interferences and other potential design problems while the plant was still

Company's failure to control design change effectively was a major factor in its failure to produce a plant that qualified for NRC operating authorization.

A. Primer on Nuclear Construction

The construction of a nuclear power plant can be divided into a number of fairly distinct though overlapping phases. The first is the design of the plant. A key to a good project is to have a substantial amount of engineering design completed before the start of construction. Typically, however, plants were begun with a fairly low percentage of the detailed engineering done.[50] (It appears to have been on the low side in the case of Comanche Peak.[51]) Detailed design thereafter tried to keep ahead of construction and continued on a reduced scale very nearly to the end of the project.

The first step in construction is site preparation and excavation, which took place in 1974 and 1975 at Comanche Peak. This is followed by the erection of reinforced concrete

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on the drawing boards. Comanche Peak did not use such a model, apparently because of the cost.

[50]By contrast, the successful Palo Verde project started with almost half of the engineering done, and the very successful St. Lucie 2 project started construction with an even higher percentage of engineering completed.

[51]A curve of the percentage of engineering drawing completed for Unit 1 shows that at the time the construction permit was granted in December 1974 only about five percent of the drawings had been issued. Chart of Engineering to Construction Percent, CPSES Retrospective Audit By Cresap, McCormick & Paget, 15 February 1985, material received in discovery.

structures. The next stage is the installation of mechanical "bulks" (piping together with its supports). More or less simultaneously, the major pieces of equipment are installed. The Comanche Peak Unit 1 pressure vessel was set on its supports on 11 May 1978. The electrical "bulks" (cables and conduits) follow the mechanical ones. During this period -- which was about 1977-79 at Comanche Peak -- the emphasis is on individual categories of equipment. When most of the equipment has been installed, the work shifts to tying it all together -- tens of miles of piping, thousands of valves, hundreds of miles of cable with hundreds of thousands of connections -- into the couple of hundred or so plant systems which perform particular functions (for example, a particular type of emergency cooling). During this period the emphasis and organization shift to a systems orientation. (At Comanche Peak the situation was of course complicated by the continual redesign which was going on in parallel.)

The plant then has to go through an elaborate test program -- first of individual components and later of plant systems -- to make sure that all the hardware functions properly and that it is appropriately interconnected. "Cold hydro" tests, which test the integrity of pressurized systems, usually come a year or more before fuel load. This was accomplished at Comanche Peak in July 1982. The integrated systems tests at operating temperatures and pressures ("hot functional tests") usually take place at least six months before fuel load. (The system heat is generated by operating the reactor coolant pumps.) These tests were begun at Comanche Peak in the spring of 1983.

Throughout the design, construction, and testing sequence there is a premium on integrating a multitude of complex activities in proper order. Experience counts heavily because many power plant systems interact closely and a change in one affects a number of others. There are indications that Comanche Peak had to redo a good deal of work which had been done out of sequence.[52] After system components were modified, previous systems tests became invalid and had to be redone.

Data accepted by both sides in a recent nuclear power plant rate-making proceeding shows that during the time Comanche Peak was being built, the average time between the first pour of concrete and fuel load for nuclear power plants being constructed more or less in parallel with Comanche Peak was about 110 months (see accompanying figure).[53] By January 1985, when the Company thought it was ready to load fuel into Unit 1, 120 months had elapsed since the first concrete pour at Comanche Peak, a generous duration for a project of this sort.

B. Comanche Peak Design Change Control

Under the requirements of Appendix B (Criterion III), design changes had to receive the same measure of review for quality as the original design. At the outset of the project, all (safety-related) changes in Comanche Peak design, including those initiated at the site, were subject to the complete Gibbs & Hill control program (and TUSI approval) before site issuance. That is, the drawings were not released to the

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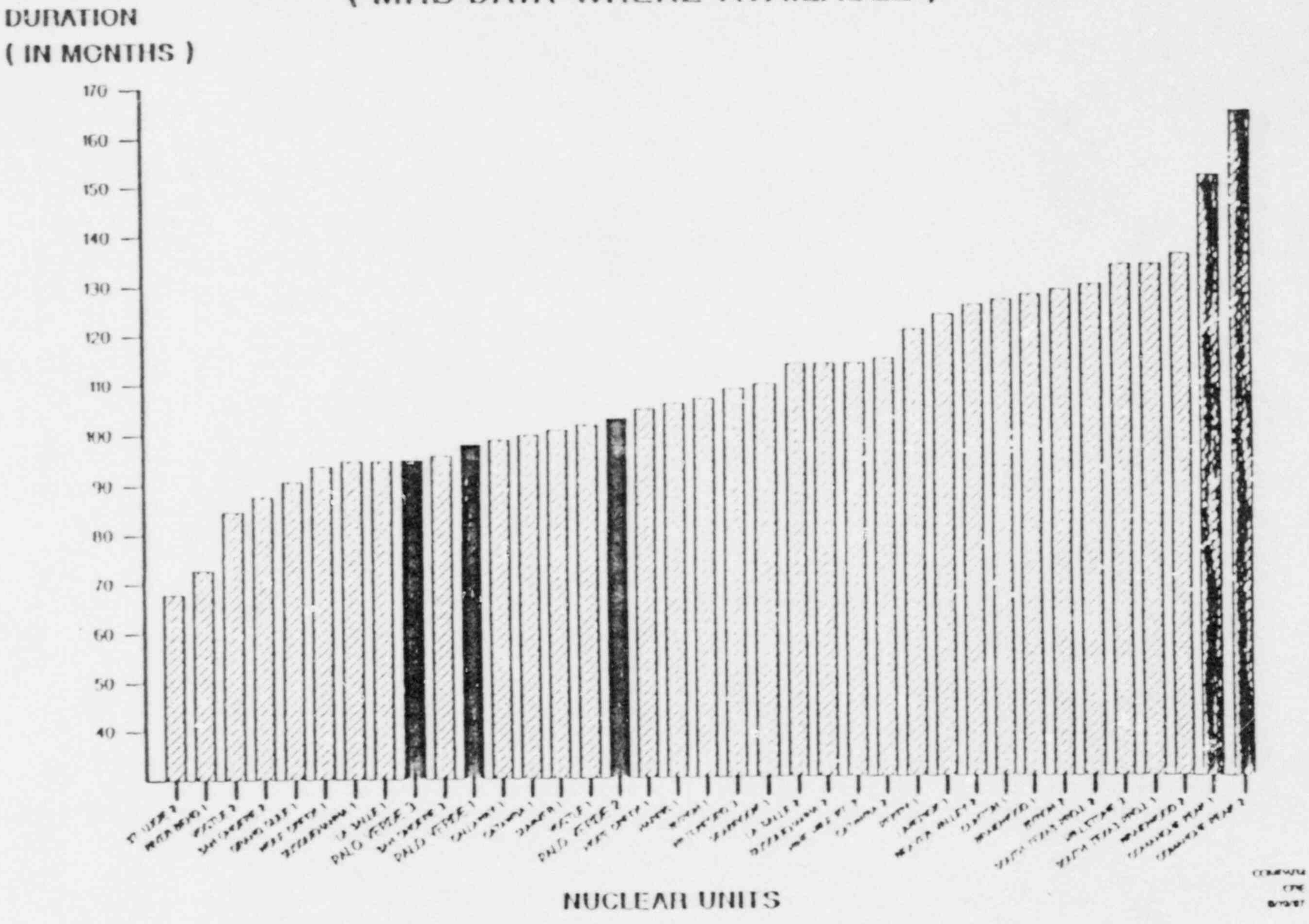
52 This was mentioned in the 1981-2 SALP report, discussed below, as illustrating TU's lack of experience.

53 The chart appears in rebuttal testimony of T.G. Woods, Jr., a witness for the utility, in the Matter of the Application of El Paso Electric Company, before the Public Utility Commission of Texas, September 1987. "MHB" in the caption refers to the consultants for the intervenor City of El Paso. The case concerned the Palo Verde plants in Arizona. For this reason the bars representing the Palo Verde plants are in black. I have altered the chart only by highlighting the bars representing the Comanche Peak units.

INDUSTRY COMPARISON

FIRST CONCRETE POUR TO FUEL LOAD

(MHB DATA WHERE AVAILABLE)



builders until the original designers had approved the changes. Around 1977, as the project was entering the bulk installation phase, as schedules were slipping and costs mounting, the Company looked for ways to speed up the processing of increasing numbers of design changes. It took a number of organizational and procedural steps to move the design change approval process to the project site, and more or less simultaneously it took over major responsibility for quality assurance.

At this time, starting around 1977, the Company was in general taking more control over the project. This would have made good sense if it had been coupled with the hiring of senior managers with commercial nuclear experience -- which the Company did not do until 1985. As it was, the move to greater direct Company control meant detailed direction of the project by the entity with the least experience and competence in commercial nuclear power. Furthermore, at about this time, the Company's fairly strict initial QA managers were replaced by a more accommodating group.

Around 1978 the Company speeded up the design change process, especially in dealing with design changes to the thousands of pipe supports, by foregoing the necessary design verifications before installation and relying instead on a post-construction check. The Company presumably hoped that in the end not many hardware changes would be required.

The story of this episode is described in the previously cited 1984 draft paper on design change control.[54] Although

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[54]Material received in discovery, "Change Paper Design Verification", 20 December 1984, (PT0024, p. 2346). At a deposition taken on 15 December 1987, Mr. Clements, the former

obviously intended to justify the Company's actions, it provides an illuminating insight into the shortcuts TU used after about 1978 in the design verification process, and what went wrong:

> Two verification processes have been utilized at Comanche Peak. They are the traditional "front-end" reviews in which a proposed change is design verified, approved and documented prior to implementation in the field; the other process is called "at risk". The "at risk" process of design verification entails releasing a design change for implementation in the field prior to formal interdisciplinary verification....
>
> ...The advantage associated with the "at risk" method of design change verification is expediting construction and improved worker morale. The drawback is that potential design inadequacies may not be detected <u>in a timely manner</u> [emphasis in original]. The potential safety concern is that design inadequacies might not be corrected because of pressure to accept the "as-built" design or the inability to implement necessary changes.
>
> The advantage with the "front end" design change verification is the additional assurance provided that the changes being implemented have been thoroughly reviewed and accepted by all impacted engineering disciplines and that all safety requirements have either been satisfactorily incorporated in, or satisfied by, the design....[55]

The author goes on to rationalize that what matters is not whether the standard or short-cut approach are used but the Company's "commitment to safety and reliability." Up to 1978, when the main activity was civil construction, the Company apparently proceeded with the usual "front-end" checks and

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TU head of nuclear operations, testified that although he could not recall having seen the report before "I would say that it was written by someone in the TU organization or someone who worked very closely with the TU organization as a consultant", p. 15.

[55]"Change Paper Design Verification," p. 2361.

reviews of changes. Roughly at that point, the work switched to installation of piping and supports and associated mechanical equipment, and soon afterwards to installation of electrical cabling, equipment, and supports. It was also roughly at this time that the Company took over major QA responsibilities from Brown & Root. The Company draft paper says that in order "to support Comanche Peak construction milestones" the Company "adopted the 'at risk' method of design verification"[56]

Trying to downplay the difference between "front-end" and "at risk" reviews, the author argues that in the "at risk" review the engineering organization making the change conducts its own review and that it is only the "formal, systematic and documented interdisciplinary/interorganization approval cycle [that] would be conducted at some later date." Nonetheless, the author says that:

> TUGCO realized the potential exposure associated with "at risk" design change verification; however, this process was implemented because it would expedite the construction of CPSES without compromising safety.
>
> TUGCO believed that the major exposures would be detected and corrected by the issuing engineers and that design changes implemented prior to formal design verification would be proven acceptable following their verification reviews. Conversely, if additional modifications were required, then TUGCO was willing to implement changes as required to assure that all safety-related functions and

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[56]Mr. Clements, TU's manager of nuclear operations and the corporate officer in charge of QA, testified in a deposition taken on 15 December 1987 in the present proceeding, that one of the reasons TU decided to take direct control of QA was that "Brown & Root's management were taking too long to solve problems. Problems would have to go to Houston from the site, be solved, massaged down there and come back, and Chapman felt TUGCO having control on the site, that those problems could be solved more quickly and get on with the project." Volume II, p. 101.

objectives were satisfied.[57]

One of the problems with the "at risk" approach was that since design change verifications did not have to be completed immediately to enable construction to go forward, they assumed a lower priority. This "coupled with the many non-safety related...[design change procedures]...resulted in a backlog of approximately 12,000 design changes in January 1983, which required formal verification." As the accompanying figure (taken from another document)[58] makes clear, the design changes numbered in the tens of thousands per year in the years 1979-1984, a very large number even granting that most of them were minor.[59]

In sum, what appears to have happened is that, in order to meet construction deadlines set by top management, TU knowingly took the "at risk" approach to design change verification, assuming that any rework required by the verification would be relatively minor. TU apparently failed to take into account

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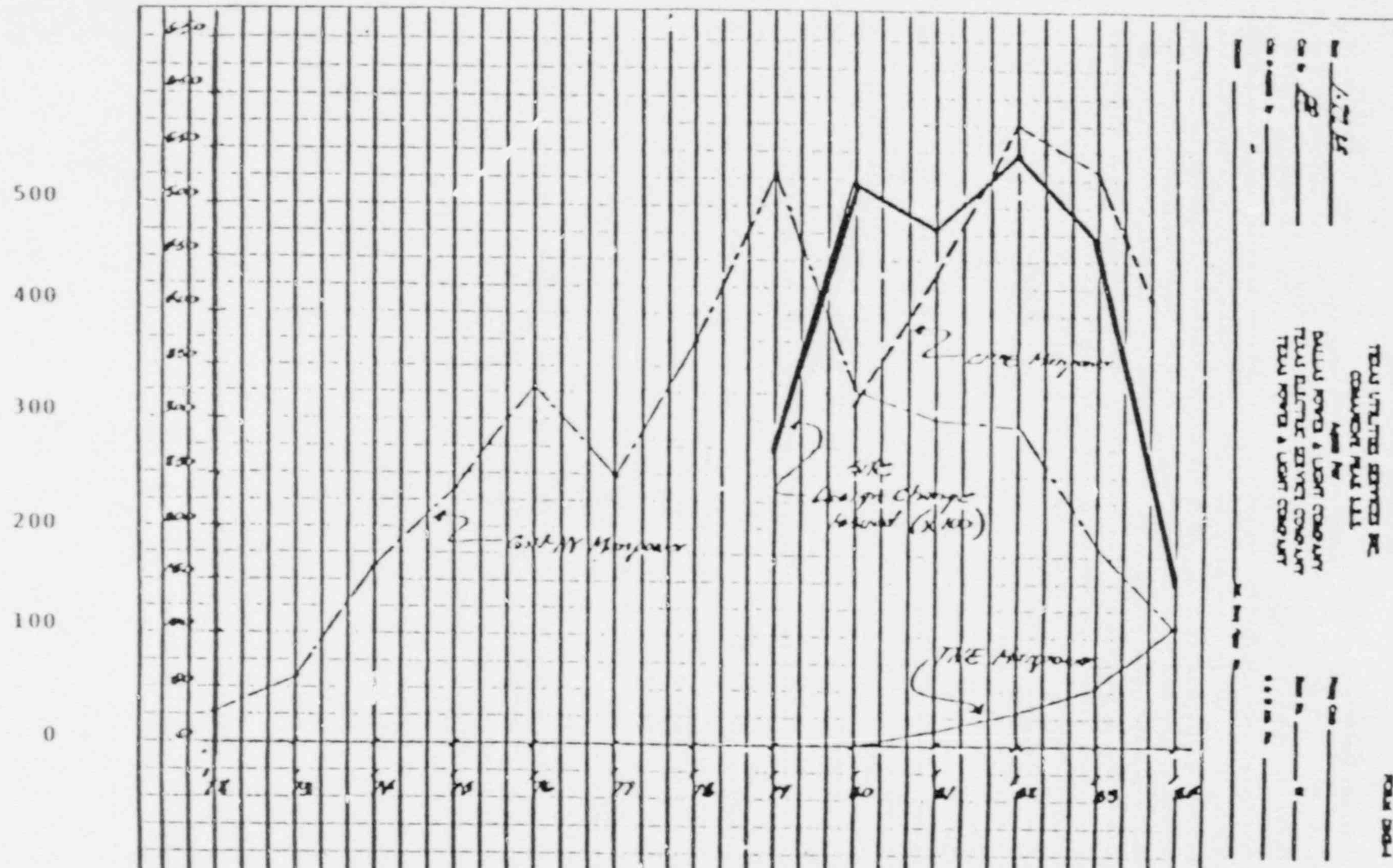
[57]Draft Paper on Design Change Control, p. 2363.

[58]Manpower Design Change Study, draft paper, 13 February 1985, material received in discovery, p. PT0025-0115. This also shows that the number of site design changes began to grow in 1977-1978 when TU took over a major part of the QA function, and that in the early 1980s the number of design engineers making changes on site was larger than the number of engineers originally employed by G&H in designing the plant. It appears the plant was designed once in New York, and then redesigned on site.

[59] The sheer number of design changes during construction suggests that there was a lot wrong with the initial design of the plant, or the construction, or both. It is worth mentioning that where a detailed engineering model of the plant was used in designing the buildings and equipment layout, as for example at Palo Verde, there were relatively few errors.



CPPE Manpower

Site
Design Change
Issued (x100)

C&H-NY Manpower

TNE Manpower

that in nuclear construction the tolerances are much tighter and the interdependence of the various systems is far greater than in conventional construction. Moreover, under the "fast track" approach the plant detailed design work is at best only a little ahead of construction. Inevitably, there are far more design changes than in other types of construction where the detailed design is well-established before construction begins. If the initial design changes are not verified and made final as they are being made, subsequent design changes which are based on them may also have to be modified if the underlying design changes have to be altered. This, combined with the backlog in doing verifications, was one of the reasons the NRC discovered so many deficiencies when it audited the work.

The Company's approach to design change control was criticized early on in a report prepared by the Management Analysis Company after an audit of the Comanche Peak project in May 1978. The report summary stated that:

> present practices in the control of design changes and of certain nonconformances do not provide the requisite level of review by the original designer. In other instances it was evident that design changes were being used in lieu of nonconformance reports.[60]

The importance of this observation is that nonconformance reports filed by quality control inspectors must be processed and resolved in strict conformance with Appendix B. The causes of significant nonconformances must be determined, corrective actions taken promptly, not only to correct the particular occurrence but also to preclude repetition, and reports must be furnished to the appropriate levels of management. What MAC

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[60]Management Analysis Company, "Texas Utilities Generating Company Audit Report," Appendix A, p. 3. The cover letter to TU President Perry Brittain, dated 17 May 1978, mentions "some failures to comply with regulatory requirements..."

was saying was that TU was making design changes on the spot to bypass the corrective discipline of the nonconformance reporting system.

The report included the following findings which could not have escaped top-level Company attention:

> The current site DC DDA [design change/design deviation authorization] system of after the fact coordination of design changes with the original designer provides a significant risk of design error and does not meet the requirements of 10CFR50 Appendix B, nor of ANSI N45.2.11, "Quality Assurance Requirements for the Design of Nuclear Power Plants."[61]

> Disposition of nonconforming items does not always achieve the requisite review by appropriately qualified design personnel....the DC DDA program has been used to bypass the nonconformance reporting system. The nonconformance control system should be the means for maintaining inspector integrity, identifying problem areas and provide a driving force for their correction.[62]

The report section on "Design Control" had the following additional observations:

> The present system of expediting field changes by referring design changes to the original organization for approval after the fact does not meet the intent of 10CFR50 Appendix B nor of ANSI N45.2.11, which require that field changes be subject to design controls commensurate with those exercised on the original design. TUGCO audits have already disclosed that the Architect/Engineer has not been reviewing field originated changes on a concurrent basis, thus the design engineers' comments may be received after the specific construction work is complete resulting in possible loss of design integrity, undue pressure on the designer to justify what has been done, loss of designer responsibility or possible extensive repairs. It is recommended that a system for expedited review and approval by the original designer be

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[61]MAC Report, p. 3.

[62]Ibid., p. 5.

> established on all safety related changes using telephone, telecopier or telex as necessary to coordinate and document change approvals.[63]

TU's senior managers disagreed with MAC's findings that the practice of "after-the-fact design change reviews" did not comply with Appendix B or that the practice posed a significant risk of error. They told Mr. Brittain, TUGCO President: "We propose to leave the design change system as is."[64] Instead, they should have immediately ordered the builders to stop using the "at-risk" approach.

It is important to note that TU did not give a copy of the MAC report to the NRC when it was written. Indeed, the NRC did not receive a copy of the MAC report until May 1985 when, in the words of the Company's 1986 annual report:

> TU Electric found a report in its file, relating to certain deficiencies in the QA program, which it believed should have been provided in response to a 1980 discovery request of the intervenor, and sent the report to the ASLB.

Had the MAC report been available to the NRC, it would have been far more difficult for the inspectors to acquiesce in the Company's approach to design changes. There was a good chance that a clearly presented report by an organization such as MAC charging the Company with violating Appendix B and the

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[63] MAC Report, Appendix B, "Texas Utilities Generating Company, Observations and Recommendations," p. 4.

[64] Memorandum, R.J. Gary and L.F. Fikar to Perry G. Brittain, 11 July 1978. The authors said they had discussed their analysis in general terms with MAC's team leader and saw no need to respond formally to the audit. In support of their belief that the "after-the-fact design change review" was in compliance with Appendix B, they cited TU internal audits and "independent audits by two separate NRC inspectors."

ANSI standards would have received NRC staff management, or even commissioner, attention. By holding back the MAC report, TU lost an opportunity to correct the Comanche Peak QA problems several years earlier.

The Company also ignored the warnings of its own QA organization. Shortly after he had become the corporate officer in charge of QA, in late 1980 - early 1981, Mr. Billy Ray Clements told his superiors in the TU hierarchy that he and his senior QA managers, Mr. Chapman and Mr. Vega, disagreed with the at-risk approach to design changes because "it put a strain on the design verification to do it that way"[65] and because they "wanted him [Mr. Gary] to know that we felt like that at-risk meant at risk".[66] Unfortunately, Mr. Clements' concerns did not lead to a re-evaluation of the TU's approach. As he put it, "the company position was set in stone".[67]

It is significant that Mr. Clements thought TU's at risk approach was "legal, and within the QA program, within 10 CFR 50 Appendix B"[68] and that be believes that "someone had checked it out with the NRC and NRC gave tacit approval".[69] In my view, the NRC staff would have balked at approving TU's at risk approach if the NRC had been asked for its formal approval (and even more so if the NRC staff had known of Mr. Clements's own conclusion and that of the Company's consultants). Had the NRC

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[65]Deposition of Mr. B.R. Clements taken on 15 December 1987 in the case between Texas Utilities Electric Company and the minority owners, volume II, p. 94.

[66]Ibid.

[67]Ibid., p. 99.

[68]Ibid., p. 94.

[69]Ibid., p. 95.

commissioners known about it, I am sure they would not have approved this practice. I would not have.

VI. CONSTRUCTION UNDER REGION IV SUPERVISION: 1975-1982

As mentioned, NRC inspection of construction was relatively light in the years before about 1979. More or less contemporaneously with the Three Mile island accident the agency inspectors began to keep a much closer watch on construction projects, and expected utilities to correct errors more promptly. Region IV was the slowest of the inspection offices to adopt a more intensive approach.

A. Region IV Inspections: 1975-1980

The NRC Region IV inspection reports for the early years of construction show few citations for violations of NRC requirements and the NRC's response to those violations seems mild. The number of critical inspection reports increased in 1979. Probably the most significant error came to light on 20 February 1979 when TU reported to the NRC resident inspector that a major error had been detected in the design of the Unit 2 reactor vessel support structure which would require considerable repair.

> The orientation error is apparently a result of the architect-engineer's (Gibbs & Hill) design of Unit 2 containment building as a mirror image of Unit 1. However, the nuclear steam system supplier (Westinghouse) supplied a RPV [reactor pressure vessel] that duplicates the RPV in Unit 1. As a result, the unit 2 RPV support are misoriented around the RPV's vertical axis. The Unit 2 RPV is en route to the site. [70]

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[70] Preliminary Notification of Event or Unusual Occurrence -- PNO-79-28, 22 February 1979. See also Inspection Report 79-07, 23 March 1979.

Although the regulations[71] require an immediate report of any deficiency in design or construction "which were it to have remained uncorrected, could have affected adversely the safety of operations of the nuclear power plant..." such a report was not filed in this instance. TU argued on narrow legal grounds that no report was required because the mistake was such a large one that the vessel could not have been installed at all, and therefore could not have affected the safety of the plant. That apparently was accepted by Region IV, but does not comport with the sense of the regulation.

Eight 1979 inspection reports which noted violations show Company weakness in following construction procedures. The Company was cited for failing to follow equipment maintenance instructions and to achieve adequate separation between redundant safety related wiring;[72] a failure to follow concrete placement procedures;[73] the failure to properly inspect field welding of cable tray supports and to maintain adequate records for about 20 percent of a sample of stainless pipe;[74] a failure to follow procedures in dealing with a large amount of electrical cable that did not conform to requirements;[75] a failure to properly train and indoctrinate QC personnel, to properly record Company inspections, and to control QC inspectors' stamps;[76] and again for failing to assure the

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[71] Section 50.55(e) of the agency's regulations.

[72] Inspection Report 79-04.

[73] Inspection Report 79-03.

[74] Inspection Report 79-06.

[75] Inspection Report 79-19.

[76] Inspection Report 79-18.

quality of the emplaced concrete.[77]

Another significant event in 1979 was the Company's failure to promptly file a deficiency report[78] with the NRC on discovering that some reinforcing steel called for by the design had not been placed in containment concrete. This led to a Company stop-work order, confirmed in a letter from Region IV.

The inspection reports filed in 1980 follow pretty much the same pattern. The Company was cited for failing to revise obsolete QA procedures and to follow current ones,[79] to provide appropriate instructions for the installation of an electrical panel,[80] to follow welding procedures,[81] to properly qualify electrical equipment,[82] and to follow procedures for cable installation (QC personnel had not been watching as they should have been doing).[83] The Company was also cited for its failure to follow procedures in repairing cable and to report a significant construction deficiency,[84] to follow pipe installation procedures,[85] to establish (any) QA program for certain categories of pipe supports, to follow construction

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[77]Inspection Report 79-24.

[78]Pursuant to Section 50.55(e).

[79]Inspection Report 79-26.

[80]Inspection Report 79-28.

[81]Inspection Report 79-31.

[82]Inspection Report 80-02.

[83]Inspection Report 80-03.

[84]Inspection Report 80-08.

[85]Inspection Report 80-11.

procedures for certain pipe hangers,[86] and to follow drawings for weld preparation details.[87]

On the whole, Comanche Peak received gentler treatment at the hands of Region IV than it would have received in another NRC region. The severity levels of violations were comparatively low, and a number of items were left open to allow the Company to make corrections to avoid being cited by the NRC (a point made by the internal 1986 NRC OIA investigation).

B. Systematic Assessments of Licensee Performance

The first Systematic Assessment of Licensee Performance (SALP) report prepared for Comanche Peak, which covered the period from August 1979 to July 1980, came to the conclusion that although 19 "noncompliances" had been identified by Region IV inspectors during that period, Region IV did not "currently see a need to make any adjustments in the IE inspection program as it relates to the Comanche Peak facilities." Region IV's evaluation of the Company's performance was that "it is generally acceptable although continued improvement in certain areas, already discussed, would be desirable."[88]

The SALP noted that "NRC personnel stated that it appears there is a continuing tendency to engineer away construction problems rather than enforce compliance to drawings and specifications." However, the NRC staff thought there was "no specific regulatory concern since safety does not appear to

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[86]Inspection Report 80-15.

[87]Inspection Report 80-17.

[88]Inspection Report 80-25, 12 November 1980, p. 6.

have been compromised as yet but could possibly be sometime in the future if appropriate actions were not taken."

Also of interest was the Company's response to Region IV's reminder that the licensee has "the principal and legal responsibility for all matters regarding the construction and operation" of the plant. "The licensee responded that he is aware of his responsibilities and that in response to these responsibilities, he continuously increased his involvement in the project during the past three years until he is now essentially in complete control of the project except for the immediate line supervision of the labor force."[89]

The second Comanche Peak SALP report, covering the period July 1980 to June 1981, which incorporated the NRC's new scheme for grading licensee performance, gave the project an overall top rating of "Category 1." The individual area ratings included four "1s" and two "2s." However, the supporting descriptions are not entirely consistent with the high grades. For example, in the top-rated Piping area there were three violations, two of which indicated "problems in the vendor component inspection program which have been rectified." In spite of this the overall comment was:

> The licensee/contractor ASME Code-based installation and quality control program is relatively simple, straightforward, and is generally well implemented. The major weakness has been, and to a degree continues to be, an inability to hire/or retain the services of competent (as distinguished from Code qualification) pipe welders.[90]

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[89] Ibid.

[90] Systematic Assessment of Licensee Performance, Inspection Report 81-20, 29 March 1982, p. 4.

In Instrumentation and Control, also top-rated, the report states:

> Although much effort has been expended in this area by the licensee's labor force, relatively few instruments are fully installed. The licensee's program for installation and quality control in this area is simple, straightforward, and effective. The assigned personnel appear to have been adequately trained and competent to carry out their assigned responsibilities. NRC inspectors have not identified any substantive problems in this functional area during the appraisal period.

Testimony later given before the Licensing Board[91] confirms that at least some Region IV inspectors held more critical views, which were not reflected in this report. For example, Robert C. Stewart, one of the NRC inspectors at Comanche Peak, testified that:

> I noted [in an informal report to his supervisor] that during the early part of 1976, it became apparent to me that the effectiveness of the licensee's QA/QC Program was in a state of degradation as a result of domineering and overpowering control by the contractor's site construction management...[92]
>
> It was my observation that the Brown & Root ("B&R") construction management, from the foreman up through the site manager, were demonstrating oppressive, domineering and intimidating attitudes toward both TUGCO QA and B&R QA/QC staff personnel. At the time, there appeared to be no attempt to correct this unpleasant atmosphere by either TUGCO or B&R corporate management...[93]

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91 Supplemental Testimony of William A. Crossman, Robert C. Stewart and Robert G. Taylor Regarding Annual Assessments of Applicants' Performance (Contention 5), filed with the Licensing Board on 19 July 1982.

92 Supplemental Testimony, page 7.

93 Supplemental Testimony, page 8.

Another NRC inspector at Comanche Peak, Robert G. Taylor, testified that:

> What I had begun to see, but had difficulty proving, was that the Brown & Root construction philosophy was to build something any way they wanted to and then leave it up to the engineer to document and approve the as-built condition. If the engineer refused, he was blamed for being too conservative and not responsive to the client's needs...[94]
>
> ...too often an installation was clearly constructed other than as originally designed and had been approved by the licensee's on-site engineering arm as fulfilling requirements. In effect, the engineer had approved a nonconforming installation in advance of QC being called. QC was then signing for the as-built condition and the underlying problem was not addressed.
>
> I stated that I wasn't at all sure that what CPSES was doing in this area was very different from what other utilities and/or engineers had done on other projects, but I didn't like it...[95]

Unfortunately, these observations were not acted upon at the time they were made (although it would be surprising if the Company was not aware of them at the time in view of its close contact with the NRC).

C. The NRC Staff Safety Evaluation Report: 1981

On 14 July 1981 the NRC licensing staff issued the Comanche Peak SER.[96] The power plant was described as similar to Duke Power's McGuire station, and the NRC staff relied where possible on the results of that earlier review.

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94 Supplemental Testimony, page 16.

95 Supplemental Testimony, pages 17-18.

96 NUREG-0797.

The SER states the NRC staff had still not "reached a determination on the acceptability of the..[operating] organization." The principal difficulty was the lack of experience: "at the corporate level, there is no experience in the actual operation of commercial nuclear power plants..."[97] The quality assurance review at this stage concerned QA during the prospective operational phase and not during construction, which is supposed to be nearly complete. Since the QA review in advance of construction had been merely an examination of Company and contractor plans, no overall examination of the construction QA program had taken place up to this point.

In October 1981 the NRC staff issued Supplement No. 1 to the SER. It returned to the open organizational questions.[98] After conducting interviews to check on the TU organization, the NRC staff gave its approval: "..the audit team was impressed with the knowledge and enthusiasm and the obvious esprit that permeates these organizations." Despite the lack of experience, all corporate staff interviewed "seem dedicated to achieving a first class operation at Comanche Peak and they are aware of the effort and personal commitment that this will entail." Mr. R. J. Gary, the Executive VP and General Manager of TUGCO was reported to spend "about 15%" of his time on the plant (which does not seem a particularly high figure).

The SER Supplement concludes with the surprising observation that "the personal involvement and commitment of the corporate officers is such that little could be gained by requiring an augmentation of the corporate staff to include a

[97] Ibid., p. 13-9.

[98] Chapter 13

person or persons with actual commercial nuclear experience."[99] As mentioned earlier, in November 1981 the ACRS had pointed to the lack of TU's hands-on experience with large commercial nuclear power plants.

D. Region IV Inspection: 1981-1982

Inspection reports for this period continue to show Region IV regulating in a fairly gentle fashion. The inspectors seem to have taken, or to have been encouraged by their managers to take, a very narrow view of their responsibilities. For example, in one instance,[100] an inspector checked a hanger design using a sample of one. He found an error in the one examined. TU reanalyzed the design and found it to be acceptable. The inspection report concludes:

> Time did not permit a detailed examination of the new analysis or examination of additional DRFs to determine whether this was an isolated case or generic in nature.

Where problems were found, especially if they were discovered as a result of allegations by critics of the Company, the Region IV inspectors almost invariably found that the "concerns expressed...have been identified and corrected by the licensee."[101] A December 1982 report[102] cites the Company for two violations (failure to inspect seismic shims on polar crane brackets, and failure to properly train and indoctrinate QC personnel), but contains a point-by-point response to

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[99] SSER No. 1, p. 13-3.

[100] Inspection Report 82-05

[101] As in Inspection Report 82-14.

[102] Inspection Report 82-11.

allegations raised during the Licensing Board hearings and concludes that they are almost all "refuted."

The SALP report issued by Region IV for the period October 1981 to September 1982 showed the effect of TU's lack of operational experience. In the area of Pre-operational Testing the Company received the lowest grade, Category 3, with the following comment which gives some indication of basic managerial problems:

> the lack of a [illegible] nuclear plant startup experience has hampered the program...scheduling of tests out of sequence with construction status, coupled with the lack of timely test procedure generation, are examples of the lack of experience.[103]

In the construction areas the grades were generally good, as before, with the exception of Vendor Procurement where the Company also received a Category 3 grade. The structural integrity of pipe whip restraints and main control boards was found to be deficient because of deficient welding by vendors:

> In each case, the licensee source inspection organization [at the vendor's work site] had documented acceptable welds which, in turn, were not reinspected at the site by reason of source inspection acceptance.

There were some hints of trouble to come in the pipe support area. Piping itself is rated Category 1. Piping Supports work, however, is rated Category 2:

> due to the significant number of field generated engineering changes that have been necessary and due to

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[103] Systematic Assessment of Licensee Performance, Inspection Report 82-12, p. 4.

> the complexity of the management controls program that has evolved because of these changes.[104]

The report also pointed to signs of trouble brewing for the project in the hearing:

> There were a substantial number of investigations and special inspections performed during the review period as a result of limited and formal appearances of persons before the ASLB....At the end of the review period, a major special inspection was ongoing in regard to the licensee's pipe support design program.[105]

E. "Licensing Delay"

In early 1981 Unit 1 was estimated to be 91 percent complete, and Unit 2 about 54 percent complete. On 30 April 1981 NRC Chairman Hendrie wrote to Congressman Bevill that the NRC was using TU's construction completion date of December 1981 to guide assignment of NRC staff to the review process. The NRC's Caseload Forecast Panel, which helped the agency schedule its licensing reviews, in fact estimated that Comanche Peak would not be ready to load fuel until December 1982, a year later than the Company's projection. TU, however, continued to insist that the plant would be able to load fuel six months before its December 1981 target date. (It is difficult to understand how this projection could have been made when basic tests essential to start-up had not been and

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[104]Ibid., p. 6.

[105]Ibid., pp. 12 - 13.

could not be completed in time.[106] Although the projected date for a full-power decision by the commissioners had been advanced from February 1983 to October 1982, this still left a projected 10-month "licensing delay" between December 1981 and October 1982. In September 1981, TU informed the NRC that the schedule had slipped and that construction could not be completed before June 1982. "Informal" information provided to NRC indicated a date after October 1982 which meant that the "licensing delay" had disappeared.

In July 1982, the NRC Caseload Forecast Panel reported that the applicant's target fuel load date for Unit 1 was June 1983. Preoperational testing was to have started in June 1982. The Caseload Forecast Panel thought installation of piping, piping hangers and cable trays was proceeding efficiently, and that on the basis of these installation rates Unit 1 could load fuel in December 1983 "provided no major delays develop during preoperational testing."

TU's approach to completing construction seems to have been to accept partially completed systems for testing in order to shorten the testing period and meet the target fuel load date. Instead of waiting for entire systems to be finished, TU apparently divided the systems into smaller testable components and partial system turnover packages which could be tested at an earlier date as they were completed.

However, such out-of-sequence testing had its price. Once a subsystem was turned over to the start-up organization, the

[106]For example, the "cold hydro" tests (to check the ability of the fluid systems to withstand design pressures), which are normally performed about a year before fuel load, had not been completed when this projection was made, about eight months prior to the December 1981 target fuel load date.

rules for working on it became more strict. At a minimum, the start-up group had to coordinate the work of the craft labor, which added an additional interface to the organization of work. In addition, the work itself became more complicated as whole systems had to be taken out of operation prior to making any changes. For example, if construction had to weld additional pipe onto a system, the permission of the test coordinator had to be obtained, any testing of the system had to be stopped, and the system had to be de-energized and drained before the work could start. At Comanche Peak, the start-up group controlled the interface between start-up and construction by requiring a Start-up Work Authorization (SWA) for each modification made to a system under its control.

TU's method of testing completed subsystems might have shortened the testing program if Comanche Peak had a less troubled construction history. Unfortunately, much of the engineering redesign and construction rework took place while the systems were in the custody of the start-up group. By late 1983, the start-up group had issued approximately 18,000 SWAs[107]. The result was that both the testing and the rework being done were slowed down.

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107 Fifty-nine percent of these SWAs were due to engineering redesign.

VII. THE LICENSING BOARD LOSES CONFIDENCE IN TEXAS UTILITIES: 1982-1983

Up to 1983, NRC's Region IV had found that with few exceptions TU was turning in an average, or above-average, performance in constructing Comanche Peak. During 1983, doubts about the adequacy of the design and construction began to creep into some of the NRC headquarter staff's reports. However, Region IV management maintained that the project was progressing satisfactorily and that no significant problems existed.

Concerns raised in the hearings in late 1982 by two CASE witnesses led the Licensing Board to look more deeply into the adequacy of QA and QC, especially in the area of design. This series of hearings culminated in the Board's 28 December 1983 opinion stating that it lacked sufficient confidence in the quality of the design work to authorize Unit 1 licensing. The Board allowed TU the opportunity to demonstrate the adequacy of the plant's design by means of an independent design review. This was the first of two major turning points in Comanche Peak's licensing history.

A. Region IV Dismisses Problems: The Special Inspection Team

In July and September 1982, Mark Walsh and Jack Doyle, two engineers who had worked on Comanche Peak for TU, raised questions about the adequacy of pipe support design before the Board.[108] Walsh and Doyle's testimony raised sufficient

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[108]The Board also heard allegations about the quality of construction from a number of other witnesses. Some of these were found not to have merit, while others led to further

concerns to cause Region IV to dispatch a "Special Inspection Team" (SIT) in late 1982 to conduct an inspection at Comanche Peak. The SIT reported on 15 February 1983 that they had inspected 19 areas that covered Region IV's understanding of the issues Walsh and Doyle had raised. (Oddly enough, the SIT never contacted Walsh and Doyle to obtain a better understanding of their perceptions of the problems at the plant.)

The SIT concluded that there were no violations of NRC regulations. A total of four matters in two areas were considered "unresolved." That is, more information was thought to be needed to reach a conclusion about the state of compliance with the quality assurance regulations.[109] In addition, there were four matters on which more effort was needed to resolve concerns. The SIT's view was that:

> In all of these cases the Applicant has identified a similar problem in the course of its design review program and is undertaking corrective action....The Applicant's design program and design review procedures are adequate to provide reasonable assurance that appropriate corrective action will be taken.[110]

The SIT also reported that a special inspection of 100 pipe support designs which were "vendor-certified" for 15 attributes did not disclose any discrepancies "which would indicate a failure of the Applicant's design verification program to identify and correct supports to assure compliance with applicable design criteria." The qualification is important. The SIT was apparently not saying that there were no

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investigation.

[109] 10 CFR 50 Appendix B.

[110] Inspection Report 50-445/82-26, 50-446/82-14, p. 3.

discrepancies, but rather that the situation they found did not indicate to them a failure of the TU design verification program.[111]

The Summary and Conclusion of the SIT's report stated that in twelve of the nineteen areas the concerns "alleged" by Walsh and Doyle "were not substantiated." In six areas some aspects of the concerns "expressed" by Walsh and Doyle had also been identified by the Applicant and "the problems have been or are being rectified." Other aspects were not substantiated. In one area, one aspect of Mr. Doyle's concern related to the bending stresses in a bolt was "in part" confirmed; as for the other aspects:

> None of the other concerns raised by Walsh and Doyle were substantiated as demonstrating serious deficiencies in the Applicant's pipe support design program.[112]

Region IV seemed determined not to give Walsh and Doyle any credit whatsoever.

B. The Construction Appraisal Team Inspection

An NRC Construction Appraisal Team inspection, conducted between January and March 1983 and involving inspectors from outside of Region IV, was more critical. The 11 April 1983 cover letter to TU from the Director of the Office of Inspection and Enforcement states that the various deficiencies

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[111]This SIT result was later cited before the Licensing Board by the NRC staff in its proposed findings of fact on pipe support design issues as "the most important evidence" supporting the TU position. NRC Staff's Proposed Findings of Fact in the Form of a Partial Initial Decision, 30 August 1983.

[112]Inspection Report 50-445/82-26, 50-446/82-14, p. 7.

noted in the installed hardware "did not indicate pervasive failures to meet construction installation requirements," except in the area of heating, ventilation and air conditioning systems (HVAC)[113], where "a breakdown in work ard quality control was identified."

The Executive Summary was blunter in stating that the inspection indicated "several construction program weaknesses":

> 1. Results of the inspection indicated a breakdown in fabrication, installation, and inspection in the...[HVAC] systems.
>
> 2. A number of examples were identified of the failure to meet criteria for separation of safety-related cables from mechanical structures and piping, and separation of redundant trains of safety systems. This was due in part to the licensee decision to not inspect installations for required separation until installation is essentially complete. The NRC CAT inspectors are concerned whether: (1) the inspections can be effectively conducted after installation, and (2) whether adequate correction actions can be accomplished after installation is completed. Correction of cable separation deficiencies at a later date could require repeating portions of system testing...
>
> 3. The licensee's quality assurance program did not ensure that certain hanger, support, electrical and mechanical equipment was installed to the latest design documents, and commensurately that an appropriate inspection was conducted to the latest design documents.
>
> 4. Findings also indicate a number of instances where nonconforming conditions were identified; however, various methods (e.g., punchlists, inspection reports, verbal, and other informal methods) were used to address and resolve these nonconformances. These methods do not comply with requirements to identify nonconforming conditions and provide corrective actions to prevent recurrence.
>
> 5. The licensee's Quality Assurance audit program should have been more effective in detecting and obtaining

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[113] These systems are vital for keeping ambient temperatures within the operating specifications of safety equipment.

> correction of deficiencies in safety-related work; such as those in the HVAC system, mechanical equipment, and electrical components.
>
> In summary, the identified weaknesses require increased dedication by management at all levels to assure completed installations meet design requirements and that inspection documentation reflects that the completed installations have been adequately inspected to the latest design document.[114]

The Executive Summary further stated that there were:

> inadequate procedures to assure reinspection of modified, previously accepted Class 1E [safety related] components....The existing program for pipe support/restraints does not appear adequate to properly verify that final as-built hardware meets the final design requirements....The HVAC welding activities reveal significant deficiencies....In the area of certain hangers, supports, electrical and mechanical equipment, the licensee's program during construction has lacked adequate controls to ensure information transmitted from the design organization was provided to the quality control organization for use in performing timely QC inspections. This fact contributed to the licensee's inability to have an adequate program in-place at the time of this inspection to ensure that field installations were constructed to the latest design document and that an appropriate quality inspection was completed. In addition, the large number (approximately 70,000 CMCs and 15,000 DCAs)[115] of design change documents contributed to the difficulty in determining whether the "final"

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[114] Inspection Report 50-445/83-18, 50-446/83-12, pp. A-1 - A-2, hereafter cited as CAT Report. The construction practices cited in paragraph 2 are similar to the "build at risk" practices discussed in the Company's 20 December 1984 paper discussed in an earlier footnote.

[115] Component Modification Cards and Design Change Authorizations were the principal documents for recording design changes after about 1978. The former were specially formatted for piping and pipe support changes.

installation was in accordance with the "final" design.[116]

The body of the document, the actual reports written by the inspectors, which typically are less edited by management than the Summary and cover letter, was blunter still. TU's activities in the pipe support/restraint area were summarized as follows:

> a. Numerous cases of QC accepted installed hardware not conforming to drawings and CMCs [component modification cards] were identified by the NRC CAT inspectors, ANI [authorized nuclear inspector[117]], and B&R QC during VCD [vendor controlled drawing] inspections, and by TUSI "as-built" personnel.
>
> b. These conditions indicate poor inspection work, unclear/erroneous drafting, and/or unauthorized, uncontrolled alterations of completed work.
>
> c. Numerous instances exist where nonconforming conditions have not been properly identified to provide the input to the QA Corrective Action Program for determining root causes and preventing recurrence.
>
> d. From discussions with site personnel and the obviously large numbers of CMCs, it appears original design drawings were used only as guides to construction, and the actual design/analysis was performed _after_ construction and inspection. This may have resulted from the many changes required due to relocated piping, interferences, and the CMC program itself.
>
> e. The acceptability of the installed hardware to meet design requirements based on a series of partial inspections (versus a final complete inspection after work is completed) is

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[116] Ibid., pp. A-2 - A-3.

[117] The authorized nuclear inspector is an independent inspector who checks conformance of piping and pressure vessels with the American Society of Mechanical Engineers' code.

questionable based on the following points:

-- Numbers of "design" changes (CMCs)

-- Somewhat unspecific inspection procedures

-- Amount of ongoing construction activities and the apparent lack of discipline regarding construction personnel tampering with QC accepted hardware.

-- Drafting and design discrepancies noted in initial drawings, CMCs and VCDs.

-- The number of discrepancies noted on supports previously accepted by QC.

-- Inspection documentation not indicating the "design" document (drawing and/or CMC) revision that was used for the inspection.

In conclusion, although extensive major technical problems were not identified in the pipe support/restraint hardware, prompt action is required to address the above program concerns. Specifically, attention must be focused in the areas of the nonconformance/corrective action program, comprehensive final inspections and inspection documentation in order to provide confidence in the acceptability of installed pipe supports/restraints.[118]

The section on Design Change Controls and Corrective Action Systems contained the following observations:

> ...some original designs in this [civil engineering] area were processed via Component Modification Card (CMC)....However, these CMCs showed no evidence of Gibbs & Hill review....The responsible licensee representative indicated these CMCs...would receive Gibbs & Hill review...[119]

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[118]CAT Report, p. III-9, emphasis added.

[119]CAT Report, p. IX-2.

> The NRC CAT inspector sampled and reviewed sixty CMCs and fifteen DCAs [for cable tray and conduit supports]. About thirty of the CMCs and DCAs had not received the appropriate review and approval by the original designer, Gibbs & Hill, as required by ANSI N45.2.11. Installation to the design document had been performed or were in-process, but the design document had not been "final" reviewed. A review of the Gibbs & Hill "CMC Master Index" (structural) indicated there were on the order of four-to-five thousand of such changes that had been generated but not yet been "final" reviewed by Gibbs & Hill....
>
> The NRC CAT inspector determined that inspections performed and completed were not always to the latest issued design document. For example, supports for twenty cable tray and conduit installations were examined. Of these twenty, twelve were not "final" inspected to the latest issued design document, even though records in the QA vault indicated "final" inspection had been performed. Later CMCs covering design changes existed for all twelve of these installations. In addition, the licensee's QC inspections were performed in six instances to CMCs with earlier revisions than the latest revision issued and in effect _at the time the inspection was performed_...
>
> ...As a result of the procedures and records reviewed relative to this area, the NRC CAT inspector considers existing procedures have not assured that the information concerning the change is transmitted to the appropriate organization...[120]

Because so much of the plant was in a state of change (approximately 70,000 CMCs and 15,000 DCAs had been issued, not counting revisions), the CAT inspectors found it impossible to determine from sampling reviews whether work was being performed to final design and whether it was properly inspected. The authors did not think there was anything in the NRC requirements that discouraged or prohibited such a system, but added

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[120] CAT Report, pp. IX-3 and IX-4 (emphasis in original).

> ...with this type of system in place, actual verification of equipment cannot be performed until "work activities" have been completed. Few, if any, installations could be verified as few have been designated as completed under the licensee's context of "completion." Thus, the final adequacy of these [design change] controls could not be determined by the NRC CAT inspector.[121]

Sixteen potential violations were referred to Region IV. This April 1983 report should have served as a powerful warning to the Company, especially in the area of design change control. The report pointed to the problems inherent in the "build at risk" approach. And once the NRC headquarters staff was aware that designs were not fully verified before construction and, even worse, that frequently design and analysis actually came after construction rather than before it, a more than usually detailed pre-operation inspection of the plant was almost inevitable.

C. Independent Design Verification

The CAT result did have one important effect in terms of further review of the Comanche Peak design. It brought into the Comanche Peak review process an independent organization which was to play a significant role in the decisions that the plant was not ready for operation.

In the aftermath of the Diablo Canyon design error experience, the NRC staff routinely asked applicants for operating licenses to arrange for an independent audit of their design activities. Such an audit was usually performed by an independent organization under contract to the applicant, and

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[121] CAT Report, p. IX-9.

was known as an independent design verification program (IDVP). TU resisted an independent review of Comanche Peak's design (on the grounds that the Company was confident of the quality of the design and construction) when the NRC raised the concept in 1982.[122] With the results of the CAT inspection in hand, the NRC grew more insistent.

An internal TU memorandum[123] on a meeting with NRC officials states that they told the Company that whereas they had previously been willing to forego an IDVP, the CAT results and continued allegations of quality problems had forced them to reconsider. "Their confidence in stating CPSES is a safe plant has been 'eroded.'" One of the items of concern was the "volume of change paper to be incorporated in project documents." Mr. J. B. George, the senior Company official present, stated "he was not in a position to agree to any additional program of the IDVP nature." The NRC officials are reported to have expressed sympathy for the Company's position, but to have restated that there was an "erosion of confidence" and a need for an IDVP to "bolster their resolve to pronounce CPSES a safe plant."

In June 1983 the Company submitted a proposed plan for an Independent Assessment Program (IAP) for Comanche Peak to be performed by Cygna Energy Services (Cygna). The plan envisioned a minimal review based on a visual inspection of a portion of the spent fuel pool cooling system, a relatively

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[122] "We believe the verification programs which we have established, including programs above regulatory requirements, provide a high confidence level which precludes the need for additional programs at this time." Letter to Harold R. Denton, Director of Nuclear Reactor Regulation (NRC), from R. J. Gary, Executive Vice President and General Manager (TU), 16 August 1982.

[123] Memorandum, J.S. Marshall to H.C. Schmidt, 11 March 1983.

peripheral system. The NRC requested review of a system other than the spent fuel cooling system. After some negotiation, the Company proposed a somewhat expanded program which the NRC accepted in September 1983.

Cygna submitted a draft final report on 5 November 1983. Cygna stated, "Based on the results of our design control and technical reviews, sufficient assurance exist for Cygna to conclude that the overall design activities on CPSES are adequate and have been properly implemented." In correspondence with the NRC, Cygna added the qualification "integrated with the previous reviews of CPSES" after "reviews." In a 21 February 1984 hearing, Cygna said it would like to qualify the statement further to apply "within the scope" of the Cygna review.[124] Cygna was to have more second thoughts about its conclusions.

D. NRC Inspection Reports

The NRC Region IV inspection reports for this period also give some flavor of what was going on. Pipe supports were an area of difficulty for the plant. Violations which were cited included a repeated mathematical error in the calculation of pipe support designs[125], a failure to follow pipe support weld procedures[126], and a number of weld violations (although the report concluded that allegations raised in the licensing hearing concerning pipe supports and electrical cable splices

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[124] SSER No. 5, pp. 7-8.

[125] Inspection Report 82-30.

[126] Inspection Report 83-07.

are not valid).[127]

Report 83-23 listed several deficiencies related to the inspection process and procedures: six out of fifty large pipe supports had discrepancies upon visual examination, as did three out of thirty five small pipe supports; one out of four conduit supports was missing. Concerning the "punchlist" -- the list of pending items -- the NRC inspector found that "basic controls do exist; however, there are problem areas...:

-- There is no procedural control of the construction punchlist.
-- There is no procedural control for punchlist input.
-- There is no procedural control for removal of punchlist items.
-- It is not clear when the construction punchlist and master system punchlist is to be combined.
-- There is no QA/QC review of the punchlist from the standpoint of the need for corrective action...

Another report[128] sheds light on the problems resulting from rework and out-of-phase construction and testing:

> Several months ago a large amount of rework was initiated by the licensee. Much of this work was in the electrical area...also ...in the mechanical areas. Since this rework commenced after the NRC inspector had completed the review on the above tests, it was determined that a random sample of the same test should be re-examined to evaluate the effect of the rework on the [preoperational] test results.

Two QA-related civil penalties were imposed. On 29 August 1983, the NRC imposed a Level III civil penalty of $40,000 on TU after the Department of Labor had determined that Brown &

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[127]Inspection Report 83-15.

[128]Inspection Report 83-40.

Root had transferred and subsequently fired a quality control inspector for filing nonconformance reports identifying quality problems.[129] On 22 December 1983, the NRC staff imposed another Level III civil penalty of $40,000 on TU, this time as a result of a QC supervisor threatening QC personnel with withdrawal of their QC certifications if they continued to write "nitpicking" nonconformance reports which had been the subject of complaints from construction managers.

E. The 1984 SALP

The Region IV SALP report for the period from 1 October 1982 to 31 October 1983, issued on 25 March 1984, gave little indication of the problems which were beginning to emerge. There was some improvement in the grade for Preoperational Testing (from Category 3 to Category 2), but a dropoff in the Construction grades (ten "2s," one "3," and one "1"). The supporting comments touch on problems obliquely.

On Piping: the licensee performance has been "excellent." On pipe supports [the area of the Walsh/Doyle concerns], the licensee has performed "well, notwithstanding the apparent number of NRC findings..."

On HVAC: the licensee QA failed to identify weld problems.

On Design and Design Change Control: "The licensee has a long established and complex system for accomplishing changes to issued engineering documents...Their accounting system has

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[129]The Fifth Circuit subsequently found that the quality inspector's actions were not within the ambit of the Atomic Energy Act's whistleblower provisions. The Department of Labor's findings of fact were not disputed.

been difficult to maintain since the logs must be maintained manually."

On Construction QA: About 450-500 licensee staff are performing inspections. "The licensee has experienced various problems in the QA area where the personnel performing inspections did not interpret the instructions in the same light as the writers..."

F. Estimated Completion Date

The Bevill Reports for this period are interesting mainly for what they say about NRC headquarter's changing view of the project. In the January 1983 report the Commission full-power vote is listed for May 1983, and construction completion for June 1983. The April 1983 report projected a license in November 1983 and noted that the Company now expected the plant to be finished in September 1983.

A 23 November 1983 summary of the Caseload Forecast Group's[130] meeting (held on September 27-29) states that the Company's date for Unit 1 fuel load is December 1983. However, the CFG projects a fuel load date between July and September 1984 "assuming no unexpected delays occur during completion of the preoperational testing program." This estimate does not take account of allegations of improper work. Minutes of the meeting with the Company include the following description of what the NRC forecasting group found on its tour:

> Throughout both buildings [safeguards and auxiliary] there is little indication that the construction mode is changing to an operational mode.

[130] The name change (from "Panel" to "Group") also signified a reduced role for the agency's in-house estimators.

> The fuel building is the only area in which construction is essentially complete.

This hardly sounds like the description of a plant that is essentially complete and nearly ready to operate, as TU represented.

G. The Licensing Board Demands Additional Assurance on Design Quality

As a result of Contention 5, which had called into question the entire Comanche Peak QA program, the Licensing Board became increasingly busy with quality assurance issues during 1983. On 29 July 1983, it issued an opinion dealing with a variety of specific QA issues including whether blasting during site preparation had damaged the bedrock, whether basemat concrete had been poured improperly, whether low worker morale had resulted in low quality work, whether improper welding practices had been followed, and whether painting had been subject to adequate QA. While the Board found that most of the allegations about inadequate QA did not amount to significant safety problems, or that they had already been remedied, it did keep a certain number as "open items" requiring further exploration.

The Board came to a more negative conclusion about QA at Comanche Peak in its 6 October 1983 Partial Initial Decision. The Board found that TU had failed to demonstrate that, in designing pipe supports using A500 steel, it had complied with two General Design Criteria: Criterion 1 (which requires applicants to establish quality standards and implement quality assurance programs) and Criterion 4 (which requires that equipment be designed to cope with both normal and accident environments). The Board reacted quite mildly. It asked TU to complete additional analyses to demonstrate the adequacy of these pipe support designs.

The major turning point did not come until 28 December 1983, when the Board issued its Memorandum and Order on Quality Assurance for Design. After hearing the issues raised by Walsh and Doyle, the Board's conclusion was that:

> The record before us casts doubt on the design quality...both because [TUGCO] has not demonstrated the existence of a system that promptly corrects design deficiencies and because our record is devoid of a satisfactory explanation for several design questions raised by [CASE]...

Apparently to protect its use of the "at risk" approach to design change verification, TU had fallen back on the argument that, while Criterion III of Appendix B admittedly requires the adoption of quality standards in design, the requirement that there be a system to insure the <u>prompt</u> identification and correction of conditions adverse to safety, set forth in Criterion XVI of Appendix B, does not apply to design. In essence, TU's position was that design errors, as opposed to construction errors, do not have to be caught promptly and that all that is required is reasonable assurance that design errors will be identified before the plant is completed.[131]

The Board rejected this view, in which the Company was supported by the NRC staff litigators, saying:

> We reject the view that the promptness requirement of the regulations applies to construction deficiencies and not

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[131] As noted above, this is what the ASLB found TU's position to be, although TU later disclaimed having so argued.

> to design deficiencies. Such a view necessarily rests on an illogical interpretation of the regulations; it would require us to believe that the Commission sought prompt correction of construction deficiencies, defined as a failure to comply with design documents that are themselves exempt from the need for prompt correction of deficiencies. In that view, quality assurance is a scholastic pursuit not related to the actual quality of the plant. A preferable view is that both construction and design deficiencies must be identified, reduced to writing, and corrected with reasonable promptness.

The Board went on to explain that the lack of an adequate design QA program was:

> a serious deficiency, mitigated only slightly because it was acquiesced in by the [NRC] staff....the principal consequence of this deficiency is that applicant, the staff and this Board must now be especially careful to determine that quality assurance standards for design have been met at the conclusion of the construction process....we intend to continue to conduct an efficient proceeding...but we will not be especially concerned about meeting applicant's construction targets. A consequence of applicant's chosen method of assuring design quality is that this Board's task with respect to the pending quality assurance contention has been partially deferred to a later stage of the design process. We consider care in performing our job to be of paramount importance.

The Board urged TU to abandon its expressed belief that its problems had to do with the composition of the Board, and told TU that "its principal difficulty has been its inability to submit rigorous, logical answers to opposing proof." The Board noted that because

> of the limited ability of ...[Walsh and Doyle]...to observe deficiencies in such a mammoth undertaking as the construction of a nuclear plant, the failure to provide logical explanations for several of their allegations raises questions about the adequacy of the design of the whole plant. The purpose of the plan [for the independent design review] we are requiring applicant to file is to assist this Board in resolving those questions.

The Board found CASE's Contention 5 "meritorious", but allowed the Company to file a plan for an independent design review to resolve the Board's concerns.

The Company sought to avoid a final negative Board finding. In its motion for reconsideration of the Design QA decision, TU asked the Board to make clear that there was not adequate evidence in the record "to determine whether the Applicant's pipe support design process satisfies Appendix B (a view which the Applicant shares) and that further evidence will be required." The Board's 8 February 1984 response noted that, up until this adverse decision, TU had repeatedly used its seemingly always imminent fuel load date to urge the Board to speed up the hearing and close the record to avoid delay in operation of the plant. At the same time, however, the Board turned down CASE's motion that TU not be allowed to reopen the record saying, "it does not seem to us logical or proper to close down a multi-billion dollar nuclear plant because of a deficiency of proof. While there would be some 'justice' to such a proposition, there would be no sense to it." The Board reaffirmed its decision, noting with approval that both TU and the NRC staff had abandoned their interpretation of Appendix B that design deficiencies do not have to be identified and corrected promptly.

The Licensing Board's actions were, in my view, reasonable and even-handed. On the basis of its findings, the Board could have denied the Company an operating license, as the Licensing Board in the Byron proceeding did in 1984, on the grounds that the Company had failed to meet the burden of establishing that it had satisfied the NRC's regulations. This would have placed on TU the heavy burden of persuading the NRC commissioners to reopen the hearing. Instead, the Board allowed the Company to introduce additional evidence.

The Licensing Board seems to have followed a balanced approach in other respects, as well. It eliminated all contentions other than Contention 5 on QA. Its investigations of the various allegations made by witnesses were thorough and fair. It had carefully reviewed and rejected the accusations made by five other CASE witnesses. In 1984 it rejected the welding allegations made by two witnesses because it had "reluctantly come to the conclusion that neither of [them] is a credible witness." On the other hand, it also kept open issues, or asked its own questions where it believed serious safety questions had not been fully resolved.

In the course of a 10 February 1984, telephone conference between the Board and parties it was agreed that Cygna (the firm which had recently submitted a draft independent assessment of the plant's design, discussed above) would conduct the independent review of design QA requested by the Board.

The Licensing Board's decision caused the Company to reconsider its use of the at risk approach in a series of top management meetings in January 1984. Surprisingly, the top managers of the Company consciously decided to continue to build at risk while attempting to convince the Licensing Board that the plant was safe and reliable[132]

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[132]Deposition of Mr. B. R. Clements in the proceeding between Texas Utilities Electric Company and the minority owners, 15 December 1987, volume II, pages 99 - 107.

VIII. THE NRC HEADQUARTERS STAFF TAKES OVER AND UNCOVERS SERIOUS PROBLEMS: 1984-1985

As March 1984 ended, TU was still talking of loading fuel into Unit 1 on 1 July 1984. It is difficult to tell whether the Company really believed in this date, in which case one has to conclude that the management had no understanding of the status of the plant, or whether the Company was trying to rush the NRC with threatened delays. For its part, the NRC Caseload Forecast Group considered the second quarter of 1985 to be a more realistic fuel load date, assuming that the various allegations had no impact on the licensing schedule.

Later in the year, TU's fuel load date moved back. On 8 May 1984, John T. Merritt, a senior Comanche Peak manager, submitted a sworn affidavit to the Licensing Board stating his belief that Unit 1 would be ready to load fuel in late September 1984. He cited a NRC senior staff member supporting this schedule as "workable."[133]

The NRC staff Executive Director's response to the Licensing Board decision on design QA and the growing number of allegations[134] about Comanche Peak was to try to determine the

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133 The Company seems to have worked hard to persuade the NRC staff to support its optimistic fuel load estimates. A 7 June 1984 NRC staff meeting summary shows the staff modified the view it held after a site visit in March. After the Company intervened with additional data, the NRC Project Manager wrote: "The staff concluded that the applicant's [TU's] projected schedule was makable [sic], but allowed little contingency for delays."

134 A second Licensing Board was empaneled in April 1984 to hear all allegations of intimidation and harassment relating to Contention 5. With the exception of one judge, the membership of this Board was the same as that of the Board

extent of the problems at the plant and to try to work out a program for resolving them as soon as possible.

A. The NRC Headquarters Staff Tries to Assess the Extent of Comanche Peak's Problems

In part because of his concern about Region IV's ability to cope with the situation, the NRC Executive Director issued a directive on 12 March 1984 establishing a program to coordinate all Comanche Peak issues and concerns prior to licensing. On 4 April 1984 the NRC announced that it had assembled a "coordinating team" to gather information on Comanche Peak. The outstanding technical issues remaining to be resolved were: (1) completion of the FSAR review, (2) completion of the NRC inspectors' review, and (3) resolution of the mounting allegations.

Shortly thereafter the Executive Director established a Special Review Team (SRT), chosen mostly from Atlanta-based Region II, to perform a ten-day "limited review" of Comanche Peak. The purpose of the SRT was to get a quick fix on the problems, in particular to determine whether there was a need to stop ongoing work while a more thorough inspection and evaluation proceeded. The SRT concluded, however, that ongoing work was "sufficiently controlled to allow continued plant construction while the NRC completes its review and inspection of the facility."[135] The SRT found some potential violations and weaknesses, but on the whole painted a rather favorable

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hearing the main case. I have not discussed the details of the Board's activities in this report as the Board's actions do not appear to have affected the course of Comanche Peak's licensing.

[135] Letter, Darrell G. Eisenhut to M. D. Spence, 13 July 1984.

picture of the project, at least as it was then being conducted. The report did contain the following caution:

> The findings and conclusions of this report of the team's review should not be construed as resolving any of the issues identified by the ASLB hearings, allegations, or staff concerns of the design adequacy of the plant.[136]

The report emphasized that the large number of change documents that attached to drawings was a weakness. The drawings themselves had not been updated. Concern over the large number of unreviewed design changes incorporated in construction was expressed throughout the report. The report observed that the "potential to lose control is high," but on the basis of interviews with workers and project inspectors the authors accepted that this was more an inconvenience than a source of error.[137] In another area, a detailed look at a particular design change found that the required detailed calculation had not been performed.[138]

The NRC reviewers discovered some interesting things about the design change process in the civil construction area:

> After the design change request is prepared [by a project civil engineer], it is transmitted to the G&H [Gibbs & Hill] onsite design engineers and to construction. Construction personnel implement the design change 'at risk.' That is, if the G&H design engineers do not approve the design change, a removal notice is issued and the work affected by the design change is either removed or reworked...Discussions with licensee engineers disclosed that approximately 99 percent of the design changes are approved by the G&H design engineer without

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[136]SRT Report, p. 4.

[137]Ibid., p. 11.

[138]Ibid., p. 35.

revision....After it is reviewed and approved, the design change is distributed per procedural requirements....[139]

Based on what he had heard from site personnel and a review of several design change documents, the NRC reviewer apparently decided that the changes were being properly reviewed and accomplished in accordance with NRC requirements, a conclusion which is difficult to square with the provisions of Appendix B. Surprisingly, there does not appear to have been any inquiry by the SRT into the use of the "at risk" approach in other areas of construction, or any searching questioning of the validity of the approach.

The report stated that there had been essentially no pre-operational testing for the previous ten months because of ongoing electrical rework and other modifications. In view of these modifications, many tests which had been performed during the July 1982 to June 1983 testing would have to be redone.[140]

Notwithstanding the SRT's seemingly favorable overall conclusions, the NRC headquarters technical staff's assumption of the task of dealing with TU on the allegations of improper design and construction was a major change in the Comanche Peak case. Normally this would have been handled by the regional office but the Executive Director's directive had shifted the initiative to Washington. The NRC headquarters experts tried to get to the bottom of the problems at Comanche Peak. They appear to have felt that all was not well at the plant but that a vigorous investigation could put things right. They, and their consultants, began to ask hard questions about the

[139] Ibid., p. 55.

[140] Ibid., p. 22.

construction of the plant. They held a series of meetings with Cygna to learn about the results of Cygna's Independent Assessment Program. The NRC staff was particularly concerned about the adequacy of the Comanche Peak document control system, especially before the introduction of a computerized system, and whether document control had been sufficiently good to permit the plant to be constructed in accord with all design changes.

Ms. N. Williams, who headed up the Cygna review, had some interesting comments: there were "a lot of unique designs" in Comanche Peak and she was not yet sure whether they were acceptable.[141] In a subsequent meeting, the NRC staff expressed concerns about what appeared to be the lower margin of safety of the Gibbs & Hill weld attachment design, about whether the as-built documents reflected the as-built condition of the plant, and about unconventional pipe and cable tray support designs. In a 30 March 1984 letter to Cygna, the NRC staff expressed concern about whether Gibbs & Hill weld designs met Code requirements.

On 5 June 1984 the NRC staff prepared a Comanche Peak Plan for the Completion of Outstanding Regulatory Issues. A Technical Review Team (TRT) was formed in early June to conduct a more thorough inspection of the project and to determine readiness for operation. On 9 July 1984 the NRC Staff began an "intensive onsite effort," involving about fifty technical specialists for ten weeks, to complete pre-licensing reviews.

It needs to be understood that the purpose of the effort was to get the plant licensed. In his 18 September 1984 letter

[141] Transcript of 19 April 1984 meeting between the NRC staff and Cygna.

to TU President Spence, Darrell Eisenhut, the NRC Director of Licensing, described the TRT as "an intensive onsite effort designed to complete a portion of the reviews necessary for the staff to reach its decision regarding the licensing of Comanche Peak Unit 1." The NRC staff clearly were not looking for a way to stop the plant but rather for a way of clearing the hurdles. What seems to have happened is that the more they looked, the more problems and deficiencies they uncovered, until they were forced to recognize that a quick turn-around was impossible.

At about the same time, changes were made to strengthen Region IV management. In August 1984 Robert Martin replaced John Collins as Region IV administrator.

As the NRC staff inquiry widened and problems mounted, the Company pressed for immediate licensing. On 7 August 1984, TU asked the Board to issue a low power license which would allow Comanche Peak to load fuel and conduct certain pre-criticality tests. On August 27 the Board ordered TU to supply evidence that the systems which would be used for fuel load and testing had been subjected to QA reviews.

The NRC Staff met with TU on 18 September 1984 to provide the Company with "a number of technical issues" -- civil structure, electrical instrumentation and control, and test program matters -- with potential safety implications which grew out of the activities of the TRT.[142] Darrell Eisenhut, the Director of Licensing of the Office of Nuclear Reactor

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142 Among other things, the TRT was concerned about whether terminations in the control room electrical panels were done properly, how nonconformance reports had been handled, the failure of control cables to meet the fire protection separation requirements, the possibility that the control room ceiling might collapse during an earthquake, and the failure to control procedure changes properly.

Regulation, said, "the ball, so to speak, goes from our court to your court." Eisenhut's formal letter to the Company[143] requested additional information on the deficiencies uncovered by the TRT and asked TU to identify the "root causes" and "collective significance" of the problems. He explained that the areas discussed covered only a "portion" of the TRT effort. A fourteen page enclosure gave details of the TRT's findings. Eisenhut required extensive reinspection and analysis by TU and the development of programs to ensure that NRC requirements were met.

B. The Pivotal Meetings

As I have mentioned, the NRC staff went into the TRT effort with the intention of finding ways of resolving the plant's problems. As the staff dug deeper, however, they gradually came to the realization that a quick fix was impossible. The turning point came in a series of meetings with TU from October 1984 to January 1985 to discuss TU's Comanche Peak Response Team (CPRT) program for dealing with the problems identified by the TRT and assessing the plant's compliance with NRC requirements. TU's performance in the meetings appears to have persuaded the NRC staff that the utility had still not grasped the seriousness of the problems it faced and that it could not be counted on to develop and implement an effective program to identify and remedy the QA shortcomings of the plant. To give a feeling for what was happening, I will quote fairly extensively from the transcripts of the meetings.

At the October 19 and 23 meetings, TU was represented,

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[143] 18 September 1984.

among others, by Michael D. Spence (President), Lewis F. Fikar (Executive Vice-President), Joe B. George (Vice-President and General Manager of Comanche Peak), and Larry Popplewell (Leader of the TU CPRT's Electrical/Instrument Group). The NRC staff group was headed by Harold Denton (Director of Nuclear Reactor Regulation), Darrell Eisenhut (Director of Licensing), and Robert Martin (Administrator of Region IV). Eisenhut began by telling TU:

> ...one of the things that I have said we're going to be looking for is how are you going to manage and how you are going to handle the review of those items...the second aspect of it is rather to look at it from why should we have confidence this time around, any issues that have slipped through the cracks, this time won't slip through the cracks...
>
> We'll be looking to the process you use so to speak in resolving these issues and regaining the confidence that it is now thoroughly done and lastly, in identifying the root cause.[144]

TU presented a point by point response to the TRT issues, but did not go beyond the items raised by the TRT.

The NRC staff suggested an independent third-party review. John T. Merritt responded for the Company and described what they had in mind. The Company did not seem to think there was very much to do:

> ...if the program plan deems it necessary, we will perform additional documentation review. As necessary we will perform reinspection. As necessary we will perform additional engineering calculation. If required we will perform additional testing.

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144 Transcript of TUEC Meeting With NRC Staff, October 19, 1984, pp. 7 - 8.

> In some cases if it seems the most prudent thing to do in order to resolve the issues, we may even [sic] have some construction rework...
>
> We are basically seeing...the issues in the first TRT report coming to a conclusion anywhere from the middle to the latter part of December...[145]

Eisenhut seemed concerned that the Company did not get the message and was less optimistic about the future course of the review:

> We should put a qualifier on that though so no one jumps to too hasty a conclusion....we may very well have additional follow-up activities...[146]
>
> Remember though that TRT by design, when we laid it out -- it was an overall evaluation. It wasn't to evaluate a hearing issue or a particular allegation or a particular technical question. It was to go over and reverify the overall competence of an area.[147]

It is indicative of the Company's poor understanding of the quality assurance problems it faced that even as late as October 1984 it was still thinki·, in terms of a relatively brief review which would justify the work previously done at the plant. Not until the full extent of the reverification work that would be necessary became clear did the Company move away from trying to justify its earlier work and accept the need to redo questionable work.

One of the major NRC concerns was that documents could not be located. The TRT had fo·nd certain inspector qualification

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[145] Ibid., pp. 27A - 28.

[146] Ibid., p. 30.

[147] Ibid., p. 33.

records were unavailable. The Company's response was to dispute the TRT's finding. Eisenhut's reaction was:

> What you keep doing is you're making an assertion with which we disagree at the moment....We're just a little bit skeptical if we've been down on the site for three months and have asked this question over and over to a number of people and didn't get the record.[148]

The following exchange must not have helped the Company's cause, either:

> MR. EISENHUT: Let me ask you a quasi-philosophical question. Were there anything in the findings of the TRT that surprised you?
>
> MR. POPPLEWELL: No.
>
> MR. FIKAR: I was going to answer that, too. We're not surprised at the findings. We can understand how you got to them.
>
> MR. EISENHUT: ...the question I was asking was more on the lines of were you surprised that these issues came up after at least, in your mind I would have expected you would have thought there would really be no significant issues that we would be identifying that would be brought up this late in the project...
>
> MR. POPPLEWELL: I am never surprised of the issues that come forth -- because there are questions to be asked and questions to be answered.[149]

Mr. Popplewell pursued his assigned subject of deficiencies in the electrical systems and questioned the safety significance of the findings, which earned a sharp response:

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[148] Ibid., p. 50.

[149] Ibid., pp. 77-78.

> MR. POPPLEWELL: ...NRC found physical locations of selected cable terminations did not agree with the drawing....We reviewed the selected cables...and found...no adverse safety significance...
>
> MR. EISENHUT: ...We recognize that some of those may have essentially no safety significance. However, it is indicative of a bigger problem. It is indicative of a problem that based on our audit of the drawings and the field installation they were different so we asked for a program to verify and to rereview what was out there.
>
> To come back and tell us that the ones that we gave you had no adverse safety significance, we probably could have come to that conclusion ourselves. That is really not the issue. The issue is that we found, we came to the conclusion on this item and on a number of other items that there is clearly a difference between what you had in your --- what you were supposed to have in your plant and what you had as dictated what was supposed to be by the drawings.
>
> What we were looking for was a program to verify that the plant was built in conformance with the drawings and the application, etc...
>
> ...frankly I was relying on you to come back and not try to punch holes in the particular examples that we listed, but rather really try and look at it in a broader context of what the problem might be.[150]

Mr. Eisenhut's frustration with TU's unwillingness to acknowledge the pervasive nature of the QA problems is evident:

> MR. EISENHUT: ...Nowhere in this report or in your presentation do you matter of fact state that the discrepancies indeed are valid.
>
> Rather it comes off as arguing -- ...[that] there's no adverse safety significance....
>
> There are physical differences out there. Now it is tied

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[150]Ibid., pp. 99-101.

> to the processes that are at work. You are supposed to have a process where you engineer the thing, design the thing and go out with drawings and construct it in accordance with that application.
>
> Clearly, it didn't work on some examples...You come back with a program clearly right where we're intended to go in the first place, that you have a program to verify how many are out there and how many discrepancies are there, is it widespread, is it limited, what is the nature of them and then you have to do a safety evaluation.
>
> That logic is what doesn't appear on either the slides and it certainly does not appear in the write-up and I think that is the item the staff is reacting to, that first you have to identify what the problem is and what the cause of the problem was.
>
> ...I by design in the September 18 letter limited the examples...
>
> ...It is incumbent upon you to convince us that, in fact, you have done a thorough enough of a review to identify all discrepancies or to at least be able to identify it well enough to have enough conscience [sic; confidence?].[151]

The Company's refusal to admit that the quality assurance system had broken down left the senior NRC licensing officials wondering whether the Company understood the scope of the problems it faced and whether it was ready to take the remedial measures that were required. It also meant to the NRC that TU's management was sending the wrong message to the Company's employees; instead of getting on with identifying and fixing the defects, they were in effect being told to try to get by with what was in place to the extent possible.

Another of the TRT's concerns was that TU inspection reports appeared to be missing. The Company claimed the NRC

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[151]Ibid., pp. 103-105.

did not know how to ask for them. The NRC staff insisted they had asked for the right documents but that the TU staff could not find them. The Company acknowledged the document system was complex.

> MR. EISENHUT: ...I think your credibility in my mind went up by one notch when you acknowledged that it is a very, very complex system....there is no place that you can go in this [plant], I don't believe, and find one single final design drawing for a given piece of system...
>
> ...with no final design -- in one place...you are asking the NRC inspector to verify it...that the system is all right, and that is a very difficult thing to do...
>
> Different utilities have handled that in different ways...[but] it is incumbent upon the utilities to bring forth whatever information we need to make that decision.
>
> MR. GEORGE: We agree with that.[152]

The outcome of these meetings was that 29 November 1984 Eisenhut again asked TU to submit a program plan and schedule for assessing the TRT issues, including "root causes" and "collective significance". A new problem emerged in the mechanical area, when the TRT found, in reviewing the SRT conclusions, that the Main Steam, Auxiliary Steam, and Feedwater piping systems were routed from the Electrical Control Building (seismic category I)[153] to the Turbine Building (non-seismic category I) without the isolation valves, separation, barrier, or restraints required by the regulations.

The threshold TU would eventually have to clear to obtain its operating license was further raised by events which raised

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[152] Ibid., pp.108-110.

[153] Which covers safety related equipment that has to operate through an earthquake.

questions about the Company's veracity. The Licensing Board's 18 December 1984, decision found that TU had misrepresented the nature of the tests it had performed on U-bolts supporting piping. TU's statement to the Board that a survey had been conducted on "a representative sample of cinched down U-bolts" turned out to have been misleading: the "sample" had been drawn with no method of insuring that it was random or representative; TU had failed to disclose that the sample had been limited to unpainted U-bolts in Unit 2; TU had failed to disclose that for Unit 2 the torque being tested was the average torque on the two bolts on each U-bolt; and TU had falsely claimed that the same torquing procedures were used on Unit 2 as on Unit 1[154]. Because of the complexity of the licensing process, the NRC is forced to rely to a large extent on the truthfulness and forthrightness of all the parties. When doubts develop about whether statements mean what they appear to say, everything has to be checked in greater detail, and the review process becomes far more cumbersome and painstaking.

C. The Results of Cygna's Independent Assessment

The next phase in the NRC staff's disillusionment was the review of Cygna's independent assessment of design control at Comanche Peak. The NRC staff set forth its evaluation of Cygna's assessment in a supplement to the SER.[155] The staff concluded that (despite its seemingly favorable conclusion) the Cygna assessment had not yet provided the staff the additional

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[154] The Licensing Board rejected TU's motion for reconsideration of this Order on 25 November 1985.

[155] NUREG-0797, Supplement No. 5, apparently issued in January 1985 but not released to the public until the response to FOIA request 85-59.

assurance it sought in the design area and had identified potential areas of concern. While design control had improved, "the important question relates to whether and how the plant was constructed in accordance with all design changes prior to establishment of an accurate document control (listing) system."

In the piping area, the NRC staff concluded that Cygna's favorable findings were contingent on successful completion of TU follow-up activities and that Cygna "has not only substantiated some of the [Licensing Board] Design Decision concerns related to piping supports but has revealed additional major design concerns related to piping analyses."

The NRC staff met with Cygna on 10 January 1985 to discuss Cygna's review of pipe supports. David Terao of the NRC staff questioned Cygna's conclusion that "...the failure by Gibbs & Hill to follow design reviewers does not itself impact design." Ms. Williams responded "...I'm not sure I would concur with this conclusion right now..."[156]

Although they seemed willing to accept the plant pipe supports, Cygna's expert consultants Bush and Kennedy were not enamored of the unconventional design:

> MR. SPENCER H. BUSH: I don't think it would be very -- necessarily good practice. That's, obviously, a personal opinion. Because I can get worried about the response. But you'd have to look at the system...
>
> MR. KENNEDY: ...you know, it's not an ideal design, but I can't see -- that type of design is used in industrial facility piping. I don't know offhand whether I've seen

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[156]Transcript, Meeting With Cygna Energy Services on Comanche Peak Steam Electric Station, Independent Assessment Program (Phase 3), January 10, 1985, pp. 16-17.

> it in a nuclear plant before or not but I don't see how you can get particularly concerned...[157]

However, Ms. Williams was now more concerned than before:

> MS. WILLIAMS: ...This is one of the reasons, though, that I feel there's a breakdown in design input control.
>
> ...we went in and checked Gibbs & Hill's work on the -- rework on mass point spacing. We took a sample of 32 problems that they had gone through and checked to make sure that it was modeled correctly, and we found three rejections. And by mil standard 105(d), that's unacceptable.[158]
>
> So we have a lot of cause for concern. Now, where Gibbs & Hill has gone back and actually done a review for the express purpose of correcting a problem it knew about, and still made errors, and that's a big concern.[159]

> MR. KENNEDY: Of the open items, some of them I have greater concern about than others. I certainly have greater concern on this missing mass, problems in the seismic evaluation of the piping and on the supports from that missing mass effect.[160]

> MR. BUSH: ...I'm not enamored with the support design but I consider them acceptable. That's a different situation.
>
> In other words, I do not find them unacceptable. I just personally wouldn't have done it that way. I prefer to see it some other way....
>
> MR. KENNEDY: ...I agree with those statements... I believe they are adequate.

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[157] Ibid., pp.32-33.

[158] A reference to a military standard for sampling for inspection purposes.

[159] Ibid., pp. 46-49.

[160] Ibid., p. 84.

> There are better ways of supporting this piping, though.[161]

The NRC staff experts had their own problems with the unconventional pipe support design:

> MR. TERAO (NRC): ...if, in the development of a support design, unconventional utilization of hardware is employed, then one must question the validity of that design. The reason for doing so is because codes and standards are developed on a consensus of design.
>
> ...to justify these unconventional potential problems by engineering judgment is not totally adequate because one, again, is exceeding the limits of standard practice and into an area where judgment has very little basis....
>
> So we are in this position now, where many of the designs that we've seen, especially in your phase 3 report, are very unconventional...
>
> ...Why did these designs develop in the first place?...
>
> MS. WILLIAMS: ...they are having problems with the thoroughness of their reviewers. It's tough to know why that is, whether it's because they don't understand or because they are not doing it thoroughly.[162]

By the conclusion of the meeting, it appeared that Cygna was also coming to the conclusion that more investigation was needed;

> MS. WILLIAMS: ...now we have put it all together. And I feel somewhat uncomfortable, actually, with what I know now from phase 4, with some of the conclusions in phase 3.
>
> We know a lot more now and I'm learning some stuff in the design control area from cable trays which is causing me

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161Ibid., pp. 86-87.

162Ibid., pp. 91-95.

to rethink what we see in that program.[163]

D. The Last Straw For The NRC Staff

In an 8 January 1985 letter, (Eisenhut to Spence) NRC informed TU of the preliminary TRT findings in the QA/QC area. The letter did not propose specific corrective actions as was done previously. Eisenhut again asked for a program and schedule for a detailed and thorough assessment of the QA issues. Again, he specified that the plan should address root causes and the collective significance of the findings, as well as propose a plan to ensure the problems would not recur. The NRC suggested that the Company should consider using managers with a fresh perspective and an independent consultant.

The NRC staff and the Company met on 17 January 1985, to discuss the TRT's preliminary findings in the QA/QC area. At the outset of the meeting TUGCO President Spence announced that "to underscore the degree of importance I place on these QA issues" he was asking the Licensing Board to defer the hearings until March and to suspend consideration of TU's motion for authorization to load fuel. This was an important turning point.

The TRT explained that about half-way through the 124 issues they were examining they found that the "hardware is not in accordance with the drawings." The TRT also found examples of "ineffective QC." The NRC staff then decided that the quality assurance problems could be overcome if it could be shown that the hardware was, in fact, adequate. To test this approach, they carried out an "as-built" inspection c' several

[163] Ibid., p. 102.

completed rooms, which had been inspected by TU and which were supposed to be ready for operation. The TRT followed the Company's QC procedures to inspect 42 pipe supports and found 46 deficiencies which the Company's QC inspectors had missed on 26 supports.

The results were about the same with snubbers and electrical supports. Of 42 supports, six required weld repair (which came to about 2.5% of all welds inspected, and "...in some other plants, the hit rate is about the same.") Supports and snubbers were found to be not in accord with license and/or code requirements and to have been missed by the QC/QA checks. There were no non-conformance reports (NCRs) for these deficiencies. The NRC staff had to remove paint to get at many of the problems. They thought they might have found more deficiencies without the paint. Out of 24 Hilti bolts (used in installing pipe hangers to the walls) examined, three were deficient.

> MR. LIVERMORE (NRC): ...The bottom line is we did a very limited sample. Yet we found a lot of problems, too many problems, we felt.[164]

The NRC staff noted that at the peak of construction there were only four QA auditors in the Comanche Peak organization. Repetitive NCRs were issued, indicating a need to retrain construction personnel. One NCR went for nine months with no action being taken. Some QC inspectors, who had previously been craft workers, were in a position to review their own work. QC sign-offs, and signatures were missing. The NRC conclusion was:

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[164]Transcript, Meeting to Discuss Technical Review Team Staff Findings - Comanche Peak, January 17, 1985, p. 29.

> Our bottom line is with the QA/QC group: we just felt that the Q management may have acquiesced to construction pressures and complaints and failed to support their own people...[165]

Eisenhut mentioned the "T-shirt incident"[166], after which he went down to Texas, and which convinced him there was a communications gap between the Company and its QA inspectors. His closing comment was: "The ball is back in your court..." Mr. Spence's response was:

> it's clear to me that some changes are going to be necessary for us to fully resolve these issues...
>
> As the owner of the plant, I recognize that the ultimate responsibility for the safety of the plant is ours and ours alone. It's not a responsibility of our contractor, our AE, and it's certainly not the responsibility of this agency...[167]

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[165] Ibid., pp. 33-34.

[166] An incident in which the Company reacted strangely to a number of Company QC inspectors wearing "Nit-Picker" T-shirts to work (in response to their being called "nit-pickers"). The inspectors were confined to a construction trailer while the security guards searched their desks, and were then sent home to change. The significance of the incident for the NRC was that it was an indication that TU management did not support its own inspectors whose work is essential to the proper functioning of quality control.

[167] Ibid., pp.55-57.

IX. EXISTENCE OF PROBLEMS CONFIRMED: 1985 AND AFTER

Once the NRC headquarters staff had lost confidence in the design and construction of Comanche Peak, the NRC licensing review went into low gear. The story from here on is that of an increasingly detailed look at the plant, both by the Company and the NRC, which confirmed the earlier conclusions that the quality of the design and construction could not be established with any degree of certainty. As this picture developed and it became clear that the existing design could not be validated, the Company gradually shifted the focus of its efforts away from the CPRT, which was oriented toward the assessment of past work and identification of the causes of past errors, and towards a corrective program which is directed at replacing questionable hardware (and thus bypassing many of the CPRT issues).

At the outset, TU was still optimistic about completing the design verification in relatively short order. However, by 23 January 1985, the Company's news release projected full-power operation of Unit 1 no earlier than 1986.

A. TRT Issues

The NRC licensing staff formally addressed the issues raised by the TRT in a series of supplements to the SER. In January 1985, Supplement No. 7 was released, covering about 80 issues in the electrical/instrumentation area and in the test programs. The quality of electrical and instrumentation installations was found to be generally acceptable except for certain listed items, whose "generic implications" TU was required to examine. These problems were described as "an indication of programmatic weaknesses in QC." Problems were noted with the document system.

Supplement No. 8, which came out in February 1985, dealt with about 80 "technical concerns and allegations" in the civil, structural and testing areas. About 900 specific issues concerning testing came from plant QA/QC inspectors. Of 57 civil and structural allegations, 20 were substantiated, and three had potential safety significance. The TRT could not determine the validity of 21 allegations. Of 24 miscellaneous allegations, nine were substantiated.

B. Closer Examination of the Walsh/Doyle Allegations

A meeting was held on 26 February 1985 between the NRC staff and TU "to reinforce with you [TU] the various technical concerns that we have regarding the Walsh-Doyle concerns that are being addressed by the Applicant." The report of the NRC staff's consultant, Donald F. Landers of Teledyne, dated 21 February, listed 9 areas of concern:

> Concern with one of the above items, or even two or three, may not necessarily result in an overall concern with respect to compliance with licensing commitments. However, when the list is viewed as a whole and when the interdependence of t tems is considered, a different perspective results....Many of the support designs for CPSES are not commonly found in commercial nuclear power plants. This is not in itself reason for concern but leads one to review the design and the supporting analysis critically since industry standards or experience cannot be totally relied on....[168]

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[168]Preliminary Consulting Report on Comanche Peak Steam Electric Station - Piping and Support Design, Teledyne Engineering Services, 21 February 1985, pp. 20-21, included in Transcript of Meeting Between Texas Utilities and the Nuclear Regulatory Commission Regarding Comanche Peak Steam Electric Station, 26 February 1985.

A feedback discussion between the NRC staff and Messrs. Walsh and Doyle (23 March 1985) sheds additional light on the staff's view of the piping problem:

> MR. TERAO (NRC): The Staff's concerns stem from the fact that many of the pipe support designs at Comanche Peak represent either an unconventional application of the component standard supports which have not previously been proven to be acceptable, or the use of unconventional support designs.[169]

Terao went on to criticize the Company's approach to pipe system stability:

> Thus, the Applicants' justification of staying within the analytically predicted deflection limits to assure system stability is not valid...
>
> The Staff finds that unstable pipe support designs at Comanche Peak do not conform to standard industry practice; that is, the unstable designs are unconventional designs.
>
> Furthermore, although the normal iterative design process is adequate for ensuring the stability of piping systems utilizing conventional pipe support designs, the process is not adequate for ensuring the stability of unconventional pipe supports which have not been adequately reviewed in its initial design conception.
>
> Thus the Staff finds the applicants' discussion of industry practice for stability and piping and pipe support designs is irrelevant.[170]

Mr. Walsh asked why no one noticed the problems before in looking at the hardware, to which Mr. Terao responded:

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[169]Transcript of Meeting to Conduct Feedback Discussion with Messrs. Walsh and Doyle Re Concerns About the Comanche Peak Plant, 23 March 1985, pp. 31-32.

[170]Ibid., pp. 34-35.

> MR. TERAO: ...if one looks at the drawings without going up to the site and looking at the supports themselves, there are just too many details in the support design to look at...
>
> If the person had the support design drawing and went to the field and looked at it, he may spot those kinds of things. But because they are unconventional, it is very difficult to look for those kinds of characteristics in a support...
>
> It is very unique to Comanche Peak, and it's very difficult in this nuclear industry to have someone look at a support characteristic that no one else has ever looked at before...[171]

> MR. TERAO: ...the Applicant relied on his engineering judgment to justify the mechanics of the support. Now, of course, the Board ruled that was not appropriate, and the Staff would concur that with unconventional designs, that is inappropriate, too.[172]

C. Further Progress of the Cygna Review

On 26 April 1985 Cygna again briefed NRC management on the Independent Assessment Program. By now, Cygna had been working for about 2 years and expended nearly 50,000 manhours -- more than ten times the manhours of the usual design review -- and about half that time had been spent on pipe supports and cable tray supports.[173] During the briefing, the following observations were made:

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[171] Ibid., p. 44.

[172] Ibid., p. 47.

[173] Transcript of Cygna Briefing to NRC Management on Comanche Peak Steam Electric Station Independent Assessment Program, 26 April 1985, p. 9.

MR. BOSNAK (NRC): ...Probably the root cause of some of the problems was that the pipe designer and the pipe support designer never communicated.[174]

MS. WILLIAMS (Cygna, re cable tray supports): ...we have had some problem with the fact that there are so many design changes, pieces of paper outstanding on a given cable tray support drawing, that it's very, very difficult to assemble all of the paper when you are talking about 500 design changes on a given civil structural drawing....the process Gibbs & Hill had used in doing their generic evaluations did not properly account for all the change paper that was out against the Gibbs supports, and we are still assessing the effect of that.[175]

MR. VOLLMER (NRC): ...Why didn't design review catch these things?

MS. WILLIAMS: ...they didn't have procedures governing the work. That appears to be part of the problem.[176]

D. More SSERs

SER Supplement No. 10 was issued in April 1985. It addressed about 400 technical concerns in the mechanical and piping areas, not including the Walsh/Doyle allegations. The issues were grouped under 50 categories in five general areas: (1) welding (including piping and hangers -- deficiencies in Brown & Root construction practices); (2) piping (design and analysis of small bore pipe, pipe installation, repair, and modification); (3) hangers and supports (design, installation, and fabrication); (4) construction and documentation; and, (5) other.

About 60 allegations were at least partially

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[174] Ibid., p. 37-38.

[175] Ibid., p. 54.

[176] Ibid., p. 58.

substantiated. The NRC staff found five issues which had potential safety significance and generic implications: uncontrolled welding repair of misdrilled holes in piping and cable tray supports; failure to assess temporary pipe and equipment supports; failure to consider potential damage to piping systems routed between seismic and non-seismic buildings; shortening of bolts holding upper steam generator lateral supports; lack of a fillet weld inspection criterion for certain types of skewed welds. TU was required to analyze the problems in these areas and to make corrections.[177]

SER Supplement No. 11 covering QA/QC issues came out in May 1985. With regard to the design process, three of six allegations were substantiated. However, the report stated that the QA/QC Group's assessment of the iterative design process had not identified any QA programmatic deficiencies which could cause a breakdown in the design process.[178]

In the document control area, of thirty allegations, thirteen were substantiated, and six partially substantiated. Current document control was acceptable, but prior to 1984 "there was a document control breakdown."[179] In the records area eight of eleven allegations could not be substantiated.

Of eight allegations regarding training and qualifications, five were substantiated. The NRC "...found numerous deficiencies in the site inspector qualification and certification program....over 80 percent of all site line QC inspectors were qualified to the secondary 'exception to rule'

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177 NUREG-0797, SER Supplement No. 10, p. N-14.

178 NUREG-0797, SER Supplement No. 11, p. O-9.

179 Ibid., p. O-10.

clause; and then to make matters more serious, this secondary program had many deficiencies...that further demeaned the credibility of the qualifications."[180] In the repair, rework, and maintenance category ten of thirteen allegations were substantiated.

Among SER Supplement No. 11's overall conclusions was that "quality management was lax in its responsibilities to direct and oversee an effective site Quality Program." The Supplement went on to state:

> The pattern of failures by QA and QC personnel to detect and document deficiencies suggests an ineffective B&R and TUGCO inspection system. This pattern, coupled with (a) the past problems in the document control system, (b) deficiencies in the QC qualification program, (c) ineffectiveness of the quality audit and surveillance systems, (d) a rudimentary and ineffective trending and corrective action system, (e) QC problems as shown in QC/QA Category 8, AQ-50[181]; and (f) instances of improper workmanship of hardware as found by all the TRT groups, challenges the adequacy of the QC inspection program at CPSES on a system-wide basis.
>
> Corrective action will require high-level management attention and a new management emphasis on the importance of quality as a vital element of an adequate construction program.[182]

In May 1986 SER Supplement No. 13 presented the NRC staff evaluation of the Comanche Peak Response Team Program Plan to resolve issues raised by the Licensing Board, CASE, the NRC staff, and Cygna. The NRC staff concluded it was a good plan

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[180]Ibid., p. O-11.

[181]AQ-50, one of the QA/QC allegations, stated "the as-built inspection program for pipe supports was too narrow in scope, and it ignored dimensional discrepancies that might exist between the field condition and final as-built drawings."

[182]NUREG-0797, SER Supplement No. 11, p. P-35.

and "if properly implemented will provide important evidence of the design and construction quality of CPSES, and will identify any needed corrective action."

E. Civil Penalties

On 2 May 1986, the NRC headquarters staff (rather than Region IV as would have been customary) issued two Notices of Significant Violation imposing civil penalties on TU which confirmed the TRT's initial findings. The first, a Level III penalty in the amount of $120,000, was imposed because of the intimidation and harassment of QA/QC personnel. In particular, the notice specified that the Company's response to the T-shirt incident[183] was likely to dissuade QC inspectors from reporting safety concerns; that "the site QC supervisor made a statement that physical or political [sic] harm could come to an auditor as a result of his audit activities;" and that a Brown & Root quality control inspector had been instructed by her supervisor to sign off on work which she believed to be inadequately documented.[184]

The second notice imposed a Level III penalty of $250,000 for improper construc*ion practices and violations of the QA requirements of Appendix B. The detailed findings tracked the results of the TRT:

-- TU's failure to insure that quality control inspectors were properly qualified and certified;

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[183] See earlier footnote.

[184] Notice of Violation and Proposed Imposition of Civil Penalties, letter to Texas Utilities from James M. Taylor, Director, NRC Office of Inspection and Enforcement, 2 May 1986.

-- numerous design and construction errors resulting from the ineffective interactions between the various engineering and construction groups;

-- the failure of the quality control inspectors to catch deficiencies because they did not follow design documents and inspection procedures;

-- TU's failure to properly implement a corrective action program to identify, evaluate and correct conditions adverse to quality; and

-- significant weaknesses in the "as-built" cable tray reinspection and documentation effort and in the procurement and installation of electrical penetration assemblies.

In addition, violations were assessed, but no penalties imposed, for failure to comply with the document control requirements applicable to design changes and for not following welding procedures.

F. MAC Report Discovered

On 29 May 1985 TU's counsel informed the Licensing Board that the Company had found Management Analysis Company's May 1978 report on the Comanche Peak quality assurance program in its inactive files and believed that it should have been produced in response to a CASE discovery request in 1980. In a 12 June 1985 letter to the Board he indicated the Company now believed that the decision of Mr. Fikar, the officer responsible for licensing, to withhold the MAC report was "clearly an error in judgment" and that Mr. Fikar had announced his retirement from the Company. The letter also stated that

Mr. Clements, who assumed responsibility for QA shortly after Mr. Fikar decided to withhold the MAC report, "was aware of the report in 1980, even though he had not read the report....was aware of the decision not to produce the report, but did not revisit that decision." The Board was also informed that Mr. Clements had been reassigned to a non-nuclear division of the Company. Two other key QA managers at the time of the decision not to produce the report, Mr. Chapman and Mr. Tolson, were reported respectively to have been reassigned to non-nuclear work and to have left the Company. The revelation that the Company had suppressed the MAC report undoubtedly undermined its credibility with the Board and increased the burden it had to bear in making its case.

G. The Stone & Webster Report

On 20 November 1986, Stone & Webster delivered its "Civil/Structural Generic Issues Report" which detailed fifteen Corrective Action Programs in Civil/Structural area. Stone & Webster's basic conclusion was:

> The calculations which form the design basis for the Reactor Containment's Concrete Design contain technical errors and inconsistencies when compared to the drawings and do not consistently meet licensing commitments. Design inputs, sources of input, assumptions, and computer analysis for these calculations are either inadequately documented or unavailable.[185]

The same statement was made with regard to ten other areas of

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[185] Stone & Webster Engineering Corporation's Civil/Structural Generic Issues Report, 20 November 1986, p. A-3.

design covering essentially the whole plant[186].

H. Continuing Developments at TU

Two significant changes made by the Company during the course of 1985 were the replacement of the plant QA director by James Wells of Duke Power on 20 February 1985 and the decision to hire William G. Counsil, a highly-regarded nuclear utility executive, previously with Northeast Utilities, to head TU's nuclear program. This showed that the Company had finally begun to realize that commercial nuclear experience is vital to managing a nuclear power project.

On 2 April 1987 Mr. Counsil led a TU presentation to the NRC staff which showed a considerable change in the Company's attitude:

> MR. TYLER (TU): [By] the fall of 1986... design adequacy program investigation...was essentially complete, indicated inadequate documentation of the design. I don't want to mislead anyone that it was a paper problem. There have been hardware problems identified, and we have been keeping everyone appraised of those through the normal 50, 55-E reporting process.
>
> MR. TYLER: ...problems were encountered in positioning the CPRT findings on a single-issue basis due to the complex interrelationships between the hardware, the design configuration, and the design-basis documents

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186 The specific areas were: Reactor Containment Concrete Internals, other Seismic Category I Concrete Structures, Seismic Category I Structural Steel, high energy pipe break and jet impingement damage evaluation, Reactor Containment Liner ("computer analysis" replaced by "computer modeling"), refueling cavity liner, the fuel pool liner and the fuel transfer tube support, Miscellaneous Supports (equipment), penetration sleeve and anchorage design, connections and anchorages, and Heavy Load Drops ("at least one inconsistency").

themselves.[187]

> MR. COUNSIL: ...we are reinspecting all pipe supports, whether we have modified them or we haven't modified them. There is 100 percent reinspection going on of all large bore pipe supports.
>
> ...lock nuts missing, nontorqued lock nuts, cotter pins missing, just some of the examples.
>
> MR. TRAMELL (NRC): ...When the plant is ready for licensing, it's true to say that the FSAR and the plant will be together?
>
> MR. COUNSIL: Absolutely correct.[188]

Mr. Counsil stressed that his new team was going to give the plant a "new look." This change in personnel was accompanied by a fundamental change in the nature of the Company's design verification effort. As it became evident that the quality of the design and construction could not be established quickly the Company concentrated on replacing questionable hardware with hardware whose compliance with NRC regulations could be more readily demonstrated.

I. Another Shakeup in Region IV

Notwithstanding the NRC staff's 12 March 1987 conclusion that none of the alleged instances of improper Region IV management pressure on NRC inspectors was "significant in terms of any direct adverse impact on plant safety,"[189] the body of the report made it clear that there were serious problems with

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[187]Transcript, Comanche Peak Response Team Program, 2 April 1987, pp. 12-13.

[188]Ibid., pp. 39-40.

[189]Report of the Comanche Peak Report Review Group (CPRRG) (EDO-002475), 12 March 1987, p. 4-1.

Region IV's management. On 24 July 1987 the NRC announced major changes in Region IV "to make this office one of our best field offices." One of the NRC Chairman's assistants, was made Deputy Regional Administrator. The NRC said additional staff positions were being allocated to Region IV "to attract qualified technical and reactor safety specialists."

J. Further Slippage in the Completion Date

On 28 January 1986, the NRC reported that during a routine review the Comanche Peak construction permit was found to have expired on 1 August 1985. After this awkward discovery, TU was obliged to stop work and ask for an extension, which was granted by the staff on 10 February 1986. On 2 May 1986, the Licensing Board accepted a CASE contention regarding the lapse of the construction permit, which initiated a new proceeding. That proceeding is still going on in parallel with the main operating license case.

As design review progressed, the Commission grew more cautious about the completion date. In July 1986, Chairman Zech wrote Congressman Bevill: "The magnitude of the Plan and associated efforts have perhaps been underestimated and the schedule...has slipped somewhat..."

In October 1986 the NRC reported that, according to TU's filings with the Securities and Exchange Commission, the plant could not be ready for commercial operation by summer 1988. The Bevill Report for the fourth quarter 1986 states the Company "underestimated [no 'perhaps,' this time] the magnitude of the Plan and its associated activities. As a result, the schedule has slipped....Based on [the Company's current] estimate, commercial operation could be achieved in early 1989....Stone & Webster [will] develop action plans to review

100% of safety related systems..." Stone & Webster is reported as also addressing pipe supports, Ebasco is looking at cable tray hangers and conduit supports (both with Impell) and HVAC, and Impell as also looking at equipment qualifications.

K. NRC Region IV Inspection Reports for 1985-86

NRC inspection reports for this period showed that adherence to procedures remained a major weakness of the project. One inspection revealed that cabinets and motor control centers which were supposed to contain 648 splices contained 603 documented splices, as well as 104 undocumented ones.[190]

Another report concluded that the preventive maintenance program "may have been fragmented...some scheduled PM [preventive maintenance] items were not being done, and some components did not have the appropriate PM items identified and scheduled upon turnover from construction to startup....it was not possible for the [resident inspector] to reach definitive conclusions....The program appears to be missing the discipline to require specific PM items, and to require that they must be done....It remains unresolved whether or not an adequate PM program has been put in place..."[191]

Under normal circumstances, NRC inspection reports are issued within a month or two of the conclusion of the inspection. During 1985 and 1986, reports which were critical of the Company were being issued by Region IV as much as six to

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190 Inspection Report 85-14.

191 Inspection Report 86-01.

ten months after the completion of the inspection.[192] As was to come out in the hearings before Senator Glenn, it was Region IV management's practice to "sit on" adverse reports until the inspector had been convinced or badgered into toning down his comments. George A. Mulley, Jr., the author of the OIA report testified:

> The conclusions that I reached were that: (1) Region IV managers acted inappropriately to limit violations assessed at Comanche Peak; and that Phillips [a Region IV inspector] was harassed and intimidated by Region IV management in an effort to get him to downgrade or delete his inspection findings. (2) The Region IV Quality Assurance Inspection Program, as implemented at Comanche Peak, could not be relied on as evidence of the safe construction of the plant...[193]

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[192] NUREG-1257, although it generally exculpated Region IV managers, criticized these delays. It mentioned Inspection Report 85-07/05 which was released seven months after the inspection, despite the NRC inspectors' Manual Chapter 0610 goal of 30 calendar days for report issuance:

> This delay was one indication that there was something wrong with the NRC inspection program as it was being implemented at the site. (p. 3-3)

[193] The NRC investigation report concluded that Thomas Westerman, the NRC Region IV Comanche Peak group leader as of mid-1985, had "established a higher than normal threshold for assessing violations at CPSES. While at another plant he might have been more liberal in citing violations, he stated that at CPSES he was being very 'tight' to make sure violations were absolutely correct. Because CPSES was in a contested hearing before the ASLB, Westerman did not want to write violations the utility could argue were technically incorrect. He believed that would create unnecessary paperwork and could even raise questions regarding Region IV's technical competency." Report of Investigation, File No. 86-10, 26 November, 1986.

L. Current Status

The Company is carrying out a Corrective Action Program (CAP) to bring the plant into demonstrable conformance with requirements. This involves substantial hardware modifications and bringing the plant and its documentation into congruence. The CPRT, which consisted of a Design Adequacy Program and a Quality of Construction Program, has been moved to the background. The Company informed the NRC that the "design validation" conducted under the CAP "obviated the necessity to continue the evaluation phase of the CPRT Design Adequacy Program."[194]

The entire design package -- in the guise of Contention 5 on design quality assurance -- will have to be litigated anew before the Licensing Board. The schedule is organized around the CPRT Collective Significance Report and the eleven Project Status Reports that are the product of the CAP. Three of these Project Status Reports indicate that 5,621 of the 12,020 large bore piping supports, 1,896 of the approximately 6,630 small bore piping supports, and 874 of the 7566 cable tray hangers

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[194]Letter W.G. Counsil to U.S. NRC, 20 August 1987. This letter describes the CPRT and CAP and how TU sees the connection. The CAP "includes a complete design and hardware validation program of the safety-related and selected non-safety-related portions of CPSES" with the exception of the Westinghouse-supplied nuclear steam supply system and other vendor-supplied items. The scope is divided into 11 disciplines (Mechanical; Civil/Structural; Electrical; Instrument & Control; Large Bore Pipe Supports; Cable Tray Hangers; Conduit Supports for Trains A, B, and C larger than 2 inches; Conduit Supports for Train C smaller than 2 inches; HVAC; and Equipment Qualification). The results of the CAP will be reported in 11 Project Status Reports for these disciplines. Five of these have now (February 1988) been submitted.

required modification.[195]

The Licensing Board has said that in evaluating these documents it will assume that the "historical QA/QC programs for design and construction have broken down."[196] The Board noted the similarity with the Diablo Canyon case and cited an Appeal Board opinion in that case in which the Appeal Board said the issue was "whether, in view of the conceded weakness of the...design quality assurance program, the applicant's verification efforts demonstrate that the safety-related structures, systems and components are properly designed." The Board further cited with approval the Appeal Board observation that the Diablo Canyon design was ultimately subjected "to a measurably greater level of scrutiny than could have been provided by a quality assurance program complying with Appendix B." The Board observed it may be even harder to demonstrate the adequacy of finished construction at Comanche Peak. It is evident that the Company will labor under a heavy burden.

Recent events continue to stretch out the Company's schedule. In a 22 January 1988 letter,[197] the NRC staff informed the Company that it could not, as it wanted to, drop the CPRT root cause analysis of past errors. The NRC staff also told the Company that it would have to develop and carry

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[195]Corrective Action Program, Project Status Report, Large Bore Piping and Pipe Supports, p. 5-24; Corrective Action Program, Project Status Report, Small Bore Piping and Pipe Supports, p. 5-24; Corrective Action Program, Project Status Report, Cable Tray and Cable Tray Hangers, p. 5-20.

[196]ASLB Memorandum and Order (Litigation Schedule), 18 November 1987. See also Transcript, Prehearing Conference, 2-3 November 1987.

[197]Letter to William G. Counsil from Stewart D. Ebneter, CPSES Licensing and Corrective Action Programs, 22 January 1988.

out a new pre-operational testing program because most of the previous test results have been invalidated by subsequent design changes and repairs.

X. CONCLUSION

The fundamental issue addressed in this report is whether TU is at fault for not having obtained an NRC operating license for Unit 1 at least by early 1985. My conclusion is that it is: TU should have been able by that date to complete the plant in compliance with regulations, and to have demonstrated that compliance to the satisfaction of the NRC Licensing Board and licensing staff. Other plants which commenced construction at the same time as Comanche Peak were able to do this. The Company failed to gain the approval of the Licensing Board and subsequently the licensing staff because of the discovery of real, and serious, problems with the design and construction of the project. These problems were confirmed in later reviews. Major efforts -- including extensive modification of equipment -- have been, and are being, made to bring the project into compliance with NRC regulations to make it eligible for licensing.

A. Does the NRC Regional Inspectors's Performance Excuse TU's Failure?

An obvious question is whether, notwithstanding the legal standard which holds the licensee responsible for the performance of a project,[198] TU was justified in relying on the

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[198] In their 8 June 1981 Memorandum and Order (CLI-81-10) on the previously cited Federal Tort Claim of General Public Utilities Corp., the NRC commissioners said, in rejecting the contention that claimants were entitled to rely on NRC reviews of construction and operation:

> The claim is without merit. The claim is at odds with the regulatory framework flowing from the Atomic Energy Act of 1954, as amended. Within that framework, the regulated industry (i.e., the licensees and their suppliers and contractors) bears the primary responsibility for the

NRC's initially favorable appraisal of the project as a sign that the project was on the right track. Up to 1983 (and to an extent, even in 1984) the NRC inspectors did, after all, find that the QA function was adequately organized and that the QA personnel were doing an acceptable job. Should the utility have looked behind these judgments?

The answer is that it should have. The reasons for this are threefold. First, under the federal system of safety regulation, the utility has always been responsible for assuring the quality of the plant. The utility is responsible for developing and carrying out a quality assurance program which ensures that the plant is designed and constructed in accordance with the NRC's safety requirements. The regulations covering these responsibilities have been in place since 1970, and the utility was fully aware of them when it undertook to build the plant.

The second reason the Company should have been more alert is that the NRC's inspections are only an overall spot-check on the system and TU had to have known that they are generally not conducted at a level of great detail. Consider, for example, the case of pipe supports. TU knew that the NRC did not actually check designs or repeat calculations, and that NRC

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proper construction and safe operation of licensed nuclear facilities. The Nuclear Regulatory Commission has the statutory responsibility for prescribing licensing standards to protect public health and safety and for inspecting industry's activities against these standards. The Commission does not thereby certify to the industry that the industry's designs and procedures are adequate to protect its equipment or operations.

This is the understanding that prevailed when NRC issued the license to operate TMI-2, as it has for more than 20 years of commercial nuclear power plant licensing and as it continues to prevail today.

inspectors typically were not expert in pipe support design. The NRC inspectors only audited whether the installed pipe supports matched the design. Before the 1979 accident at Three Mile Island, and to a large extent thereafter as well, the NRC inspectors took a fairly narrow approach to performing their duties, leaving the initiative for assuring that the detailed safety work was done properly almost entirely to the Company. TU also had to have known that its own auditing of the site QA effort, apparently involving four auditors for the entire project at the peak of construction, did not provide for much control. Finally, TU had to be aware from its conversations with other utilities that, compared with other NRC regions, Region IV took a fairly "soft" approach to its responsibilities and therefore that the significance of Region IV's approval or acquiescence had to be sharply qualified.

The third aspect of the answer is that TU had to have become aware that after 1979 NRC was demanding a much higher level of conformance to QA regulations than it had done previously. In part, this was the result of the deficiencies uncovered by the TMI accident. The tougher approach to enforcement of the QA regulations was also the product of the design and construction deficiencies subsequently uncovered at a number of construction projects. The Midland plant in Michigan had foundation and quality assurance problems which led to much closer NRC scrutiny starting in 1978. The Marble Hill plant in Indiana was found to have deficient concrete and safety-related construction was stopped in 1979. In 1980 NRC discovered problems closer to home, at the South Texas plants, which led to the replacement of Brown & Root on that project by Bechtel. (Brown & Root was of course the major contractor at Comanche Peak.) The Zimmer plant in Ohio was extensively investigated when questions arose in 1981 about the conformity of materials and welding to requirements, even though the plant was very nearly completed. (Midland, Marble Hill, and Zimmer were ultimately abandoned as nuclear power plants.) Seismic design errors discovered at Diablo Canyon in September 1981 pointed up the possibility of errors being made in design as well as in construction, and the absence of any NRC review of detailed design. This led the NRC to adopt the practice of requiring third-party design reviews before licensing a unit for operation.

That these problems were ushering in a tougher NRC approach to construction and pre-operational inspection should also have been evident from Chairman Palladino's testimony before the House Interior Committee on 19 November 1981. He said:

> I believe that an effective quality assurance program is a vital element in the management of activities that must be accomplished during the design and construction of each nuclear power plant. Quality assurance should be used as a formal management tool to attain the mutually complementary goals of assuring that the design is correct and that the plant is constructed in full accord with the design...
>
> After reviewing both industry and NRC past performance in QA, I readily acknowledge that neither has been as effective as it should have been in view of the relatively large number of construction-related deficiencies that have come to light....I hope that our testimony today will demonstrate NRC's resolve to deal forcefully with construction-related deficiencies and the QA problems they reveal.[199]

Equally significant was the statement by the NRC Executive Director for Operations, the head of the NRC staff, that:

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[199]Hearing on Quality Assurance in Nuclear Powerplant Construction, Subcommittee on Energy and the Environment, Committee on Interior and Insular Affairs, U.S. House of Representatives, 19 November 1981, pp. 4-5.

> there have been serious quality assurance breakdowns with broad repercussions at Marble Hill, Midland, Zimmer, South Texas, and Diablo Canyon construction sites.[200]

On Zimmer, the Executive Director said "Before the plant can be licensed a comprehensive quality confirmation program will have to be conducted and identified problem areas resolved."[201] The Executive Director went on to state that most of the problems:

> can be traced to failure of quality assurance due to ineffective management control of the QA program. There are a myriad of excuses and reasons why management fails. Some are explicit failures of performance or lack of attention. Other failures rising from poor attitudes and perceptions are difficult to identify. The NRC cannot tolerate these defects because of their potential impact in terms of public risk.[202]

These hearings were closely covered by industry organizations and the trade press.

Even if TU missed the Interior Committee hearing, it undoubtedly heard about the NRC Chairman's speech (and probably top Company officials heard it in person) to the annual meeting of the Atomic Industrial Forum, the nuclear industry trade association, on 1 December 1981, when he said:

> I want to make a point of fundamental and critical importance....
>
> If the nuclear industry does not do its part, no amount of regulatory reform will save it from the consequences of its own failures to achieve the quality of construction and plant operation it must have for its own well-being and for the safety of the public it serves....

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[200] Ibid., p. 89.

[201] Ibid., p. 92.

[202] Ibid., p. 8.

> Based on the quality assurance failures that have recently come to light, I am not convinced that all of the industry has been doing its part....
>
> There have been lapses of many kinds -- in design analyses resulting in built-in design errors; in poor construction practices; in falsified documents; in harassment of quality control personnel....
>
> During my first five months as NRC Chairman, a number of deficiencies at some plants have come to my attention which show a surprising lack of professionalism in the construction and preparation for operation of nuclear facilities. The responsibilities for such deficiencies rests squarely on the shoulders of management....
>
> I don't mean to absolve the NRC of its portion of responsibility at all. (In a sense, every deficiency that is identified or finds its way into a plant or its operation can be viewed as an NRC failure as well as an industry failure.)
>
> I intend that NRC examine regulatory policies toward quality assurance. The industry would also do well to examine its managerial policies toward quality assurance (QA). One can ask a number of questions about management attention to QA, but the most important is, does senior management back up the QA staff in a way that lets everyone concerned understand that it means business?
>
> I suggest that, just as all utilities have certified independent financial audits of their fiscal activities, so should they have certified independent performance audits of their QA activities....If utilities don't do these audits themselves, we may have to require them.[203]

The utilities which performed well during this period were sensitive to this emphasis on QA. There is little sign that TU took a hard look at itself after the problems at other plants had become manifest.

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[203] Remarks by Nunzio J. Palladino, Chairman, U.S. Nuclear Regulatory Commission, at the Atomic Industrial Forum Conference 1981, San Francisco, California, 1 December 1981.

B. The Failure to Gain NRC Approval Resulted from the Company's Questionable Design and Construction Practices

The Company's failure to adhere in design and construction to the procedures set forth in the regulations, and the many unanswered questions about design deficiencies, left the Licensing Board with substantial doubts about the adequacy of the Comanche Peak design. In my view, the Board acted properly and reasonably. In its December 1983 decision it legitimately could have denied the Company an operating license for Unit 1 on the grounds that the utility had not shown that it had satisfied NRC regulations, which would have placed upon TU the legal burden of persuading the Commission to reopen the proceeding. Instead, the Board allowed TU to directly supplement the shortcomings of the record by means of an independent design review.

The NRC staff sent in the Technical Review Team in 1984 to resolve, as quickly as possible, the questions that clouded Unit 1 licensing -- the Board's decision on quality assurance in design, the results of previous inspections, the numerous allegations of improper design and construction, and concerns about the Company's attitude toward its own inspectors. As more problems emerged, the staff's look at the plant naturally became more intensive. The large application of NRC staff resources was not intended to put roadblocks in the way of licensing; it was rather an effort to clear the way for an operating license. In the end, however, there were simply too many important deficiencies for the NRC licensing staff to allow the project to proceed to operation. These deficiencies, together with the Company's initial reluctance to acknowledge the problems, led to a loss of confidence in the Company's work on the part of senior NRC staff officials. These were competent and responsible persons who by no stretch of imagination could be regarded as hostile to the goal of licensing Unit 1. The Company's problem was that it performed so poorly that it lost their confidence.

It is important to underline that the delay in Comanche Peak's licensing was caused by the Company's failure to build Comanche Peak in accordance with NRC safety regulations and established practice. This was not a case of an unusually detailed NRC review turning up problems which would be overlooked by a normal review, but rather of a project which attracted closer scrutiny because of the unusually extensive design and construction problems which came to light.

C. Other Nuclear Projects Managed to Deal Satisfactorily with Tightening Safety Standards

There is no question that building a nuclear plant in the late 1970s and early 1980s was a very demanding undertaking. To one extent or another, all builders encountered industrial and financial difficulties, and they had to accommodate tighter enforcement of safety standards than they had expected. They had also to accommodate a number of new or revised standards, some of which they could not reasonably have foreseen.

Nonetheless, TU's difficulties were the result of the Company's failure to meet the performance standards of the nuclear industry which numerous other utilities were able to meet and TU's failure is not excused by events beyond the Company's reasonable control.

Comanche Peak should have been able to complete construction, by the end of 1984, of a plant in full conformance with NRC regulations, while accommodating all the changes in circumstances in the 1975-1984 period. Most contemporaneous plants were able to complete construction in less time and handle the changing safety standards satisfactorily.[204] The difference is that the successful utilities prepared themselves more effectively for the work before them and took a more forthcoming approach to satisfying safety requirements.

D. A Major Factor In TU's Failure Was Lack of Management Experience with Commercial Nuclear Projects

One of the basic problems with Comanche Peak is that the Company's management had no experience with the design, construction or operation of commercial nuclear power plants and that the Company did not organize itself for building a nuclear plant. This problem was compounded by the Company's misplaced self-confidence which led it to disregard the warnings of consultants and its own QA organization and to try to elbow its way past all difficulties. In the absence of experienced management, which the Company did not obtain until 1985, it is doubtful that the Company could have built a plant which fully complied with NRC requirements.

TU's architect-engineering firm (Gibbs & Hill) had designed only one previous commercial nuclear power plant in the U.S., and its constructor (Brown & Root) had only built one

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[204]Consider, for example, San Onofre 2 and 3, and the three Palo Verde plants -- which are roughly of the same type as Comanche Peak and were built contemporaneously. San Onofre 2 was begun in mid-1974 and loaded fuel in early 1982; Palo Verde 1 was begun in mid-1976 (first concrete in November 1976) and loaded fuel in January 1985.

station.[205] Highly experienced contractors might have compensated for an inexperienced utility. An experienced utility might have made up for the shortcomings of an inexperienced architect/engineer and builder. A nuclear project with so little collective experience as Comanche Peak, however, could not have gotten through the late 1970s and early 1980s without encountering serious difficulties.

Comanche Peak required an extraordinarily .rge number of design changes during construction, apparently because the detailed engineering design had not been done well in the first place. To keep up the pace of construction, the Company then tried to short cut the demanding and time consuming process for handling design changes mandated by federal safety regulations. The Company should have known at the outset that by taking this course it was assuming a real risk of serious problems at the end of construction. When the NRC tightened up enforcement of its regulations as a result of unfortunate experiences at a number of other sites, TU should have reevaluated its approach and insured that it was in full compliance with NRC requirements. Instead, it ignored the warning signs, denied that anything was wrong, and tried to push its way through to a license.

TU does not seem to have learned from the nearby example of Houston Lighting & Power's problems with its South Texas plants. And when outside firms pointed to problems at Comanche Peak, the Company did not heed the advice to resolve the problems. Nor did TU heed the advice of its own quality assurance managers. It continued to compound the problem.

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[205]B&R was simultaneously working on the South Texas Project for Houston Lighting & Power, but that project went awry, with B&R eventually settling the lawsuit brought by HL&P for about $750 million.

Only when the NRC finally woke up and insisted on it, did the Company begin the by-then mammoth task of reevaluation and correction. The Company could hardly have done more than it did to bring about the troubles it eventually encountered in trying to get the plant licensed.

Appendix A: List of Acronyms

ACRS	Advisory Committee on Reactor Safeguards (NRC)
AEC	Atomic Energy Commission
ANI	Authorized Nuclear Inspector (ASME)
ASLAB	Atomic Safety and Licensing Appeal Board
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
AWS	American Welding Society
BEPC	Brazos Electric Power Cooperative, Inc.
B&R	Brown & Root
CASE	Citizens Association for Sound Energy
CAT	Construction Appraisal Team (NRC)
CB&I	Chicago Bridge & Iron
CFG	Caseload Forecasting Group (NRC)
CFP	Caseload Forecasting Panel (NRC)
CMC	Component Modification Card
CP	Construction Permit
CPRT	Comanche Peak Response Team
DAP	Design Adequacy Program (CPRT)
DCA	Design Change Authorization
DC/DD	Design Change/Design Deviation
DC/DDA	Design Change/Design Deviation Authorization
DE/CD	Design Engineering/Change Deviation
EQ	Environmental Qualification
G&H	Gibbs & Hill
HVAC	Heating, Ventilation, and Air Conditioning
IAP	Independent Assessment Program (Cygna)
IDVP	Independent Design Verification Program
IE	Office of Inspection and Enforcement (NRC)
IEEE	Institute of Electrical and Electronic Engineers
ISAP	Issue Specific Action Plan
MAC	Management Analysis Corporation
NCR	Nonconformance Report

NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation (NRC)
NSSS	Nuclear Steam Supply System
OI	Office of Investigation (NRC)
OIA	Office of Inspector and Auditor (NRC)
OL	Operating License
QA	Quality Assurance
QC	Quality Control
SALP	Systematic Assessment of Licensee Performance
SRT	Special Review Team
S&W	Stone & Webster
SWEC	Stone & Webster
TMI	Three Mile Island
TMPA	Texas Municipal Power Agency
TRT	Technical Review Team
TU	Texas Utilities
TUEC	Texas Utilities Electric Company
TUGCO	Texas Utilities Generating Company
TUSI	Texas Utilities Services, Inc.
VDC	Vendor Document Checklist

REPORT ON

RURAL ELECTRIC COOPERATIVES

FEBRUARY, 1988

by

O. Franklin Rogers

SOUTHERN ENGINEERING COMPANY

Atlanta, Georgia

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REPORT ON

RURAL ELECTRIC COOPERATIVES

prepared for

BRAZOS ELECTRIC COOPERATIVE, INC.

Waco, Texas

by

O. Franklin Rogers

I EXPERIENCE

This report is prepared for Brazos Electric Power Cooperative, Inc., Waco, Texas and is based on the experience of Southern Engineering Company (Southern Engineering) and my personal experience related to the Rural Electrification Act (the RE Act), the evolution of the nation's rural electric cooperatives, the Rural Electrification Administration (REA) Loan Procedure and the undivided joint ownership arrangements.

A. Southern Engineering Company Experience

Southern Engineering was founded in 1945 by five engineers, among them Mr. B. E. B. Snowden. Before they founded Southern Engineering, these five men worked for J. B. McCrary Company. During 1935 and 1936 when the RE Act was written and passed by the United States Congress, Mr. Snowden was the head of the electrical engineering department of J. B. McCrary

Company which was involved in the formation of rural electric cooperatives and provided engineering services to these cooperatives. Since the first day of the founding of Southern Engineering, the majority of its projects have provided engineering services to these electric cooperatives. In a span of over 40 years, Southern Engineering has provided engineering and architectural services to over 300 electric cooperatives. These electric cooperatives are located in the following states: Alabama, Alaska, Arizona, Arkansas, Colorado, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Mississippi, Missouri, Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, and West Virginia. The engineering and architectural services provided by Southern Engineering to the electric cooperatives include: distribution design work plans, financial forecasts, retail rate studies, wholesale rate studies, headquarters design, data processing, power supply studies, negotiations to obtain bulk power supplies and joint ownership of generation and transmission facilities, transmission, distribution and substation design, power requirements studies, mapping, communications, television receive only (TVRO), load management, load research, supervisory control and data acquisition (SCADA), water and sewer, work order inspections, forensic engineering, and to assist these electric cooperatives in obtaining financing from the Rural Electrification Administration (REA) by preparing the required studies evaluating the economics of constructing their proposed facilities.

Southern Engineering has a long history of leadership in developing power supply concepts for rural electric cooperatives. Southern Engineering has evaluated a variety of power supply options including self-owned generation, purchases from other utilities, and jointly-owned generation and transmission facilities. Some of these have involved studies of construction of transmission lines or acquisition of transmission service (wheeling). Southern Engineering has provided the loan support services for power supply projects resulting in billions of dollars in loans to its clients. Southern Engineering was instrumental in the formation of power supply arrangements for G&T cooperatives such as: Buckeye Power, Inc. (OH), Alabama Electric Cooperative, Inc. (AL), Oglethorpe Power Corporation (GA), Central Electric Power Cooperative (SC), Seminole Electric Power Cooperative (FL), South Mississippi Electric Power Association

(MS), Old Dominion Electric Cooperative (VA), Wabash Valley Electric Cooperative (IN), Allegheny Electric Cooperative (PA), Northeast Texas Electric Cooperative (TX), Sam Rayburn G&T, Inc. (TX), Tex-La Electric Cooperative of Texas, Inc. (TX), North Carolina Electric Membership Cooperative (NC), Kansas Electric Power Cooperative (KS), Big Rivers Electric Cooperative (KY), Southern Illinois Electric Cooperative (IL), and Saluda River Electric Cooperative (SC).

B. Experience of O. Franklin Rogers

I received the degree of Bachelor of Industrial Engineering from the Georgia Institute of Technology in 1955. Upon graduation from Georgia Tech, I served three years as an officer in the United States Navy, after which I began working for Southern Engineering in 1958. During my 30 years of employment with Southern Engineering, I have held the following positions: engineer, Retail and Wholesale Rates Department Head, Vice President, Executive Vice President, and I am currently the President of this firm. During my career I have conducted numerous rate studies for public power systems, both rural electric cooperatives, and municipal electric systems. I have prepared or participated in the preparation of numerous cost of service studies of investor-owned utilities, rural electric cooperatives, and municipal electric systems. I have participated in wholesale rate and contract negotiations with over 30 investor-owned utilities in some 19 states. I have participated in negotiations to obtain undivided joint ownership of generation and transmission facilities for my clients with the investor-owned electric systems. I was the lead negotiator for clients in obtaining undivided joint ownership in the states of Georgia, North Carolina, and South Carolina. I have prepared or participated in the preparation of numerous power supply feasibility studies. I was instrumental in the formation of Oglethorpe Power Corporation in Georgia. I have assisted clients in obtaining loans from the Federal Finance Bank (FFB) through the REA guaranteed loan program.

I have testified before the Federal Energy Regulatory Commission (FERC), and several state public service commissions as a rate expert. I have testified before the Atomic Energy Commission (AEC), now the Nuclear Regulatory Commission (NRC), on issues related to anti-trust matters.

II DEVELOPMENT OF THE RURAL ELECTRIFICATION ACT (RE Act) OF 1936

In 1879 Thomas Alva Edison invented an incandescent lamp which burned continuously for two days. He next invented a bulb which would burn for several hundred hours. In 1882 he opened the Pearl Street Station, which generated and delivered power throughout New York's lower Manhattan district, thus providing the first "Central Station Service" for street lighting and homes. Hence, part of America, the cities, entered into the 20th century with electric power. However, the other part of America, rural America, was left behind in the 19th century without the benefits of electricity enjoyed by city dwellers. Rural Americans were told that it was not economical to provide electricity to them because there would be no profit to the investors. The rural citizen suffered the hardships of being without electricity as stated by Senator George W. Norris of Nebraska, one of the co-sponsors of the Rural Electrification Act:

> "I had seen first-hand the grim drudgery and grind which had been the common lot of eight generations of American farm women. I had seen the tallow candle in my own home,

followed by the coal-oil lamp. I knew what it was to take care of the farm chores by the flickering, undependable light of lantern in the mud and cold rains of the fall, and the snow and icy winds of winter.

"I had seen the cities gradually acquire a night as light as day.

"I could close my eyes and recall the innumerable scenes of the harvest and the unending punishing tasks performed by hundreds of thousands of women, growing old prematurely; dying before their time; conscious of the great gap between their lives and the lives of those whom the accident of birth or choice placed in the towns and cities.

"Why shouldn't I have been interested in the emancipation of hundreds of thousands of farm women?"[1]

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[1] Richard A. Pence, Editor, The Next Greatest Thing, National Rural Electric Cooperative Association (NRECA), Washington, 1984, p 13.

If a rural community was fortunate enough to have access to electricity, the cost was several times higher than the cost of electricity paid by their urban counterparts. On August 11, 1938 when President Roosevelt dedicated the lines of Lamar Electric Membership Corporation in Barnesville, Georgia, he stated:

> "There was only one discordant note in that first stay of mine at Warm Springs: When the first-of-the-month bill came in for electric light for my little cottage, I found that the charge was 18 cents a kilowatt-hour - about four times as much as I paid in Hyde Park, New York. That started my long study of proper public-utility charges for electric current and the whole subject of getting electricity into farm homes."[2]

Because of the personal experiences of President Roosevelt and those of Senator Norris and Representative Sam Rayburn of Texas, a bill was introduced in Congress calling for a permanent REA. The RE Act became law on May 21, 1936 when it was signed by President Roosevelt.

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[2] Ibid. p 77.

Some of the important milestones of the development of the RE Act are:

"1. 1935. The Rural Electrification Administration was created by Executive Order 7037 on May 11 under authority of the Emergency Relief Appropriation Act of 1935, approved April 8, 1935 (49 Stat. 115).

"2. 1936. Statutory provision for the agency was made in the Rural Electrification Act (RE Act) of 1936, approved May 20 (49 Stat. 1363; 7 U. S. Code, Chapter 31).

"3. 1973. On May 11, the Rural Electrification Act was amended to establish a revolving fund for insured and guaranteed loans under Title III [87 Stat. 65; 7 U.S.C. 931-940]."[3]

A copy of the Rural Electrification Act of 1936 [7 U.S.C. 901-950b] with Amendments as approved through December 22, 1981 is attached to this Report as Appendix No. 1.

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3 The Rural Electrification Act of 1936 with Amendments as Approved through October 30, 1986.

Executive Order 7037 which created the REA stated the following duties and functions of the REA to be executed and performed by the Administrator:

> "To initiate, formulate, administer, and supervise a program of approved projects with respect to the generation, transmission, and distribution of electric energy in rural areas."

The Administrator was authorized to the extent necessary to carry out the provisions of the Executive Order to require, by purchase or by the power of eminent domain, any property or any interest therein and improve, develop, grant, sell, lease (with or without the privilege of purchasing), or otherwise depose of any property or interest therein.[4]

The RE Act was approved by the Senate and the House of Representatives on May 20, 1936 and signed by President Roosevelt on May 21, 1936. A copy of "History" and "Chronology of Legislative Changes, Rural Electrification Act of 1936, 7 U.S.C. 901-950b" from "A Brief History of Rural Electric and Telephone Programs" published by the

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4 Establishment of the Rural Electrification Administration, Executive Order, May 11, 1935.

Rural Electrification Administration, United States Department of Agriculture, revised December, 1986, is attached herewith as Appendix No. 2.

III DEVELOPMENT OF RURAL ELECTRIC COOPERATIVES

In the 1920's and early 30's this nation was a study in contrast, one portion of the nation, the cities, used electricity to provide lighting and power to perform the back breaking work which used to be done by human beings, the other portion, the rural areas, without electricity lived in relative darkness.

Lives in the rural areas during that period were hard compared to the lives of their brothers and sisters who lived in the cities, or compared to our lives today. During that period, there was no electric light; kerosene lamps were used for reading at night. Cooking and heating were provided by wood burning stoves, cows were milked by hand which was hard work and time consuming. There was no running water, hence no indoor plumbing.

There was no wash and wear clothing at that time, and almost all clothing required starch before ironing. The Department of Agriculture has observed that "Young women today are not aware of the origin of the word "iron" as they press clothes with light-weight appliances of aluminum or hollow stainless steel."[5] In those days the farm wives ironed their clothes with a six- or seven-pound wedge of iron which was heated on the wood stove. As described in Robert A. Caro's The Path of Power, the Years of Lyndon Johnson:

> "Nevertheless, the irons would burn a woman's hand. The wooden handle or the potholder would slip, and she would have searing metal against her flesh; by noon, she might have blister atop blister - on hands that had to handle the rag that had been dipped in salt. Ironing always took a full day - often it went on into Tuesday evening and a full day of lifting and carrying six- or seven-pound loads was hard on even these hardy Hill Country women."

The women of the Hill Country of Texas, as well as the women in other rural areas all over the nation, called the instruments they used every Tuesday "sad irons."

Life in the rural areas during the first half of this century was nothing but "drudgery." In a speech before

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5 Robert A. Caro, The Path to Power, Random House, Inc., New York, 1982, p 510.

Congress, Representative John E. Rankin of Mississippi described the "drudgery" a typical farm wife endured, "burning up in a hot kitchen and bowing down over the washtub or boiling the clothes over a flaming fire in the summer heat." Representative Rankin also said, he remembered, "seeing his mother lean over that hot iron hour after hour until it seemed she was tired enough to drop."[6]

Representative Rankin's description was familiar to the mothers of the rural areas of this great nation at that time.

The drudgery of life in the rural areas during that period was numbing. However, that was not the worst thing these people had to endure. The worst thing was the despair created by the lack of hope that they might improve their lives by improving their economic condition. For example, because their cows had to be milked by hand, rather than by an electric machine, there was a limit to the number of cows one could milk. This in turn limited the farmer's income. Also, because there was no electricity on the farm, there was no refrigeration to keep the milk cool. Farmers had to travel to town in order to purchase ice which was used to keep the milk cool. If there was no ice on any given day or if the weather was too hot for the ice to keep the

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[6] Ibid, p 511.

temperature of the milk below 50 degrees fahrenheit, the milk produced that day was not marketable and had to be destroyed. The farm family then lost all its income from the sale of the milk that day.

The drudgery of everyday life and the despair of the people in the rural areas provided the spark necessary to start the electrification of rural America.

The power companies concluded that there was little financial incentive to provide power to the rural areas.

The big power companies estimated that it cost between $1,500 to $2,000 to build a mile of electric lines to serve the rural areas. They also argued that there was insufficient load in the rural areas to support such an investment. They claimed that people in the rural areas would use electricity only for lighting. According to the power companies, there was no profit in providing electricity to the rural areas. Even President Roosevelt had doubts whether electrification of the rural areas could be accomplished. President Roosevelt was not convinced until he reviewed Mr. Morris L. Cooke's now famous "12-minute memo" that the electrification of rural areas could be accomplished.[7]

A copy of the "12-minute memo" is attached herewith as Appendix 3. Mr. Cooke later was appointed to be the first Administrator of the REA.

President Roosevelt had two objectives in signing Executive Order 7037 establishing the REA. The first objective was to create jobs in the rural areas in order to relieve the pressure of the Depression. The second objective, which turned out to be one of his biggest accomplishments, was to electrify the rural areas in order to improve the living standard of the people in those areas. To this end he sought and received $100 million for rural electrification as part of a $5 billion public works bill.

During the first year of the REA, very little was accomplished. Mr. Cooke, the first Administrator of the REA, thought that the power companies would take advantage of government loans and use their know-how to assist the government in electrification of the rural areas. Instead, the power companies conducted a study showing that with the

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7 Donald H. Cooper, Editor, Rural Electric Facts American Success Story, National Rural Electric Cooperative Association, 1970, p 57.

available $100 million loan from the REA, they would be able to electrify fewer than one million farms. Mr. Cooke determined that was insufficient. He then assembled a team of lawyers, engineers, accountants, and administrators to assist in organizing the electric cooperatives.

The lawyers drafted a model bylaw for the electric cooperatives to adopt, the engineers established the design of the electric facilities and assigned field engineers to inspect these facilities to assure their quality. The accountants developed the accounting systems which would be used by the cooperatives.

Even with all the assistance from REA personnel, the electrification of the rural areas would not have been successful without the devotion, trust, and honesty of the people within the rural communities. In the beginning, the REA required electric cooperatives to have a minimum of three member-consumers per mile of line before it would approve a loan. The organizers of the electric cooperatives had to enlist their neighbors to sign up as member-consumers of the cooperative.

In order to be a member-consumer in good standing, these trusting people were required to pay a $5.00 membership fee without any assurance that they would have electricity. In the early 1930's $5.00 was a large sum of money to the people in rural areas. These rural people trusted their neighbors who organized the cooperatives, and in return the organizers honored their trust. After the cooperatives were formed, in a great many instances, the member-consumers provided the right-of-way for the construction of lines and assisted in the construction of those lines which brought electricity to their homes and farms.

The cooperatives were formed based on the following principles:

"° Offers open membership to all who can use its services, without restriction as to sex, color, national origin, religion, political affiliation, or other distinction.

"° Is democratically controlled, with each member having one vote.

"° Operates on a non-profit basis by returning any net savings on the basis of patronage ("capital credits" in most rural electric cooperatives).

"° Limits financial gain on share capital (rural electrics do not issue capital stock, and they pay no interest or dividends on capital credits held in the member's account)."[8]

The power companies did not give up easily. As the cooperatives were being organized, the power companies used a practice called "cream skimming" or building "spite lines." Using this practice the power companies built only those lines to the areas which could be easily reached from the existing lines of the power companies. This practice left the cooperatives to serve the less sparsely populated and difficult to reach areas.

However, even with all the obstacles confronting them, the electric cooperatives were formed. They built the lines to distribute the wholesale power they purchased from the federal government and power companies. Hence, these utilities were called distribution cooperatives. Because of the formation of these distribution cooperatives, electricity was available to rural Americans to light their homes and have the convenience of electric appliances. But more important was the use of electric motors to help perform the backbreaking farm labor. Since electricity was

[8] Ibid, p 57.

then affordable and widely used to improve incomes and productivity of these rural people, the demand for electricity increased. Because of increases in the demand of electricity in the rural areas, some of the distribution cooperatives began to install small diesel engines which were used to generate electricity in order to meet the requirements imposed on the systems by their member-consumers.

Distribution cooperatives are generally small organizations which find it effective to join together in certain endeavors. In order to meet the demand of electricity imposed on the distribution cooperatives, these distribution cooperatives formed generation and transmission cooperatives (G&T Cooperatives) to investigate and obtain the lowest possible cost bulk power supply to their member-consumers. G&T Cooperatives are owned by their member distribution cooperatives. The Boards of Directors of G&T Cooperatives are either members of Boards of Distribution Cooperatives and/or Managers of Distribution Cooperatives. There are three types of G&T Cooperatives. They are:

1. "Paper G&T Cooperatives" are those which do not own any generation or transmission facilities. They are formed to represent the distribution cooperatives in order to obtain a reasonable wholesale power contracts. They

are also formed to investigate the feasibility of any alternative which can provide a lower cost of power to its members.

2. The G&T Cooperatives which own only generation facilities or transmission facilities b[illegible]oth.

3. The G&T Cooperatives which own both gene[illegible]ion and transmission facilities.

In 1937 two adjacent distribution cooperatives located in Iowa decided to pool their resources and build a generation facility. They decided to take advantage of economies of scale by building a larger generator to meet their combined needs. They obtained the first generation loan from REA in 1937. Later, these two Iowa distribution cooperatives formed the Corn Belt Power Cooperative, a G&T Cooperative.

Even though the first generation loan was made by the REA in 1937, getting the power companies to recognize G&T cooperatives was no easy task. Some power companies did not recognize G&T cooperatives until the early 1970's. The power companies attempted to ignore the G&T's by insisting that their wholesale power contracts be between themselves and the individual distribution cooperatives instead of between themselves and the G&T cooperatives. Also, in several instances when a G&T cooperative determined it would be economical for them, with loans from the REA, to construct generation and transmission facilities, the neighboring power companies would lower their wholesale electric rates so that the project would no longer be feasible. Rural Electric Facts, American Success Story stated:

> "In 1945 the REA Administrator Claude Wickard told a House Interstate and Foreign Commerce Subcommittee about eight separate cases in which the mere consideration of a generation loan had brought down company prices. Prior to consideration of a loan to Brazos Transmission Cooperative and Farmers Generation and Transmission Cooperative, in Texas, Mr. Wickard testified, the average rate charged cooperatives by Texas Power and Light Company was 11.2 mills. After the possibility of an REA loan arose, the price dropped to 5.6 mills. The rate of Southwestern Gas & Electric Company fell from 12.8 mills to 5.6 mills, Texas Electric Service Company from 12.5 mills to 5.6 mills,

Central Power & Light Company from 13.5 mills to 7 mills, and Gulf States Utilities Company from 12.9 mills to 8.25 mills."[9]

Because of these tactics, there were not many generation and transmission loans made by the REA during the first two decades of the life of the REA. Beginning in 1961, after Mr. Norman M. Clapp became the seventh Administrator of the REA, the agency began to make large generation and transmission loans.

The power companies had not abandoned their fight to stop the operation of generation and transmission cooperatives. After the Hoosier Energy Division of Indiana's Statewide Rural Electric Cooperative (Hoosier Energy) obtained a loan and built its generation and transmission facilities in 1968, Southern Indiana Gas & Electric Company filed suit against the Hoosier Energy Division. After the Indiana Supreme Court held that the right of Hoosier Energy Division to operate generation and transmission facilities under Indiana's Rural Electric Membership Corporation Act of 1935 had lapsed because of failure to use it earlier, Mr. Clapp for the first time invoked Section 7 of the RE Act which allows the Administrator to take over and operate an REA financed facility in order to protect the government's

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[9] Ibid, p 71.

investment. Later, the suit was settled; hence, Hoosier Energy was able to operate the facilities. Mr. Clapp left the REA in 1969.

From 1969 to the mid 70's, again, there were few generation and transmission loans made by the REA. However, about the mid 70's when the cooperatives forecasted substantial growth in demand of electricity from their member-consumers, some power companies started to give indications they were not willing to construct new generating facilities to serve the cooperative loads. As a result, the REA began to make generation and transmission loans again. The generation and transmission loans made by the REA during this period were mostly for joint ownership of generation and transmission facilities between the G&T cooperatives and the power companies. The availability of the joint ownership alternative for generation and transmission facilities to G&T cooperatives was enhanced because the Department of Justice's review of the activities of the licensees of nuclear generation facilities. Under Section 105, Antitrust Provisions of the Atomic Energy Act, it was often determined that in order to avoid the creation or maintenance of monopolies in the electric industry by nuclear generation licensees or avoid aiding anticompetitive practices, G&T cooperatives and other public power systems should have access to various types of coordination with the system of the licensee. This led to joint participation in nuclear generation facilities for many G&T cooperatives. Also, during this period, many power companies were having difficulty raising sufficient capital to maintain their construction programs. Therefore, they were willing to allow the G&T cooperatives to obtain joint ownership not only in their nuclear generation facilities but also in coal-fired generation and transmission facilities. During this period several G&T cooperatives were transformed from so-called "paper G&T's" to G&T cooperatives which owned both generation and transmission facilities.

IV REA LOAN PROCEDURES

REA loan procedures are outlined in various REA bulletins. REA Bulletin 20-2 on the subject of Electric Loan Policies and Application Procedures, dated June 13, 1977 states, among other things, the following:

> "Loans . . . . . shall not be made unless the Administrator finds and certifies that in his judgment the security therefor is reasonably adequate and such loans will be repaid within the time agreed.

"<u>Generation and Transmission Facilities</u>:
1. The initial construction of generation facilities by distribution or power supply borrowers, and of transmission facilities by power supply borrowers, only under the following conditions:

"a. Where no adequate and dependable source of power is available to meet the consumers' needs, or

"b. Where the rates offered by existing power sources would result in a higher cost of power to the consumer than the cost from facilities financed by REA, and the amount of the power cost savings that would result from the REA-financed facilities bears a significant relationship to the amount of the proposed REA loan."

"<u>Lien on Borrower's System</u>: A first lien on the borrower's total system normally will be required. It shall be in the form of a mortgage by the borrower to the Government or a deed of trust made by and between the borrower and a trustee, satisfactory to the Administrator.

"1. Where a borrower is unable by reason of pre-existing encumbrances, or otherwise, to furnish a first mortgage lien on its entire system the Administrator may, if he determines such security to be reasonably adequate and the form and nature thereof otherwise appropriate, accept other forms of security.

"2. To facilitate supplemental financing for Act purposes, the Government's first lien may be shared where the Administrator finds that this would be in the best interests of the borrower and the Government."

A copy of REA Bulletin 20-2 is attached herewith as Appendix No. 4. A copy of REA Bulletin 20-22 (referenced in REA Bulletin 20-2), Guarantee of Loans for Bulk Power Supply Facilities, is attached herewith as Appendix No. 5.

REA Bulletin 20-6, Loans for Generation and Transmission sets the policy for making such loans. It states the policy as follows:

"Policy:

A. The Rural Electrification Administration will make loans to finance the initial construction of generation facilities by distribution or power supply borrowers, and of transmission facilities by power supply borrowers, only under the following conditions:

"1. Where no adequate and dependable source of power is available to meet the consumers' needs, or

"2. Where the rates offered by existing power sources would result in a higher cost of power to the consumers than the cost from facilities financed by REA, and the amount of the power cost savings that would result from the REA-financed facilities bears a significant relationship to the amount of the proposed REA loan.

"The policy stated in REA Bulletin 111-1, "Wholesale Contracts for Purchase and Sale of Electric Energy," will be considered in evaluating all power supply proposals."

A copy of REA Bulletin 20-6 is attached herewith as Appendix No. 6.

When a G&T cooperative determines that it plans to apply for a loan or loan guarantee for generation or transmission facilities from REA, it will request the REA to begin a power supply survey procedure. REA Bulletin 111-3 states the REA's policy as follows:

"Requirement for Power Supply Surveys: A Power Supply Survey is required prior to acceptance by REA of applications for loans or loan guarantees for generation and/or major transmission where the facilities to be constructed would displace existing contractual arrangements with a private power company. No such application will be accepted for consideration by REA unless (a) a Power Supply Survey has been completed, or (b) it is determined by the Administrator that completion of the Survey requires full review of the application.

> "Where a Survey is required, the applicant shall provide a full description of existing contractual arrangements for power supply, a statement of any special problems, a general summary of power supply needs, copies of any proposals made by the existing supplier, and a summary of negotiations with the existing supplier."

REA Bulletin 111-3 also outlines the conduct of survey and certifications required when survey procedures result in a loan or loan guarantee by the REA. A copy of REA Bulletin 111-3 is attached herewith as Appendix No. 7.

The G&T cooperative applying for a loan must have an up-to-date Power Requirements Study (PRS) which forecasts the demand for electricity of its member distribution cooperatives. The G&T cooperative must also describe the planned facilities and prepare a Borrower's Environmental Report (BER) to determine the impact, if any, of the planned facilities on the environment. It must also provide to REA a copy of the policy approved by the cooperative's Board of Directors regarding energy conservation.

The G&T cooperative must prepare a Power Supply Feasibility Study to indicate that in its opinion the application for a loan meets one of two conditions specified in REA Bulletin 20-6. The outline of the Power Supply Feasibility Study should contain the following:

1. Describe the existing system.
2. The current bulk power resources.
3. The proposed bulk power resources.
4. The forecasted requirement of electricity.
5. The sources and availability of fuels.
6. The proposed agreements.
7. Alternatives of bulk power resources investigated.
8. The best alternative chosen.
9. The savings, if any, of each alternative chosen as compared to the existing arrangement.

Power Supply Feasibility Studies should cover a period of at least ten years from the year in which the proposed facilities become commercially operational. Based upon the forecasted power cost of the alternative chosen in the Power Supply Feasibility Study, the G&T cooperative prepares a Financial Forecast for the same period showing the revenues it will require from its member distribution cooperatives. The Board of Directors of the G&T cooperative should then approve the necessary resolutions sanctioning the Power Supply Feasibility Study and Financial Forecast and authorizing management to apply for a loan with the REA.

The G&T cooperative and its member distribution cooperatives are required to enter into an all requirements contract which requires the member distribution cooperatives to purchase all their electricity for resale from the G&T cooperative. Without this agreement, REA will not approve the loan. The REA considers the all requirements contract as part of the security for the loan made, or guaranteed, by the Federal government. The G&T cooperative must also provide the REA a copy of any agreements related to the facilities such as the ownership agreement, operation agreement, and transmission agreement for the Administrator's approval. All these agreements must be previously approved by the Board of Directors of the G&T cooperative.

The Administrator has the authority, at his sole discretion, to approve or disapprove the loan application of the G&T cooperative. If the Administrator decides to approve the loan application, the REA will publish in the Federal Register the intention of the Administrator to make such loan. After the notice period expires, the Administrator then approves the loan and any associated agreements.

After the Administrator's approval of the loan, the G&T cooperative is assured of the amount of money approved. However, the entire amount of the loan cannot be taken down by the G&T cooperative. The G&T cooperative can request an advance of funds to cover only the amount necessary to meet its construction expenditures each month. The interest of the fund advanced each month can be fixed for the term of the loan or for a shorter period at the option of the G&T cooperative.

If the G&T cooperative exhausts the funds included in the original loan, and the project has not been completed and more money is required from the REA, the G&T cooperative may apply for an additional loan, called a "Deficiency Loan." Generally, the G&T cooperative will have to go through the same loan procedure as described earlier. When the REA approves a loan for any construction project, it is the REA's policy to provide sufficient financing to complete the project based on the economic feasibility as then determined. This is true for initial loans and deficiency loans. For a joint ownership project, estimates of the cost and time to complete the project must come from the principal owner or project manager.

Once a G&T cooperative becomes a borrower from the REA, all the contracts entered into by the G&T cooperative are subject to the Administrator's approval. In joint ownership arrangements the REA must approve all contract amendments and all related capital financing. The REA will hold liens on all the assets of the G&T cooperative. Prior approval from the REA must be obtained before a G&T cooperative can use its general funds for construction of additions to certain facilities, such as "communications, generation and transmission facilities, other facilities in increased dollar amount and potential generating sites up to $2 million." This is contained in REA Bulletin No. 103-2 attached herewith as Appendix No. 8.

The Administrator, at his sole discretion, has the authorization to give a lien accommodation in order to allow the G&T cooperative to borrow money from other lending institutions. Experience indicates that if the Administrator disapproves a loan or loan guarantee from the REA, he will also disapprove any lien accommodation. The evaluation of the request of lien accommodation is the same as the evaluation used to approve or disapprove loans or loan guarantee applications of the G&T cooperative. The Administrator has approved certain lien accommodations related to pollution control facilities in order for G&T

cooperatives to issue pollution control bonds. These bonds carry an interest rate lower than that of the guaranteed loan.

V JOINT OWNERSHIP ARRANGEMENTS

Beginning in the early 1970's the Justice Department's Antitrust Division conducted reviews under the antitrust provisions in Section 105 of the Atomic Energy Act. These reviews were performed in connection with licensing proceedings being conducted by the Atomic Energy Commission (now the Nuclear Regulatory Commission). These reviews concluded that without corrective license conditions most of the nuclear generation facilities to be constructed by the power companies would create or maintain monopoly or anticompetitive situations in the electric utility industry. In several instances, the Justice Department recommended that the NRC include licensing conditions as part of the license awarded to the power companies for the construction and operation of nuclear generating facilities. In some cases, these licensing conditions gave the public power systems, including G&T cooperatives, the option of obtaining an undivided joint ownership interest in the nuclear generating facilities. At least one licensing condition ..so gave public power systems the right to obtain an undivided joint ownership in certain generating facilities, including coal-fired facilities, to be constructed by the power companies in the future.

As stated earlier in this report, in the 1970's the G&T cooperatives forecasted substantial growth in the demand of electricity of their members. Because of the oil embargo, that created long lines at gasoline stations, substantially higher prices for gasoline and oil, led to the passage of the Fuel Use Act, and the curtailment plan of the Federal Energy Regulatory Commission, the cooperatives wanted the option of obtaining undivided joint ownership in nuclear generating facilities then under construction by the power companies.

Many public power systems, including G&T cooperatives, obtained an undivided joint ownership in these nuclear generating facilities. Some of the reasons that encouraged the G&T cooperatives to participate in undivided joint ownership arrangements were:

1. To meet the future requirements of their members,

2. To avoid the substantial wholesale rate increases imposed on them during the early and mid 1970's,

3. To lower the cost of power,

4. To diversify their fuel resources,

5. To assist the federal government's goal that the United States be energy independent, and

6. To take advantage of the opportunity to add small increments of generating capability and yet at the same time take advantage of the economies of scale realized in constructing large generating facilities.

Joint ownership arrangements are those which allow two or more owners to each have an undivided ownership interest in the facilities as a tenant in common. Each owner is entitled to his pro rata share of the output from the facilities. With rare exception, the majority owner of the facility has the responsibility for the construction and operation and maintenance of the facility based on prudent utility practices. The majority owner, usually a large investor-owned electric utility, has this responsibility because it has more expertise in the construction, operation, and maintenance of the facilities. Such utility constructing the nuclear facility invariably insisted on this role. In addition, the NRC has indicated it prefers to work with one entity that has full responsibility for the construction, operation, and maintenance of the nuclear facility.

The joint ownership agreements delineate responsibilities, obligations, ownership, and capacity and energy entitlement of each owner.

In the Joint Ownership Agreement among Dallas Power & Light Company, Texas Electric Service Company, Texas Power & Light Company, Texas Utilities Generating Company, Texas Municipal Power Agency and Brazos Electric Power Cooperative, Inc., and later Tex-La Electric Cooperative of Texas, Inc., for Comanche Peak Steam Electric Station (Comanche Peak Agreement), Texas Utilities Generating Company (TUGCO) was given control over the design, construction, and licensing of Comanche Peak Steam Electric Station for all parties to the Comanche Peak Agreement. In return, TUGCO was required to perform in accordance with the standards specified in the Comanche Peak Agreement. The Comanche Peak Agreement is typical of joint participation agreements in the electric utility industry.

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Rural Electrification Act of 1936 (with a[illegible]ents as approved through October 30, 1986

A Brief History of the Rural Electric and Telephone Programs (revised December, 1986)

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

REA Bulletin 1-3 (Electric)
REA Bulletin 300-2 (Telephone)

RURAL ELECTRIFICATION ACT OF 1936
[7 U.S.C. 901-950b]

WITH AMENDMENTS AS APPROVED THROUGH OCT. 30, 1986

CHRONOLOGY

1935. The Rural Electrification Administration was created by Executive Order 7037 of May 11 under authority of the Emergency Relief Appropriation Act of 1935, approved April 8, 1935 (49 Stat. 115).

1936. Statutory provision for the agency was made in the Rural Electrification Act (RE Act) of 1936, approved May 20 (49 Stat. 1363; 7 U.S. Code, Chapter 31).

1938. Title IV of the Work Relief and Public Works Appropriation Act of 1938, approved June 21 ("RE Act of 1938," 52 Stat. 818) authorized further borrowing from the Reconstruction Finance Corporation and added a requirement that borrowers from REA agree to use materials and supplies produced in the United States.

1939. REA became a part of the Department of Agriculture under Reorganization Plan II, effective July 1.

1944. Title V of the Department of Agriculture Organic Act of 1944, approved September 21 (58 Stat. 739; 7 U.S.C. 903-905; 915) liberalized the terms of REA loans and removed the time limitation from its lending program.

1944. On December 23, the Rural Electrification Act was further amended to authorize REA to refinance certain rural electrification obligations owed to the Tennessee Valley Authority (58 Stat. 925; 7 U.S.C. 904).

1947. The Department of Agriculture Appropriation Act, 1948, approved July 30, (61 Stat. 546; 7 U.S.C. 903) further amended the Rural Electrification Act by transferring from the Reconstruction Finance Corporation to the Secretary of the Treasury the authority to make loans to REA.

1948. On June 29, the Rural Electrification Act was again amended to authorize REA to refinance certain additional rural electrification obligations owed to the Tennessee Valley Authority (62 Stat. 1070; 7 U.S.C. 904).

1949. On October 28, the Rural Electrification Act was further amended to authorize REA to make loans for the purpose of furnishing and improving rural telephone service (63 Stat. 948; 7 U.S.C. 901-914; 922-924).

1955. On June 15, the Rural Electrification Act was amended by revising the formula governing the allotment of electrification loan funds (69 Stat. 131; 7 U.S.C. 903; 904).

1962. On October 23, the Rural Electrification Act was amended by broadening the definition of telephone service (76 Stat. 1140; 7 U.S.C. 924).

1971. On May 7, the Rural Electrification Act was amended to establish a Rural Telephone Account and the Rural Telephone Bank (85 Stat. 29; 7 U.S.C. 903; 922; 931; 932; 941-950b).

1972. On June 30, the Rural Electrification Act was amended to authorize the Secretary of the Treasury to purchase Telephone Bank debentures (86 Stat. 390; 7 U.S.C. 947).

1973. On May 11, the Rural Electrification Act was amended to establish a revolving fund for insured and guaranteed loans under Title III (87 Stat. 65; 7 U.S.C. 903; 931-940; 945-948).

1975. On November 4, the Rural Electrification Act was amended to expressly authorize the assignment of REA guarantees to the extent provided in contract of guarantee, to clarify the incontestability of the Government guarantee, and to specifically require justification of budget estimates (89 Stat. 677; 7 U.S.C. 906; 936; 938).

1976. On April 21, the "Fiscal Year Adjustment Act," amended the Rural Electrification Act to reflect necessary changes in laws because of the October-September fiscal year. (90 Stat. 378; 7 U.S.C. 910; 946; 950).

1976. On October 20, the Rural Electrification Act was amended to correct unintended inequities in the interest rate criteria and to transfer the unobligated balance of the 1973 loan authorizations to the Rural Electrification and Telephone Revolving Fund. (90 Stat. 2701; 7 U.S.C. 931; 935).

1977. On August 4, the "Department of Energy Organization Act," added section 16 to title I, to require the Administrator, when making or guaranteeing generation or transmission loans, to consider general criteria published by the Secretary of Energy. (91 Stat. 608; 7 U.S.C. 916).

1981. On August 13, the "Omnibus Budget Reconciliation Act of 1981," amended the Rural Electrification Act (1) to establish a 5 percent interest rate, with certain exceptions, for loans from the revolving fund, and (2) to require the Federal Financing Bank to make a loan under an REA guarantee if requested by a borrower with such a guarantee. (95 Stat. 379; 7 U.S.C. 935-937).

1981. On December 22, the "Agriculture and Food Act of 1981," amended the Rural Electrification Act to extend for another 10 years the authorization for Federal stock purchases in the Rural Telephone Bank. (95 Stat. 1347; 7 U.S.C. 946).

1986. On October 21, the "Omnibus Budget Reconciliation Act of 1986," amended the Rural Electrification Act to authorize the prepayment of certain loans made by the Federal Financing Bank and guaranteed by the Rural Electrification Administration. The Act further provides for sale or prepayment of direct or insured loans by the borrower through September 30, 1987. (100 Stat. 1875; 7 U.S.C. 936a).

1986. On October 30, an act entitled "Joint Resolution making continuing appropriations for the fiscal year 1987, and for other purposes", amended the Rural Electrification Act to establish a privatization demonstration program to allow electric and telephone borrowers under the Rural Electrification Act to prepay with private capital all their loans guaranteed or otherwise made by and through the Rural Electrification Administration providing certain conditions are met. (100 Stat. 3341-333; 7 U.S.C. 940a) NOTE: Legislation which enacted this amendment provides that its provisions "shall apply only to the rural electrification program in the State of Alaska". (100 Stat. 3341-352).

GUIDE TO PROVISIONS OF RURAL ELECTRIFICATION ACT

PROVISIONS RELATING TO ORGANIZATION AND GENERAL FUNCTIONS OF REA - APPLICABLE TO BOTH ELECTRIFICATION AND TELEPHONE OPERATIONS: TITLE I

SEC. 1—establishes REA in the Department of Agriculture; directs that powers of REA be exercised by Administrator.

SEC. 2—authorizes REA Administrator to make rural electrification and telephone loans; and to investigate and publicize condition and progress of rural electrification and telephone service.

SEC. 3—provides for REA electrification and telephone loan funds; and establishes State allotment formula for electrification loan funds (not applicable to telephone loan funds).

SEC. 6—authorizes appropriation of funds for administering electrification and telephone loan programs.

SEC. 7—relates to acquisition and disposition by REA Administrator of property securing loans; prohibits disposition of property acquired by borrowers with REA loan funds, unless REA Administrator approves, until loan is fully repaid.

SEC. 8—makes Rural Electrification Act applicable to certain loans and contracts entered into prior to effective date of Act (May 20, 1936).

SEC. 9—requires administration of Act and selection of employees on nonpartisan, nonpolitical basis.

SEC. 10—requires annual report to Congress.

SEC. 11—authorizes Administrator to appoint officers and employees and to make certain administrative expenditures.

SEC. 12—empowers Administrator to extend payment of loans with certain limitations.

SEC. 13—defines the terms "rural area", "farm", "person" and "Territory".

SEC. 14—technical "saving clause".

SEC. 15—authorizes certain administrative expenditures.

PROVISIONS RELATING TO RURAL ELECTRIFICATION LOANS ONLY: TITLE I

SEC. 4—authorizes Administrator to make loans for rural electrification; specifies eligible borrowers, preferences, purposes, terms and conditions, security and self-liquidation requirements.

SEC 5—authorizes Administrator to make loans to finance wiring installations and electrical and plumbing appliances and equipment. (Sec. 3(a) prescribes a 5-year maximum maturity for such loans.)

SEC. 16—requires the Administrator when making or guaranteeing generation or transmission loans to consider general criteria published by the Secretary of Energy.

PROVISIONS RELATING TO RURAL TELEPHONE LOANS ONLY: TITLE II

SEC. 201—authorizes Administrator to make loans for furnishing and improving rural telephone service; specifies eligible borrowers, terms and conditions, purposes, preferences generally, preferences during initial year of program, area coverage requirements, security and self-liquidation requirements; authorizes financing of nonrural facilities under certain conditions; authorizes limited refinancing of existing indebtedness; requires applicants to comply with State certification requirements, and, where such requirements are inapplicable, specifies the determination which the Administrator is required to make.

SEC. 202—recognizes jurisdiction of State regulatory bodies.

SEC. 203—defines the terms "telephone service" and "rural area".

PROVISIONS RELATING TO RURAL ELECTRIFICATION AND TELEPHONE REVOLVING FUND ONLY: TITLE III

SEC. 301—establishes in the U.S. Treasury a "Rural Electrification and Telephone Revolving Fund" and specifies the existing and future assets to be included in the fund.

SEC. 302—sets forth the liabilities of the fund and outlines the exclusive purposes for which the assets of the fund are available.

SEC. 303—requires that moneys in the fund shall remain on deposit in the United States Treasury until required for disbursement.

SEC. 304—sets forth the financial transactions authorized by the fund, including borrowings from the Treasury and the sale of borrowers' notes or interests in them to the Treasury or the private money market.

SEC. 305—authorizes the Administrator to make insurable loans at 5 percent with loans at a lesser rate, but not less than 2 percent, available only to borrowers in specified circumstances.

SEC. 306—authorizes the Administrator to guarantee loans made by other lending agencies at interest rates agreed on by the borrower and the lender, with or without a concurrent insured loan, and requires the Federal Financing Bank to make a loan under a REA guarantee when requested by a borrower with such a guarantee.

SEC. 306A—authorizes the prepayment of certain loans made by the Federal Financing Bank and guaranteed by the Rural Electrification Administration and requires the Administrator to establish eligibility criteria based on greatest need of benefits associated with prepayment to cooperative borrowers.

SEC. 306B—provides that direct or insured loans may not be sold or prepaid at less than face value except as therein provided during fiscal year 1987.

SEC. 307—authorizes the Administrator to request that a borrower obtain other financing, concurrently with an insured loan at the standard rate, under specified conditions.

SEC. 308—provides that any contract of insurance or guarantee made under Title III shall be supported by the full faith and credit of the United States.

SEC. 309—provides that loans made from or insured through the fund under Title III shall be for the same purposes and on the same terms and conditions as those provided for loans under Titles I and II of the Act, except as otherwise provided in sections 303 through 308.

SEC. 310—authorizes the Administrator, at the request of the borrower, to refinance any loans made for rural electric and telephone facilities under the Consolidated Farm and Rural Development Act.

SEC. 311—establishes a privatization demonstration program for electric and telephone Rural Electrification Administration (REA) borrowers with outstanding REA-guaranteed Federal Financing Bank (FFB) loans and provides an option to such borrowers to prepay all outstanding REA-guaranteed FFB loans, without a prepayment premium. (NOTE: Legislation which enacted this section provides that its provisions "shall apply only to the rural electrification program in the State of Alaska".)

PROVISIONS RELATING TO TELEPHONE BANK ONLY: TITLE IV

SEC. 401—establishes telephone bank as a body corporate and an instrumentality of the United States, to obtain supplemental funds from non-Federal sources and utilizes them in making loans, operating on self-sustaining basis to extent practicable.

SEC. 402—sets forth general powers of telephone bank.

SEC. 403—lists special provisions governing telephone bank as United States agency until conversion of ownership, control and operation.

SEC. 404—makes REA Administrator Governor of telephone bank until conversion of ownership, control and operation.

SEC. 405—provides for board of directors of bank and sets forth procedures for its selection.

SEC. 406—provides for capitalization of telephone bank and establishes classes of stock to be issued.

SEC. 407—authorizes and limits borrowing by telephone bank and describes status of debentures.

SEC. 408—authorizes lending by telephone bank and establishes restrictions on telephone bank loans.

SEC. 409—makes any receipts of telephone bank available for all its obligations and expenditures.

SEC. 410—provides for conversion of ownership, control and operation of telephone bank when specified amount of Class A stock has been retired.

SEC. 411—sets forth rights of stockholders on liquidation or dissolution of telephone bank.

SEC. 412—prohibits a SEC. 201 loan to a borrower having net worth in excess of 20% of assets in preceding year unless Administrator finds it cannot obtain the loan from the bank or other reliable sources on reasonable terms.

DEFERRED AMENDMENTS TO THE GOVERNMENT CORPORATION CONTROL ACT

STATEMENTS OF CONGRESSIONAL POLICY

Rural Telephone Loan Legislation, 1949
Rural Telephone Bank Legislation, 1971 and 1972
Rural Electrification and Telephone Revolving Fund Legislation, 1973
Effect of Technical Amendments on Pending Applications
Effect of Omnibus Budget Reconciliation Act Amendments on Pending Applications

PROVISIONS OF DISASTER RELIEF ACT AFFECTING REA

"BUY AMERICAN" PROVISION

RURAL ELECTRIFICATION ACT OF 1936

With Amendments as Approved Through Oct. 30, 1986
[U.S. Code, Title 7, Chap. 31]

AN ACT

To provide for rural electrification, and for other purposes.

TITLE I

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That there is hereby created and established in the Department of Agriculture an agency of the United States, to be known as the "Rural Electrification Administration", all of the powers of which shall be exercised by an Administrator, under the general direction and supervision of the Secretary of Agriculture, who shall be appointed by the President, by and with the advice and consent of the Senate, for a term of ten years. (See NOTE.) This Act may be cited as the "Rural Electrification Act of 1936". [May 20, 1936, Ch. 432, Title I, §1, 49 Stat. 1363; 1939 Reorg. Plan No. II, §5, eff. July 1, 1939, 4 F.R. 2732, 53 Stat. 1434; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 901.] (NOTE: Provisions of this section which prescribed the basic annual compensation of the Administrator were omitted to conform to the provisions of the Federal Executive Salary Schedule. See section 2210 et. seq. of Title 5, Executive Departments and Government Officers and Employees.)

SEC. 2. The Administrator is authorized and empowered to make loans in the several States and Territories of the United States for rural electrification and the furnishing of electric energy to persons in rural areas who are not receiving central station service, and for the purpose of furnishing and improving telephone service in rural areas, as hereinafter provided; to make, or cause to be made, studies, investigations, and reports concerning the condition and progress of the electrification of and the furnishing of adequate telephone service in rural areas in the several States and Territories; and to publish and disseminate information with respect thereto. [May 20, 1936, ch. 432, Title I, §2, 49 Stat. 1363; Oct. 28, 1949, Ch. 776, §§2, 3, 63 Stat. 948; 7 U.S.C. 902.]

SEC. 3.(a) The Secretary of the Treasury is hereby authorized and directed to make loans to the Administrator, upon the request and approval of the Secretary of Agriculture, in such amounts in the aggregate for each fiscal year commencing with the fiscal year ending June 30, 1948, as the Congress may from time to time determine to be necessary, either without interest or at such rate of interest per annum, not in excess of the rate provided for in sections 4 and 5 of this Act, as the Secretary of the Treasury may determine, upon the security of the obligations of borrowers from the Administrator appointed pursuant to the provisions of this Act or from the Administrator of the Rural Electrification Administration established by Executive Order Numbered 7037. Interest rates on the unpaid balance of any loans made by the Reconstruction Finance Corporation to the Administrator prior to July 1, 1947, shall be adjusted to the interest rate, if any, established for loans made after June 30, 1947, in accordance with the foregoing provision: Provided, That such obligations incurred for the purpose of financing the construction and operation of generating plants, electric transmission and distribution lines, or systems and for the purpose of financing the improvement, expansion, construction, acquisition, and operation of facilities to render telephone service shall be fully amortized over a period not to exceed thirty-five years, and that the maturity of such obligations incurred for the purpose of financing the wiring of premises and the acquisition and installation of electrical and plumbing appliances and equipment shall not exceed two-thirds of the assured life thereof and not more than five years. The Administrator is hereby authorized to make all such endorsements, to execute all such instruments, and to do all such acts and things as shall be necessary to effect the valid transfer and assignment to the Secretary of the Treasury of all such obligations, and to execute such trust instruments as shall be agreed upon by the Administrator and the Secretary of the Treasury providing for the holding in trust by the Administrator of all such obligations for the Secretary of the Treasury as security for loans to the Administrator heretofore made by the Reconstruction Finance Corporation or made or to be made by the Secretary of the Treasury. All rights, interests, obligations, and duties of the Reconstruction Finance Corporation arising out of loans made or authorized to be made to the Administrator are, as of the close of June 30, 1947, vested in the Secretary of the Treasury; the Reconstruction Finance Corporation is authorized and directed to receive all loans outstanding on that date, plus accrued unpaid interest, theretofore made to the Administrator under the provisions of this Act, and all notes and other evidences thereof and all obligations constituting the security therefor. The Secretary of the Treasury shall cancel notes of the Reconstruction Finance Corporation, and sums due and unpaid upon or in connection with such notes at the time of such cancellation, in an amount equal to the unpaid principal of the loans so transferred, plus accrued unpaid interest through June 30, 1947. Subsequent to June 30, 1947, the Reconstruction Finance Corporation shall make no further loans or advances to the Administrator; and the Secretary of the Treasury is hereby authorized and directed, in lieu of the Reconstruction Finance Corporation, to lend or advance to the Administrator, in accordance with the provisions of this subsection 3 (a), any unobligated or unadvanced balances of the sums which the Reconstruction Finance Corporation has theretofore been authorized and directed to lend to the Administrator. For the purpose of making loans or advances pursuant to this section, the Secretary of the Treasury is authorized to use as a public debt-transaction the proceeds from the sale of any securities issued under the Second Liberty Bond Act, as amended, and the purposes for which securities may be issued under that Act are extended to include such loans or advances to the Administrator. Repayments to the Secretary of the Treasury on such loans or advances shall be treated as a public-debt transaction of the United States.

(b) There are hereby authorized to be appropriated such sums as the Congress may from time to time determine to be necessary for the purposes of this Act as hereinafter provided.

(c) Twenty-five per centum of the annual sums herein made available or appropriated for loans for rural electrification pursuant to sections 4 and 5 of this title shall be alloted yearly by the Administrator for loans in the several States in the proportion which the number of their farms not then receiving central station electric service bears to the total number of farms of the United States not then receiving such service: Provided, That if any part of such sums are not loaned or obligated during the first six months of the fiscal year for which they are made available, such part shall thereafter be available for loans by the Administrator without allotment: Provided, however, That not more than 25 per centum of said sums may be employed in any one State or in all of the Territories. The Administrator shall within ninety days after the beginning of each fiscal year determine for each State and for the United States the number of farms not then receiving such service.

(d) The remaining 75 per centum of such annual sums shall be available for rural electrification loans in the several States and in the Territories, without allotment as hereinabove provided in such amounts for each State and Territory as, in the opinion of the Administrator, may be effectively employed for the purposes of this Act, and to carry out the provisions of section 7: Provided, however, That not more than 25 per centum of said unallotted annual sums may be employed in any one State, or in all of the Territories.

(e) If any part of the annual sums made available for the purposes of this Act are not loaned or obligated during the fiscal year for which they are made available, such unexpended or unobligated sums shall be available for loans by the Administrator in the following year or years without allotment: Provided, however, That not more than 25 per centum of said sums for rural electrification loans may be employed in any one State or in all of the Territories. [May 20, 1936, ch. 432, Title I, §3, 49 Stat. 1364; June 21, 1938, ch. 554, Title IV, §401, 52 Stat. 818; Sept. 21, 1944, ch. 412, Title V, §§501, 503, 504, 58 Stat. 739, 740; July 30, 1947, ch. 356, Title I, §1, 61 Stat. 546; Oct. 28, 1949, ch. 776, §§2, 4 (a)-(d), 63 Stat. 948; June 15, 1955, ch. 139, 69 Stat. 131; May 7, 1971, Public Law 92-12, §3(a), 85 Stat. 37; May 11, 1973, Public Law 93-32, §3,87 Stat. 70; 7 U.S.C. 903]

SEC. 4. The Administrator is authorized and empowered, from the sums hereinbefore authorized, to make loans for rural electrification to persons, corporations, States, Territories, and subdivisions and agencies thereof, municipalities, peoples' utility districts and cooperative, nonprofit, or limited-divided associations organized under the laws of any State or Territory of the

United States, for the purpose of financing the construction and operation of generating plants, electric transmission and distribution lines or systems for the furnishing of electric energy to persons in rural areas who are not receiving central station service, and loans, from funds available under the provisions of sections 3(d) and 3(e) but without regard to the 25 per centum limitation therein contained, to cooperative associations and municipalities for the purpose of enabling said cooperative associations and municipalities to the extent that such indebtedness was incurred with respect to electric transmission and distribution lines or systems or portions thereof serving persons in rural areas, to discharge or refinance long-term debts owed by them to the Tennessee Valley Authority on account of loans made or credit extended under the terms of the Tennessee Valley Authority Act of 1933, as amended: Provided, That the Administrator, in making such loans, shall give preference to States, Territories, and subdivisions and agencies thereof, municipalities, peoples' utility districts, and cooperative nonprofit, or limited-dividend associations, the projects of which comply with the requirements of this Act. Such loans shall be on such terms and conditions relating to the expenditure of the moneys loaned and the security therefor as the Administrator shall determine and may be made payable in whole or in part out of the income: Provided further, That all such loans shall be self-liquidating within a period of not to exceed thirty-five years, and shall bear interest at the rate of 2 per centum per annum; interest rates on the unmatured and unpaid balance of any loans made pursuant to this section prior to September 21, 1944, shall be adjusted to 2 per centum per annum, and the maturity date of any such loans may be readjusted to occur at a date not beyond thirty-five years from the date of such loan: And provided further, That no loan for the construction, operation, or enlargement of any generating plant shall be made unless the consent of the State authority having jurisdiction in the premises is first obtained. Loans under this section and section 5 shall not be made unless the Administrator finds and certifies that in his judgment the security therefor is reasonably adequate and such loan will be repaid within the time agreed. [May 20, 1936, ch. 432, Title I, §4, 49 Stat. 1365; Sept. 21, 1944, ch. 412, Title V, §§502(a), 503, 58 Stat. 739, 740; Dec. 23, 1944, ch. 725, 58 Stat. 925, 926; June 29, 1948, Ch. 703, 62 Stat. 1070; Oct. 28, 1949, ch. 776, §§2, 4(e), 63 Stat. 948; June 15, 1955, ch. 139, §2, 69 Stat. 132; 7 U.S.C. 904.]

SEC. 5. The Administrator is authorized and empowered, from the sums hereinbefore authorized, to make loans for the purpose of financing the wiring of the premises of persons in rural areas and the acquisition and installation of electrical and plumbing appliances and equipment. Such loans may be made to any of the borrowers of funds loaned under the provisions of section 4, or to any person, firm, or corporation supplying or installing the said wiring, appliances or equipment. Such loans shall be for such terms, subject to such conditions, and so secured as reasonably to assure repayment thereof, and shall be at a rate of interest of 2 per centum per annum; interest rates on the unmatured and unpaid balance of any loans made pursuant to this section prior to September 21, 1944, shall be adjusted to 2 per centum per annum. [May 20, 1936, ch. 432, Title I, §5, 49 Stat. 1365; Sept. 21, 1944, ch. 412, Title V, §502(b), 58 Stat. 739; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 905.]

SEC. 6. For the purpose of administering this Act and for the purpose of making the studies, investigations, publications, and reports herein provided for, there is hereby authorized to be appropriated, out of any money in the Treasury not otherwise appropriated, such sums as shall be necessary. On or before February 15 of each calendar year beginning with calendar year 1976, or such other date as may be specified by the appropriate committee, the Secretary of Agriculture shall testify before the House Committee on Agriculture and the Senate Committee on Agriculture and Forestry and provide justification in detail of the amount requested in the budget to be appropriated for the next fiscal year for the purpose of administering this Act and for the purpose of making the studies, investigations, publications, and reports herein authorized.
[May 20, 1936, ch. 432, Title I, §6, 49 Stat. 1365; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; Nov. 4, 1975, Public Law 94-124, §3, 89 Stat. 677; S. Res. 4, Feb. 4, 1977; 7 U.S.C. 906.]

SEC. 7. The Administrator is authorized and empowered to bid for and purchase at any foreclosure or other sale, or otherwise to acquire, property pledged or mortgaged to secure any loan made pursuant to this Act; to pay the purchase price and any costs and expenses incurred in connection therewith from the sums authorized in section 3 of this Act; to accept title to any property so purchased or acquired in the name of the United States of America; to operate or lease such property for such period as may be deemed necessary or advisable to protect the investment therein, but not to exceed five years after the acquisition thereof; and to sell such property so purchased or acquired, upon such terms and for such consideration as the Administrator shall determine to be reasonable.

No borrower of funds under section 4 or section 201 shall, without the approval of the Administrator, sell or dispose of its property, rights, or franchises, acquired under the provisions of this Act, until any loan obtained from the Rural Electrification Administration, including all interest and charges, shall have been repaid.
[May 20, 1936, ch. 432, Title I, §7, 49 Stat. 1365, 1366; Oct. 28, 1949, ch. 776, §§2, 4(f), 63 Stat. 948; 7 U.S.C. 907.]

SEC. 8. The administration of loans and contracts entered into by the Rural Electrification Administration established by Executive Order Numbered 7037, dated May 11, 1935, may be vested by the President in the Administrator authorized to be appointed by this Act; and in such event the

provisions of this Act shall apply to said loans and contracts to the extent that said provisions are not inconsistent therewith. The President may transfer to the Rural Electrification Administration created by this Act the jurisdiction and control of the records, property (including office equipment), and personnel used or employed in the exercise and performance of the functions of the Rural Electrification Administration established by such Executive Order.
[May 20, 1936, ch. 432, Title I, §8, 49 Stat. 1366; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 908.]

SEC. 9. This Act shall be administered entirely on a nonpartisan basis, and in the appointment of officials, the selection of employees, and in the promotion of any such officials, or employees, no political test or qualification shall be permitted or given consideration, but all such appointments and promotions shall be given and made on the basis of merit and efficiency. If the Administrator herein provided for is found by the President of the United States to be guilty of a violation of this section, he shall be removed from office by the President, and any appointee or selection of officials or employees made by the Administrator who is found guilty of a violation of this Act shall be removed by the Administrator.
[May 20, 1936, ch. 432, Title I, §9, 49 Stat. 1366; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 909.]

SEC. 10. The Administrator shall present annually to the Congress not later than the 20th day of April in each year a full report of his activities under this Act.
[May 20, 1936, ch. 432, Title I, §9, 49 Stat. 1366; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; April 21, 1976, Public Law 94-273, §11(1), 90 Stat. 378; 7 U.S.C. 910.]

SEC. 11. In order to carry out the provisions of this Act the Administrator may accept and utilize such voluntary and uncompensated services of Federal, State, and local officers and employees as are available, and he may without regard to the provisions of civil-service laws applicable to officers and employees of the United States appoint and fix the compensation of attorneys, engineers, and experts, and he may, subject to the civil-service laws, appoint such other officers and employees as he may find necessary and prescribe their duties. The Administrator is authorized, from sums appropriated pursuant to section 6, to make such expenditures (including expenditures for personal services; supplies and equipment; lawbooks and books of reference, directories and periodicals; travel expenses; rental at the seat of government and elsewhere; the purchase, operation, or maintenance of passenger-carrying vehicles; and printing and binding) as are appropriate and necessary to carry out the provisions of this Act.

[May 20, 1936, ch. 432, Title I, §11, 49 Stat. 1366; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 911.]

SEC. 12. The Administrator is authorized and empowered to extend the time of payment of interest or principal of any loans made by the Administrator pursuant to this Act: Provided, however, That with respect to any loan made under section 4 or section 201, the payment of interest or principal shall not be extended more than five years after such payment shall have become due, and with respect to any loan made under section 5, the payment of principal or interest shall not be extended more than two years after such payment shall have become due: And provided further, That the provisions of this section shall not apply to any obligations or the security therefor which may be held by the Reconstruction Finance Corporation under the provisions of section 3.
[May 20, 1936, ch. 432, Title I, §12, 49 Stat. 1366; Oct. 28, 1949, ch. 776, §§2, 4 (f), 63 Stat. 948; 7 U.S.C. 912.]

SEC. 13. As used in this Act the term "rural area" shall be deemed to mean any area of the United States not included within the boundaries of any city, village, or borough having a population in excess of fifteen hundred inhabitants, and such term shall be deemed to include both the farm and nonfarm population thereof; the term "farm" shall be deemed to mean a farm as defined in the publications of the Bureau of the Census; the term "person" shall be deemed to mean any natural person, firm, corporation, or association; the term "Territory" shall be deemed to include any insular possession of the United States.
[May 20, 1936, ch. 432, Title I, §13, 49 Stat. 1367; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948; 7 U.S.C. 913.]

SEC. 14. If any provision of this Act, or the application thereof to any person or circumstances, is held invalid, the remainder of the Act and the application of such provision to other persons or circumstances shall not be affected thereby.
[May 20, 1936, ch. 432, Title I, §14, 49 Stat. 1367; Oct. 28, 1949, ch. 776, §2, 63 Stat. 948, 7 U.S.C. 914.]

SEC. 15. The Rural Electrification Administration is authorized to purchase such financial and credit reports as may be necessary to carry out its authorized work: Provided, That purchases under this authority shall not be made unless provision is made therefor in the applicable appropriation and the cost thereof is not in excess of limitations prescribed therein.
[Sept. 21, 1944, ch. 412, Title V, §505, 58 Stat. 740; 7 U.S.C. 915.]

SEC. 16. In order to insure coordination of electric generation and transmission financing under this Act with the national energy policy, the Administrator in making or guaranteeing loans for the construction, operations, or enlargement of generating plants or electric transmission lines or systems, shall consider such general criteria consistent with the provisions of this Act as may be published by the Secretary of Energy. [Aug. 4, 1977, Public Law 95-91, Title VII, §709(f), 91 Stat. 608; 7 U.S.C. 916.]

TITLE II

SEC. 201. From such sums as are from time to time made available by the Congress to the Administrator for such purpose, pursuant to section 3 of this Act, the Administrator is authorized and empowered to make loans to persons now providing or who may hereafter provide telephone service in rural areas, to public bodies now providing telephone service in rural areas and to cooperative, nonprofit, limited dividend, or mutual associations. Except as otherwise provided by this title, such loans shall be made under the same terms and conditions as are provided in section 4 of this Act, for the purpose of financing the improvement, expansion, construction, acquisition, and operation of telephone lines, facilities or systems to furnish and improve telephone service in rural areas: Provided, however, That the Administrator, in making such loans, shall give preference to persons providing telephone service in rural areas, to public bodies now providing telephone service in rural areas and to cooperative, nonprofit, limited dividend, or mutual associations: And provided further, That for a period of one year from and after the effective date of this title applications for loans received by the Administrator from persons who on the effective date of this title are engaged in the operation of existing telephone service in rural areas shall be considered and acted upon before action is taken upon any application received from any other person for any loan to finance the furnishing or improvement of telephone service to substantially the same subscribers. The Administrator in making such loans shall, insofar as possible, obtain assurance that the telephone service to be furnished or improved thereby will be made available to the widest practical number of rural users. When it is determined by the Administrator to be necessary in order to furnish or improve telephone service in rural areas, such loans may be made for the improvement, expansion, construction, acquisition, and operation of telephone lines, facilities, or systems without regard to their geographical location. The Administrator is further authorized and empowered to make loans for the purpose of refinancing outstanding indebtedness of persons furnishing telephone service in rural areas: Provided, That such refinancing shall be determined by the Administrator to be necessary in order to furnish and improve telephone service in rural areas: And provided further, That such refinancing shall constitute not more than 40 per centum of any loan made under this title. Loans under this section shall not be made unless the Administrator finds and certifies that in his judgement the security therefor is reasonably adequate and such loan will be repaid within the time agreed, nor shall such loan be made in any State which now has or may hereafter have a State regulatory body having authority to

regulate telephone service and to require certificates of convenience and necessity to the applicant unless such certificate from such agency is first obtained. In a State in which there is no such agency or regulatory body legally authorized to issue such certificates to the applicant, no loan shall be made under this section unless the Administrator shall determine (and set forth his reasons therefor in writing) the' no duplication of lines, facilities, or systems, providing reasonably adequate services will result therefrom.
[Oct. 28, 1949, ch. 776, §5, 63 Stat. 948; May 7, 1971, Public Law 92-12, §3(b), 85 Stat. 37; 7 U.S.C. 922.]

SEC. 202. Nothing contained in this Act shall be construed to deprive any State commission, board, or other agency of jurisdiction, under any State law, now or hereafter effective, to regulate telephone service which is not subject to regulation by the Federal Communications Commission, under the Communications Act of 1934, including the rates for such service.
[Oct. 28, 1949, ch. 776, §5, 63 Stat. 948; 7 U.S.C. 923.]

SEC. 203. (a) As used in this title, the term "telephone service" shall be deemed to mean any communication service for the transmission of voice, sounds, signals, pictures, writing, or signs of all kinds through the use of electricity between the transmitting and receiving apparatus, and shall include all telephone lines, facilities, or systems used in the rendition of such service; but shall not be deemed to mean message telegram service or community antenna television system services or facilities other than those intended exclusively for educational purposes, or radio broadcasting services or facilities within the meaning of section 3(o) of the Communications Act of 1934, as amended.

(b) As used in this title, the term "rural area" shall be deemed to mean any area of the United States not included within the boundaries of any incorporated or unincorporated city, village, or borough having a population in excess of one thousand five hundred inhabitants.
[Oct. 28, 1949, ch. 776, §5, 63 Stat. 948; Oct. 23, 1962, Public Law 87-862, 76 Stat. 1140; 7 U.S.C. 924.]

TITLE III

SEC. 301. RURAL ELECTRIFICATION AND TELEPHONE REVOLVING FUND.—(a) There is hereby established in the Treasury of the United States a fund, to be known as the Rural Electrification and Telephone Revolving Fund (hereinafter referred to as the "fund"), consisting of:

(1) all notes, bonds, obligations, liens, mortgages, and property delivered or assigned to the Administrator pursuant to loans heretofore or hereafter made under sections 4, 5, and 201 of this Act and under this title, as of the effective date of this title, as revised herein, and all proceeds from the sales hereunder of such notes, bonds, obligations, liens,

title, as of the effective date of this title, as revised herein, and all proceeds from the sales hereunder of such notes, bonds, obligations, liens, mortgages, and property, which shall be transferred to and be assets of the fund;

(2) undisbursed balances of electric and telephone loans made under sections 4, 5, and 201, which as of the effective date of this title, as revised herein, shall be transferred to and be assets of the fund;

(3) notwithstanding section 3(a) of title I, all collections of principal and interest received on and after July 1, 1972, on notes, bonds, judgments, or other obligations made or held under titles I and II of this Act and under this title, except for net collection proceeds previously appropriated for the purchase of class A stock in the Rural Telephone Bank, which shall be paid into and be assets of the fund;

(4) all appropriations for interest subsidies and losses required under this title which may hereafter be made by the Congress and the unobligated balances of any funds made available for loans under the item "Rural Electrification Administration" in the Department of Agriculture and Agriculture-Environmental and Consumer Protection Appropriations Acts;

(5) moneys borrowed from the Secretary of the Treasury pursuant to section 304(a); and

(6) shares of the capital stock of the Rural Telephone Bank purchased by the United States pursuant to section 406(a) of this Act and moneys received from said bank upon retirement of said shares of stock in accordance with the provisions of title IV of this Act, which said shares and moneys shall be assets of the fund.

[May 7, 1971, Public Law 92-12, §2, 85 Stat. 29; May 11, 1973, Public Law 93-32, §2, 87 Stat. 66; Oct. 20, 1976, Public Law 94-570, §2, 90 Stat. 2701; 7 U.S.c. 931.]

SEC. 302. LIABILITIES AND USES OF FUND.—(a) The notes of the Administrator to the Secretary of the Treasury to obtain funds for loans under sections 4, 5, and 201 of this Act, and all other liabilities against the appropriations or assets in the fund in connection with electrification and telephone loan operations shall be liabilities of the fund, and all other obligations against such appropriations or assets in the fund arising out of electrification and telephone loan operations shall be obligations of the fund.

(b) The assets of the fund shall be available only for the following purposes:

(1) loans which could be insured under this title, and for advances in connection with such loans and loans previously made, as of the effective date of this title, as revised herein, under sections 4, 5, and 201 of this Act;

(2) payment of principal when due (without interest) on outstanding loans to the Administrator from the Secretary of the Treasury for electrification and telephone purposes pursuant to section 3(a) of this Act and

RURAL ELECTRIFICATION AND TELEPHONE REVOLVING FUND

The rural electrification and telephone revolving fund legislation contains the following statements of Congressional policy:

. . . it is hereby declared to be the policy of the Congress that adequate funds should be made available to rural electric and telephone systems through direct, insured and guaranteed loans at interest rates which will allow them to achieve the objectives of the Rural Electrification Act of 1936, as amended; and that such rural electric and telephone systems should be encouraged and assisted to develop their resources and ability to achieve the financial strength needed to enable them to satisfy their credit needs from their own financial organizations and other sources at reasonable rates and terms consistent with the loan applicant's ability to pay and achievement of the Act's objectives. The Rural Electrification Act of 1936, as amended (7 U.S.C. 901-950(b)), is therefore further amended as hereinafter provided. [May 11, 1973, Public Law 93-32, § 1, 87 Stat. 65; 7 U.S.C. 930.]

. . . No funds provided under the Rural Electrification Act of 1936, as amended, shall be used outside the United States or any of its territories. [May 11, 1973, Public Law 93-32, § 10, 87 Stat. 71; 7 U.S.C. 906a.]

EFFECT OF TECHNICAL AMENDMENTS ON PENDING APPLICATIONS

The "Rural Electrification Administration Technical Amendments of 1976," provides that insured loans made pursuant to applications for such loans which would otherwise lose eligibility for special rate financing upon enactment of the bill, received by the Rural Electrification Administration and still pending on the date of enactment, shall bear interest as determined under section 305(b) of the Rural Electrification Act of 1936, as amended, before its amendment by the bill. [October 20, 1976, Public Law 94-570, 90 Stat. 2701.]

EFFECT OF OMNIBUS RECONCILIATION ACT AMENDMENTS ON PENDING APPLICATIONS

The "Omnibus Reconciliation Act of 1981," amendments to the RE Act "shall apply to loans the applications for which are received by the Rural Electrification Administration after July 24, 1981." [August 13, 1981, Public Law 97-35, Title I, § 165(d), 95 Stat. 379; 7 U.S.C. 935.]

PROVISIONS OF THE DISASTER RELIEF ACT OF 1970 AFFECTING REA

Section 236(a) of the Disaster Relief Act 1970 (December 31, 1970, Public Law 91-606, Title II, §236(a), 84 Stat. 1754; 7 U.S.C. 912a) expanded the loan extension authority provided in section 12 of the Rural Electrification Act as follows:

In addition to the loan extension authority provided in section 12 of the Rural Electrification Act, the Secretary of Agriculture is authorized to adjust and readjust the schedules for payment of principal and interest on loans to borrowers under programs administered by the Rural Electrification Administration, and to extend the maturity date of any such loan to a date not beyond forty years from the date of such loan where he determines such action is necessary because of the impairment of the economic feasibility of the system, or the loss, destruction, or damage of the property of such borrowers as a result of a major disaster.

"BUY AMERICAN" PROVISION

Rural Electrification Act of 1938 (June 21, 1938, ch. 554, Title IV §401, 52 Stat. 818) provided in part as follows:

In making loans pursuant to this title and pursuant to the Rural Electrification Act of 1936, the Administrator of the Rural Electrification Administration shall require that, to the extent practicable and the cost of which is not unreasonable, the borrower agree to use in connection with the expenditure of such funds only such unmanufactured articles, materials, and supplies, as have been mined or produced in the United States, and only such manufactured articles, materials, and supplies as have been manufactured in the United States substantially all from articles, materials or supplied mined, produced, or manufactured, as the case may be, in the United States.

payment of principal and interest when due on loans to the Administrator from the Secretary of the Treasury pursuant to section 304(a) of this title;

(3) payments of amounts to which the holder of notes is entitled on insured loans: Provided, That payments other than final payments need not be remited to the holder until due or until the next agreed annual, semiannual, or quarterly remittance date;

(4) payment to the holder of insured notes of any defaulted installment or, upon assignment of the note to the Administrator at his request, the entire balance due on the note;

(5) purchase of notes in accordance with contracts of insurance entered into by the Administrator;

(6) payment in compliance with contracts of guarantee;

(7) payment of taxes, insurance, prior liens, expenses necessary to make fiscal adjustments in connection with the application, and transmittal of collections or necessary to obtain credit reports on applicants or borrowers, expenses for necessary services, including construction inspections, commercial appraisals, loan servicing, consulting business advisory or other commercial and technical services, and other program services, and other expenses and advances authorized in section 7 of this Act in connection with insured loans. Such items may be paid in connection with guaranteed loans after or in connection with the acquisition of such loans or security thereof after default, to the extent determined to be necessary to protect the interest of the Government, or in connection with any other activity authorized in this Act;

(8) payment of the purchase price and any costs and expenses incurred in connection with the purchase, acquisition, or operation of property pursuant to section 7 of this Act.

[May 7, 1971, Public Law 92-12, §2, 85 Stat. 30; May 11, 1973, Public Law 93-32, 87 Stat. 66; 7 U.S.C. 932.]

SEC. 303. DEPOSIT OF FUND MONEYS.—Moneys in the fund shall remain on deposit in the Treasury of the United States until disbursed.
[May 11, 1973, Public Law 93-32, 87 Stat. 67; 7 U.S.C. 933]

SEC. 304. FINANCIAL TRANSACTIONS OF THE FUND.—(a) The Administrator is authorized to make and issue interim notes to the Secretary of the Treasury for the purpose of obtaining funds necessary for discharging obligations of the fund and for making loans, advances and authorized expenditures out of the fund. Such notes shall be in such form and denominations and have such maturities and be subject to such terms and conditions as may be agreed upon by the Administrator and the Secretary of the Treasury. Such notes shall bear interest at a rate fixed by the Secretary of the Treasury, taking into consideration the current average market yield of outstanding marketable obligations of the United States having maturities comparable to the notes issued by the Administrator under this section. The Secretary of the Treasury is authorized to use as a public debt transaction the proceeds from the sale of any securities issued under the Second Liberty Bond Act, as amended, and the purposes for which such securities may be issued under such Act, as amended, are extended to include the purchase of notes issued by the Administrator. All redemptions, purchases, and sales by the Secretary of the Treasury of such notes shall be treated as public debt transactions of the United States: Provided, however, That such interim notes to the Secretary of the Treasury shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by statute on expenditures and net lending (budget outlays) of the United States.

(b) The Secretary of the Treasury is authorized and directed to purchase for resale obligations insured through the fund when offered by the Administrator. Such resales shall be upon such terms and conditions as the Secretary of the Treasury shall determine. Purchases and resales by the Secretary of the Treasury hereunder shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by statute on expenditures and net lending (budget outlays) of the United States.

(c) The Administrator may, on an insured basis or otherwise, sell and assign any notes in the fund or sell certificates of beneficial ownership therein to the Secretary of the Treasury or in the private market. Any sale by the Administrator of notes individually or in blocks shall be treated as a sale of assets for the purposes of the Budget and Accounting Act, 1921, notwithstanding the fact that the Administrator, under an agreement with the purchaser or purchasers, holds the debt instruments evidencing the loans and holds or reinvests payments thereon as trustee and custodian for the purchaser or purchasers of the individual note or of the certificate of beneficial ownership in a number of such notes. Security instruments taken by the Administrator in connection with any notes in the fund may constitute liens running to the United States notwithstanding the fact that such notes may be thereafter held by purchasers thereof.

[May 11, 1973, Public Law 93-32, §2, 87 Stat. 67; 7 U.S.C. 934]

SEC. 305. INSURED LOANS; INTEREST RATES AND LENDING LEVELS.—(a) The Administrator is authorized to make insured loans under this title and at the interest rates hereinafter provided to the full extent of the assets available in the fund, subject only to limitations as to amounts authorized for loans and advances as may be from time to time imposed by the Congress of the United States for loans to be made in any one year, which amounts shall remain available until expended: Provided, That the Congress in the annual appropriation Act may also authorize the transfer of any excess cash in the fund for deposit into the Treasury as miscellaneous receipts: And provided further, That any such loans and advances shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by statute on expenditures and net lending (budget outlays) of the United States.

(b) Insured loans made under this title shall bear interest at 5 per centum per annum, except that the Administrator may make insured loans to electric or telephone borrowers at a lesser interest rate, but not less than 2 per centum per annum, if, in the Administrator's sole discretion, the Administrator finds that the borrower—

(1) has experienced extreme financial hardship; or

(2) cannot, in accordance with generally accepted management and accounting principles and without charging rates to its customers or subscribers so high as to create a substantial disparity between such rates and the rates charged for similar service in the same or nearby areas by other suppliers, provide service consistent with the objectives of this Act.

(c) Loans made under this section shall be insured by the Administrator when purchased by a lender. As used in this Act, an insured loan is one which is made, held, and serviced by the Administrator, and sold and insured by the Administrator hereunder; such loans shall be sold and insured by the Administrator without undue delay.

[May 11, 1973, Public Law 93-32, §2, 87 Stat. 68; Oct. 20, 1976, Public Law 94-570, §3, 90 Stat. 2701; Aug. 13, 1981, Public Law 97-35, Title I, §165(a), 95 Stat. 379; 7 U.S.C. 935.]

SEC. 306. GUARANTEED LOANS; ACCOMMODATION AND SUBORDINATION OF LIENS.—The Administrator may provide financial assistance to borrowers for purposes provided in the Rural Electrification Act of 1936, as amended, by guaranteeing loans, in the full amount thereof, made by the Rural Telephone Bank, National Rural Utilities Cooperative Finance Corporation, and any other legally organized lending agency, or by accommodating or subordinating liens or mortgages in the fund held by the Administrator as owner or as trustee or custodian for purchases of notes from the fund, or by any combination of such guarantee, accommodation, or subordination. No fees or charges shall be assessed for any such guarantee, accommodation, or subordination. With respect to guarantees issued by the Administrator under this section, on the request of the borrower of any such loan so guaranteed, the loan shall be made by the Federal Financing Bank and at a rate of interest that is not more than the rate of interest applicable to other similar loans then being made or purchased by the Bank. Guaranteed loans shall bear interest at the rate agreed upon by the borrower and the lender. Guaranteed loans, and accommodation and subordination of liens or mortgages, may be made concurrently with an insured loan. The amount of guaranteed loans shall be subject only to such limitations as to amounts as may be authorized from time to time by the Congress of the United States: Provided, That any amounts guaranteed hereunder shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by satute on expenditures and net lending (budget outlays) of the United States. As used in this title, a guaranteed loan is one which is initially made, held, and serviced by a legally organized lending agency and which is guaranteed by the Administrator hereunder. A guaranteed loan, including the related guarantee, may be assigned to the extent provided in the contract of guarantee executed by the Administrator under this title; the assignability of such loan and guarantee shall be governed exclusively by said contract of guarantee.

[May 11, 1973, Public Law 93-32, §2, 87 Stat. 69; Nov. 4, 1975, Public Law 94-124, §1, 89 Stat. 677; Aug. 13, 1981, Public Law 97-35, Title I, §165(b), 95 Stat. 379, 7 U.S.C. 936.] (NOTE: Legislation which included a provision authorizing the prepayment of loans by rural electrification and telephone systems (July 2, 1986, Public Law 99-349, Title I, Chapter 1, 100 Stat. 713) was subsequently amended and the authorization repealed (Oct. 21, 1986, Public Law 99-509, Title I, §1011(b), 100 Stat. 1876.))

SEC. 306A. PREPAYMENT OF LOANS.—(a) Except as provided in subsection (c), a borrower of a loan made by the Federal Financing Bank and guaranteed under section 306 of this Act may prepay such loan (or any loan advance thereunder) by paying the outstanding principal balance due on the loan (or advance), if—

(1) the loan is outstanding on July 2, 1986;

(2) private capital, with the existing loan guarantee, is used to replace the loan; and

(3) the borrower certifies that any savings from such prepayment will be passed on to its customers or used to improve the financial strength of the borrower in cases of financial hardship.

(b) No sums in addition to the payment of the outstanding principal balance due on the loan may be charged against the borrower, the fund, or the Rural Electrification Administration.

(c)(1) A borrower will not qualify for prepayment under this section if, in the opinion of the Secretary of the Treasury, to prepay in such borrower's case would adversely affect the operation of the Federal Financing Bank.

(2) Paragraph (1) shall be effective in fiscal year 1987 only for any loan the prepayment of the principal amount of which will cause the cumulative amount of net proceeds from all such prepayments made during such year to exceed $2,017,500,000.

(d)(1) The Administrator shall permit, subject to subsection (a), prepayments of principal on loans in fiscal year 1987 under this section or Public Law 99-349 in such amounts as to realize net proceeds from all such prepayments in fiscal year 1987 in an amount not less than $2,017,500,000.

(2) The Administrator shall establish—

(A) eligibility criteria to ensure that any loan prepayment activity required to be carried out under this subsection will be directed to those cooperative borrowers in greatest need of the benefits associated with prepayment, as determined by the Administrator; and

(B) such other eligibility criteria as the Administrator determines are necessary to carry out this subsection.

(e) Any guarantee of a loan prepaid under this section shall be fully assignable under the provisions of section 306 of this Act and transferrable. However, the Administrator may require that any such guarantee, if transferred or assign, be transferred or assigned to a loan or security that, if sold, will be grouped with non-guaranteed loans or securities and sold in a manner to ensure that such sale will not unreasonably compete with the marketing of obligations of the United States.

[Oct. 21, 1986 Public Law 99-509, Title I, §1011(a), 100 Stat. 1875; 7 U.S.C. 936a.] (NOTE: Legislation which enacted this section provides that "[t]he Secretary of Agriculture shall issue regulations to implement this section within 60 days after the date of enactment of this Act. Such regulations—

(1) shall facilitate prepayment of loans under section 306A of the Rural Electrification Act of 1936, as amended by subsection (a); and

(2) may not require any rural utility that is a borrower of loans subject to section 306A to make unreasonable reductions in rates to its customers as a condition of such prepayment." (Oct. 21, 1986, Public Law 99-509, Title I, §1011(c), 100 Stat. 1876.))

SEC. 306B. SALE OR PREPAYMENT OF DIRECT OR INSURED LOANS.—A direct or insured loan made under this Act shall not be sold or prepaid at a value less than the face value of any outstanding principal balance on such loan, except when sold to or prepaid by the borrower at the lesser of the outstanding principal balance due on the loan or the loan's present value discounted from the face value at maturity at the rate set by the Administrator. The exception contained in the preceding sentence shall be effective for the period ending September 30, 1987.

[Oct. 21, 1986, Public Law 99-509, Title I, §1011(a), 100 Stat. 1875; 7 U.S.C. 936a.] (NOTE: Legislation which enacted this section provides that "[t]he Secretary of Agriculture shall issue regulations to implement this section within 60 days after the date of enactment of this Act." (Oct. 21, 1986, Public Law 99-509, Title I, §1011(c), 100 Stat. 1876.))

SEC. 307. OTHER FINANCING.—When it appears to the Administrator that the loan applicant is able to obtain a loan for part of his credit needs from a responsible cooperative or other credit source at reasonable rates and terms consistent with the loan applicant's ability to pay and the achievement of the Act's objectives, he may request the loan applicant to apply for and accept such a loan concurrently with an insured loan, subject, however, to full use being made by the Administrator of the funds made available hereunder for such insured loans under this title.

[May 11, 1973, Public Law 93-32, §2, 87 Stat. 70; Aug. 13, 1981, Public Law 97-35, Title I, §165(c), 95 Stat. 379, 7 U.S.C. 937.]

SEC. 308. FULL FAITH AND CREDIT OF THE UNITED STATES.—Any contract of insurance or guarantee executed by the Administrator under this title shall be an obligation supported by the full faith and credit of the United States and incontestable except for fraud or misrepresentation of which the holder had actual knowledge at the time it became a holder.
[May 11, 1973, Public Law 93-32, §2, 87 Stat. 70; Nov. 4, 1975, Public Law 94-124, §2, 89 Stat. 677; 7 U.S.C. 938.]

SEC. 309. LOAN TERMS AND CONDITIONS.—Loans made from or insured through the fund shall be for the same purposes and on the same terms and conditions as are provided for loans in titles I and II of this Act except as otherwise provided in sections 303 to 308 inclusive.
[May 11, 1973, Public Law 93-32, §2, 87 Stat. 70; 7 U.S.C. 939]

SEC. 310. REFINANCING OF RURAL DEVELOPMENT ACT LOANS.—At the request of the borrower, the Administrator is authorized and directed to refinance with loans which will be insured under this Act, at the interest rates provided in section 305, any loans made for rural electric and telephone facilities under any provision of the Consolidated Farm and Rural Development Act.
[May 11, 1973, Public Law 93-32, §2, 87 Stat. 70; 7 U.S.C. 940]

SEC. 311. PRIVATIZATION PROGRAM.—The Administrator shall establish a privatization demonstration program which shall permit borrowers to repay loans made by the Federal Financing Bank and guaranteed under section 306 of this Act by paying the outstanding principal balance due on the loans. No sums in addition to the payment of the outstanding principal balance due on the Federal Financing Bank loans may be charged as the result of such prepayment against the borrower, the fund, or the Rural Electrification Administration. Federal Financing Bank loans shall be refinanced using the existing section 306 loan guarantee, with private capital, in an amount not to exceed the outstanding principal amount prepaid: Provided, That such guarantee of private capital shall be 90% of the principal amount of the loan or any portion thereof plus accrued interest outstanding at any time during the maturity period of the loan and shall be fully transferable and assignable. Notwithstanding any other provision of law, borrowers may prepay Federal Financing Bank loans under this section, except that such borrowers shall be required to prepay all of their outstanding loans made or guaranteed under this Act within one year of prepayment of the first loan. A direct or insured loan prepaid under this section shall be prepaid by the borrower at the lesser of the outstanding principal balance due on the loan or the loan's present value discounted from the face value at maturity at the rate set by the Administrator. A Rural Telephone Bank loan shall be prepaid by paying the outstanding principal balance on the loan. No guarantee or other financial assistance shall be available to the borrowers to refinance outstanding loans prepaid hereunder. In the case of an electric borrower prepaying under this section or otherwise prepaying a loan at less than the outstanding principal balance due on the loan, after the date of prepayment, no loans, loan guarantees or other financial assistance shall be provided pursuant to this Act to the borrower or its successors or for the purpose of financing the construction or operation of generating plants or bulk transmission lines for the purpose of furnishing electric energy in the area served on a retail or wholesale basis by such borrower. In the case of a telephone borrower prepaying under this section, or otherwise prepaying a loan at less than the outstanding principal balance due on the loan, after the date of prepayment, no loans, loan guarantees or other financial assistance shall be provided pursuant to this Act to the borrower or its successors or for the purpose of furnishing or improving telephone service in the area served by such borrower. In determining the service area of electric borrowers, the Administrator shall make allowances and adjustments to avoid adversely affecting the eligibility of other borrowers for financial assistance under this Act where such borrowers are currently providing electric supply services for retail loads in the same area and which are reasonably expected to continue providing electric supply services for retail loads in such areas. In the event that the borrower prepaying under this section shall be using a majority of its generating capacity to directly serve its retail consumers, other borrowers which are purchasing power from such borrower as of September 30, 1986, shall continue to remain eligible for financing under this Act for needs in their service area. Nothing in this section shall prohibit a borrower which has prepaid pursuant to this section from participating in generation and transmission projects with borrowers which have not prepaid, so long as the borrower which has prepaid utilizes private capital financing without financial assistance under this Act: Provided further, That nothing in this section shall prohibit short-term power purchases by borrowers which have prepaid under this section from borrowers which have not prepaid. The Administrator shall issue regulations to implement this section within 60 days.

[Oct. 30, 1986, Public Law 99-591, Title VI, §623, 100 Stat. 3341-333; 7 U.S.C. 940a.] (NOTE: Legislation which enacted this section provides that its provisions "shall apply only to the rural electrification program in the State of Alaska." (Oct. 30, 1986, Public Law 99L-591, Title VIII, Part C §115, 100 Stat. 3341-352.))

TITLE IV

SEC. 401. ESTABLISHMENT, GENERAL PURPOSES, AND STATUS OF THE TELEPHONE BANK.—(a) There is hereby established a body corporate to be known as the Rural Telephone Bank (hereinafter called the telephone bank).

(b) The general purposes of the telephone bank shall be to obtain an adequate supply of supplemental funds to the extent feasible from non-Federal sources, to utilize said funds in the making of loans under section 408 of this title, and to conduct its operations to the extent practicable on a self-sustaining basis.

(c) the telephone bank shall be deemed to be an instrumentality of the United States, and shall, for the purposes of jurisdiction and venue, be deemed a citizen and resident of the District of Columbia. The telephone bank is authorized to make payments to State, territorial, and local governments in lieu of property taxes upon real property and tangible personal property which was subject to State, territorial, and local taxation before acquisition by the telephone bank. Such payment may be in the amounts, at the times, and upon such terms as the telephone bank deems appropriate but the telephone bank shall be guided by the policy of making payments not in excess of the taxes which would have been payable upon such property in the condition in which it was acquired. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 30; 7 U.S.C. 941.]

SEC. 402. GENERAL POWERS.—To carry out the specific powers herein authorized, the telephone bank shall have power to (a) adopt, alter, and use a corporate seal; (b) sue and be sued in its corporate name; (c) make contracts, leases, and cooperative agreements, or enter into other transactions as may be necessary in the conduct of its business, and on such terms as it may deem appropriate; (d) acquire, in any lawful manner, hold, maintain, use, and dispose of property: Provided, That the telephone bank may only acquire property needed in the conduct of its banking operations or pledged or mortgaged to secure loans made hereunder or in temporary operation or maintenance thereof: Provided further, That any such pledged or mortgaged property so acquired shall be disposed of as promptly as is consistent with prudent liquidation practices, but in no event later than five years after such acquisition; (e) accept gifts or donations of services or of property in aid of any of the purposes herein authorize; (f) appoint such officers, attorneys, agents, and employees, vest them with such powers and duties, fix and pay such compensation to them for their services as the telephone bank may determine; (g) determine the character of and the necessity for its obligations and expenditures, and the manner in which they shall be incurred, allowed, and paid; (h) execute, in accordance with its bylaws, all instruments necessary or appropriate in the exercise of any of its powers; (i) collect or compromise all obligations assigned to or held by it and all legal or equitable rights accruing to it in connection with the payment of such obligations until such time as such obligations may be referred to the Attorney General for suit or collection; and (j) exercise all such other powers as shall be necessary or incidental to carrying out its functions under this title. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 30; 7 U.S.C. 942.]

SEC. 403. SPECIAL PROVISIONS GOVERNING TELEPHONE BANK AS AN AGENCY OF THE UNITED STATES UNTIL CONVERSION OF OWNERSHIP, CONTROL, AND OPERATION.—Until the ownership, control, and operation of the telephone bank is converted as provided in section 410(a) of this title and not thereafter—

(a) The telephone bank shall be an agency of the United States and shall be subject to the supervision and direction of the Secretary of Agriculture (hereinafter called the Secretary): Provided, however, That the telephone bank shall at no time be entitled to transmission of its mail free of postage, nor shall it have the priority of the United States in the payment of debts out of bankrupt, insolvent, and decedents' estates;

(b) in order to perform its responsibilities under this title, the telephone bank may partially or jointly utilize the facilities and the services of employees of the Rural Electrification Administration or of any other agency of the Department of Agriculture, without cost to the telephone bank;

(c) the telephone bank shall be subject to the provisions of the Government Corporation Control Act, as amended (31 U.S.C. 841, et seq.), in the same manner and to the same extent as if it were included in the definition of "wholly owned Government corporation" as set forth in section 101 of said Act (31 U.S.C. 846);

(d) the telephone bank may without regard to the civil service classification laws appoint and fix the compensation of such officers and employees of the telephone bank as it may deem necessary;

(e) the telephone bank shall be subject to the provisions of sections 517, 519, and 2679 of title 28, United States Code. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 31; 7 U.S.C. 943.]

SEC. 404. GOVERNOR.—Subject to the provisions of section 410, the Administrator of the Rural Electrification Administration shall serve as the chief executive officer of the telephone bank (herein called the Governor of the telephone bank). Except as to matters specifically reserved to the Telephone Bank Board in this title, the Governor of the telephone bank shall exercise and perform all functions, powers, and duties of the telephone bank. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 31; 7 U.S.C. 944.]

SEC. 405. BOARD OF DIRECTORS.—(a) The management of the telephone bank, within the limitations prescribed by law, shall be vested in a board of directors (herein called the Telephone Bank Board) consisting of thirteen members.

(b) The Administrator of the Rural Electrification Administration and the Governor of the Farm Credit Administration shall be members of the Telephone Bank Board. Five other members of the Telephone Bank Board shall be designated by the President to serve at his pleasure, three of whom shall be officers or employees of the Department of Agriculture but not officers or employees of the Rural Electrification Administration, and two of whom shall be from the general public and not officers or employees of the Federal Government. The Administrator and other officers and employees of the Department of Agriculture and the Governor of the Farm Credit Administration shall serve as members without additional compensation.

(c) As soon as practicable after enactment of this title, the President of the United States shall appoint six additional members of the initial Telephone Bank Board to be selected from the directors, managers, and employees of any entities eligible to borrow from the telephone bank and of organizations controlled by such entities, with due regard to fair representation of the rural telephone systems of the Nation. The six members thus appointed shall serve until their successors shall have been duly elected in accordance with subsection (d).

(d) Within twelve months following the appointment of the six members of the initial Board as provided in subsection (c), the Governor of the telephone bank shall call a meeting of all entities then eligible to borrow from the telephone bank and organizations controlled by such entities for the purpose of electing members of the Telephone Bank Board. Each such entity and organization shall be entitled to notice of and shall have one noncumulative vote at said meeting. Six members of the Telephone Bank Board shall be elected for a two-year term, three from among the directors, managers, and employees of cooperative-type entities eligible to vote and organizations controlled by such entities, and three from among the managers, directors, and employees of commercial-type entities eligible to vote and organizations controlled by such entities. These six members shall be elected by majority vote of the entities and organizations eligible to vote and such entities and organizations may vote by proxy.

(e) Thereafter, the cooperative-type entities and organizations holding class B and class C stock, voting as a separate class, shall elect three directors to represent their class by a majority vote of the stockholders voting in such class; and the commercial-type entities and organizations holding class B and class C stock, voting as a separate class, shall elect three directors to represent their class by a majority vote of the stockholders voting in such class. Limited proxy voting may be permitted, as authorized by the bylaws of the telephone bank. Cumulative voting shall not be permitted.

(f) Any Telephone Bank Board member may continue to serve after the expiration of the term for which he is elected until his successor has been elected and has qualified. Telephone Bank Board members designated from the general public, pursuant to subsection (b), or appointed or elected pursuant to subsections (c), (d), and (e), shall receive $100 for each day or part thereof, not to exceed one hundred days per year for the first three years after enactment of this title and not to exceed fifty days per year thereafter, spent in the performance of official duties, and shall be reimbursed for travel and other expenses in such manner and subject to such limitations as the Telephone Bank Board may prescribe.

(g) The Telephone Bank Board shall prescribe bylaws, not inconsistent with law, regulating the manner in which the telephone bank's business shall be conducted, its directors and officers elected, its stock issued, held, and disposed of, its property transferred, its bylaws amended, and the powers and privileges granted to it by law and exercised and enjoyed.

(h) The Telephone Bank Board shall meet at such times and places as it may fix and determine, but shall hold at least four regularly scheduled meetings a year, and special meetings may be held on call in the manner specified in the bylaws of the telephone bank.

(i) The Telephone Bank Board shall make an annual report to the Secretary for transmittal to the Congress on the administration of this title IV and any other matters relating to the effectuation of the policies of title IV, including recommendations for legislation. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 32; May 11, 1973, Public Law 93-32, §4, 87 Stat. 70; 7 U.S.C. 945.]

SEC. 406. CAPITALIZATION.—(a) The telephone bank's capital shall consist of capital subscribed by the United States, by borrowers from the telephone bank, by corporations and public bodies eligible to become borrowers from the telephone bank, and by organizations controlled by such borrowers, corporations, and public bodies. Beginning with the fiscal year 1971 and for each fiscal year thereafter but not later than fiscal year 1991, the United States shall furnish capital for the purchase of class A stock and there are hereby authorized to be appropriated such amounts, not to exceed $30,000,000 annually, for such purchases until such class A stock shall equal $600,000,000, Provided, That on or before July 1, 1975, the Secretary shall make a report to the President for transmittal to the Congress on the status of capitalization of the telephone bank by the United States with appropriate recommendations. As used in this section and section 301, the term "net collection proceeds" shall be deemed to mean payments from and after July 1, 1969, of principal and interest on loans heretofore or hereafter made under section 201 of this Act, less an amount representing interest payable to the Secretary of the Treasury on loans to the Administrator for telephone purposes pursuant to section 3(a) of this Act.

(b) The capital stock of the telephone bank shall consist of three classes, class A, class B, and class C, the rights, powers, privileges, and preferences of the separate classes to be as specified, not inconsistent with law, in the bylaws of the telephone bank. Class B and class C stock shall be voting stock, but no holder of said stock shall be entitled to more than one vote, nor shall class B and class C stockholders, regardless of their number, which are owned or controlled by the same person, group of persons, firm, association, or corporation, be entitled in any event to more than one vote.

(c) Class A stock shall be issued only to the Administrator of the Rural Electrification Administration on behalf of the United States in exchange for capital furnished to the telephone bank pursuant to subsection (a), and such class A stock shall be redeemed and retired by the telephone bank as soon as practicable after September 30, 1995, but not to the extent that the Telephone Bank Board determines that such retirement will impair the operations of the telephone bank: Provided, That the minimum amount of class A stock that shall be retired each year after said date shall equal the amount of class B stock sold by the telephone bank during such year. Class A stock shall be entitled to a return, payable from income, at the rate of 2 per centum per annum on the amounts of said class A stock actually paid into the telephone bank. Such return shall be cumulative and shall be payable annually into miscellaneous receipts of the Treasury.

(d) Class B stock shall be held only by recipients of loans under section 408 of this Act. Borrowers receiving loan funds pursuant to section 408(a)(1) or (2) shall be required to invest in class B stock 5 per centum of the amount of loan funds so provided. No dividends shall be payable on class B stock. All holders of class B stock shall be entitled to patronage refunds in class B stock under terms and conditions to be specified in the bylaws of the telephone bank.

(e) Class C stock shall be available for purchase and shall be held only by borrowers, or by corporations and public bodies eligible to borrow under section 408 of this Act, or by organizations controlled by such borrowers, corporations and public bodies, and shall be entitled to dividends in the manner specified in the bylaws of the telephone bank. Such dividends shall be payable only from income and, until all class A stock is retired, shall not exceed the current average rate payable on its telephone debentures.

(f) If a firm, association, corporation, or public body is not authorized under the laws of the jurisdiction in which it is organized to acquire stock of the telephone bank, the telephone bank shall, in lieu thereof, permit such organization to pay into a special fund of the telephone bank a sum equivalent to the amount of stock to be purchased. Each reference in this title to capital stock, or to class B, or class C stock, shall include also the special fund equivalents of such stock, and to the extent permitted under the laws of the jurisdiction in which such organization is organized, a holder of special fund equivalents of class B or class C stock, shall have the same rights and status as a holder of class B or class C stock, respectively. The rights and obligations of the telephone bank in respect of such special fund equivalent shall be identical to its rights and obligations in respect of class B or class C stock, respectively.

(g) After payment of all operating expenses of the telephone bank, including interest on its telephone debentures, setting aside appropriate funds for reserves for losses, and making payment in lieu of taxes, and returns on class A stock as provided in section 406(c), and on class C stock, the Telephone Bank Board shall annually set aside the remaining earnings of the telephone bank for patronage refunds in accordance with the bylaws of the telephone bank. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 33; May 11, 1973, Public Law 93-32, §5, 87 Stat. 70; April 21, 1976, Public Law 94-273, §2(2), 90 Stat. 375; Dec. 22, 1981, Public Law 97-98, Title XVI, §1607, 95 Stat. 1347; 7 U.S.C. 946.]

SEC. 407. BORROWING POWER.—(a) The telephone bank is authorized to obtain funds through the public or private sale of its bonds, debentures, notes, and other evidences of indebtedness (herein collectively called telephone debentures). Telephone debentures shall be issued at such times, bear interest at such rates, and contain such other terms and conditions as the Telephone Bank Board shall determine: Provided, however, That the amount of the telephone debentures which may be outstanding at any one time pursuant to this section shall not exceed twenty times the paid-in capital and retained earnings of the telephone bank. Telephone debentures shall not be exempt, either as to principal or interest, from any taxation now or hereafter imposed by the United States, by any territory, dependency, or possession thereof, or by any State or local taxing authority. Telephone debentures shall be lawful investments and may be accepted as security for all fiduciary, trust, and public funds, the investment or deposit of which shall be under the authority and control of the United States or any officer or officers thereof.

(b) The Telephone Bank is also authorized to issue telephone debentures to the Secretary of the Treasury, and the Secretary of the Treasury may in his discretion purchase any such debentures, and for such purpose the Secretary of the Treasury is authorized to use as a public debt transaction the proceeds of the sale of any securities hereafter issued under the Second Liberty Bond Act, as now or hereafter in force, and the purposes for which securities may be issued under the Second Liberty Bond Act as now or hereafter in fore are extended to include such purchases. Each purchase of telephone debentures by the Secretary of the Treasury under this subsection shall be upon such terms and conditions as to yield a return at a rate not less than a rate determined by the Secretary of the Treasury, taking into consideration the current average yield on outstanding marketable obligations of the United States of comparable maturity. The Secretary of Treasury may sell, upon such terms and conditions and at such price or prices as he shall determine, any of the telephone debentures acquired by him under this subsection. All purchases and sales by the Secretary of the Treasury of such debentures under this subsection shall be treated as public debt transactions of the United States.

(c) Purchases and resales by the Secretary of the Treasury as authorized in subsection (b) of this section shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by statute on expenditures and net lending (budget outlays) of the United States.

[May 7, 1971, Public Law 92-12, §2, 85 Stat. 34; June 30, 1972, Public Law 92-324, §2, 86 Stat. 390; May 11, 1973, Public Law 93-32, §§6, 7, 87 Stat. 70; 7 U.S.C. 947.]

SEC. 408. LENDING POWER.—(a) The Governor of the telephone bank is authorized on behalf of the telephone bank to make loans, in conformance with policies approved by the Telephone Bank Board, to corporations and public bodies which have received a loan or loan commitment pursuant to section 201 of this Act, or which have been certified by the Administrator to be eligible for such a loan or loan commitment, (1) for the same purposes and under the same limitations for which loans may be made under section 201 of this Act, (2) for the purposes of financing, or refinancing, the construction, improvement, expansion, acquisition, and operation of telephone lines, facilities, or systems, in order to improve the efficiency, effectiveness, or financial stability of borrowers financed under sections 201 and 408 of this Act, and (3) for the purchase of class B stock required to be purchased under Section 406(d) of this Act but not for the purchase of class C stock, subject, as to the purposes set forth in (2) hereof, to the following provisos: That in the case of any such loan for the acquisition of telephone lines, facilities, or systems, the acquisition shall be approved by the Secretary, the location and character thereof shall be such as to improve the efficiency, effectiveness, or financial stability of the telephone system of the borrower, and in respect of exchange facilities for local services, the size of each acquisition shall not be greater than the borrower's existing system at the time it receives its first loan from the telephone bank, taking into account the number of subscribers served, miles of line, and plant investment. Loans and advances made under this section shall not be included in the totals of the budget of the United States Government and shall be exempt from any general limitation imposed by statute on expenditures and net lending (budget outlays) of the United States.

(b) Loans under this section shall be on such terms and conditions as the Governor of the telephone bank shall determine, subject, however, to the following restrictions:

(1) All loans made under this section shall be fully amortized over a period not to exceed fifty years.

(2) Funds to be loaned under this Act to any borrower shall be loaned under this section in preference to section 201 if the borrower is eligible for such a loan and funds are available therefor. Notwithstanding the foregoing or any other provision of law, all loans made pursuant to this Act for facilities for telephone systems with an average subscriber density of three or fewer per mile shall be made under section 201 of this Act; but this provision shall not preclude the making of such loans from the telephone bank at the election of the borrower.

(3) Loans under this section shall bear interest at the "cost of money rate." The cost of money rate is defined as the average cost of moneys to the telephone bank as determined by the Governor, but not less than 5 per centum per annum.

(4) Loans shall not be made under this section unless the Governor of the telephone bank finds and certifies that in his judgment (i) the security therefor is reasonably adequate and such loan will be repaid within the time

agreed, and (ii) the borrower has the capability of producing net income or margins before interest at least equal to 150 per centum of the interest requirements on all of its outstanding and proposed loans, or such higher per centum as may be fixed from time to time by the Telephone Bank Board in order to allocate available funds equitably among borrowers or to improve the marketability of the telephone debentures: Provided, however, That the Governor of the telephone bank may waive the requirement of (ii) above in any case if he shall determine (and set forth his reasons therefor in writing) that this requirement would prevent emergency restoration of the borrower's system or otherwise result in severe hardship to the borrower.

(5) No loan shall be made in any State which now has or may hereafter have a State regulatory body having authority to regulate telephone service and to require certificates of convenience and necessity to the applicant unless such certificate from such agency is first obtained. In a State in which there is no such agency or regulatory body legally authorized to issue such certificates to the applicant, no loan shall be made under this section unless the Governor of the telephone bank shall determine (and set forth his reasons therefor in writing) that no duplication of lines, facilities, or systems, providing reasonably adequate services will result therefrom.

(6) As used in this section, the term telephone service shall have the meaning prescribed for this term in section 203(a) of this Act, and the term telephone lines, facilities, or systems shall mean lines, facilities, or systems used in the rendition of such telephone service.

(7) No borrower of funds under section 408 of this Act shall, without approval of the Governor of the telephone bank under rules established by the Telephone Bank Board, sell or dispose of its property, rights, or franchises, acquired under the provisions of this Act, until any loan obtained from the telephone bank, including all interest and charges, shall have been repaid.

(c) The Governor of the telephone bank is authorized under rules established by the Telephone Bank Board to adjust, on an amortized basis, the schedule of payments of interest or principal of loans made under this section upon his determination that with such readjustment there is reasonable assurance of repayment: Provided, however, That no adjustment shall extend the period of such loans beyond fifty years. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 35; May 11, 1973, Public Law 93-32, §§8, 9, 87 Stat. 70; 7 U.S.C. 948.]

SEC. 409. TELEPHONE BANK RECEIPTS.—Any receipts from the activities of the telephone bank shall be available for all obligations and expenditures of the telephone bank. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 36; 7 U.S.C. 949.]

SEC. 410. CONVERSION OF OWNERSHIP, CONTROL AND OPERATION OF TELEPHONE BANK.—(a) Whenever fifty-one per centum of the maximum amount of class A stock issued to the United States and outstanding at any time after September 30, 1985, has been fully redeemed and retired pursuant to section 406(c) of this title—

(1) the powers and authority of the Governor of the telephone bank granted to the Administrator of the Rural Electrification Administration by this title IV shall vest in the Telephone Bank Board, and may be exercised and performed through the Governor of the telephone bank, to be selected by the Telephone Bank Board, and through such other employees as the Telephone Bank Board shall designate;

(2) the five members of the Telephone Bank Board designated by the President pursuant to section 405(b) shall cease to be members, and the number of Board members shall be accordingly reduced to eight unless other provision is thereafter made in the bylaws of the telephone bank;

(3) the telephone bank shall cease to be an agency of the United States, but shall continue in existence in perpetuity as an instrumentality of the United States and as a banking corporation with all of the powers and limitations conferred or imposed by this title IV except such as shall have lapsed pursuant to the provisions of this title.

(b) When all class A stock has been fully redeemed and retired, loans made by the telephone bank shall not continue to be subject to the restrictions prescribed in the provisos to section 408(a)(2).

(c) Congress reserves the right to review the continued operations of the telephone bank after all class A stock has been fully redeemed and retired. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 36; 7 U.S.C. 950; April 21, 1976, Public Law 94-273, §2(2), 90 Stat. 375; 7 U.S.C. 950.]

SEC. 411. LIQUIDATION OR DISSOLUTION OF THE TELEPHONE BANK.—In the case of liquidation or dissolution of the telephone bank, after the payment or retirement, as the case may be, first, of all liabilities; second, of all class A stock at par; third, of all class B stock at par; fourth , of all class C stock at par; then any surpluses and contingency reserves existing on the effective date of liquidation or dissolution of the telephone bank shall be paid to the holders of class A and class B stock issued and outstanding before the effective date of such liquidation or dissolution, pro rata. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 37; 7 U.S.C. 950a.]

SEC. 412. BORROWER NET WORTH.—Except as provided in subsection (b)(2) of section 408, notwithstanding any other provision of law, a loan shall not be made under section 201 of this Act to any borrower which during the immediately preceding year had a net worth in excess of 20 per centum of its assets unless the Administrator finds that the borrower cannot obtain such a loan from the telephone bank or from other reliable sources at reasonable rates of interest and terms and conditions. [May 7, 1971, Public Law 92-12, §2, 85 Stat. 37; 7 U.S.C. 950b.]

DEFERRED AMENDMENTS TO THE GOVERNMENT CORPORATION CONTROL ACT

Sections 4 and 5 of the Act of May 7, 1971 (Public Law 92-12; 85 Stat. 37) establishing the Rural Telephone Bank, included the following deferred amendments to the Government Corporation Control Act:

SEC. 4. Section 201 of the Government Corporation Control Act, as amended (31 U.S.C. 856), is amended, effective when the ownership, control, and operation of the telephone bank is converted as provided in section 410(a) of the Rural Electrification Act of 1936, as amended, by striking "and" immediately before "(5)" and by inserting, "and (6) the Rural Telephone Bank" immediately before the period at the end.

SEC. 5. The second sentence of subsection (d) of section 303 of the Government Corporation Control Act, as amended (31 U.S.C. 868), is amended, effective when the ownership, control, and operation of the telephone bank is converted as provided in section 410(a) of the Rural Electrification Act of 1936, as amended, by inserting "the Rural Telephone Bank," immediately following the words "shall not be applicable to."

STATEMENTS OF CONGRESSIONAL POLICY

RURAL TELEPHONE LOANS

The rural telephone legislation enacting clause contains the following statement of Congressional policy:

. . . it is hereby declared to be the policy of the Congress that adequate telephone service be made generally available in rural areas through the improvement and expansion of existing telephone facilities and the construction and operation of such additional facilities as are required to assure the availability of adequate telephone service to the widest practicable number of rural users of such service. In order to effectuate this policy, the Rural Electrification Act of 1936 is amended as hereinafter provided. [Oct. 28, 1949, ch. 776, §1, 63 Stat. 948; 7 U.S.C. 921.]

RURAL TELEPHONE BANK

The telephone bank legislation enacting clauses contain the following statement of Congressional policy:

. . . it is hereby declared to be the policy of the Congress that the growing capital needs of the rural telephone systems require the establishment of a rural telephone bank which will furnish assured and viable sources of supplementary financing with the objective that said bank will become an entirely privately owned, operated, and financed corporation. The Congress further finds that many rural telephone systems require financing under the terms and conditions provided in title II of the Rural Electrification Act of 1936, as amended. In order to effectuate this policy, the Rural Electrification Act of 1936, as amended [7 U.S.C. 921-924], is amended as hereinafter provided. [May 7, 1971, Public Law 92-12, 85 Stat. 29; 7 U.S.C. 921a].

. . . it is hereby declared to be the policy of the Congress that the Rural Telephone Bank should have the capability of obtaining adequate funds for its supplementary financing program at the lowest possible costs. In order to effectuate this policy, it will be necessary to expand the market for debentures to be issued by the Telephone Bank. The Rural Electrification Act of 1936, as amended [7 U.S.C. 901-950(b)], is therefore further amended as hereinafter provided. [June 30, 1972, Public Law 92-324, §1, 86 Stat. 390; 7 U.S.C. 921b.]

United States
Department of
Agriculture

Rural
Electrification
Administration

Revised
December 1986

A Brief History of the Rural Electric and Telephone Programs

CHRONOLOGY OF LEGISLATIVE CHANGES
Rural Electrification Act of 1936
7 U.S.C. 901-950b

1935	The Rural Electrification Administration was created by Executive Order 7037 of May 11 under authority of the Emergency Relief Appropriation Act of 1935, approved April 8, 1935 (49 Stat. 115).
1936	Statutory provision for the Agency was made in the Rural Electrification Act of 1936, approved May 20 (49 Stat. 1363; 7 U.S. Code, Chapter 31).
1938	Title IV of the Work Relief and Public Works Appropriation Act of 1938, approved June 21 ("RE Act of 1938," 52 Stat. 818) authorized further borrowing from the Reconstruction Finance Corporation and added a requirement that borrowers from REA agree to use materials and supplies produced in the United States.
1939	REA became part of the Department of Agriculture under Reorganization Plan II, effective July 1.
1944	Title V of the Department of Agriculture Organic Act of 1944, approved September 21 (58 Stat. 739; 7 U.S.C. 903 - 905; 915) liberalized the terms of REA loans and removed the time limitation from its lending program.
1944	On December 23, the Rural Electrification Act was further amended to authorize REA to refinance certain rural electrification obligations owed to the Tennessee Valley Authority (58 Stat. 925; 7 U.S.C. 904).
1947	The Department of Agriculture Appropriation Act, 1948, approved July 30, (61 Stat. 546; 7 U.S.C. 903) further amended the Rural Electrification Act by transferring from the Reconstruction Finance Corporation to the Secretary of the Treasury the authority to make loans to REA.
1948	On June 29, the Rural Electrification Act was again amended to authorize REA to refinance certain additional rural electrification obligations owed to the Tennessee Valley Authority (62 Stat. 1070; 7 U.S.C. 904).
1949	On October 28, the Rural Electrification Act was further amended to authorize REA to make loans for the purpose of furnishing and improving rural telephone service (63 Stat. 948; 7 U.S.C. 901 - 914; 922 - 924).
1955	On June 15, the Rural Electrification Act was amended by revising the formula governing the allotment of electrification loan funds (69 Stat. 131; 7 U.S.C. 903; 904).
1962	On October 23, the Rural Electrification Act was amended by broadening the definition of telephone service (76 Stat. 1140; 7 U.S.C. 924).
1971	On May 7, the Rural Electrification Act was amended to establish a Rural Telephone Account and the Rural Telephone Bank (85 Stat. 29; 7 U.S.C. 903; 922; 931; 932; 941 - 950b).

1972 On June 30, the Rural Electrification Act was amended to authorize the Secretary of the Treasury to purchase Telephone Bank debentures (86 Stat. 390; 7 U.S.C. 947).

1973 On May 11, the Rural Electrification Act was amended to establish a revolving fund for insured and guaranteed loans under Title III (87 Stat. 65; 7 U.S.C. 903; 931 - 940; 945 - 948).

1975 On November 4, the Rural Electrification Act was amended to expressly authorize the assignment of REA guarantees to the extent provided in contract of guarantee, to clarify the incontestability of the Government guarantee, and to specifically require justification of budget estimates (89 Stat. 677; 7 U.S.C. 906; 936; and 938).

1976 On April 21, the "Fiscal Year Adjustment Act," amended the Rural Electrification Act to reflect necessary changes in laws because of the October-September fiscal year (90 Stat. 375; 31 U.S.C. 910; 946; 950).

1976 On October 20, the Rural Electrification Act was amended to correct unintended inequities in the interest rate criteria and to transfer the unobligated balance of the 1973 loan authorizations to the Rural Electrification and Telephone Revolving Fund (90 Stat. 2701; 7 U.S.C. 931; 935).

1977 On August 4, the "Department of Energy Organization Act" added Section 16 to Title I, to require the Administrator, when making or guaranteeing generation or transmission loans, to consider general criteria published by the Secretary of Energy (91 Stat. 608; 7 U.S.C. 916).

1981 On August 13, the "Omnibus Reconciliation Act of 1981," amended the Rural Electrification Act: (1) to establish a 5 percent interest rate, with certain exceptions, for loans from the revolving fund; and (2) to require the Federal Financing Bank to make a loan under an REA guarantee if requested by a borrower with such a guarantee (95 Stat. 379; 7 U.S.C. 935 - 937).

1981 On December 22, the "Agriculture and Food Act of 1981," amended the Rural Electrification Act to extend for another 10 years the authorization for Federal stock purchases in the Rural Telephone Bank (95 Stat. 1347; 7 U.S.C. 946).

1986 On October 21, the "Omnibus Budget Reconciliation Act of 1986," amended the Rural Electrification Act to authorize the prepayment of certain loans made by the Federal Financing Bank and guaranteed by the Rural Electrification Administration. The Act further provides for sale or prepayment of direct or insured loans by the borrower through September 30, 1987. (___ Stat. ___ ; 7 U.S.C. 936.) *

1986 On October 30, an act "Making Continuing Appropriations For Fiscal Year 1987, And For Other Purposes," amended the Rural Electrification Act to establish a privatization demonstration program in the State of Alaska to allow electric and telephone borrowers under the Rural Electrification Act to prepay with private capital all their loans guaranteed or otherwise made by and through the Rural Electrification Administration providing certain conditions are met. (___ Stat. ___ ; 7 U.S.C. ___.) *

* Complete legislative citations were not available at the time of publication.

'This Report Can Be Read In 12 Minutes'

WHY RURAL ELECTRIFICATION IMPORTANT

Agriculture is a major problem. It must evolve toward the status of a dignified and self-sustaining sector of our social life. So agriculture demands all the *pertinent* production and comfort facilities now available to industry. It must not be conceived, as heretofore, a marginal sector of life. Food and material industries are basic and entitled to corresponding consideration.

Emergence from depression compels a program of public works—i.e. of collective assistance to works having public service character. Those should be favored which (1) contribute to social life, (2) require united investment beyond interest and capacity of private industry. Rural electrification inherently meets these specifications and technically demands large-scale development instead of endless piecemeal extensions.

The reflex influence of widespread rural electrification on the industry providing electric power and light would be enormous. The addition of a small increment of rural extensions has no measurable influence; but large-scale additions of this character would have large measurable and favorable influence on volume, load and demand factors, and on cost per unit of capital investment. The influence on the general rate level and on regulation would be enormous. This development would probably afford the beginnings of real control of the electric industry.

WHAT IS THE TASK?

Of the six million farms in the United States over 800,000 are "electrified." But only about 650,000 have "high line" service. The balance have individual Delco plants, expensive to operate and limited as to use. Over 5,000,000 farms are entirely without electric service. Estimates as to the number of these which can now economically be given service range from one to three million.

Unless the Federal government, assisted in particular instances by State and local agencies, assumes an active leadership and complete control this task can be accomplished. Except in sporadic instances, such as where power is a by-product of an irrigation or flood control project, rural electrification is now the responsibility solely of the private interests.

Electrical systems are developed by attaching new construction to that already existent, in large measure because of technical considerations. But it is done also for political advantage—to secure exclusive control of a given territory. So strong is this urge for continuity—for having all of a company's territory and lines tied into an integrated system—that in Pennsylvania to connect widely separated areas under common ownership there are strips of chartered territory 200 feet wide where for mile after mile transmission lines are carried without the right of the owner to take off current. Discontinuity or division of the property into isolated segments is taboo within any given system. Hence no private company is likely to create a new center of power production simply in order to serve a rural area.

EXISTING RURAL SERVICE CONSTITUTES THE FRINGE OF THE PRESENT SYSTEM

One reason why only about 10 per cent of the nation's farms are electrified is that at present electric power is largely generated in central stations usually at considerable distance from farming areas. The greater this distance the greater the investment needed to reach the rural consumer and the greater are the energy losses en route. These expenditures in farming areas are relatively less profitable unless rural rates are made high enough. Unlike the railroads or manufacturers the utilities usually require farmers to advance a portion, or all, of the extra investment. Sometimes it is paid in monthly installments over a period of years. . . .

In many cases farm areas can be supplied more economically by small local stations (operated by Diesel oil engine, by water power or even by coal or lignite burning stations—if there is a mine nearby) as the lower cost of generation in the [illegible] over-balanced by the smaller investment. . . .

The essential elements of a rural electric system are simple and easily manipulated. Distribution involves only poles, wires, transformers and meters. Even the generating units now obtainable require a minimum of attention and are all but fool proof. In Ireland, Norway, New Zealand, Bavaria, Ontario, Switzerland, Alsace and elsewhere a very large part of the rural population have the benefit of electric service.

ADVANTAGES OF RURAL ELECTRIFICATION

Both for the farmer and his wife the introduction of electricity goes a long way toward the elimination of drudgery. The electric refrigerator will effect a considerable change in diet—more fresh vegetables and less salt and cured meats. The inside bathroom, made possible by automatic electric pumping, brings to the farm one of the major comforts of urban life. Electricity will be a strong lever in keeping the boys and girls on the farm—in encouraging reading and other social and cultural activities. As we go into "part-time agriculture" the demand for rural electrification will probably become more insistent.

"The possibility of diversifying our industrial life by sending a fair proportion of it into the rural districts is one of the definite possibilities of the future. Cheap electric power, good roads and automobiles make such a rural industrial development possible." (Address by President Roosevelt at French Lick, Indiana, June, 1931)

Looking even further ahead, widely distributed electricity will become a requisite in the anti-erosion campaign. The tendency must be to discourage corn and cotton and other crops requiring constant harrowing and disturbance of the surface soil, especially in sections having heavy downpours in contrast to a well distributed rainfall. In such regions we must encourage a sod agriculture—meadow land, alfalfa and other legumes—and this means electricity for *moderate* irrigation, for dairying and even for artificially curing grass otherwise uncurable in such climates. . . .

HOW MAKE THE START

Having recognized the advantages of rural electric service and reached the conclusion that only under Governmental leadership and control is any considerable electrification of "dirt farms" possible, the obvious obligation is to get it done. Perhaps the start should be through an allotment of $25,000 or $50,000 to make a survey. But an allotment of $100,000,000 actually to build independent self-liquidating rural projects would exert a mighty influence. . . .

This proposal does not involve competition with private interests as in the case where municipal plants are financed. *This plan calls for entering territory not now occupied* and not likely to be occupied to any considerable extent by private interests. The proposal has only become possible recently through the marvelous development of the Diesel engine.

SOURCE OF POWER FOR RURAL SERVICES

In the public development as here outlined, whether (a) to connect up with existing private or public generating or transmission systems (where such facilities are available) or (b) to create an independent source of power is a question of policy or cost or convenience, or all three. Perhaps when first getting under way the preference would be given to connecting up with existing lines where fair prices for current can be secured. Independent sources of power might well be kept in the background.

But if it is decided to create a new source of power there are everywhere and always available Diesel engine installations and frequently local, or reachable, hydro-electric development sites. The electric current itself, in any case, can be made available to the rural population at a figure considerably below what is charged for it on existing rural lines. We here assume that the current can be made available at 2 cents or less per K.W.H.

Continued on page 62

DISTRIBUTION LINES

The cost of a mile of "high wire" line naturally depends on a number of variables, most important among them under normal conditions being the number of customers per mile and the method followed in doing the work, whether for instance it is piecemeal or large-scale construction. This cost of the line with transformers and meters included for one to three customers will range from $500 to $800 the mile. To amortize this cost in twenty years at 4 per cent involves a cost to each of three customers on a mile of line of about one dollar a month.

LARGE USE THE KEY TO LOW RATES

Real rural electrification implies large average use of current, for without large use rates cannot be made low enough to effect the coveted social advantages. Gifford Pinchot once said:

"Electricity in the home and on the farm must be made free—of course with a freedom of its own. We must work away from the point of view where we use it sparingly. Of course we should not waste it. But it is such a low-cost commodity that we must learn to substitute it for human labor. In this direction lies national economy. No intelligent person spares the use of water as a means to comfort and cleanliness—even though it costs enough to warrant its being metered. Water as a factor in our lives is free—not as free as air—but so free as to permit us to partake fully of its benefits."

The electrical industry because it secures over 60 per cent of its revenue from small consumers is all but stymied by its high-rate low-use situation. In planning for national rural electrification we must do everything to encourage the largest possible average use. Large average use, especially in the initial stages, seemingly requires a planning and investment beyond the capacity of a private company to initiate. Perhaps only the power and force of the Government can master the initial problem.

RATES

Both the form of electric rate schedules and the rates themselves vary widely throughout the United States. It has only [illegible] that most of these variations have little relation to cost. There will be variations in the cost of the rural electric service proposed. But how many of them are sufficiently important to recognize in rate variations is another matter. It is believed that charges as follows will quite generally cover costs for normal use:

A. $1.00 to $1.25 a month Connection Charge. Note: This is to pay for the line. Whenever the individual customer's share of the cost of the line is paid off this charge stops.

B. $1.00 a month Minimum Charge—includes 10 K.W.H.

C. 3 cents per K.W.H. for next 40 K.W.H.

D. 2 cents per K.W.H. balance

It would appear that under the expected consumptions the present average rural rate will certainly be cut in half.

DISTANCE BETWEEN FARMS

In the absence of a survey we can only approximate the mileage of line required to connect up any given number of customers. By a comparison state by state of the mileage of roads of all classes as furnished by the Bureau of Public Roads with the Census figures for the number of farms, the average number of farms per mile of road seems to vary from two to five to the mile. As the tendency will be first to electrify the most advantageous locations, three farms on the average to the mile can be used in making our estimates.

FINANCING OF LINES

If we connect up 500,000 farms not now having "high line" service we will more than double the number of connected "dirt farms" because a considerable percentage of the farms included in the Census figures are located in the neighborhood of large cities and are "farms" only in a very technical sense. The whole capital cost of rural electric service is divided between—

a. the cost of the distribution lines; and

b. the cost of the generating units required for areas which cannot be furnished current by the private companies.

For estimating purposes we have chosen units of 500,000 farms.

Mr. Otto M. Rau in estimates finds the costs of building lines for this number to be $112,000,000 or $225 the farm.

The Fairbanks, Morse Co. have given us an estimate of $262,000 for a generating unit to supply 1500 farms within a radius of ten miles. In many situations of course no new generating equipment will be needed. But to get the complete picture we can assume the wholly unlikely outcome that company service is nowhere available and that to serve a population of 500,000 divided into units of 1500 customers each, 333 such plants will be required at a total cost of $87,000,000.

Therefore to connect up 500,000 farms not now having service and providing current from power sources to be created anew would mean a capital outlay of $200,000,000 or $400 the farm. If one half of these farms could get current from existing sources the total outlay would be $150,000,000, or $300 the farm.

FEDERAL LEGAL SITUATION

It may be wise temporarily to utilize emergency legislation and funds to get this work started. However, there would appear to be no legal objection to organizing the work upon a permanent basis. A system of banks established expressly for the purpose could be set up, similar to existing Acts for the extension of agricultural credits, such as the Federal Land Bank Act of 1916. If it is desirable to operate by direct loans without the use of a special banking system, authority is found in the appropriating power of Congress under the so-called "general welfare" clause of the Constitution.

STATE LEGISLATIVE SITUATION

Present legislation in some states will act as a practical bar to rural electrification along the lines proposed. This is true in such states as Illinois and Pennsylvania which have no statutes authorizing the creation of power districts. Even here, however, the plan might be put into effect through farmers' mutuals operating without profit. In other states such as California and Nebraska adequate legislation exists and one hundred per cent cooperation would be possible.

A part of the plan would be to set up uniform state legislation and have the farmer-folk within the several states press for its adoption. Provision should be made for the incorporation of rural electric districts upon the favorable vote of a sufficient majority of inhabitants and/or of the owners of a sufficient majority of the acreage. Such districts should have power to acquire, construct and operate electric plants and to furnish electric service to their inhabitants and to others nearby. Provision should also be made for the organization of consumers' mutual electric companies. These electric service districts and consumers' mutual companies should receive Federal and/or State aid in the form of expert engineering, accounting and management advice, as farmers are now advised by experts in farm management, farm accounting, domestic science, farm crops, animal husbandry, fruit raising and the like.

Regions conspicuously without service should be investigated for determination of and report upon the advisability of Federal and/or State contributions toward the cost of rural lines such as are made by the Provincial Government of Ontario and in several European countries, and, if advisable, the methods to be followed in making such contributions.

THE ANSWER—A RURAL ELECTRIFICATION AGENCY

It is proposed to set up in the Department of the Interior—a section, manned by socially minded electrical engineers, who, having standardized rural electrification equipment, will cooperate with groups within the several states in planning appropriate developments. In many instances no Federal financing will be required. Where such schemes are self-liquidating financing in whole or in part may be provided. The possible bearing of proposed municipal power developments on rural electrification might properly influence allotments during the life of PWA. In fact the proposed Rural Electrification Section should take an active hand in planning out the rural use of current from such developments as Grand Coulee, Ft. Peck, Bonneville, Boulder Dam, Tygart Dam, etc. Cooperation with the Electric Home and Farm Authority would be an important function of the Rural Electrification Section.

—*MORRIS LLEWELLYN COOKE*

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

June 13, 1977
Supersedes 2/19/71

REA BULLETIN 20-2

SUBJECT: Electric Loan Policies and Application Procedures

I. General:

A. This bulletin sets forth REA policy and procedures concerning electrification loans under the Rural Electrification Act (the Act).

B. REA Bulletin 20-22, Guarantee of Loans for Bulk Power Supply Facilities, sets forth REA policies and requirements concerning loan guarantees for the financing of bulk power supply facilities under Section 306 of the Rural Electrification Act.

II. REA Loans - General Purposes and Eligibility: Generally, rural electrification loans made by REA are insured loans made under Section 305 of the Act for the purposes and on the terms and conditions set forth in Section 4 of the Act. Section 4 provides in part:

A. "The Administrator is authorized.....to make loans for rural electrification to persons, corporations, States, Territories, and subdivisions and agencies thereof, municipalities, peoples' utility districts and cooperative, nonprofit, or limited-dividend associations organized under the laws of any State or Territory of the United States, for the purpose of financing the construction and operation of generating plants, electric transmission and distribution lines or systems for the furnishing of electric energy to persons in rural areas who are not receiving central station service....."

B. ".....the Administrator, in making such loans shall give preference to States, Territories, and subdivisions and agencies thereof, municipalities, peoples' utility districts, and cooperative, nonprofit, or limited-dividend associations, the projects of which comply with the requirements of this Act."

C. "Such loans shall be on such terms and conditions relating to the expenditure of the moneys loaned and the security therefor as the Administrator shall determine and may be made payable in whole or in part out of the income: Provided further, That all such loans shall be self-liquidating within a period of not to exceed thirty-five years....."

D. "Loans.....shall not be made unless the Administrator finds and certifies that in his judgment the security therefor is reasonably adequate and such loans will be repaid within the time agreed."

E. ".....no loan for the construction, operation, or enlargement of any generating plant shall be made unless the consent of the State authority having jurisdiction in the premises is first obtained."

III. Revolving Fund - Insured Loans: Sections 301 and 302 establish a revolving fund in the Treasury of the United States the assets of which are available for the purpose of providing funds for insured loans under Section 305 of the Act. Section 305 provides in part:

A. "The Administrator is authorized to make insured loans.....to the full extent of the assets of the Rural Electrification and Telephone Revolving Fund, subject only to limitations as to amounts authorized for loans and advances as may be from time to time imposed by the Congress of the United States....."

B. "Loans made under this section shall be insured by the Administrator when purchased by a lender. As used in this Act, an insured loan is one which is made, held and serviced by the Administrator, and sold and insured by the Administrator hereunder. Such loans shall be sold and insured by the Administrator without undue delay."

C. "Insured loans.....shall bear interest at either 2 per centum per annum (hereinafter called the "special rate"), or 5 per centum per annum (hereinafter called the "standard rate"). Loans bearing the special rate shall be available only for an electric.....borrower which.....had at the end of the most recent calendar year ending at least six months before approval of the loan, an average consumer density of two or fewer per mile or an average adjusted plant revenue ratio of over 9.0, such ratio being a simple average of the ratios obtained by dividing the sum of its distribution plant and general plant by its annual gross revenue less cost of power for that calendar year and the two immediately preceding calendar years. As used in this subsection the sum of distribution plant and general plant shall be the total of the amounts shown in accounts numbered 360 through and including 399 of the uniform system of accounts approved, as of the effective date of this amendment, by the Administrator, for use by Rural Electrification Administration borrowers; gross revenue shall be the amount shown in account numbered 400 of said system of accounts; and the cost of power shall be the total of amounts shown in accounts numbered 500 through and including 573 of said system of accounts as the same is constituted: Provided, however, That the Administrator may, in his sole discretion, make a loan to a borrower at the special rate if he finds that the borrower:

"(A) has experienced extenuating circumstances or extreme hardship; or

"(B) cannot, in accordance with generally accepted management and accounting principles, produce net income or margins before interest at least equal to 150 per centum of its total interest requirements on all outstanding and proposed loans with an interest rate greater than 2 per centum per annum on the entire current loan, and still meet the objectives of the Act, or

"(C) cannot, in accordance with generally accepted management and accounting principles and without an excessive increase in the rates charged by such borrowers to their consumers or subscribers, provide service consistent with the objectives of the Act."

IV. Other Financing: Section 307 of the Act provides in part: "When it appears to the Administrator that the loan applicant is able to obtain a loan for part of his credit needs from a responsible cooperative or other credit source at reasonable rates and terms consistent with the loan applicant's ability to pay and the achievement of the Act's objectives, he may request the loan applicant to apply for and accept such a loan concurrently with a loan insured at the standard rate....."

V. Definition of Rural Area: Section 13 of the Act provides in part: "As used in this Act the term 'rural area' shall be deemed to mean any area of the United States not included within the boundaries of any city, village, or borough having a population in excess of fifteen hundred inhabitants, and such term shall be deemed to include both the farm and nonfarm population thereof....."

VI. General REA Policies:

A. Borrowers are encouraged to use self-generated funds to minimize their requirements for debt capital. Borrowers which can borrow from other sources are encouraged to do so, and may be required to obtain non-REA financing as a supplement to financing available from REA. (See Section IV above and REA Bulletin 20-14 on "Supplemental Financing.")

B. In accordance with the objectives of the Act and the obligations undertaken in the loan contract, borrowers are obligated to provide electric service on an area coverage basis to the maximum practicable extent. (See REA Bulletin 112-3.)

C. Loan applications from distribution borrowers for distribution or transmission facilities generally should include the amount of new loan funds required during the next two years. The proposed loan may be revised downward by REA when necessary to allocate available loan funds to meet borrowers' priority needs.

D. Loan applications from power supply borrowers for transmission facilities, where no generating unit is included, should not exceed the amount of new loan funds required during the next three years.

E. Loan applications from distribution or power supply borrowers for generation facilities should include the amount of new loan funds required for transmission facilities to deliver the power from the generating units as needed to support the feasibility of the loan.

F. In reviewing loan applications, the amount and management of a borrower's general funds will be considered by REA on the basis of the guidelines contained in REA Bulletin 1-7, General Funds.

VII. Facilities and Other Items Which May be Financed: REA loans may be approved for:

A. Distribution Facilities: The construction of new rural distribution facilities or systems and the net cost of system improvements to meet load growth requirements or improve the quality of electric service. The net cost of system improvements means the cost of construction plus the cost of removal of any property retired, less the salvage value of any materials or equipment recovered in connection with the property retirement. System improvements are defined as the changes or additions in electric plant facilities to improve the quality of electric service or increase the quantity of electric power available to Act beneficiaries. Changes or additions as used in the above definition include replacing units with like units or larger units and rearranging or retiring conductor when such changes are associated with and are a necessary part of a system improvement.

B. Generation and Transmission Facilities:

1. The initial construction of generation facilities by distribution or power supply borrowers, and of transmission facilities by power supply borrowers, only under the following conditions:

a. Where no adequate and dependable source of power is available to meet the consumers' needs, or

b. Where the rates offered by existing power sources would result in a higher cost of power to the consumer than the cost from facilities financed by REA, and the amount of the power cost savings that would result from the REA-financed facilities bears a significant relationship to the amount of the proposed REA loan.

2. Supplemental loans for these purposes, for the net cost of system improvements as defined in A above, and for the construction of transmission facilities by distribution borrowers. Applications for such financing will be considered and evaluated in terms of whether the proposed additional facilities constitute the most effective and economical arrangement for meeting the increasing power requirements of the consumers. (Also see REA Bulletin 20-6.)

C. Headquarters Facilities: The purchase, remodeling, or construction and related costs of headquarters facilities required for the operation of the borrower's system. (Also see REA Bulletin 86-3.)

D. Acquisitions: The purchase, rehabilitation and integration of existing electric facilities where the acquisition of such facilities is an incidental and necessary means of providing service to persons in rural areas who are not receiving central station service. (Also see REA Bulletin 27-1.)

E. General Plant Equipment: The purchase of office, transportation, communication, and working equipment, if requested by the applicant and found necessary.

F. Interest: Payments of interest during the period preceding the first scheduled principal payment or for a period not to exceed five years, whichever is the shorter, if requested by the borrower and found necessary. (Also see REA Bulletin 20-9.)

G. Operations: Working capital required for the initial operation of the borrower's system or for the protection of outstanding REA loans.

H. Ordinary Replacements: The excess of the total cost of ordinary replacements over the original cost of the production, transmission, or distribution plant being replaced, if requested by the applicant and found necessary. For this purpose "ordinary replacements" means replacing units of plant with like or similar units when made necessary by normal wear and tear, damage beyond repair, or obsolescence of the facilities. In order to qualify as an ordinary replacement, the replacement must involve one or more complete "retirement units" as identified in REA Bulletin 181-2.

I. Reimbursement of General Funds: The reimbursement of general funds, if the borrower establishes that the general plan or program for the expansion of its system is known to REA, and that it received prior REA approval for such expenditure in accordance with REA Bulletin 103-2.

VIII. Loan Terms and Conditions:

A. Interest Payments: Interest payments will be required in accordance with the terms of the note, bond, or other evidence of debt as set forth in REA Bulletin 20-9.

B. Scheduled Principal Payments: Principal payments are due in accordance with the terms of the note, bond, or other evidence of debt. Generally, as provided in REA Bulletin 20-9, principal payments will begin three years from the date of the note, but may begin at a later date if there is a demonstrated need. Repayment of principal may be scheduled to begin earlier if the borrower desires or if required by REA. Notes providing funds for the acquisition of facilities already in revenue-producing status generally will require that principal payments begin within a year from the date of the note.

C. Advance Payments: Payments in advance of the scheduled due date may be made as set forth in Bulletin 20-9. An interest credit is allowed on the amount in the advance payment account or accounts. This interest credit reduces interest charges.

D. Lien on Borrower's System: A first lien on the borrower's total system normally will be required. It shall be in the form of a mortgage by the borrower to the Government or a deed of trust made by and between the borrower and a trustee, satisfactory to the Administrator.

1. Where a borrower is unable by reason of pre-existing encumbrances, or otherwise, to furnish a first mortgage lien on its entire system the Administrator may, if he determines such security to be reasonably adequate and the form and nature thereof otherwise appropriate, accept other forms of security.

2. To facilitate supplemental financing for Act purposes, the Government's first lien may be shared where the Administrator finds that this would be in the best interests of the borrower and the Government.

E. Other Terms and Conditions: The loan contract, and mortgage or deed of trust, will include such terms and conditions as are appropriately related to loan security.

IX. Application Procedures:

A. Prior to preparation of an application, except as specified in paragraph B below, a distribution-type applicant should notify the Area Operations Field Representative of its intention to apply for a loan and secure from him the necessary instruction and application forms:

1. A loan application should be based on an approved two-year construction work plan consistent with an acceptable long-range engineering plan, or similar engineering support of the need for the facilities and the amounts to be included in the loan.

2. Generally, a board-approved current 10-year financial forecast will be required in support of a loan application. To be considered current, the financial forecast should have been prepared within the past year and, since preparation, no wholesale power or retail rate changes or unanticipated downward trends in margins or debt service ratio have occurred.

3. Additional supporting data usually required will include among other items: board resolutions setting forth the borrower's area coverage and line extension policies, and for cooperatives, the borrower's plan for revolving capital credits; copies of current retail rate schedules; and information summarizing the physical condition of the system and consumer hours outage data.

B. REA Bulletin 111-3, Power Supply Surveys, should be reviewed by all applicants seeking funds for generation and/or major transmission facilities where the facilities to be constructed would displace existing contractual arrangements with a private power company. Applicants should notify the Area Director of their intention to apply for a loan or loan guarantee for this purpose. No application for this purpose will be accepted for consideration by REA unless (a) a Power Supply Survey has been completed, or (b) it is determined by the Administrator that completion of the survey requires full review of the application.

C. REA Operations and Engineering Field Representatives are available to advise and assist applicants in the preparation of loan applications. Applications should be reviewed by the Operations Field Representatives prior to transmittal to the Washington office.

X. Availability of Information Pertaining to Loan Applications:

A. REA publishes at the end of each calendar quarter a list of pending applications for loans containing the names of the applicants, the amount of each application, and brief descriptions of the proposed projects. In addition, information on pending applications is given upon request.

B. The Chairmen of the Appropriations Subcommittees on Agriculture, Rural Development and Related Agencies of the Senate and House of Representatives will be notified in writing by REA at least thrity (30) days in advance of approval of the following:

1. All loan guarantee commitments.

2. All insured loans in excess of $10 million for generation and/or transmission facilities.

No such requests for an insured loan or loan guarantee will be approved by REA unless such notification has been furnished.

XI. Notification of REA Loans: The Chairman of the House Appropriations Subcommittee on Agriculture, Rural Development and Related Agencies will be notified of the amount and purpose of each generation and major transmission loan approved by REA.

XII. Applications Closed Without Loan: If REA determines an application for a loan need not or cannot be processed for approval, or the applicant withdraws or cancels the application, the application shall be considered "closed without loan" and removed from official records of pending applications. The loan applicant and the Committees of Congress notified of the application will be notified accordingly.

David A. Hamil
Administrator

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UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION
WASHINGTON, D.C. 20250

APR 12 1979

Reviewed and Approved For Reprinting July 1982

SUBJECT: Implement the Conservation Policy (Supplement to REA Bulletin 20-2, January 31, 1979)

TO: All Electric Borrowers

The recent supplement to REA Bulletin 20-2 sets forth energy conservation information that will be required to support future loan applications from distribution borrowers. These information requirements are:

1. A copy of the policy approved by the board of directors on energy conservation.

2. A report of the efforts of the borrower to conserve electric energy in the operation of its headquarters and facilities. The activities of the borrower should demonstrate to its members that it has adopted and is carrying out its own in-house program of energy conservation. The report should include the amount that this program has reduced annual operating cost and the necessary capital expenditures, if any, to achieve this reduction.

3. A report describing the efforts of the borrower to assist its members to make the most efficient use of energy. The report should include a conservation work plan and budget which reflects the activities planned and conducted, with related staff time and costs, and a statement of the estimated benefits to the member and the borrower.

For loan applications received during 1979, we cannot expect to receive evidence of accomplishments from those who must initiate new programs or hire new personnel to comply with the policy. However, in most instances, we do expect to receive a board policy, a report on actions planned, and an estimate of resources (both staff time and dollars) to be devoted to energy conservation.

After January 1, 1980, and as appropriate in 1979, the following information should be provided with the loan application:

1. Copy of board policy.

2. Copy of work plan and budget for energy conservation.

3. Names and titles of staff assigned full-time to energy conservation and their major work assignment(s).

the longer-range cost of electric service; for example, an estimate of the increased cost of electricity for the next five or ten years.

Recommendations of REA

. . . Cooperate with consumers who want to install alternative energy systems for their own use, such as windmills, biomass facilities, and solar systems for cooling, space and water heating, and wood burning systems.

. . . Seek assistance and where appropriate, coordinate conservation efforts with NRECA, statewides, other electric cooperatives, power suppliers, state energy offices, Farmers Home Administration, and other organizations with programs or resources that can help the cooperative with its conservation objectives.

. . . Make arrangements with the Farmers Home Administration, community action agencies, local banks, etc., to finance conservation measures for those consumers in need of such assistance.

. . . Work with local contractors and suppliers in helping assure that consumers received quality workmanship and proper conservation materials.

. . . Work with local building contractors to help assure the construction of energy efficient homes.

. . . In advising electric cooperative members about electric heating or air conditioning, that the cooperative provide estimates of

RECOMMENDATIONS OF REA

. . . The energy conservation policy adopted by the board of directors should require, (1) a commitment to an aggressive program to conserve electric energy in the headquarters and other co-op facilities, (2) a commitment to an aggressive program to help consumers conserve and use energy efficiently, and (3) the necessary authority to develop a plan and budget to accomplish the objectives, and to develop appropriate reports to assess results.

. . . Identify opportunities to promote more efficient use of energy and set priorities for assistance to consumers by analysis of consumer uses of energy, billing records, high bill complaints, delinquent accounts, etc.

. . . Provide trained personnel to provide—on a "one-to-one" basis—technical assistance, advice and information for members of the cooperative for the efficient use of electric energy in the home, farm, business or public building, including estimates of the cost of insulation or other expenditure necessary to achieve energy conservation and the estimated savings in electricity costs resulting from any investment or conservation practice.

. . . Encourage and promote insulation standards as recently adopted by the Farmers Home Administration.

As a general guideline, REA will consider that a system with 4,000 or more members should devote, as a minimum, the time of one person working full-time, or the equivalent time of several persons, as a reasonable effort to assist its members to conserve energy. In applying this guideline for smaller systems, consideration will be given to pooling of resources with other organizations. In applying this guideline to larger systems, the amount of additional staff time should be appropriate to its work plan and objectives and consistent with the number of members.

The attachment includes suggestions and recommendations for consideration by borrowers in developing board policies for energy conservation and for planning and conducting energy conservation programs. This information is also included in REA's Energy Conservation Handbook.

Robert W. Feragen

ROBERT W. FERAGEN
Administrator

:File With REA:
:Bulletin 20-2:

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

January 31, 1979

SUBJECT: Supplement to REA Bulletin 20-2, Electric
I an Policies and Application Procedures

.O: All Electric Distribution Borrowers

All REA electric distribution borrowers will be required to develop energy conservation programs as a requirement for continued REA financing. The purpose of this supplement is to set forth the energy conservation information to accompany a loan application. To be considered, a loan application must include the following additions:

1. A copy of the policy approved by the board of directors on energy conservation.

2. A report of the efforts of the borrower to conserve electric energy in the operation of its headquarters and facilities. The activities of the borrower should demonstrate to its members that it has adopted and is carrying out its own in-house program of energy conservation. The report should include the amount that this program has reduced annual operating cost and the necessary capital expenditures, if any, to achieve this reduction.

3. A report describing the efforts of the borrower to assist its members to make the most efficient use of energy. The report should include a conservation work plan and budget which reflects the activities planned and conducted, with related staff time and costs, and a statement of the estimated benefits to the member and the borrower.

In determining the reasonableness of the conservation program, REA will consider the number of members served, geographic locations, land-area served, energy use patterns and the needs of the members.

An aggressive program to assist members to use energy most efficiently will require staff persons trained for that responsibility with appropriate facilities and materials to perform their assignments. Because of the diversity of REA borrower systems, the allocation of staff time and other resources will vary from system to system.

conservation; that measures are planned or underway to conserve energy in cooperative facilities; and that an information and technical assistance program is planned or underway to help consumers conserve energy.

The level of resources indicated in the conservation workplan and budget accompanying the loan application will also serve as an indication of compliance with the intent of the REA policy. The long-term savings to members by energy conservation which result from technical advice and assistance from cooperative personnel should be considered when developing objects of a workplan and budget for this assistance.

REA looks to the directors, managers and staff members of the electric cooperatives to respond to the energy conservation needs of the member-owners with the same dedication and determination which characterized those early days of rural electrification.

The critical need for understanding by the members of the difficulties and costs associated with providing power supply for the future -- and conservation by them as a means to cope, in part, with those higher costs -- is as formidable a challenge as was developing the cooperatives and building the first distribution system.

A decision on the proposed REA Bulletin 120-2 has been delayed. This policy would have required information concerning the diversified demand and other data concerning service to previously unserved cooperative members. It is being delayed because REA is reviewing the entire Power Requirements Survey and Load Forecasting procedures and coordinating this review with similar efforts of the NRECA-CFC Power Supply Study Committee.

ROBERT W. FERAGEN
Administrator

Attachment

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

January 31, 1979

SUBJECT: Energy Conservation Policy and Recommendations

TO : All Electric Borrowers

The attached supplement to REA Bulletin 20-2 sets forth the REA Energy Conservation Policy and the information which should accompany loan applications from distribution borrowers. It has been developed after nearly 6 months of study and research by REA which included several opportunities for comment and discussion by all of the electric borrowers.

Because of the varying circumstances due to weather and load patterns of the distribution cooperatives, the policy provides flexibility in planning and conducting energy conservation programs.

The importance of the efforts called for by the policy cannot be overstated. Energy conservation is the best means for the people we serve to reduce their cost of electric energy. The most efficient use of energy by the members can reduce, in the long run, the need for new generating facilities. An aggressive program of conservation which includes energy audits or advice based on visits to homes or businesses provides an excellent and very important opportunity to reestablish or to improve the person-to-person relationships between cooperative staff and members -- relationships on which rural electrification was founded and which are its greatest strength. These visits also provide an opportunity for the cooperative to develop an understanding by the members of the cooperative of important facts concerning operation of the cooperative, such as retail rates, cost of wholesale power, future plans of the cooperative and membership opportunities and obligations.

This policy should not be interpreted as a suggestion of REA to promote "zero growth." REA realizes that revenues of the cooperative, besides providing funds to repay loans, must also provide for sound operation of the cooperative.

The REA recommendations accompanying the policy can serve as a guide in developing energy conservation programs. An REA Energy Conservation Handbook which you will receive under separate cover contains material that will be of further help in planning and carrying out your energy conservation programs. There is no restriction on the use of this material and the material can be reproduced in whole or in part.

REA anticipates that the reports called for by the policy will vary from system to system. To test conformance to the Bulletin, REA will be looking for information that indicates that the cooperative is committed to energy

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

June 13, 1977

REVISED REA BULLETIN 20-2

Attached is a revision of REA Bulletin 20-2, Electric Loan Policies and Application Procedures, superseding the edition of this bulletin dated February 19, 1971, and all amendments thereto.

The revised bulletin removes limitations on the amount which could be approved in a single loan to electric distribution borrowers for their two-year construction requirements.

The bulletin has been brought up-to-date to reflect all amendments to the Rural Electrification Act through October 20, 1976, relating to REA insured electrification loans.

Attachment

All Electric Borrowers

4. Names and titles of staff assigned part-time to energy conservation--and percentage of their time devoted to energy conservation activities.

5. Brief description of services offered by the cooperative to assist members in conserving energy (such as energy audits or onpremise assistance and advice).

6. Brief description of other energy conservation activities.

7. Brief description of how the cooperative encourages energy conservation by its members and provides information for them--such as newsletters, brochures, etc.

8. Brief description of efforts with others, such as home contractors, Farmers Home Administration, etc., to promote energy conservation.

9. Brief summary of efforts of the cooperative to conserve electric energy in the operation of its headquarters and facilities--including cost savings and amount of capital expenditures necessary to achieve the reduction.

10. Number of members who were provided, onpremise, this type of assistance in last calendar year.

11. Evaluation and comments of the manager on the energy conservation program of the cooperative as it benefits or affects the members and the cooperative.

12. Dollars spent by cooperative in previous calendar year and estimate of dollars to be spent in current calendar year for energy conservation for the following purposes: (Previous year data may not be available until 1981)

	Previous Year	This Year
Personnel	$	$
Information Activities		
Capital Expenditures		
Supervision		
In Cooperation With Others		
Other (office space, etc.)		
List:		

As stated in the January 31, 1979, supplement to REA Bulletin 20-2, REA will consider the number of members served, geographic locations, land area served, energy use patterns and the needs of the members in determining the reasonableness of the conservation program.

Robt. W. Feragen

ROBERT W. FERAGEN
Administrator

APPENDIX No. 5

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

April 18, 1977*
Supersedes 2/4/75

REA BULLETIN 20-22

Reviewed and Approved
For Reprinting July 1983

SUBJECT: Guarantee of Loans for Bulk Power Supply Facilities

I. Purpose: The purpose of this bulletin is to set forth Rural Electrification Administration policies and requirements concerning the guaranteeing under Section 306 of the Rural Electrification Act, as amended, "the RE Act," of loans made by legally organized lending agencies for bulk power supply facilities.

II. Policy:

A. It is the policy of REA to guarantee bonds, notes and other evidences of indebtedness (hereinafter collectively referred to as "loans"), in accordance with the provisions of this bulletin, in order to facilitate the obtaining of financing for bulk power supply facilities from non-REA sources as authorized by Public Law 93-32 approved on May 11, 1973.

B. The Administrator will consider guaranteeing loans for bulk power supply facilities if such loans could have been made by REA in conformity with all REA bulletins applicable to such loans under the RE Act.

C. Any loan guaranteed will be guaranteed in the full amount of principal and interest. A loan guarantee may be made concurrently with an REA loan made at the standard interest rate of 5 percent for the same project.

D. Loan guarantees will be considered on a case-by-case basis for loans made by the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and any other legally organized lending agency, or by a combination of such lenders, which the Administrator determines to be qualified to make, hold and service the particular loan.

E. The terms "legally organized lending agency" and "lender" as used in this bulletin include commercial banks, trust companies, mortgage banking firms, insurance companies and any other institutional investor authorized by law to loan

*Revised to provide in paragraph III.C. for loan arrangements involving variable interest rates and in section VI. for "assignments" of the contract of guarantee.

moneys, any one or more of which may make or participate in a loan for bulk power supply facilities.

F. In view of the Government's full faith and credit 100 percent guarantee of any loan, only REA will obtain mortgage security on account of the guaranteed loan.

G. Generally, the term of each of the notes evidencing the loan to be guaranteed will not exceed 35 years. Interest will be payable as it accrues and principal will be amortized commencing on a date related to the estimated start of commercial operations.

H. No loan shall be guaranteed if the income from such loan or the income from obligations issued by the holder of such loan, which obligations are created by such loan, is excluded from gross income for the purposes of Chapter I of the Internal Revenue Code of 1954.

III. Development of Guaranteed Loan Project:

A. REA preloan procedures pertaining to REA loans for bulk power supply facilities will be followed in developing a project to be financed by a loan made by legally organized lending agencies and guaranteed by the Administrator. The borrower will be responsible for developing the application and related documents, including the engineering and economic feasibility studies and the environmental analysis.

B. A list of all power supply cooperatives owned by REA borrowers will be furnished by REA to any interested lender on request. When REA receives an application for financing of bulk power facilities, which involves REA guaranteeing a loan, it will publish a notice in the Federal Register. The notice will include a description of the proposed project, the estimated total cost, the estimated amount of the guaranteed loan, a statement that the Federal Financing Bank has a standing loan commitment agreement with REA, and the name and address of the borrower from which additional information may be obtained and to which financing proposals may be submitted.

C. If the applicant receives other proposals than from the Federal Financing Bank, it will be responsible for evaluating all proposals and furnishing REA with a report on the evaluations and its choice of proposals. If an applicant's preferred proposal provides an interest rate which is not fixed but varies during the term of the loan, the applicant's evaluation shall also particularly address that aspect of the proposal, including effects on the feasibility forecast and protection against lender's control of the rate variations.

IV. Contract of Guarantee:

A. If REA is satisfied with the engineering and economic feasibility of the project and approves the borrower's choice of proposal, subject to the submission of satisfactory financing documents and to the satisfaction of other pertinent terms and conditions, REA will prepare a contract of guarantee to be executed by the borrower, the lender, and REA within a specified time.

B. The lender, or its representative, will have the right to examine the borrower's engineering, economic and environmental studies submitted to REA in support of its request for financial assistance.

C. The contract of guarantee will require that arrangements satisfactory to REA be made to service the loan. Required servicing will include:

1. Determining that all prerequisites to each advance of loan funds by the lender under the terms of the contract of guarantee, all financing documents and related security instruments have been fulfilled. Such determinations may be met by obtaining REA approval of each advance.

2. Billing and collecting loan payments from the borrower.

3. Notifying the Administrator promptly of any default in the payment of principal and interest on the loan and submitting a report, as soon as possible thereafter, setting forth its views as to the reasons for the default, how long it expects the borrower to be in default, and what corrective actions the borrower states it is taking to achieve a current debt service position.

4. Notifying the Administrator of any known violations or defaults by the borrower under the lending agreement, contract of guarantee, or related security instruments, or conditions of which the lender is aware which might lead to nonpayment, violation or other default.

V. Payments Under the Contract of Guarantee:

A. Upon receipt of the notification required in paragraph IV.C.3 above, REA will pay the lender the amount of the installment in default with interest to the date of payment.

B. When REA has made a payment under a contract of guarantee, it will establish in its accounts the amount of the payment as due and payable from the borrower, with interest at the rate of interest specified in the lending agreement.

C. REA will work with the borrower and the lender in an effort to eliminate the borrower's default as soon as possible. REA may also proceed to act under other remedies available under its security instruments.

VI. Pledging of Contract of Guarantee: Subject to applicable law, REA will consider, on a case-by-case basis, permitting pledging or assignments of the contract of guarantee in order to facilitate the obtaining of funds by the lending agency to make the guaranteed loan.

David A. Hamil

Administrator

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GUARANTEE OF LOANS:
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APPENDIX No. 6

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

May 7, 1969
Supersedes 5/31/61

REA BULLETIN 20-6

SUBJECT: Loans for Generation and Transmission

I. Purpose: The purpose of this Bulletin is to set forth Rural Electrification Administration loan policy concerning generation and transmission facilities.

II. Policy:

A. The Rural Electrification Administration will make loans to finance the initial construction of generation facilities by distribution or power supply borrowers, and of transmission facilities by power supply borrowers, only under the following conditions:

1. Where no adequate and dependable source of power is available to meet the consumers' needs, or

2. Where the rates offered by existing power sources would result in a higher cost of power to the consumers than the cost from facilities financed by REA, and the amount of the power cost savings that would result from the REA-financed facilities bears a significant relationship to the amount of the proposed REA loan.

B. Applications for supplemental loans for these purposes, and for the construction of transmission facilities by distribution borrowers, will be considered and evaluated in terms of whether the proposed additional facilities constitute the most effective and economical arrangement for meeting the increasing power requirements of the consumers.

The policy stated in REA Bulletin 111-1, "Wholesale Contracts for Purchase and Sale of Electric Energy," will be considered in evaluating all power supply proposals.

David A. Hamil

Administrator

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LOANS: Generation and Transmission Facilities

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

April 4, 1978*
Supersedes 8/4/69

REA BULLETIN 111-3

SUBJECT: Power Supply Surveys

I. Purpose: This bulletin sets forth REA policy with regard to Power Supply Surveys and certifications thereto by the Administrator in relation to the approval of loans and loan guarantees for certain generation and/or transmission facilities.

II. Policy:

A. Requirement for Power Supply Surveys: A Power Supply Survey is required prior to acceptance by REA of applications for loans or loan guarantees for generation and/or major transmission where the facilities to be constructed would displace existing contractual arrangements with a private power company. No such application will be accepted for consideration by REA unless (a) a Power Supply Survey has been completed, or (b) it is determined by the Administrator that completion of the Survey requires full review of the application.

Where a Survey is required, the applicant shall provide a full description of existing contractual arrangements for power supply, a statement of any special problems, a general summary of power supply needs, copies of any proposals made by the existing supplier, and a summary of negotiations with the existing supplier.

B. Conduct of Survey:

1. The Survey shall be so conducted as to determine the basis upon which the existing supplier is prepared to cooperate in the development of an assured source of power financed with the proposed loan or loan guarantee.

2. If arrangements satisfactory to the Administrator under (1) above are not available and the existing supplier has made a proposal for continuing the existing supply arrangements, the Survey shall determine whether the proposal is reasonable for purposes of the Rural Electrification Act.

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* Revised to incorporate changes requested in Senate Report 95-296 and to increase the financing level requiring certifications to the Congress when certain Power Supply Surveys are conducted.

3. If the Administrator finds such proposal unreasonable for purposes of the Rural Electrification Act, REA will advise the existing supplier wherein the proposal is unreasonable and endeavor to have such proposal made reasonable. The REA borrower or potential borrower shall be made a party to any negotiations between REA and such power supplier. When necessary to avoid dilatory tactics or protracted delays, the Administrator shall advise the parties in such cases of a definite time limit for negotiations under the Survey, and final cutoff date for proposals which are to be considered in evaluation of the application.

C. Certifications Required When Survey Procedure Results in a Loan or Loan Guarantee by REA: No loan or loan guarantee for generation and/or transmission facilities will be approved except in compliance with all applicable bulletins and, if a Power Supply Survey is required pursuant to paragraph II-A, unless certification is made by the Administrator to the Secretary of Agriculture that the loan or loan guarantee has been approved after completion of a Survey that shows that the loan or loan guarantee is (a) needed to provide an assured source of power which has been developed in cooperation with the existing power supplier; or (b) needed because the proposal from the existing supplier to provide the facilities or service to be financed was found to be unreasonable for the purposes of the Rural Electrification Act, the supplier was advised of the provisions that made its proposal unreasonable, REA attempted to have such proposal made reasonable, and the existing supplier had failed or refused to do so within the time set by the Administrator.

A loan or loan guarantee requiring a Power Supply Survey shall also be certified to the Comptroller General, the Senate and House of Representatives of the United States, as directed by the respective bodies, if it (i) exceeds $10,000,000 and is certified pursuant to (a) above, or (ii) is certified pursuant to (b) above. Such additional certifications shall be accompanied by the following information:

1. The name and address of the applicant borrower and the date of the application.

2. Description and estimated cost of the proposed generation facilities. Indicate if the proposed facilities are the initial or additional unit or units of a plant comprised of one or more units.

3. Description and estimated cost of proposed transmission facilities, including any immediate or future plans to interconnect with other transmission systems.

4. Description of any long-range plans the applicant may have for construction of additional generation and transmission facilities and the estimated cost of the planned facilities.

5. Comparison of the estimated costs of generation by the applicant borrower with the cost of power available from the existing supplier, including the final offer by the supplier including terms and conditions offered to meet applicant's long-term energy needs.

6. Summary of the efforts made by the applicant and by REA to obtain the applicant's power and energy requirements from existing power suppliers and the reasons why such efforts have not been successful.

7. Explanation of the applicant's reasons for seeking an REA loan or loan guarantee.

8. The amount of electric energy which the applicant will cease to purchase from the existing supplier upon construction of the generating plant for which REA financing is being sought.

9. Explanation of the extent to which the feasibility of the requested loan or loan guarantee for generation and transmission facilities depends upon the use of a portion of the facilities by others (including Federal power marketing agencies).

10. Details of the applicant's plans to sell or otherwise make available any of the power and energy from the proposed generation facilities to others (including Federal power marketing agencies).

11. Names of State agencies and commissions having jurisdiction over the applicant borrower.

David A Hamil
Administrator

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

December 17, 1980
Supersedes 6/18/71

R E A Bulletin 103-2

SUBJECT: Use and Approval of General Funds for Additions to Plant

I. Purpose: To set forth procedures and requirements relating to R E A approval of borrowers' use of general funds for plant additions.

II. General: Under provisions of the R E A Standard Form of Mortgage and the R E A Supplemental Lender Mortgage, borrowers are required to obtain R E A approval for plant additions. The making of a loan or a loan guarantee is considered to be R E A approval of the plant addition and facilities covered by the loan or loan guarantee when loan requirements are met. This bulletin provides for R E A approval of additions financed by general funds when the applicable requirements are met. The proceeds from short-term unsecured loans are considered to be general funds and as such are subject to the provisions of this bulletin with respect to additions to plant.

III. R E A Approval: Except for additions to plant referred to in IV below, R E A approval for the use of general funds for plant additions is hereby given to borrowers where such R E A approval is required in writing by provisions in the security instruments, provided:

A. The additions are consistent with the objectives of the Rural Electrification Act as amended and could be financed from loan or guaranteed funds in accordance with R E A policy; and

B. The expenditure is for a purpose within the scope of the borrower's corporate powers, and is in compliance with all appl[illegible]le F[illegible]deral, State and local statutes; and

C. The Administrator has not taken any action to [illegible]strict such use of general funds; and

D. The borrower is not in default on any interest [illegible]al payments due R E A or other lenders on any outstanding note or [illegible]otes; and

E. The expenditure of general funds for such plant additions will not (1) result in a foreseeable default in the payment of any of the borrower's obligations, nor (2) obligate future revenues of the borrower; and

F. The construction for distribution systems is included in a construction work plan, including supplements approved in accordance with R E A Bulletin 60-10, Construction Work Plans, Electric Distribution Systems; and

G. Plans and specifications for transmission facilities have been approved by the appropriate REA office; and

H. REA has reviewed and approved the action to the extent required by REA Bulletin 20-21, Environmental Policies and Procedures; and

I. REA procedures will be complied with in respect to (1) meeting the requirements of REA Bulletin 40-6, Construction Methods and Purchase of Materials and Equipment, and (2) accounting for construction expenditures.

IV. Prior REA Approval Required: The use of general funds for any of the following additions to plant requires prior REA approval whether or not reimbursement with loan funds is to be sought:

A. All new generating facilities or additions or modifications to existing facilities that

1. Result in increased capacity; or

2. Involve an expenditure exceeding $500,000; except, power supply borrowers may expend an amount equal to the lessor of $2,000,000 or 3 percent of the total plant in service to acquire interest or the right to acquire interest in potential power plant sites.

B. Transmission facilities or modifications in design of existing facilities that:

1. Provide for or connect to new power sources; or

2. Involve an expenditure per facility in excess of $500,000 for distribution borrowers and $1,000,000 for power supply borrowers.

C. Acquisition of existing electric plant in service.

D. Additions to serve large power loads when (1) the anticipated load will exceed 4,000 kilowatts, or (2) the investment exceeds $400,000 for a single consumer.

E. Additions which involve new service to persons at a location already receiving central station electric service from an existing supplier; or service to persons in areas included within the boundaries of any city, village, or borough having a population in excess of 1,500 inhabitants for which REA has given no general prior approval.

F. The purchase of an automatic data processing system (including software), where the cost will exceed $50,000 or $10 per consumer, whichever is greater for distribution borrowers and $250,000 for power supply borrowers.

G. Headquarters facilities, or the remodeling of headquarters facilities, which involve an estimated expenditure exclusive of the cost of land, which will result in a total investment in headquarters facilities by a distribution borrower of more than seven percent of its overall investment in distribution plant. Investment in headquarters by a power supply borrower of more than $1,000,000.

H. Construction or acquisition of housing or other nonutility facilities.

I. Communications and controls facilities including microwave, power line carrier, mobile radio, load control and energy management, and SCADA which involve an expenditure in excess of $300,000 for distribution borrowers and $1,000,000 for power supply borrowers.

V. <u>Borrowers' Requests for REA Approval:</u>

A. Request for REA approval for use of general funds for plant additions in IV above shall be made by an appropriate resolution of the borrower's board of directors specifying the purpose and amount requested. REA Form 740a, "Review of General Funds," and Form 7, "Financial and Statistical Reports," (Form 12 in the case of power supply borrowers), shall be submitted to support the total amount of the borrower's general funds at the time of the request.

B. After approval of a borrower's request to use general funds, REA procedures will be complied with in respect to, (1) meeting the requirements in REA Bulletin 40-6, "Construction Methods and Purchase of Materials and Equipment," and (2) accounting for construction expenditures.

Administrator

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

December 17, 1980

Revision of REA Bulletin 103-2

Enclosed is revised REA Bulletin 103-2, Use and Approval of General Funds for Additions to Plant. The revised bulletin gives REA approval, under certain conditions, for electric borrowers' use of general funds for:

- Certain communications, generation and transmission facilities.
- Certain other facilities in increased dollar amount.
- Power supply borrowers to acquire interest or the right to acquire interest in potential generating plant sites up to $2,000,000.

The revised bulletin also provides that the requirements of REA Bulletin 20-21, Environmental Policies and Procedures, be satisfied as a condition to REA's prior approval.

ADDENDUM TO

REVIEW & ANALYSIS

of

ENGINEERING, CONSTRUCTION & TESTING

at

THE COMANCHE PEAK NUCLEAR PROJECT

April 29, 1988

RANDEL ASSOCIATES, INC.

April 29, 1988

FOREWORD

During the period February through April 1988, I have continued my research and analysis of the engineering, construction and testing at the Comanche Peak Nuclear Project. Although I have reviewed additional information which supports my conclusions, the main report (dated February 12, 1988) and this addendum (dated April 29, 1988) are still based upon information available and reviewed to date; discovery is still continuing. I have found no information, however, which changes my earlier conclusions.

In the main report, it was pointed out that the records and documents referred to therein were neither all-inclusive of the documents I reviewed, nor did they reflect all of the problems encountered by TU at CPSES. In fact, the listing of types of project documents I reviewed was described as containing examples of documents. It should be pointed out that for the most part those documents were obtained through discovery. Most of those documents had not previously been made available to Brazos or Tex-La.

Consequently, it should be emphasized that my conclusions, which were based on those documents and on my prior background and experience, were developed after thorough review of those documents. As a result, conclusions describing the clarity with which cost and schedule information was known are based on the breadth of information and documentation I reviewed. Such information, which was available contemporaneously to TU as the Project Manager, was not available to others.

I. Introduction

The main report was completed in February 1988. This Addendum has been prepared in April 1988 and reflects an area of research and analysis performed after the preparation of the original report. The addendum includes information derived from the intervening discovery and deposition efforts.

The primary sources of information for this addendum are several reports issued by TU in late 1987 and early 1988 (and their backup documentation as available) describing the results of several CPRT efforts. These reports include:

December 2, 1987	ISAP I.d.1, QC Inspector Qualifications, Revision 1
December 17, 1987	ISAP VII.c, Construction Reinspection/ Documentation Review Plan, Revision 1
December 18, 1987	Collective Evaluation Report, Revision 0
February 24, 1988	Collective Significance Report, Revision 0

The conclusions in this addendum are based upon information available and reviewed to date. They may be further expanded and modified based upon the findings of additional research and analysis.

II. ISAP VII.c Results/Collective Evaluation

There are several references in CPRT documents to the Quality of Construction (QOC) program, which was to be a stati..ically sampled reinspection program. ISAP VII.c is the result of the Quality of Construction program, although the "QOC" designation has not been emphasized. ISAP VII.c became the primary basis for the conclusions of the Collective Evaluation Report, even though ISAP VII.c represented only a part of the total reinspection effort.

It appears that TU unreasonably biased the results of its efforts in order to portray the results most favorably. First, some of the worst items were excluded. For example, Cable Tray Hangers and HVAC Duct Hangers were known to have many design deficiencies and construction coordination problems. These were covered under separate reports (Discipline Specific Action Plans -DSAP's) and therefore were excluded from ISAP VII.c. Second, other previously corrected items appear to have been included in the reinspection.

Third, once an Adverse or Unclassified Trend was identified for a specific attribute, the reinspections were stopped. TU attempted to justify this action in the report by noting that the corrective action process would address the specific problems. For example, the inspection point and deviation statistics for the 1E Lighting and HVAC Duct Support Construction Work Categories (CWC) were excluded from the summary statistics. Furthermore, the 1E Lighting CWC appears to have been created to segregate poor results from good results. This was done by transferring the lighting wiring and lighting conduit reinspection packages from the Cable and Conduit CWC's.

The reinspection program took over two years to determine the quality of construction of approximately 3800 safety-related items which TU claims were randomly selected. All of these items previously had undergone QC inspection and QA acceptance. This sample represented about 1% of the total safety-related items in the plant. Rather than provide documentation of the plant's high quality, the reinspection effort found over 10,100 physical deviations and 2100 documentation deviations. Thus, each reinspected item had an average of 3.2 deviations. As part of TU's effort, each deviation was evaluated for safety significance.

The Collective Evaluation Report described a number of serious problems, which were summarized into ninety-three (93) Findings (forty-three significant Construction Deficiencies and fifty significant Adverse and Unclassified Trends). Each Finding was reviewed to determine the root cause and generic implication. The five most frequently cited Root Causes were:

1. Inadequate QC inspection procedures;
2. Inadequate construction procedures;
3. Inadequate engineering drawings/specifications/instructions;
4. Construction personnel inattention/workmanship/supervision/management
5. "Unable to determine due to insufficient information."

The report includes corrective action recommendations for the ninety-three (93) Findings. The project apparently is implementing the corrective actions under another program, the Post Construction Hardware

Validation Program (PC-VP). Although the less serious deviations were characterized as "Insignificant", many of these "Insignificant Deviations" required exhaustive engineering evaluations to show that the safety-related items could perform their safety functions.

TU, on the other hand, expressed the negative results as positively as possible, claiming that approximately 98 percent of the inspection points and documentation review points were found to be in conformance with applicable design requirements, and that more than three-fourths of the deviations found were insignificant. It is important to remember, however, that TU's percentage calculations are based on 630,000 reinspection decision points, not on 3800 reinspected items. Obviously, by basing the statistics on the larger number of inspection points, the percentage of deviations found can be made to appear small. Using TU's method, for example, an item with one fatally flawed decision point and 164 acceptable decision points would be judged 99.4% acceptable. The seriousness of the single flaw is not considered in the statistical tabulations.

The frequency of previously undocumented deviations found in ISAP VII.c is a serious concern. Either the original inspectors had not recognized the deviations, or the inspectors had judged them to be insignificant. Such actions are an indictment of the original inspection process. Judging the safety significance of a deviation is not the responsibility of QC Inspectors.

The frequency of reinspection deviations is evidence of a very poor QA/QC effort; it also confirms the ASLB's conclusion that there had been a programmatic breakdown in the QA programs for design and construction.

III. ISAP I.d.1, QC Inspector Qualifications

A review of the certification of CPSES QC Inspectors, ISAP I.d.1, was conducted concurrently with ISAP VII.c. Questions about the certification of the inspectors who performed the original inspections for items reinspected in ISAP VII.c were referred to ISAP I.d.1. One extremely disturbing conclusion of ISAP I.d.1 is that TU did not have a program that satisfied its FSAR commitment to institute the QC Certification requirements of NRC Regulatory Guide 1.58. (No widespread problems with inspector certification were found for the Brown & Root inspectors, even though TU had taken over the QA functions from Brown & Root in 1978.) Another serious concern is that the inspection records of several unqualified inspectors were not located. It is unclear what, if any, corrective action will be taken to correct these problems.

TU's flawed inspector certification process and flawed procedures, as well as the intimidating atmosphere which existed at the jobsite, are directly linked to the poor quality documented in ISAP VII.c. These contradict TU's arguments in ISAP I.d.1 that the flawed inspector certification process did not result in poor inspection.

IV. ISAP VII.b.4, Hilti Bolts Installation

ISAP VII.b.4, which was conducted concurrently with ISAP VII.c, reviewed the quality of the installation of Hilti bolts at CPSES. The third party reviewers found several serious problems with Hilti Bolt installation, including:

1. Use of Hilti bolts for anchoring rotating equipment, in direct violation of the manufacturer's recommendation.
2. "Bottomed-out" nuts and insufficient torque application.
3. Substitution of "before-setting" embedment depth in the QC Inspection procedure for the manufacturer's "after-setting" criteria.

A fourth problem which was not addressed by the third party reviewers, but which was allowed by TU procedures, is improper field modifications of the bolts.

Concrete expansion bolts became an industry wide concern when the NRC discovered failed anchor bolts which had been used on safety-related pipe hangers at two operating plants in early 1979 (Hilti is the brand of concrete expansion bolts used at CPSES). After it had investigated the use of these devices at other plants and found wide variations in the installation procedure requirements, the NRC issued I&E Bulletin 79-02 in 1979 requiring all operating license and construction permit holders to perform an extensive review of the use of concrete anchor bolts to ensure their anchor bolt installations satisfied design and manufacturer's requirements.

In October 198[illegible], TU reported a serious Hilti bolt problem to the

NRC in a 10 CFR 50.55(e) report. TU performed an extensive evaluation in 1980 and 1981 after a former worker alleged that Hilti bolts had undergone unauthorized modifications. The worker identified two Hilti bolts that had had their precision factory-machined tapered ends cut off; new tapers had been cut with field grinders. Neither bolt was properly set, and both bolts pulled out at a load lower than the design load. Furthermore, both bolts had been QC accepted.

ISAP VII.b.4 discussed the 1980/1981 evaluation:

> This (the use of letter length codes stamped on the end of the bolt) was judged to be adequate based on the findings of an extensive ultrasonic testing (UT) program performed on site during the period 1980 to 1981, when some 10,000 Hilti's were examined. The results of the test program showed that only thirteen bolts were found to have been modified prior to installation. (emphasis added)

Neither ISAP VII.b.4 nor the 10 CFR 50.55(e) reports point out that the analysis of improper modifications was limited to alterations of the tapered end of the bolt. TU did not tell the NRC it had procedures which allowed modifications to the threaded end:

> 3.1.6.1 When it is necessary, as a result of reinforcing steel interference or on-site unavailability of correct length bolts or for other reasons, Hilti bolts may be modified, with proper QC witnessing, on-site by shortening, rethreading, and stamping the new length designation. This shall be done only on a case-by-case basis upon approval of the design engineer (emphasis added) responsible for the fixture or item involved and upon completion of a Component Modification (CMC) or by revising the FSE. Final bolt length shall be sufficient to satisfy the design requirement.

Reference: Brown & Root Instruction CEI-20, "Installation of Hilti Drilled-In Bolts", Draft Revision 8, November 19, 1982. (Note: We have found no requirement to document threaded end modifications. Thus, there is no way to go back through the QC documentation and determine which bolts were modified. Furthermore, a Design Change Authorization removed the "case-by-case" requirement.)

The use of Hilti bolts to anchor rotating equipment is a violation of the manufacturer's recommendations. Not only did TU find loose Hilti bolts which had been used to anchor a piece of safety-related rotating equipment, but also the installation had been accepted by QA/QC.

The CPRT identified an Unclassified Trend for Hilti bolts with bottomed-out nuts/unacceptable torque. The CPRT reinspection technique provided for determining the bottomed-out condition by adding the nut thickness to the thread projection above the nut and comparing it to the manufacturer's minimum thread length, which is an acceptable method for unmodified bolts. It is not an acceptable method for modified bolts whose length is unknown. (The modification instruction does not ensure that the modified bolt minimum thread length meets the manufacturer's requirements, and the QC procedure for bolt modification does not include an inspection attribute for minimum thread length.) Consequently, there may be many bottomed-out anchor bolts which were not detected by the reinspection technique.

ISAP VII.b.4 documented 15 deviations related to failures to meet minimum embedment depth requirements, ranging up to 3/4 inch less than the required minimum. The reinspection-required minimum used the prior-to-setting definition. Thus, although the manufacturer's strength recommendations are based on after-setting embedment depth, and the tests conducted by the manufacturer at Comanche Peak document the after-setting embedment depth, the reinspection utilized an embedment depth prior to setting.

This issue was documented in Discrepancy/Issue Resolution (DIR) Report D-0578, Revision 1, dated January 2, 1987, which includes the following comment:

> This violates the Hilti criteria and invalidates the use of Hilti catalog allowables both for shear and tension.

Curiously, neither DIR Report D-0578, dated January 2, 1987, nor the issue of the differing embedment depth definition was mentioned in ISAP VII.b.4 dated May 14, 1987. We have found no resolution of this problem as of this date.

V. Concrete Problems

One of the Construction Work Categories reinspected under ISAP VII.c was safety related concrete placement; poor QA/QC of concrete placement was one of the earliest issues at Comanche Peak. The concrete reinspection included a review of the inspection paperwork and a visual inspection of the surface conditions. The third party inspectors inspected the concrete surfaces for honeycombing (voids), embedded debris, and bonding at construction joints. Although the inspectors found several instances of debris, the Safety Significance Evaluation determined there was no safety significance because the debris was widely scattered and tightly bonded to the concrete.

The concrete reinspection results raise several concerns that were not discussed in the ISAP or Collective Evaluation Reports. These concerns include:

1. Subsequent discovery of poor concrete construction joint bonding behind embedded debris. This led to the additional discovery of a programmatic failure to test concrete joint Starter Grout.
2. Subsequent discovery of inconsistencies and misunderstandings of the proper use of concrete mix inspection pour cards.
3. Lack of analysis of potential interaction between embedded debris and concrete anchorages.

The inspectors found two safety related concrete columns, one in the Unit 1 reactor containment building and one in the auxiliary building, with large pieces of embedded lumber. The inspectors documented the embedded debris items on Deviation Reports (DR's), and DR copies were sent to the project for non-conformance reporting. The non-conformance reports were dispositioned to remove the lumber and repair the surfaces.

Serious problems were revealed when the lumber was removed. Unconsolidated concrete (cold joints) and foreign matter, i.e. sawdust, were discovered in the joints. A significant percentage of the cross sectional areas of both columns had to be removed in order to extract the unconsolidated concrete.

The third party reviewers examined the original procedures and inspection records for concrete joints. Starter Grout should have been used to ensure an effective concrete bond was created between the old and new concrete. (Starter Grout is a concrete mix made to the same requirements as the corresponding structural concrete mix but without the large aggregate.) The Gibbs & Hill specification requires the starter grout to be tested to the same requirements as the corresponding structural concrete mix. The Brown & Root construction procedures have no starter grout testing requirements.

Since there were no starter grout inspection records for the two columns, and in light of the cold joints, it is doubtful starter grout was used. It is also clear from the existence of the lumber and sawdust that quality control of the concrete placement was inadequate.

These concrete construction joint problems are contained in the findings in ISAP VII.c., under the title of Unsound Concrete Mortar. The finding was evaluated an Unclassified Trend, however, because the root cause could not be determined. A review of the ISAP VII.c. files does not reveal what the final corrective action will be since it will be performed as part of the PCHVP.

The reviewers also discovered that the concrete pour cards were not completed in a consistent manner. The inconsistency could have resulted in concrete with a higher than specified water to cement ratio. Since the water to cement ratio is a primary determinant of ultimate concrete strength, a high water content could have caused inadequate concrete strength.

One item not addressed by the third party reviewers is the potential interaction between embedded debris and concrete anchors. Concrete anchors (including Hilti bolts, Richmond inserts, and embedded plates with Nelson studs) normally fail when the concrete fails. A nonuniformity (such as debris) in the concrete which intersects the surface of an anchor's concrete shear cone has the potential to reduce the strength of the anchor.

Embedded debris is an indication of poor construction practices and shoddy workmanship. Although there usually is no quantified minimum acceptance criteria for embedded debris, embedded debris has a negative effect on concrete strength. The behavior of concrete with embedded debris is unreliable.

VI. Loose Threaded Parts

One serious concern raised by the findings in ISAP VII.c relates to the number of findings for threaded parts such as nuts, bolts and hardware. The following is a listing compiled from ISAP VII.c:

ISAP VII.c Reference	Construction Work Work Category	Finding/Description
Page 44	Electrical Conduit	Missing Bushings
Page 44	Electrical Conduit	Loose Unions
Page 48	Electrical Cable Tray	Improper Installation of Splice Plate (two bolts in a four bolt plate)
Page 55	Electrical Cable	Loose Connections on Weid-muller Terminal Blocks
Page 56	Electrical Cable	Loose Connections on Terminal Blocks
Page 64	Electrical Equipment Installation	Damaged and Incorrectly Reassembled Equipment Doors and Access Panels
Page 68	Instrument Equipment Installation	Flexible Hose Installed with Excessive Twist
Page 68	Instrument Equipment Installation	Unapproved Thread Sealant
Page 73	Mechanical Large Bore Piping Configuration	Loose Expansion Joint Tie Rod
Page 87	Mechanical Equipment Installation	Broken Bolts
Page 89	Mechanical Equipment Installation	Manway Covers [Under Tightened Bolts]
Page 95	Structural Steel	Substitution of Smaller Diameter Bolts
Page 95	Structural Steel	Lack of Jam Nuts on Unit 1 Rotating Platform
Page 96	Structural Steel	Lack of Jam Nuts on Unit 1 Pressurizer Platform
Page 97	Structural Steel	Gaps Between Components Transmitting Seismic Loads [Due to undertightened bolts]
Page 98	Structural Steel	Gaps Between Connected Plies [Due to undertightened bolts]

Page 103	Supports: Large-Bore Supports - Rigid	Incorrect Components (undersized vendor supplied bolts)
Page 105	Supports: Large-Bore Supports - Rigid	Inappropriate Locking Devices [Paint on threads]
Page 107	Supports: Large-Bore Supports - Rigid	Loose Jam Nuts
Page 108	Supports: Large-Bore Supports - Rigid	Loose Hardware Fasteners
Page 105	Supports: Large-Bore Supports - Non-Rigid	Inappropriate Locking Devices [Paint on threads]
Page 112	Supports: Large-Bore Supports - Non-Rigid	Broken Cotter Keys
Page 115	Supports: Small-Bore Pipe Supports	Inappropriate Locking Devices [Paint on threads]
Page 116	Supports: Small-Bore Pipe Supports	Unsecured Fasteners
Page 119	Supports: Instrument Tube Supports	Inadequately Torqued and Misaligned Unistrut Spring Nut
Page 119	Supports: Instrument Tube Supports	Loose Bolt
Page 120	Supports: Instrument Tube Supports	Insufficient Thread Engagement
Page 125	Supports: Pipe Whip Restraints	Missing and Incorrectly - Installed Locking Devices
Page 125	Supports: Pipe Whip Restraints	Lack of Joint Tightness
Page 133	Other - Details Concrete Inserts	Less Than Required Thread Engagement

It is surprising that all of these findings are for safety-related components which previously had been QA/QC accepted. The Collective Evaluation and Collective Significance Reports do not address the relevance of this pervasive inability to properly use and inspect threaded components. Furthermore, it is hard to understand how even unqualified QC inspectors could have accepted such obviously poor workmanship.

TU has attempted to characterize these flaws as normal for this type of construction. TU also has suggested as a possible explanation for these flaws activities which occurred subsequent to final inspection. The nature and extent of such flaws is not normal; to the contrary, it reflects poor construction practices or undisciplined activities after final QC inspection and acceptance.

Summary

Based on review of CPRT materials to date, the reinspection program has identified major flaws in the design and construction of the plants and confirms serious deficiencies in the QA/QC program, notwithstanding TU's efforts to minimize those flaws in its reports on the program results.

REVIEW & ANALYSIS

of

ENGINEERING, CONSTRUCTION & TESTING

at

THE COMANCHE PEAK NUCLEAR PROJECT

February 12, 1988

RANDEL ASSOCIATES, INC.

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FOREWORD

This draft report was prepared by Robert A. De Lorenzo of RANDEL Associates, Inc. based on research on the Comanche Peak nuclear project conducted through January, 1988. This report is still preliminary in nature since discovery is still continuing. Consequently, as further discovery provides additional information and basis for analysis, research and analysis will continue. The conclusions in this report are supported by the review and analysis done to date.

This report contains a lengthy discussion of problems which occurred at Comanche Peak. The discussion is not intended to be an all-inclusive listing of the problems. Rather, it is intended to provide a series of examples which demonstrate the seriousness of those problems; furthermore, the examples selected may demonstrate other problems in addition to the ones specifically cited.

It also should be pointed out that the records and documents referred to in describing and analyzing problems are not all-inclusive either. They provide examples, selected from all the records and documents which were reviewed, which assist in understanding the nature and extent of the problems. Additionally, the records and documents cited in one section also may be examples of problems described in other sections.

Finally, in reviewing the problems described herein, one should be mindful that in the context of nuclear power, safety means quality. Deficiencies in the achievement of quality, the control of quality, and the assurance of quality can be translated into a decrease in the public health and safety, and should not be accepted.

I. INTRODUCTION

A. General

The Comanche Peak Steam Electric Station (CPSES) has not been a successful nuclear project. Texas Utilities (TU)* began the project in 1972, with an expected total cost at completion of $779 million, and with scheduled completion dates of January 1980 for Unit #1 and January 1982 for Unit #2. Now, nearly sixteen (16) years later, (and eight (8) years after the scheduled Unit #1 completion date), the plant is expected to cost on the order of $8 billion or more. Neither Unit #1 nor Unit #2 is yet on-line to deliver electric power to the customers in Texas, and it is unclear when, if ever, the plants will operate.

TU has been the Project Manager for Comanche Peak. In that capacity, TU has been responsible for the planning, construction and operation of the project. TU mismanaged that responsibility.

Cumulative design, construction, personnel training, licensing and management errors point to pervasive mismanagement contrary to proper project management. A list of Comanche Peak errors includes such diverse actions by TU or its contractors as:

- o improper placing of concrete
- o orienting the Unit #2 Reactor Vessel supports in the wrong direction
- o leaving an inadequate seismic gap between buildings
- o having unqualified inspectors

* TU refers to any and/or all of the companies within the Texas Utilities group of companies.

- permitting Brown & Root's N-stamp and their own Construction Permit to expire
- forcing relocation of a major steam pipe with the polar crane
- improperly separating cable trays
- constructing non-conforming pipe supports

It is clearly evident that TU's mismanagement caused unusually severe problems at Comanche Peak. As a result of their mismanagement, TU has been unable to obtain an Operating License (OL) from the NRC. Furthermore, in an attempt to identify and correct their problems, TU has had to embark on costly programs (the Comanche Peak Response Team - CPRT - and the Corrective Action Program - CAP) to provide assurance that:

- the design meets all licensing commitments
- the as-installed hardware meets the validated design

If TU had not mismanaged their responsibility as Project Manager, the assurance they are now trying to develop in order to obtain an OL would have been evident upon completion of engineering/design, construction and preoperational testing.

The concept of project management, and the role of a project manager, has been clearly described in the past. One example of such a description is the following by Mr. Russell D. Archibald:

> "The entire objective of project management may be stated as achieving proper control of the project to assure its completion on schedule and within budget, while achieving the desired quality of the resulting product or service."

"Each project has a single point of integrative responsibility: the project manager."

"Each project is planned and controlled on an integrated basis, including all contributing functional areas through all life cycle phases."

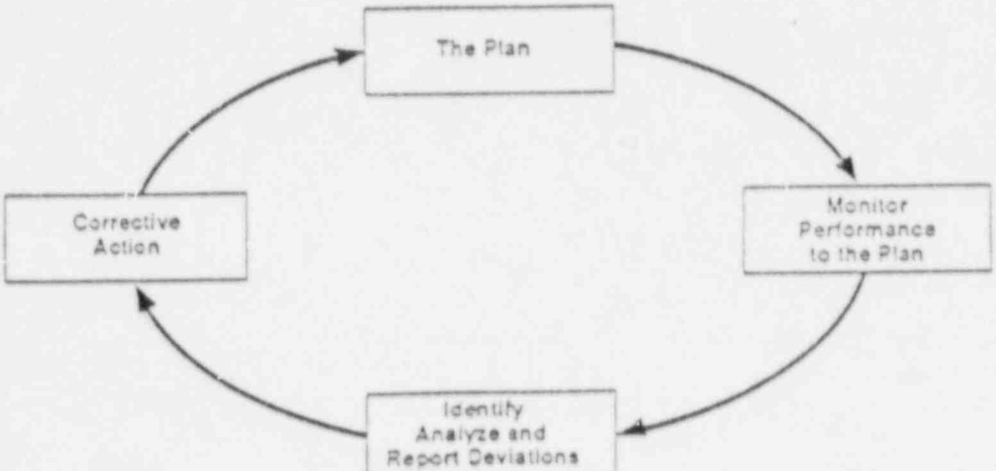
(Managing High-Technology Programs and Projects, Russell D. Archibald.)

In describing control, Mr. Archibald emphasized how it applies in a project context:

"Project control is not control in the classic sense of ownership, domination, rule or reign. It is control established by: mutually setting objectives and goals, defining the tasks to be done, planning and scheduling the tasks based on required and available resources, and measuring progress and performance through an established, orderly system."

(Managing High-Technology Programs and Projects, Russell D. Archibald.)

In the context of a nuclear power project, control may be expressed graphically as The Control Cycle.



The Control Cycle

B. The Requirements of Nuclear Power

Nuclear power is a very complex and potentially very dangerous technology. The fact that there are over 100 nuclear power plants in operation, however, is an indication that the projects are manageable and that, with limited exceptions, the plants can be run safely.

In order to design, construct, and operate a nuclear plant successfully, given the complexity and potential danger, a utility as the owner must be dedicated to safety. And in the nuclear industry, safety means quality. The utility must not only assure that the structures, components and systems themselves satisfy the safety requirements, but also that the documentation supporting the structures, components and systems provides objective evidence that the safety requirements have been satisfied. The hardware and documentation both must provide a consistent presentation.

The utility as the licensee of the Nuclear Regulatory Commission (NRC) is responsible for achieving and assuring the quality of a nuclear power plant. Even though the utility as the licensee may delegate responsibility to designers, vendors and contractors, the utility as the licensee retains ultimate responsibility.

The NRC, on the other hand, is not directly responsible for nuclear power plant quality; its concern lies with the health and safety of the public. Even if a utility has not fulfilled its responsibility as the licensee for building a safe plant, the NRC can still protect its concern by denying an operating license.

This means that a utility must treat its relationship with the NRC very carefully during the life of the project. Since the utility as the licensee and the NRC are in almost constant contact during a substantial part of the project's lifetime, the interactions must be constructive and forthright. Furthermore, the NRC must develop confidence in the technical capabilities and in the integrity of the utility and its management. Otherwise, it would be difficult for the NRC to conclude that the plant was designed and built to the safety requirements, that supporting documentation was adequate to assure proper design and construction of the plant, and that the utility was capable of operating its nuclear plant safely. Without that conclusion, the NRC will not issue an operating license.

Successful project management and the achievement of quality are very closely related. In fact, quality is difficult, if not impossible to achieve, without proper project management. The relationship between quality and project management was described very clearly in an NRC report commonly referred to as NUREG-1055.

> "The principal conclusion of this study is that nuclear construction projects having significant quality-related problems in their design or construction were characterized by the inability or failure of utility management to effectively implement a management system that ensured adequate control over all aspects of the project."
>
> "...breakdowns in the quality assurance program were part of larger breakdowns in overall project management, including planning, scheduling, procurement, and oversight of contractors."
>
> (NUREG-1055, Improving Quality and the Assurance of Quality in the Design and

Construction of Nuclear Power Plants.)

C. Comanche Peak Response Team and Corrective Action Program

TU provided a summary description of the Comanche Peak Response Team (CPRT) and Corrective Action Program (CAP), along with its position on how the two programs interrelated, in a recent letter to the NRC. In that letter, TU also described the origins of CPRT and CAP:

> "The genesis of the current Comanche Peak Programs was the external source issues identified by the following:
>
> - NRC Staff Special Review Team (NRC-SRT)
> - NRC Staff Special Inspection Team (SIT)
> - NRC Staff Construction Appraisal Team (CAT)
> - Citizens Association for Sound Energy (CASE)
> - Atomic Safety & Licensing Board (ASLB)
> - NRC Region IV Inspection Reports (RIV-IR)
> - NRC Staff Technical Review Team (TRT) - SSER 7-11
> - Cygna Independent Assessment Program (IAP)
>
> (W.G. Counsil letter to NRC dated 8/20/87)

These issues are commonly referred to as the "external source issues."

TU described the Comanche Peak Response Team (CPRT) in several documents. Most recently, the CPRT was described as follows:

> "The Comanche Peak Response Team (CPRT) was established by TU Electric to investigate various issues regarding the Comanche Peak Steam Electric Station (CPSES). The CPRT is comprised of third-party individuals who have had no prior responsibility for design or construction of CPSES."

"The CPRT program consisted of two principal types of activities. First, the CPRT performed investigations to determine the adequacy of various types of programs and hardware at CPSES and made recommendations for corrective action where required. Second, having concurred with the Project's plans for addressing these recommendations, the CPRT is overviewing implementation of the corrective actions."

(CPRT Collective Evaluation Report)

The CPRT consisted of two basic elements:

- o Design Adequacy Program (DAP)
- o Quality of Construction (QOC) Program

As the CPRT began implementation of the Program Plan, the need for corrective action became obvious.

"A qualitative and quantitative review by TU Electric of the preliminary results of the DAP investigative phase revealed that the findings identified were very broad in scope and included most disciplines. The significance of these preliminary findings prompted TU Electric to initiate a comprehensive Corrective Action Program (CAP)."

(W.G. Counsil letter to NRC dated 8/20/87)

The Corrective Action Program, initiated by TU in response to the findings of the DAP, is a very broad program, using third-parties to identify and correct the many deficiencies which resulted from TU's mismanagement.

D. Conclusions

The remainder of this report describes the approach, research and analytical results of Mr. R.A. De Lorenzo. The following are the conclusions I have reached:

1. Texas Utilities did not act properly with regard to engineering/design, construction and preoperational testing/startup as the Project Manager of Comanche Peak.

2. TU's improper actions as Project Manager of Comanche Peak were significant and caused cost overruns and schedule delays of the project.

3. The Comanche Peak Response Team and Corrective Action Program and the failure to obtain an Operating License for Comanche Peak resulted from TU's improper actions.

4. By December 1978, it was clear that the project could not be placed into Commercial Operation in January 1981 (Unit #1) and January 1983 (Unit #2).

5. TU knew that the January 1981 (Unit #1) and January 1983 (Unit #2) Commercial Operation dates could not be attained.

6. By December 1979, the Definitive Estimate of $1.7 billion was not realistic.

7. By December 1979, it was clear that the project could not be placed into Commercial Operation in July 1981 (Unit #1) and

January 1983 (Unit #2).

8. By May 1982, the project was in such serious trouble that it clearly could not be placed into Commercial Operation in January 1984 (Unit #1) and June 1985 (Unit #2).

9. There was sufficient evidence available in 1982 that TU knew or should have known that the project was in serious trouble and could not be placed into Commercial Operation in January 1984 (Unit #1) and June 1985 (Unit #2).

II. BACKGROUND

A. Assignment

Robert A. De Lorenzo of RANDEL Associates, Inc. was retained by Brazos and Tex-La to provide the viewpoint of an experienced nuclear project executive. Among other things, Mr. De Lorenzo was asked:

- To review Texas Utilities' (TU's)* management and implementation of the engineering/design, construction and preoperational testing/startup of the project and to determine whether or not TU had acted properly in performing its contractual obligations.

- To review the progress and status of the project throughout its entire duration including during the JOA negotiations with minority owners, before and during 1979, and before and during 1982, and to determine as of those times whether or not the project could have achieved Commercial Operation in January 1981 (Unit #1) and January 1983 (Unit #2), or in January 1984 (Unit #1) and June 1985 (Unit #2), respectively, and, if not, whether or not TU knew or should have known at those times that the project would not or could not have achieved Commercial Operation on such dates.

* TU refers to any and/or all of the companies within the Texas Utilities group of companies.

A recent resume of Mr. De Lorenzo's background and experience is provided in Appendix A.

B. Approach

It was my view that the assignment contained two closely related parts. Consequently, my approach to the assignment also was broken into two parts. In order to address the assignment, I conceptualized general questions to be answered.

Among the questions addressed were:

1. "Did Texas Utilities act properly?" Research and analysis related to this question was done in a series of steps:

- Identify and review technical problems which had significant impact on the progress and completion of the project (e.g. problems addressed by the Comanche Peak Response Team (CPRT) and the Corrective Action Program (CAP)), as well as other problems.

- Review contemporaneous project records and documents as well as later records and documents developed by others, including the CPRT and CAP, to identify the nature, extent, origin, and root cause (where possible) of the problems.

- Attend depositions and/or review deposition transcripts of TU employees (and others) to identify and to understand relationships between actions of project personnel and resulting technical problems.

- o Reach conclusions about the propriety of actions by TU and other project personnel.

2. "What did Texas Utilities know or should it have known in 1979 and in 1982 and disclosed to the minority owners?" Review and analysis related to this question also was conducted in a series of steps:

- o Review project progress and status in engineering/design, construction and preoperational testing/startup throughout the entire project duration.

- o Identify contemporaneous information which was available about completion results from other nuclear projects which was used or which could have been used by TU to assess the realism and achievability of its schedule.

- o Reach conclusions about what TU knew or should have known about the Fuel Load dates, Commercial Operation dates, etc. and represented to the minority owners.

C. References/Sources of Information

Our research and analysis was based in part on records and documents which would have been available to project decision makers as the project unfolded.

Numerous project documents were reviewed. Some examples of these are:

- o Weekly and monthly progress reports.
- o Routine correspondence.
- o Inspectors and auditors reviews.
- o Project meeting minutes.
- o Final Safety Analysis Report (FSAR).
- o Project review reports (MAC, LOBBIN, etc.).
- o Comanche Peak Response Team reports.
- o Corrective Action Program reports.
- o Nuclear Regulatory Commission records and documents.

Our research and analysis also was based on other nonproject documents which are customarily used by consultants in evaluating nuclear project management performance. Some examples of these documents are:

- NUREG-1055: Improving Quality and the Assurance of Quality in the Design and Construction of Nuclear Power Plants.

- INPO 83-018: Performance Objectives and Criteria for Construction Project Evaluation.

III. STANDARDS FOR PERFORMANCE EVALUATION

A primary standard utilized for evaluation of the performance of Texas Utilities was the Joint Ownership Agreement (JOA). Although the entire JOA was reviewed and in fact was utilized, the following sections were those which were referred to most often in development of a standard. These sections contained language which was particularly meaningful for purposes of evaluating TU's performance.

Parties	3.04	8.03
Recitals	5.01	9.03(a)
1.18	5.02	22.
1.19	5.03	23.08
2.02	5.04	23.15
2.03(d)	8.01	23.16
	8.02	23.17

Although the JOA was utilized as a primary standard, the standard was interpreted in terms common to nuclear project management for purposes of evaluation. The interpretation of the standard was based on the personal background and experience of Mr. R.A. De Lorenzo. The standard was interpreted to take the following general form:

- As the Project Manager, TU was responsible for performing at least as a reasonably qualified person in managing and/or implementing the engineering/design, construction and testing of a nuclear project.

o Evaluation should be based on the facts which were known or should have been known at the time.

Application of the standard to the management performance of TU thus took the following form:

o As Project Manager, TU had the responsibility to ensure that project planning and control for engineering/design, construction and preoperational testing/startup were done properly.

(Definition: Planning is the predetermination of the course of action.
Definition: Control is ensuring progress according to the plan - "The Control Cycle".)

o As Project Manager, TU had the responsibility to ensure that the implementation/execution of engineering/design, construction and preoperational testing/startup was done properly.

(Definition: Implementation/Execution is the systematic application of project resources to perform the planned activities, identification of discrepancies, and carrying out of corrective action.)

Experience shows that the way the utility management carries out its responsibilities is critical to the success or failure of nuclear construction projects.

- o This is the major conclusion of an extensive NRC investigation into the reasons for the success and failure of nuclear projects. (NUREG-1055).
- o This conclusion is supported by the industry itself.
- o This conclusion is fully supported by Mr. De Lorenzo's own training and experience.

What this means is that as Project Manager of Comanche Peak, TU could not shift ultimate responsibilities to anyone else.

Several other sources were reviewed to ensure that characterization of the standard was consistent with methods and practices within the nuclear industry. For example, Title 10 of the Code of Federal Regulations was reviewed to determine some of the basic regulatory requirements. Application of these requirements through industry standards, regulatory guides and NRC staff positions, for example, reflected the industry perspective.

Several reports were reviewed which provided evaluations of TU by others within the nuclear community, which also provided additional industry perspective.

IV. ENGINEERING, CONSTRUCTION AND TESTING OF A NUCLEAR PROJECT

A. Brief Description of Engineering/Design

The ultimate objective of nuclear power plant engineering/design is to provide a plant configuration which not only assures the safety of the public and provides a reliable operating plant to the owner, but also provides a design which is constructible. Since the traditional approach is to engineer and design the plant, and then to construct the plant as designed, it is important that the designer consider the capabilities of the constructor in his design.

The engineering/design of a nuclear power plant is typically done in three phases:

Phase 1 - Planning & Conceptual Engineering

Phase 2 - Preliminary Engineering

Phase 3 - Detailed Engineering & Design.

Phase 1 - Planning and Conceptual Engineering

Planning & Conceptual Engineering begins at the utility's decision to commit funds to a new nuclear power plant project and continues through the award of the Nuclear Steam Supply System (NSSS) and Turbine/Generator (T/G) purchase orders.

Some typical tasks during Phase 1 include: Architect/Engineer (A/E) selection; retention of specialty consultants (e.g. Archeology, meteorology, seismology, etc.); site selection studies; NSSS selection; conceptual design studies; preparation of preliminary schedules and costs estimates; preparation of a Project

Quality Assurance Program and a Procedures Manual; preliminary licensing actions; and Turbine/Generator (T/G) selection.

At the end of Phase 1 the basic conceptual parameters of the plant design have been determined. These parameters include site related features, basic NSSS and Balance of Plant (BOP) systems, conceptual building sizes and arrangement, and design analysis parameters including preliminary seismic criteria.

Phase 2 - Preliminary Engineering

Preliminary Engineering consists primarily of those activities supporting the preparation and submittal of the Preliminary Safety Analysis Report (PSAR), which begins once the NSSS Vendor is selected, and the Environmental Report (ER), which is normally begun as part of the site selection process.

Typical tasks of Phase 2 include: establishing plant/system design criteria and requirements; coordinating design and criteria information from NSSS and T/G vendors; preliminary turbine cycle studies and heat balances at NSSS maximum output; and engineered equipment procurement (including supporting calculations).

Preliminary design activities conducted in Phase 2 include the following eight categories:

- Civil/Structural: site arrangement drawings, performance of reactor containment accident pressure transient analysis (to determine containment design criteria and optimum economic size of containment), reactor containment design analysis, preliminary architectural, civil/structural design drawings, and seismic criteria development (Operating Basis Earthquake/Safe Shutdown Earthquake, Amplified Response Spectra).

- Nuclear: accident analysis, radiation shielding analysis, pressure transient analysis, fuel handling/transfer design, review and comment on NSSS information and drawing submittals, establishment of radiation zones, and accessibility and maintenance requirements.

- Mechanical: preparation of engineering and economic studies for establishing plant design features, preparation of Process and Instrument Diagrams (P&ID's) of BOP systems, preparation of General Arrangement drawings (GA's) including consideration for equipment dimensions, clearances maintenance and In-Service Inspection (ISI) requirements from vendors.

- Electrical: preparation of electrical one line diagrams

- Controls: preparation of control system logic diagrams, obtaining design criteria for various systems from equipment vendors.

- Cost and Schedule: preparation of milestone engineering, construction and startup schedules, determination of basic construction sequence, preparation of preliminary cost estimates and cash flow forecasts.

- Quality Assurance: implementation of design QA program.

- Licensing: preparation of PSAR and ER including identification of all applicable Nuclear Regulatory Commission (NRC) Regulatory Guides, codes, standards, regulations and laws that must be met, circulating water optimization studies (cooling tower versus reservoir, reservoir sizing/temperature, evaporation makeup/concentration, etc.), coordination of report input form NSSS vendor and specialty contractors.

Phase 3 - Detailed Engineering and Design

Detailed Engineering and Design begins at the submittal of the PSAR and ER and continues through the construction and startup phase. A significant event during this phase is the submittal of the Final Safety Analysis Report (FSAR).

Activities performed during this phase include: response to NRC PSAR Questions; PSAR Amendment preparation; FSAR preparation and defense; preparation of detailed systems descriptions; preparation of detailed schedules and cost estimates; completion of equipment procurement activities and coordination of vendor activities with construction needs; performance of detailed engineering calculations; preparation of final drawings and release for construction; and engineering support of construction including analysis of field initiated design changes and revision of drawings to incorporate changes.

Engineering Quality - Engineering and design activities must be performed in strict accordance with the Engineering Quality Assurance Program. This program must address the basic Quality Assurance requirements, including those embodied in: 10 CFR 50 Appendix B, ANSI N45.2, and ANSI N45.2.11.

10 CFR 50 Appendix B contains the broadest requirements. Title 10, Code of Federal Regulations, Part 50 (10 CFR 50), Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants - was first proposed on April 17, 1969, and was officially issued on June 27, 1970. The assurance of quality is necessary for the NRC to assure public safety.

10 CFR 50 Appendix B was issued by the Atomic Energy Commission and includes eighteen criteria that every licensee must address in its Preliminary Safety Analysis Report. The Criteria are not detailed prescriptions but rather are standards to be used to evaluate the licensee's Quality Assurance program. The entire eighteen criteria of the Appendix are contained in 5 pages of the Code of Federal

Regulations.

The industry recognized the non-specific nature of 10 CFR 50 Appendix B and wanted to develop a document which would provide more definitive direction. To address this concern, the industry sponsored a second basic document, American National Standards Institute (ANSI) Standard N45.2 - Quality Assurance Program Requirements for Nuclear Facilities (first published in 1971).

The foreword to ANSI N45.2 states:

> "In May 1969, the American National Standards Committee N45 established an ad hoc Committee on Quality Assurance Program Requirements. The purpose of this committee was to prepare a standard for general industry use that would, among other things, satisfy the intent and amplify the requirements of the AEC Quality Assurance regulations and provide a basis for the development of detailed quality assurance practices and procedures."

ANSI N45.2 was adopted by the NRC in Regulatory Guide 1.28 as being generally acceptable and providing an adequate basis for complying with the program requirements of 10 CFR 50 Appendix B.

ANSI N45.2 was accepted by the NRC as general QA guidance. The NRC wanted more specific guidance on the engineering/design phase, however, and began the preparation of a Regulatory Guide. The industry recognized the potential problems of modifying the historical engineering processes and procedures to meet a new NRC Regulatory Guide, so the industry requested the NRC to suspend its effort and allow ANSI to develop an industry consensus standard for Engineering and Design QA. The NRC agreed and the industry developed ANSI

N45.2.11 - Quality Assurance Requirements for the Design of Nuclear Power Plants, which was approved on June 6, 1974.

ANSI N45.2.11 is much more specific in addressing the concerns of design basis, design organization interactions, design verification, and design change control. This document (ANSI N45.2.11) had immediate impact upon the engineering process of some A/E's by requiring independent design verification, and:

> "Documented procedures shall be provided for design changes to approved design documents, including field changes, which assure that the impact of the change is carefully considered, required actions documented and information concerning the change is transmitted to all affected persons and organizations. These changes shall be justified and subjected to design control measures commensurate with those applied to the original design."
> (ANSI N45.2.11, 1974)

ANSI N45.2.11 was adopted by the NRC in Regulatory Guide 1.64.

ANSI Committee Membership consisted of individuals who represented a broad cross section of the organizations involved in the Nuclear Power Industry. This included the Atomic Energy Commission (AEC), the Environmental Protection Agency (EPA), national laboratories, labor unions, technical societies, insurance companies, fuel suppliers, and nuclear steam supply system (NSSS) manufacturers, as well as utilities, architect-engineers, and constructors.

B. Brief Description of Construction

The ultimate objective of nuclear power plant construction is to construct and turnover for testing and operation a facility which assures the safety of the public and provides a reliable operating plant to the owner. A comprehensive Quality Assurance and Quality Control (QA/QC) program is established to ensure that in constructing the plant to the design the construction work performed is of the highest quality and that future problems will not occur during the operation of the plant due to faulty or incomplete workmanship. (In this context, quality assurance can be described as a management tool for ensuring that the plant is built as designed and that defects are corrected.)

The construction of a nuclear power project is generally divided into the following four phases:

Phase 1 - Site Preparation

Phase 2 - Civil/Structural Construction

Phase 3 - Bulk Mechanical/Electrical Installation

Phase 4 - Systems Completion/Turnover

Phase 1 - Site Preparation

Site preparation, which usually begins once a Construction Permit (CP) is obtained, can be started with the receipt of a Limited Work Authorization (LWA). An LWA allows certain non-safety related site construction activities up to placement of first nuclear concrete to commence prior to receipt of the CP. Typical tasks which occur during this phase are:

- Clearing
- Grubbing
- Excavation (mass and structural)

- Placement of Engineered Backfill

Phase 2 - Civil/Structural Construction

The start of Civil/Structural Construction is marked by the placing of first nuclear concrete on the project, which is usually the Containment basemat. Typical tasks which are performed during this phase are:

- Base Mats (Containment, Auxiliary Building, Safeguards Building, Control Building)
- Turbine/Generator Pedestal
- Containment Liner Erection
- Reinforced Concrete Walls
- Floors (Formed Elevated Slabs, Q-decking/Concrete Slabs)
- Cooling Water Reservoir Excavation and Dam Material Placement
- Circulating Water Intake and Discharge Pipe Excavation and Placement

The efforts during this phase serve to prepare the buildings for the commencement of sustained mechanical and electrical installation work. If future access into various areas of buildings is restricted as civil construction progresses, certain large pieces of mechanical equipment and tanks may be set as the building progresses. If the large pieces of equipment are not available, large vertical and/or horizontal construction openings may be blocked out in the major structures to facilitate craft access for the later placement of the large pieces of mechanical and electrical equipment.

The quantities of materials used in civil construction are significantly greater than those encountered in non-nuclear work. The magnitude and volume of the physical plant is enormous due to seismic design criteria, containment of toxic waste in the event of a postulated accident, and measures for protection of the plant from external sources of damage.

Phase 3 - Bulk Mechanical/Electrical Installation

Bulk Mechanical/Electrical Installation begins in earnest with the setting of the NSSS vessels in the Containment. (The NSSS vessels are the Reactor Vessel, the Steam Generators and the Pressurizer.) While some mechanical and electrical bulk commodity installation may have been in progress in the lower elevations of the Auxiliary Building, Safeguards Building and Control Building prior to this point in time, the NSSS vessel placements signal the start of sustained bulk commodity installation. The NSSS vessel sets allow the erection of the large bore reactor coolant pipe spools and other NSSS support systems in the Containment.

Bulk installation of any commodity (e.g. large bore pipe, small bore pipe, wire and cable) usually begins at approximately 10% complete for that commodity and lasts until approximately 90% of that commodity has been installed; major mechanical and electrical commodities are installed on an area basis regardless of system during bulk installation. Quantity targets may be established for weekly and monthly production, and productivity should be at its optimum.

Typical activities which are performed during the bulk installation phase are:

- Placement of large equipment pieces

- Large bore (>2 1/2") pipe installation
- Heating, Ventilating and Air Conditioning (HVAC) duct installation
- Large bore pipe hangers and restraints
- Cable tray supports and cable tray
- Small bore (2 1/2" and under) pipe and supports
- Conduit and supports
- Instruments
- Cable pulling
- Cable terminations

Phase 4 - Systems Completion/Turnover

There are many complex plant systems in a nuclear project. As a result, there are large quantities of mechanical and electrical commodities which must be installed. For example, hundreds of thousands of feet of process pipe are intertwined with similar quantities of cable tray and conduit. Millions of feet of cable must be pulled and terminated (connected) prior to completion of construction.

Two factors are key to successful installation of the commodities to achieve cost, schedule and quality objectives. First, the order of placement of commodities is important because installation out of order can cause interferences between commodities which are costly and time consuming to overcome. Order of placement is also important because certain commodities are easier to install and difficult installation problems are more easily overcome if commodities are installed in proper order. Second, in order to achieve high production and productivity rates, it is important to take advantage of the bulk installation capabilities of the construction crafts. Installing bulks in plant areas is more efficient than installing throughout the plant only those commodities related to a particular system.

The ultimate objective in any major nuclear power project is the successful start-up and commercial operation of the plant. Consequently, at some time point in the construction process there must be a transition between bulk commodity installation and systems completion and turnover. System completion and turnover priorities are driven by the overall start-up schedule and the order in which the start-up organization needs systems and subsystems in order to support their schedule. After transition to the systems completion mode, the construction crafts begin installing the commodities required to complete specific systems. Production in this mode is less efficient than in bulk installation, and therefore it is more costly and time consuming.

C. Brief Description of Testing

Upon completion of construction of the systems which constitute the plant, those systems must undergo testing to determine whether or not all of the structures, systems and components of the plant will perform satisfactorily in service. Testing is usually accomplished in two phases; the first phase precedes the loading of nuclear fuel, and the second phase takes place after fuel loading.

Preoperational testing consists of those tests which are conducted prior to fuel load. Although preoperational tests are generally thought of as pertaining to safety related systems, other tests such as acceptance tests of non-safety related systems are also included within the preoperational testing program.

Initial startup testing consists of those tests conducted after fuel load through commercial operation. These tests are conducted with nuclear fuel in the reactor vessel. The tests consist of precritical tests (prior to initial criticality of the nuclear core) as well as tests leading to and subsequent to initial criticality.

Although preoperational testing and startup refer to the two phases of testing conducted before fuel loading and after fuel loading, respectively, TU often referred to both phases as "startup". From the content of the records, there was no confusion about which phase was being addressed. Consequently, in this report startup will sometimes be used to refer to both phases. If identification of the specific phase is important, the more precise word will be used.

Due to the importance of the testing program, the NRC has established several requirements which pertain to preoperational testing. Appendix B to 10 CFR 50 contains requirements in subparagraph XI- Test Control, for example. Other NRC requirements are contained in Regulatory Guide 1.68.

The initial test program is usually described in Chapter 14 of the Final Safety Analysis Report (FSAR). In Chapter 14, the licensee not only describes the nature and extent of the test program, but more importantly, the licensee makes particular commitments to the NRC related to the test program.

The preoperational test program normally proceeds from relatively small, uncomplicated tests to more complex and larger scale tests. These can be described as follows:

- o Component and subsystem testing - these tests are conducted to verify satisfactory operation of individual components (valves, motors, pumps, etc.) as well as inter-related components which comprise subsystems.
- o System testing - these tests (preoperational tests and acceptance tests) are conducted to verify satisfactory operation of entire systems.
- o Integrated testing - these large scale tests verify satisfactory operation of interrelated systems. Examples of integrated tests are cold hydrostatic testing of the reactor coolant system (RCS Cold Hydro), hot functional testing (Hot Functional), and integrated leak rate testing (ILRT).

Satisfactory completion of the preoperational test program is a prerequisite for fuel loading. Not only do the various tests have to be completed, but the NRC has identified review requirements for test data to determine whether the test procedure and results are satisfactory.

Several milestones characterize the preoperational testing program. Although the program cannot begin until the construction forces have completed plant systems and turned over custody of those systems to testing personnel (system turnover), the usual milestone which indicates commencement of the preoperational testing program is initial energization of the startup transformer. Through initial energization, electric power is available to supply normal plant circuits for testing the plant components and systems. Other major milestones include RCS Cold Hydro, Secondary Hydro, Hot Functional testing, and ILRT, as well as several others.

Industry experience in the late 1970's reflected that completion of the preoperational testing program required approximately two and one half years. An extremely tight schedule for preoperational testing by an experienced organization might be as short as two years (24 months). Our previous review of one class of commercial nuclear plants reflected an average preoperational testing duration of 27 months from initial energization to fuel load.

D. Fast Track Engineering & Construction

In an attempt to minimize the schedule duration for large complex projects like nuclear plants, utility owners generally used the "fast track" approach. Rather than completing all engineering and design prior to commencing construction, which would result in a longer schedule, fast track allowed construction to commence with engineering and design only partially complete. Similarly, testing began prior to completion of construction.

E. Planning, Execution and Control for the Fast Track Approach

Use of the fast track approach placed more stringent requirements on planning, execution, and control. For example, since engineering and design were less than totally complete prior to commencement of construction, it was important that the necessary engineering and design to support the initial construction effort had been completed prior to beginning construction. Furthermore, it was also important that completion of engineering stayed well ahead of construction at all times.

Nuclear project experience in the 1970's highlighted the importance of completing as much engineering as possible before starting construction. In fact, successful owners and contractors recognized that a reasonable target was to have initial engineering and design approximately one-half done prior to starting construction. Beginning construction with less than fifty percent of engineering/design complete entailed additional risk.

Nuclear project experience in the 1970's also indicated the importance in construction of making a timely transition from the bulk commodity installation mode to the systems completion mode. This was required to accommodate the fast track relationship of construction and testing. This meant that in order to support the testing program, as systems were completed by construction, they could be turned over to preoperational testing personnel for subsequent testing of those systems leading to fuel load. As a result, the sequence of system turnovers from construction to testing was important.

It is important to note, however, that although rules of thumb such as 50% engineering complete prior to beginning construction are useful, it is most important that the right 50% be done. This means that the planning function must identify very carefully the engineering and design activities which are required to support construction activities, and that construction activities must be identified which are required to support testing activities. (In the terminology of project management, the schedules must be integrated.) This also means that the activities must be performed according to the plan in order that the preceding activities be completed to support subsequent activities; control is required to insure that deficiencies in activity execution are identified and corrected.

F. Major Differences From Fossil Projects

Nuclear projects differ from fossil projects in at least two respects. First, there are regulatory differences based on the regulatory role of the Nuclear Regulatory Commission (NRC), formerly the Atomic Energy Commission (AEC). Second there are project differences, based on the substantial differences between the fossil heat source and the nuclear heat source.

Regulatory differences for nuclear projects first became apparent with passage by the U.S. Congress of the Atomic Energy Act of 1954. From the very beginning, nuclear power was recognized as being different from fossil fuel power.

Regulatory differences for nuclear projects became even more apparent at least as early as 1969 and 1970 with the development of 10 CFR 50 Appendix A and Appendix B. Appendix A, entitled "General Design Criteria for Nuclear Power Plants," provides a detailed listing of design criteria. Appendix B, entitled "Quality Assurance Criteria for Nuclear Plants and Fuel Reprocessing Plants," which was issued in

1970, describes the criteria for assuring the quality of the project. Additional requirements, in the form of Safety Guides and Regulatory Guides, also were beginning to be issued at that time as the regulatory climate for nuclear projects changes. There are no similar regulatory requirements for fossil projects.

The Atomic Energy Act and 10 CFR 50 also require that a utility possess a Construction Permit (CP) prior to commencing construction of a nuclear project. A Limited Work Authorization (LWA) allows the utility as the licensee to begin site work before obtaining a CP under certain circumstances. An Operating License (OL) is also required to operate a nuclear plant. The application for a Construction Permit includes a Preliminary Safety Analysis Report (PSAR), which is reviewed in great detail by the NRC staff. The application for an operating license includes a Final Safety Analysis Report (FSAR), which is also reviewed in great detail by the NRC staff. Again, there are no similar requirements for fossil projects.

In order to facilitate the role of the utility as the licensee in a changing environment, the NRC in 1973 and early-1974 issued a series of books (the Rainbow Books) which addressed the regulatory environment for engineering and design, construction, and operation of nuclear plants. Once again, there were no similar requirements nor was there similar guidance for fossil projects.

One other regulatory difference is noteworthy. A nuclear plant was required to be constructed as designed; there was no latitude for construction on its own to improvise on the design for the sake of constructibility. Fossil plant construction had much more latitude for improvisation. In fact, on a nuclear plant, it was also necessary to verify that the as-built configuration of components, structures and systems satisfied the original design criteria. For fossil construction, on the other hand, it was sufficient to document the as-built configuration without any further analysis.

The second set of differences between fossil and nuclear projects relates to the projects themselves. Nuclear was recognized by many utilities very early as being much more complex than fossil, and those utilities that achieved success acknowledged that nuclear was different!

Although nuclear generated electricity was viewed as being less expensive than fossil generated electricity, the cost components of nuclear generated electricity were different from the cost components of fossil generated electricity. For example, nuclear projects were recognized as being capital intensive; fossil projects, on the other hand, required less capital to construct them, but their fuel costs were a higher proportion of the ultimate electricity cost. The capital cost of nuclear plants was significantly greater than the capital cost of fossil plants.

The increased capital costs of nuclear plants reflected, among other things, that there were more construction commodities in a nuclear plant. There were higher quantities of process pipe, for example, as well as higher quantities of wire and cable. Quality Assurance/Quality Control also increased the difficulty of commodity installation as reflected in installation unit rates. These higher quantities and installation difficulty contributed to the complexity of nuclear projects.

In addition, because of the greater complexity of the project, the schedule duration for nuclear plants exceeded the schedule duration for fossil plants.

Finally, the documentation required to support a nuclear plant was recognized as being much more extensive. The procedural requirements were greater, and the documentation required to verify the adequacy of design, construction, and testing was also greater. These documentation requirements further contributed to the concept that nuclear was different from fossil fuel, and posed many more potential problems.

G. Public Health and Safety Requirements

The NRC is responsible for the health and safety of the public as it pertains to commercial nuclear power plants. It is not responsible for the quality or lack of quality of the nuclear power plant itself.

It is the utility as the licensee which is responsible for achieving and assuring the quality and reliability of a nuclear power plant. Even though the utility may delegate certain responsibilities to contractors and subcontractors, ultimate responsibility is retained by the utility as the licensee.

In the face of improper behavior on the part of the utility as the licensee in the design and construction of a nuclear plant, the NRC can still fulfill its responsibility as it pertains to public health and safety. The NRC, with its authority for issuing an operating license, can assure the public health and safety by denying issuance of the Operating License to the utility which has failed to meet its safety obligations. Thus, if the utility as the licensee has not fulfilled its commitments for building a safe plant, the NRC will deny the Operating License. Moreover, since the utility will be responsible for operating the plant after it is placed into Commercial Operation, the NRC also must have confidence in the capabilities of the utility operator before issuing an OL.

H. Conclusion

As evidenced by this chapter, nuclear power poses considerable complexities and problems beyond the demands of a fossil fuel project. Nuclear projects require the creation of a completely new set of design and construction criteria, increasingly more complicated designs, and a greater emphasis on safety and quality. As Project Manager of Comanche Peak, TU had the responsibility to be aware of these differences and to incorporate them into its planning, control and execution of plant design and construction. As this report examines the history of Comanche Peak design and construction, the standards outlined in these introductory sections will serve as guidelines to assess TU's failure to fulfill this responsibility.

V. THE COMANCHE PEAK NUCLEAR PROJECT (CPSES)

A. Brief Description of CPSES

The Comanche Peak nuclear project is a two unit nuclear plant under construction approximately 65 miles southwest of the Dallas-Fort Worth Metropolitan Area of Texas. The nuclear steam supply system (NSSS) for each unit is a pressurized water reactor (PWR) rated at approximately 1150 megawatts of net electrical output. The NSSS was supplied by Westinghouse. The turbine/generator was supplied by Allis-Chalmers.

Each reactor is enclosed within a containment building. The containment buildings are reinforced concrete cylinders with steel liners and hemispherical domes.

The project was initially announced in 1972. The original cost estimate for the project was $779 million. At that time the units were scheduled to begin commercial operation as follows:

- Unit #1 - January 1980 (Fuel Load - 3/79)
- Unit #2 - January 1982 (Fuel Load - 5/81)

In order to understand the electrical capacity of the plants, it should be recognized that a city with a population of approximately 500,000 people utilizes approximately 1000 megawatts of electricity. Consequently, it was envisioned that upon completion each unit at Comanche Peak would provide electricity equivalent to the requirements of a city approximately the size of Austin.

B. Project Chronology

The following is a listing of some of the major events which have occurred over the history of the Comanche Peak project and which are of particular relevance in this report.

- Project announced - 7/72
- Westinghouse NSSS selected - 7/72
- Gibbs & Hill contracted as architect/engineer - 8/72
- Brown & Root contracted as constructor - 2/73
- Construction Permit application submitted to NRC (PSAR) - 7/73
- Limited Work Authorization (LWA) - 10/74
- Construction Permit (CP) - 12/74
- First nuclear (safety-related) concrete - 7/75

- Startup program plan approved - 5/77
- Operating license application submitted to NRC (FSAR) - 2/78
- Unit #1 reactor vessel set - 5/78
- TMPA signed JOA - 1/79
- Brazos signed JOA - 6/79
- First system turned over - 6/79
- Brazos received REA approval and closed JOA - 12/79
- Initial Energization of Startup Transformer - 1/80
- Tex-La letter of intent - 5/80
- Tex-La joined JOA - 12/80
- Tex-La final closing on JOA - 5/82
- RCS cold hydro - 7/82
- Secondary hydro - 7/82

- o Hot functional test completed - 5/83

- o Nuclear fuel on site - 5/83

- o Test of emergency plan - 12/83

- o Initial core on site - 1/84

C. Early Schedule to Accomplish Project Milestones

In April 1973, Brown & Root provided a master construction schedule to TU for Comanche Peak. That schedule reflected obtaining a Limited Work Authorization in October 1974 and a Construction Permit in March 1975. At that time, the scheduled date for commercial operation of Unit #1 was January 1980; the scheduled date for commercial operation of Unit #2 was January 1982.

Intermediate milestones for Unit #1 on that schedule were the following:

- o First nuclear concrete - 7/75
- o Unit #1 nuclear vessel set - 5/77
- o RCS cold hydro - 1/79
- o Hot functional test - 3/79
- o Fuel load - 5/79
- o Commercial operation - 1/80

D. Project Progress and Status Prior to 1977

By the end of 1976, progress on the project had fallen behind the original schedule. Although the construction permit had been obtained approximately 3 months ahead of schedule, between issuance of the CP and late 1976 the project had experienced delay. In fact, in October 1976 the scheduled commercial operation date for Unit #1 was slipped by TU from January 1980 to January 1981. The schedule for Unit #2 remained unchanged at January 1982.

The status of engineering products issued by Gibbs & Hill at the end of 1974 (Construction Permit issued in December 1974) was as follows:

- o Structural drawings - 13
- o Mechanical drawings - 16
- o Specifications - 51
- o Purchase orders - 3
- o Bid evaluations - 18

In December 1976, Gibbs & Hill was reporting the status of engineering and design as follows:

- o Design - 44% complete
- o Engineering - 37% complete

In their December 1975, progress report, Gibbs & Hill reported the following:

- o Equivalent drawings complete - 40%

o Specifications issued - 57%

TU began investigating startup activities and their relation to the startup schedule in 1975. The startup engineer retained at that time (R.E. Camp of Impell) indicated that the original startup schedule was to be performed within a six to seven month period. This was required to support fuel load in 1979. It was apparent to Camp that there was insufficient time in the schedule to accomplish the testing.

Also in 1975, TU had some indications that Gibbs & Hill did not fully understand the regulatory requirements for engineering and design which had been issued by the NRC. In reviewing a Gibbs & Hill request for additional compensation, TU's Manager of Quality Assurance (H.C. Schmidt), stated the following:

> "At the date of our contract, G&H had in existence a QA program document, which although claimed to be in "agreement" with Appendix B did not <u>fully comply</u> with Appendix B requirements." (emphasis in original)
>
> (H.C. Schmidt memo to J.L. Forbis dated 8/18/75)

Prior to the end of 1976, TU also had obtained some evidence that Brown & Root was not doing what it had to do to meet NRC requirements. TU's findings were confirmed by the NRC.

> "The Brown & Root, Inc. (B&R) QA/QC Manual for Nuclear Projects, Construction Phase, Volume II, was found to be unacceptable to TUSI in that the Manual was deficient in meeting applicable portions of 10 CFR 50, Appendix B."
>
> (NRC letter to Perry G. Brittain dated 7/11/74)

B&R's system for handling nonconformance also was questionable and could lead to future problems.

> "I believe that your present system for the handling of non-conformance is vulnerable and, if not modified may, some years hence, result in a mandatory review by the ASLB as have others similarly structured."
>
> (Joseph M. Varela letter to T.H. Gamon dated 2/6/76)

VI. ENGINEERING/DESIGN OF COMANCHE PEAK

The analysis of the Engineering/Design of Comanche Peak began with a review of the various documents resulting from the reinspection/reverification effort. These documents included, for example, ASLB orders and memoranda, CAT and TRT inspection reports, ISAP reports, DSAP reports, other CPRT documents and witness deposition transcripts. Problems identified in these documents were analyzed for possible engineering origins.

These analyses led to reviews of project engineering documents and correspondence to understand the genesis of particular problems. Seemingly unrelated technical problems were traced to documents which often indicated a relationship associated with a common engineering technique or management action.

A. Planning and Control of Engineering/Design

Evolution of the Gibbs & Hill (G&H) Contract

The contract between Texas Utilities and Gibbs & Hill for the engineering of CPSES has undergone several revisions. The evolution of the contract and significant changes to the contract are summarized below:

12/23/71 Gibbs & Hill Letter proposal to Texas Utilities to Evaluate the NSSS Vendor Proposals

08/15/72 Texas Utilities and Gibbs & Hill signed a cost reimbursable plus fixed fee ($2.29 million) CPSES Engineering Contract.

05/26/73 Engineering Contract Supplement Number 1 - TU agreed to exercise options offered in the original contract including Supplemental Field Services, Expediting and Shop inspection Services, and additional Quality Assurance Services. (J.L. Forbis explained that this would increase TU's responsibility for construction management)

> "...we have reduced the scope of G&H field services from 'Construction Management' in the original option to 'Supplemental Field Services'...with resulting smaller number of G&H field based personnel..."
>
> "This arrangement will increase the TUSI field staff in number and responsibility."
>
> (J.L. Forbis memo to the Administrative Committee dated 6/6/73)

04/26/74 Engineering Contract Supplement Number 2 addressed two items:

TU contract responsibilities were reassigned from TUSI to TUGCO and,

Required Gibbs & Hill to develop a Quality Assurance (QA) Program which complied with 10CFR50, Appendix B, and ANSI Standard N45.2.11 (Adopted after AEC inspection of Gibbs & Hill raised questions about the A/E's QA Program.)

07/26/74 Engineering Contract Supplement Number 3 increased Gibbs & Hill fee by $41,600 for reorienting the Turbine-Generator in response to AEC turbine blade missile questions. (TU's initial opposition to this change was an early example of its reluctance to recognize and to accept improvements required by the NRC)

01/19/76 Engineering Contract Supplement Number 4 documented a Quality Assurance item from a PSAR Amendment 2 requirement. Gibbs & Hill increased their fee by $C9,000 for ANSI N45.2.11 Design Verification. (TU QA Manager Schmidt disagreed that G&H should be given an increase in their fee. He wrote in a memo that G&H had told TU they had an acceptable QA program. Schmidt stated that the requirements of N45.2.11 were not new and therefore were not an increase in G&H's scope.)

06/30/77 Engineering Contract Supplement Number 8 introduced a Manhour Target Incentive/Penalty clause of $6/MHR for the difference from 1,000,000 Manhours of current scope work up to a maximum of $720,000.

01/15/78 Engineering Contract Supplement Number 9 established a 6% fee for the Dallas Office pipe support design effort. (TU was contracting for pipe support design services at a time when pipe supports should have been in the process of being installed.)

01/15/80 Engineering Contract Supplement Number 10 acknowledged the scope and magnitude had grown beyond what either party anticipated. G&H agreed to place a full time senior company official in charge of the work in 1979. They also agree to furnish additional staff and services at the locations and of the types requested by TUGCO. (This reflects extremely late recognition of an increase in project scope which apparently was not included in the existing schedule.)

06/23/81 Engineering Contract Supplement Number 11 eliminated the manhour target incentive/penalty clause when G&H paid TU $360,000. (Four years after the clause was adopted as a method to "hold G&H's feet to the fire" it was dropped.)

02/01/84 Engineering Contract Supplement Number 13 benefitted Gibbs & Hill by including an Owner Full Control Clause, and reducing G&H's liability. Contract expiration was extended to February 1, 1985.

12/21/87 Wall Street Journal Article announced agreement between TU and G&H to settle all outstanding CPSES issues for $25 million to be paid to TU in an unspecified combination of cash, deferred payments, and discounts on future work.

Evolution of the Estimate of Engineering Costs

The estimate of Gibbs & Hill engineering costs increased dramatically over time. The following is a table of the engineering budget over time developed from several documents obtained in discovery:

July 26, 1972	$18,590,000.00
January 2, 1975	$39,605,000.00

October 31, 1975	$45,351,000.00
May 4, 1976	$60,000,000.00
December 6, 1976	$76,000,000.00
June 9, 1978	$105,384,685.00
December 1, 1978	$117,200,000.00

This is not a complete history of the CPSES engineering budget increases because the last entry is in late 1978. A regression line fit to the last five data points shows G&H's budget was growing $1.8 million per month at a time when G&H's invoices appear to be in the range of $2 million per month.

The increase in G&H's budget became a major concern to TU. The contract supplement #8, signed on June 30, 1977, was the direct result of TU's efforts to "keep G&H's feet to the fire" in an effort to maintain the budget. Restricting the growth of G&H's budget in this critical phase of engineering eventually led to many of the problems which later occurred at CPSES. TU used several different techniques to restrict G&H, only to discover years later they would have to increase the site engineering staff to over 400 people in an attempt to address the problems caused by inadequate engineering. It is noteworthy that the 1981 G&H invoices totalled $30 million, and the 1981 invoices of the other consultants totalled $19 million. ($49 million was spent on these services in 1981; in December 1978, the total engineering budget was approximately $117 million.)

An estimate of Gibbs & Hill's total billings for 1974 thru 1984 is from $175 million to $210 million. (This is based on TU's report of 7.2 million Architect/Engineer manhours over this time span.) Additional information about the total cost of A/E services is being sought in order for this analysis to be more precise.

The July 26, 1972 estimate of $18.5 million implies a man-hour total of approximately 1 million (1972 engineer manhour cost is estimated to be between $15 per hour and $20 per hour.)

(These estimates will be replaced with actual expenditure figures as they become available.)

Engineering Manpower Expended vs. Time

TU provided the following table to Cresap, McCormick and Paget (CMP) in response to a prudency audit question:

Year	Constructor (mhrs)	% of '84 Total*	Architect/ Engineer (mhrs)	% of '84 Total*
1974	121,887.	0.2%	331,324.4	4.5%
1975	2,226,077.	3.2%	473,383.8	11.0%
1976	4,537,979.	9.5%	671,384.3	20.3%
1977	5,453,185.	17.0%	512,772.4	27.3%
1978	8,303,559.	28.5%	855,536.9	39.1%
1979	9,444,790.	41.5%	1,210,571.2	55.7%
1980	8,400,809.	53.1%	724,714.2	65.6%
1981	7,545,762.	63.5%	674,486.2	74.9%
1982	9,605,966.	76.8%	749,670.8	85.2%
1983	9,475,252.	89.8%	626,276.6	93.8%

1984	7,358,477.	100.0%	452,400.4	100.0%
Total*	72,473,743.		7,282,521.2	

(*NOTE: Totals and percentages not shown on original.)

As will be described later, these statistics reflect the inadequate lead time of engineering relative to construction.

This tabulation is incomplete because it does not contain Architect-Engineer manhours for the years 1972 and 1973 nor data for the years 1985, 1986, and 1987. It is also unclear how, and if, any of the site engineering effort was included in these figures.

The 7.3 million manhour total for Architect/Engineer manhours is expected to grow, when the missing data is added, to a number exceeding 8 million manhours. This is approximately eight times greater than the original July 1972 engineering estimate.

Significance of 1977 A/E Manpower Reduction

During the 1976-1977 time frame, TU's actions demonstrated their lack of comprehension of the seriousness of the problems at hand. Prompt and meaningful response to situations requiring management attention is essential to the success of a nuclear project. In response to the coordination problems of 1976 and 1977, TU did not act promptly or meaningfully. Instead, TU imposed budget limitations on engineering/design and continued to stress the overwhelming importance of maintaining schedule.

The A/E manhour tabulation shows a reduction in 1977 A/E manhours relative to 1976. This is in contrast with an increase in the constructor's manhours for the same year. This 1977 reduction was corroborated in the deposition of Mr. Ed Gibson, TU Project Engineer during this time period. Mr. Gibson explained that TU was under a corporate cash flow restriction due to bond rating concerns.

1977 was a critical year for the engineering of CPSES. The constructor was focusing all of its efforts on the civil/structural work leading to the May 1978 milestone of setting the Unit #1 Reactor Pressure Vessel. The constructor was continuously asking for assistance from the A/E. The A/E was also producing the Final Safety Analysis Report (FSAR) which was submitted to the NRC in February 1978 as the first step toward obtaining an Operating License.

The A/E in 1977 was thus: providing solutions to urgent civil/structural construction problems; preparing a critical and lengthy licensing document; and reducing the number of outstanding vendor drawings in response to QA Audit TGH-4 (explained in greater detail below). In 1978 serious problems in the installation of electrical and mechanical items began to manifest themselves. Reduction of engineering resources in 1977 limited the accomplishment of mechanical and electrical drawing development which was a major cause of the subsequent mechanical and electrical problems.

These mechanical and electrical installation problems plagued CPSES throughout the remaining construction period and were a major focus of the CPRT. The techniques employed by TU, in an attempt to complete construction in an unreasonably short time frame, led to the massive design change document backlog, the Walsh/Doyle allegations, the "At-Risk" field design change procedure, and the ASLB order to perform independent design verification.

In the tight cash flow year of 1977, CPSES experienced a 43% shortfall in anticipated payments to Gibbs & Hill equipment vendors. There are no indications in the documents reviewed that this shortfall was planned. This shortfall should have provided additional evidence that the vendors were unable to proceed as planned into the equipment fabrication phase.

This shortfall was consistent with the method utilized to respond to the major deficiency identified in TU's Audit TGH-4 of G&H in October 1976. This audit cited Gibbs & Hill with violating their Project Guide requirement regarding the length of time taken by G&H to review and approve vendor drawings.

Gibbs & Hill explained that the submitted drawings represented a large number of vendor technical problems which required unexpectedly long time periods to resolve. G&H implied that resolution of the problem was hampered by limited manpower resources. TU's response was critical of G&H's suggestions to increase personnel and TU re-emphasized G&H's commitment regarding the time period for drawing review. G&H later replied that they had "re-evaluated" their procedures and had "re-emphasized" the importance of drawing turnaround time. G&H reported they had succeeded in achieving a significant reduction in the number of delinquent drawings without increasing manpower. This response was silent about the original concern of resolving vendor technical problems.

This response and, later, the unexpected 1977 vendor progress payment total shortfall, implies that the reduction in overdue vendor comment drawings did not resolve vendor technical problems. Gibbs & Hill responded to the symptom of the number of overdue vendor drawings but did not correct the underlying root cause of unresolved vendor technical problems. The unresolved problems would later manifest themselves in incomplete G&H Construction drawings and in equipment delivery delays.

Status of Engineering/Design Products vs. Time

Engineering Products (Drawings, Specifications, SAR Sections, etc.)

There is evidence that G&H: did not comprehend the magnitude of the engineering effort; was unable to execute vendor equipment orders expeditiously; did not issue construction release drawings in a timely manner; and was unable to support construction requests. The extent of the problem is reflected in the following table:

Year	Cumulative PO's*	% of 1984 Total PO's	Cumulative Drawings	% of 1984 Total Drawings
1973	0.	0.0%	0.	0.0%
1974	0.	0.0%	29.	0.0%
1975	3.	1.4%	989.	1.5%
1976	47.	22.5%	3794.	5.6%
1977	161.	77.0%	7479.	11.0%
1978	181.	86.6%	12230.	18.0%
1979	199.	95.2%	19967.	29.4%
1980	209.	100.0%	29296.	43.1%

1981	209.	100.0%	40077.	58.9%
1982	209.	100.0%	48138.	70.8%
1983	209.	100.0%	59645.	87.7%
1984	209.	100.0%	68025.	100.0%

Reference: TU response to CMP request for G&H products by year, dated 6/24/85

*Note: PO's are Equipment Purchase Orders

By the start of construction in October 1974, Gibbs & Hill had less than one tenth of one percent of the drawings completed and not a single equipment purchase order had been placed beyond the basic NSSS and T/G orders.

TU was also badly mistaken about the status of engineering in July 1977 when Mr. Fikar wrote:

> "Engineering is not the major problem - we are well ahead in this area. Admittedly there are more irritants - such as the need to complete holds on some drawings for equipment foundations - but these are being worked on. We can turn loose the purse strings and get all the engineering support needed if necessary."
>
> (L.F. Fikar note to P.G. Brittain)

Measurement of Engineering Percent Complete

The table in the previous paragraph reflects the engineering products method of determining engineering progress. Using this method, CPSES construction completion (see table on page VI-5) was ahead of drawing completion for the entire 1974 to 1984 time period. It can be argued this method under-represents engineering progress because work performed prior to the issuance of a document does not receive credit until issuance of the document. This may be particularly true at CPSES later in the project's history because drawing revisions were purposely delayed through the use of several types of design change documents.

Another common method of measuring engineering progress is to calculate the percent of the engineering manhours budget which has been expended. This method can be very misleading if the engineering manhours budget is not a true reflection of the entire engineering effort. After the fact, this method can determine where the project stood at any particular point by dividing the expenditures to date into the actual total. This calculation is shown in the table on page VI-5; this analysis shows that CPSES engineering led construction by only 10% to 15% throughout most of the project. By either method, engineering was not far enough ahead of construction.

As described earlier, 50% engineering completion at the time of issuance of the construction permit was a reasonable target on nuclear power plant projects. Projects which fell significantly below this target still may have been successful if they had anticipated and managed the greater coordination burden between the engineering and construction efforts. The smaller the relative difference between engineering and construction, the greater the coordination burden.

A project with only 10% to 15% difference (or less) between engineering and construction would suffer inefficiencies in engineering and construction because there was very little time available to overcome a drawing omission or to clarify an ambiguity before it impacted the construction schedule.

This coordination effort had to be carefully planned and managed if it was to be successful. TU did not anticipate the magnitude of this effort; this is obvious when one compares the previously cited 1973 memo from J.L. Forbis to the Administrative Committee with Mr. J.B. George's words in his February 1981 letter to F.D. Hutchinson of Gibbs & Hill:

> "Furthermore, G&H must face up to the fact that they must share a good part of the responsibility for the CPSES delay! This based on the fact that engineering being late or inaccurate has cost the project millions of dollars for delays and rework."
>
> "This is evidenced by the fact that I now have over a 400 man engineering staff on site reengineering the project at a cost of millions."

Gibbs & Hill's Relationship with Owner and Constructor

TU had worked with Gibbs & Hill before Comanche Peak. Gibbs & Hill had been the engineer on four recent TU fossil plants: TESCO's Eagle Mountain Unit 3 and Handley Station Units 4 and 5, and, TP&L's DeCordova Station.

G&H had prior European nuclear experience, mostly in conjunction with Westinghouse. Their only U.S. nuclear experience was on the Fort Calhoun nuclear plant, which had been scheduled to be completed in 1972. In 1971, TU assigned G&H the task of preparing specifications and evaluating the bids for the NSSS and T/G equipment orders.

The early project activities consisted of the conceptual engineering studies, the preparation of the PSAR, and major equipment procurement. There were signs of early G&H problems: QA program implementation; delays in the placument of equipment purchase orders; site cooling water system design; containment pressure calculations and size; and turbine generator orientation.

Documents from the October 1976 time period indicate a deterioration in Gibbs & Hill's performance. TU announced the scheduled Commercial Operation Date was delayed from January 1980 until January 1981; they cited delays in the civil structural work associated with QA and engineering problems.

In October 1976, TUGCO QA Audit TGH-4 was critical of G&H's management of the procurement and vendor coordination process. G&H's early response implied a shortage of manpower. TU's reply indicated their perception of a lack of G&H efficiency. This audit was not closed out for a year a half, after the G&H QA Manager had been replaced because of TU QA displeasure.

> "G&H-QA problems blamed on manpower reduction."
> (Summary of TUGCO briefing March 8, 1978)

> "Further, please be aware that as a result of TUGCO QA's displeasure, Mr. Norman Hyman has been moved from the CPSES project as Manager of quality assurance. His duties will be taken up by Mr. Jospeh Jusko, who will be reporting directly to Mr. Frank Mele. Also, I was somewhat concerned to find that the QA moves will mean some additional people being added to the job. Harvey Rock told me that the QA was requesting about 600 mandays to be added."
> (J.B. George memorandum to H.O. Kirkland dated 3/6/78.)

There were serious difficulties in coordination between Gibbs & Hill and Brown & Root in the early 1977 time period, as described in the following:

"It is becoming more and more evident that getting Gibbs & Hill to cooperate with our field construction group is getting more and more difficult. ...."

"....I do think that TUSI management should be made aware that G&H has not cooperated and appears to have no intention of cooperation with Brown & Root field forces. And, with this new target manhours program, it won't help resolve the situation."
(Memo, H.C. Dodd, Brown & Root Project Manager, May 31, 1977)

Engineering/Design Interaction With Construction

G&H made several references to their inability to respond to Brown & Root field problems beginning in early 1977. These included:

"C. New Problem Areas

"It is anticipated the escalating number of field problems combined with the cap on expenditures will seriously affect production of design drawings."
(Gibbs & Hill Monthly Progress Report, March 1977)

and:

"C. Problem Areas

"The number of vendor and field problems requiring significant expenditures of home office design and engineering resources continues to escalate."
(Gibbs & Hill Monthly Progress Report, May 1977)

Gibbs & Hill found it difficult to perform as their workload continued to expand and their efforts were constrained by TU budgetary limitations.

An example of this is the following:

"4. TUSI (LFF) will be responsible for the $196 (million) figure for client costs. Action to be taken: TUSI (LFF) will hold G&H's (RG) feet to the fire on engineering through target man-day or other guarantees with appropriate incentives/penalties.

5. TUSI(LFF) will get together with B&R and G&H to

make sure there are no gaps in the interface between engineering each is doing --example, "Who does the construction detail drawings?"

(Memo to CPSES File, April 20, 1977 by L.F. Fikar of decisions made in high level meeting of TU/G&H/B&R.)

Note: "Client Costs": largest single component is Gibbs & Hill costs. LFF refers to LF Fikar, RG refers to Roy Gordon, G&H President.

Mr. Fikar's question about "who does the construction detail drawings" is shocking. This question should have been addressed and resolved during the formation of the Brown & Root contract. For it to appear two and one half years after construction had started indicates that it was either not resolved during the construction contract formation or the detailed responsibilities had been modified. With separate engineering and construction firms this important area of coordination must be managed by the owner. If the owner is holding the engineer's "feet to the fire" at a time when the NRC's safety and quality concerns are increasing the engineer's effort, the engineer would have an incentive to shift the burden of detailed construction drawings to the constructor. Leaving this important issue unresolved was a serious indication of mismanagement which led to many of the later problems.

B. Execution/Implementation of Engineering/Design

Some of the other A/E firms considered by TU were larger and had significantly more domestic nuclear experience than G&H. TU documents indicate Gibbs & Hill was chosen over these firms because it had an intact nuclear project team coming off of the Fort Calhoun project, and none of the other firms could offer a similar team. TU documents also indicate that TU was concerned the other A/E organizations were too busy and too large to provide the senior management attention TU wanted. TU stated in the Cresap, McCormick and Paget (CMP) prudency audit responses that they were able to negotiate a contract with G&H with commercial terms beneficial to them. Specifically, TU cited the use of a fixed fee rather than the often-used percentage fee. The original TU - Gibbs & Hill contract contained liability terms more favorable to the owner than other A/E's were willing to accept at that time.

The larger firms also had attributes that TU documents do not address: for example, their size and volume of multiple ongoing nuclear projects allowed them to benefit from cross fertilization, and their financial ability allowed them to hire and retain highly specialized individuals and to share them between multiple projects. A smaller firm would have to defer to an outside consultant or to forego the service. Retaining as much engineering work as possible in-house allowed the larger firms to retain greater control as well as the ability to respond to increasing NRC safety and quality concerns.

An example of the additional resources a large A/E firm could command were the senior technical personnel who represented their firms on various industry organizations and code committees.

Bechtel, Ebasco and Stone & Webster, for example, all had representatives on the ANSI N45.2 committee. Gibbs & Hill did not. Having personnel on these committees allowed the larger firms to better understand the direction of future codes and standards, to influence their direction, and to plan for and to accommodate their effects.

In an effort to provide more timely response to field requests G&H opened a Dallas office in 1977. This office was assigned responsibility for small bore pipe support design and included a field support group which would respond to Brown & Root field requests. The 6% fee established in Supplement #10 indicated that the small bore pipe support design was an addition to G&H's scope and was not previously assigned to them.

Also in 1977, G&H assigned additional experienced engineering personnel to the site in response to TU requests. In September 1977, at TU's request, the field support group responsibilities were transferred from the Dallas office to the site. G&H continued to increase the number of site assigned personnel through the remainder of the project. G&H site personnel peaked at a number exceeding 130.

The G&H site assigned engineering personnel were initially under the direction of G&H supervisory personnel. Over the life of the project, as described below, these personnel were reorganized into groups under the direct supervision of TU employees.

Over the life of CPSES, G&H was faced with increased NRC safety and quality requirements including: more sophisticated seismic analysis; Browns Ferry related fire protection issues (Appendix A and Appendix R); I&E Bulletins 79-02 and 79-04; "As-Built" Stress Analysis required by 79-14; and TMI Impacts. They failed to respond satisfactorily.

Gibbs & Hill took a number of actions either with the intent to minimize their manday expenditure or as a result of TU restrictions on their manday expenditures. These included: inadequate vendor design review leading to field problems; inadequate interdiscipline design review contributing to interferences and other field problems; minimizing the number of construction drawings they produced through the use of typical drawings used for multiple installations; assigning large amounts of piping and pipe hanger engineering to vendors; and relying on the constructor to prepare large numbers of detail drawings.

Actions Taken by TU Relative to Engineering/Design

TU began CPSES by performing various early studies and preparing reports in close coordination with G&H. TU allowed Gibbs & Hill to proceed in performing its responsibilities with minimal direct TU oversight. The PSAR was prepared and submitted, and after resolution of several problems, an LWA was issued in October 1974, and the CP was issued in December 1974. The NRC had criticized TU's early quality performance, and the ASLB threatened to hold up LWA hearings because of these problems. Only quick revisions to Gibbs & Hill's Quality Assurance Program allowed the hearing to be held as scheduled.

Gibbs & Hill's budget estimate increased in the 1975-1976 time period. This increase was attributed by G&H to be the result of the NRC increasing safety and quality concerns. A memo from Homer Schmidt in August 1975 discussed G&H's request for a fee increase for adoption of ANSI N45.2.11; Mr. Schmidt stated he disagreed with Gibbs & Hill's justification and with the amount of the particular increase. A second memo from J.R. Ainsworth in 1977 questioned the validity of G&H's estimate of effort for the auxiliary feedwater system modifications made to satisfy NRC safety concerns. These memos and several letters admonishing G&H to be more efficient indicates that TU did not accept G&H's increasing cost justifications.

Beginning in late 1976, TU took several actions to assert itself over the engineering effort to a greater extent than seen previously: TU reduced the number of G&H personnel assigned to the job due to cash flow restrictions; TU assigned a full time representative to the New York Office who took an active role in directing the day-to-day effort (to the extent that he authored and signed G&H letters); TU scrutinized the Dallas office effort; TU modified the engineering contract to include a manhour incentive/penalty clause; TU took direct responsibility for some equipment and material procurement; TU took responsibility for coordination of pipe and pipe hanger delivery; and TU began a long series of organizational changes to increase the engineering capability at the site and their control over it.

Impacts of TU Efforts

TU's actions to exert greater direct influence over the engineering of CPSES were in response to their perceptions of the dual problems of escalating engineering costs and lack of timely engineering support of the construction effort. TU was faced with the consequences of an architect/engineer who was not performing adequately either because of inadequate resources or because of misapplication of those resources.

Many of TU's efforts initially were conceived with the objective of maintaining the construction schedule. Their efforts, however, were either not thoroughly cc eived, under staffed or a combination of both. For example, installation interferences, due to a variety of causes ranging from incomplete engineering before construction proceeding, inadequate design engineering detail, inadequate interdiscipline design review, field changes, and increasing NRC safety and quality concerns, became the major construction schedule problem. The effort to respond by bringing more engineering responsibility to the site and changing the organization through evolution created a large and very confusing organization. In an effort to maintain some construction progress, TU relaxed several of the QA procedural requirements. This led to the "At-Risk" field design change process.

C. Problems in Engineering/Design of CPSES

There were numerous problems with the Engineering/Design of CPSES. These include:

Early Problems With Engineering and Design

The first meeting between TU and the NRC in March 1973 addressed the philosophy of and the need for Quality Assurance. The NRC stressed that their early inspections would focus on the overall implementation of TU's QA program, the QA procedures for engineering, and equipment procurement.

The January 1974 NRC inspection cited TU for failure to have a QA program that complied with 10 CFR 50 Appendix B. Specifically, TU was cited for the failure to assure control of design done by others. TU also was cited for not establishing the program as soon as practical.

A followup NRC inspection conducted in March 1974 listed a "remaining concern", the need to make it clear that "all activities affecting quality will be in compliance with...ANSI N45.2.11."

In July 1974, TU QA audited Gibbs & Hill (TU audit TGH-1) and identified 34 deficiencies in G&H's QA manual and 18 deficiencies in their implementation. In August 1974, TU requested Gibbs & Hill senior management assistance to correct the deficiencies promptly in order to avoid the threatened postponement of the October ASLB hearing which was a prerequisite to the issuance of the Limited Work Authorization. G&H responded and the LWA was granted on October 18, 1974. Later, TU QA Audits continued to call into question the effectiveness of Gibbs & Hill's QA Program.

Other early engineering problems included such basic issues as the orientation of the turbine/generator building, the method of calculating the volume of the containment building, the temperature of the cooling water, and the relative locations of the intake and out-fall structures.

The PSAR was filed in June 1973, and the NRC began multiple rounds of PSAR technical questions, which was standard practice for all license applications. Some questions were unique to the particular plant, but many were generic and dealt with the NRC's increased safety and quality concerns. The process of answering these questions was time consuming, and it often resulted in commitments by the utility as the licensee to change portions of the plant design. Those A/E firms which had multiple nuclear projects benefited from their ability to share technical resources in developing answers to generic questions, and to collaborate and provide a joint response to particularly difficult NRC concerns.

These rounds of questions and answers resembled a negotiation process, whereby the NRC regulatory staff posed a set of abnormal plant operating circumstances to the licensee, and the licensee demonstrated how his design could assure public safety under these circumstances. The licensee prepared his response and defended it. The licensee was free to use a variety of techniques to satisfy the NRC. The better prepared and more reasoned the response, the better the licensee's chances were of having his response accepted. Secondary questions resulted from incomplete or inadequate initial responses.

After the Construction Permit was issued, the design changes resulting from the NRC concerns imposed through the PSAR round of questions subsided but they did not stop. The licensees continued to respond to a variety of safety issues identified in regulatory guides, Branch Technical Positions, Inspection and Enforcement Bulletins, NUREG reports and various industry code and standard revision and interpretations.

The number of specific design requirements resulting from NRC safety and quality concerns had begun to increase with the publishing of 10 CFR 50 Appendices A and B in 1969 and 1970, and continued to grow through the 1970's and into the early 1980's. Each NRC safety and quality concern imposed a specific responsibility on the industry. All licensees were impacted by changed requirements, but as stated in NUREG 1055 the licensee responses to the NRC concerns differed markedly. Successful utilities actively managed the process of response through a conservative, quality first philosophy and through a program of anticipating new NRC concerns by monitoring the NRC and industry code committees. TU's failure to respond adequately resulted in serious quality, cost and schedule impacts.

Early Engineering and Construction Problems

o Containment Blasting Overbreak

The Containment buildings at CPSES are founded on rock. Since seismic design analysis techniques are based upon the known foundation conditions, changes to the foundation conditions could invalidate the calculations which were performed to assure public safety from the effects of an earthquake.

The excavation for the containment buildings required blasting, which was planned to limit rock breakage in order to avoid rock breakage beyond the area needed for the containment excavation. This limited breakage did not occur; there were significant amounts of rock breakage outside the original intended excavation. To correct this overbreak, a significant amount of additional rock had to be removed and replaced with concrete. Some additional broken rock had to be cemented back together through the use of grout.

The NRC investigated the overbreakage and cited TU for not having Quality Assurance procedures for this activity. TU acknowledged the NRC's comments, but they took exception to the lack of QA procedures. TU's view represented a narrow interpretation of the NRC regulations. They argued that excavation was allowed under the Limited Work Authorization rules. The NRC view represented a broader interpretation of the intent of the regulations, since they felt blasting could change the seismic foundation design basis. Therefore blasting of safety related structures was separate and distinct from "excavation" allowed under the LWA. The NRC ruled that "blasting" was a safety related activity and that the requirements of a Quality Assurance/Quality Control program for safety related activities applied.

- <u>Concrete Placement Problems</u>

Brown & Root had many difficulties with Gibbs & Hill civil/structural design documents during the early stages of construction. Examples of these difficulties included:

- Stringent nuclear grade concrete specifications
- Rebar density, complexity and design changes

- Blockouts (holes) left in concrete walls and slabs due to unavailability of embedment information.
- Missing anchor bolt location information due to lack of vendor data

These difficulties impacted B&R's productivity and further jeopardized the construction schedule. Furthermore, B&R had not accounted for these difficulties in their plans. Neither had B&R planned for the additional time required to install Richmond inserts into the concrete forms.

Blockouts are holes left in concrete placements to accomodate components to be installed at a later time. The blockouts may be required, for example, for equipment foundations, embedded plates, anchor bolts, and penetration sleeves. When insufficient design information is available, blockouts are provided on drawings; the blockouts are completed using grout once the necessary information (and components) becomes available. This is a more difficult, time-consuming and costly method than installation at the time of the initial concrete placement.

The number of blockouts at Comanche Peak was abnormal. For example:

> "There are over 4,000 blockouts of one kind or another averaging approximately 1/3 cubic yard each."
>
> (B&R document attached to October 10, 1978 agenda for mini summit meeting.)

This contributed to the delays and overruns at Comanche Peak.

o Unit 2 RPV Support Misorientation

The structural drawings for the Unit #2 RPV support were developed based on a mirror image of Unit #1. Westinghouse information and G&H mechanical and electrical drawings were based on a 180 degree rotation from Unit #1. This difference was undetected until the Unit #2 RPV Support was partially built in February 1979, 45 degrees out of position. TU told the NRC that this misorientation had no safety significance because the unit could not have been completed in the erroneous configuration. TU attributed the problem to "human error" in the coordination of Westinghouse vendor drawings with G&H's structural drawings.

TU overlooked the failure of G&H's interdiscipline design review process to identify the error. The failure to implement proper interdiscipline design review was a major source of field interferences.

TU also overlooked the fact that citing human error as the cause cast serious doubt on the proper implementation of the previous resolution of the deficiency identified in Audit TGH-4, which dealt with vendor design coordination. (TGH-4 was conducted in October 1976 and finally closed out in March 1978.)

Design Change Control Mechanism Complexities

Early in the construction phase of the project the number and complexity of field design changes became a problem. The large number of different mechanisms used to effect a change, and the lack of emphasis on revising the original drawing, caused a variety of problems. In 1977, there were seven different ways to document a design change, and it was not uncommon to find drawings with dozens of unincorporated changes. The most serious problem was the loss of configuration control, i.e., confusion of the design intent leading to construction and inspection errors, and impacting the ability to perform subsequent interference checks. This configuration control concern was expressed in the 1978 MAC report, but it was not adequately addressed by TU.

The volume of design change documents also created serious logistical problems for document control, since all safety related documents, and all outstanding changes to the documents, had to be controlled and retrievable.

TU did respond to some of the concerns expressed in the 1977 MAC Report by reducing the number of different change mechanisms. The crux of the problem, however, the loss of configuration control due to the lack of incorporation of multiple changes in subsequent revisions, was to affect the project well into the CPRT/CAP time period.

Examples of volume of design changes:

150	DE/CD's	(Design Engineering/Change Deviation)
700	FPAR's	(Field Problem Action Request)
26,000	DCA's	(Design Change Authorization)
100,000	CMC'S	(Component Modification Card)
2,000	Vendor drawings changed by CPPE/TNE	
55,000	G&H drawings changed by G&H	
10,000	G&H drawings changed by CPPE/TNE	

40,000	CMC's issued by PSE
10,000	BOP Typical Drawings
16,200	Non-safety Related Hits Drawings

(ISAP VI.a.)

The volume of changes became a logistical nightmare. Dobie Hatley, an ex-QC inspector, stated to the NRC that in 1983 the average drawing had 300 outstanding design changes logged against it, and a single installation document package given to the field often weighed two to three pounds. Configuration control under these circumstances would be confusing, very difficult, and very time-consuming. The design would be subject to different interpretations, thereby easily leading to inspection problems.

Design Verification - the "At-Risk" Approach

Design changes were not an unusual occurrence at nuclear projects. Rather, design changes due to design errors, construction interferences, operational preferences and NRC safety improvements, were to be expected. Experienced project managers realized this and established systems for accomplishing the design changes while satisfying the requirements of 10 CFR 50 Appendix B regarding design control.

> "Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design and be approved by the organization that performed the original design unless the applicant designates

another responsible organization."
(10 CFR 50, Appendix B)

The traditional approach utilized in the nuclear industry for design change control was characterized by TU as "front end" review.

> "Two verification processes have been utilized at Comanche Peak. They are the traditional "front-end" reviews in which a proposed change is design verified, approved and documented prior to implementation in the field;"
> (TU Change Paper Design Verification, dated 12/20/84.)

This approach to design change control is traditional in the nuclear industry because it satisfies the letter as well as the intent of 10 CFR 50 Appendix B.

Prior to approximately 1977 or 1978, indications are that TU utilized the traditional industry approach.

> "All design or change documents were originated and controlled by the Gibbs & Hill New York office."
>
> "All initiated changes were transmitted to Gibbs & Hill for acceptance. Resulting revisions or changes were subjected to complete Gibbs & Hill control program and TUSI approval prior to site issuance."
> (TU Change Paper Design Verification, dated 12/20/84)

Of course, adherence to this design change control approach meant that construction of a change to a system, component or structure could not commence until formal site issuance of the change, after the change had been subjected to the complete Gibbs & Hill control program. If G&H were behind in engineering, or if there were an inordinate number of design changes, there would be an impact to construction due to late issuance of the design changes.

Gibbs & Hill clearly was behind in engineering. Consequently, sometime in the period 1977 to 1978, TU apparently made a decision, later formalized in 1979, to abandon the traditional industry approach for design change control and to adopt another approach. TU characterized this approach as the "At-Risk" approach.

> "...the other process is called 'at risk.' The 'at-risk' process of design verification entails releasing a design change for implementation in the field prior to formal interdisciplinary verification."
>
> (TU Change Paper Design Verification dated 12/20/84.)

TU described their decision to adopt the At-Risk approach as a major decision in a paper prepared by TU for the Cresap, McCormick and Paget audit.

> "In October 1979, it was determined that effectiveness of Gibbs & Hill providing small bore hanger designs form (sic) the Dallas office was not sufficient to support the project."
>
> "...Also, at this point, TUGCO decided to adopt the "at risk" design change verification program. This was a major decision since it permitted design changes, initiated onsite, to be implemented by craft prior to the design verification being completed."
>
> (TU Change Paper Design Verification dated 12/20/84.)

The "At Risk" approach amounted to a program whereby the complete design change control process, in particular the interdisciplinary design verification, was deferred until after the system, component or structure addressed in the design change had been constructed. In effect, the item was constructed before it was completely designed, contrary to the traditional nuclear industry approach. TU's characterization of the approach as "At Risk" related to the possible need to modify, or to tear out and reconstruct, the item if the design for the item as-constructed could not be verified.

TU felt that as long as the formal, systematic and documented interdisciplinary/interorganizational approval cycle was completed prior to loading nuclear fuel, they would satisfy the NRC requirements that the design be safe.

TU apparently considered the advantages and disadvantages of the "At Risk" approach when they adopted it. The most attractive advantage was expediting the construction schedule. A serious disadvantage, however, which was the fundamental reason behind the traditional "front end" approach, was characterized by TU as follows:

> "The drawback is that potential design inadequacies may not be detected <u>in a timely manner</u>."
>
> "The advantage with the 'front end' design change verification approach is the additional assurance provided that the changes being implemented have been thoroughly reviewed and accepted by all impacted engineering disciplines and that all safety requirements have either been satisfactorily incorporated in, or satisfied by, the design."
>
> (TU Change Paper Design Verification dated 12/20/84.) (emphasis in original)

The primary drawback of the "At Risk" approach is that once a system, component or structure has been built, the engineer doing the after-the-fact design change verification will be pressured to accept the change.

"The safety concern is that the design verification process may be expedited, at the expense of completeness and accuracy, in a misguided attempt to satisfy construction schedules."

(TU Change Paper Design Verification dated 12/20/84.)

TU was warned in 1978 that the "At-Risk" approach violated 10 CFR 50 Appendix B, ANSI N45.2.11 and ANSI N45.2. MAC provided one such warning:

"The present system of expediting field changes by referring design changes to the original design organization for approval after the fact does not meet the intent of 10CFR50 Appendix B nor of ANSI N45.2.11, which require that field changes be subject to design controls commensurate with those exercised on the original design. TUGCO Audits have already disclosed that the Architect/Engineer has not been reviewing field originated changes on a concurrent basis, thus the design engineer's comments may be received after the specific construction work is complete resulting in possible loss of design integrity, undue pressure on the designer to justify what has been done, loss of designer responsibility or possible extensive repairs."

(June 1978 Management Analysis Company Audit Report)

(NOTE: This Audit was headed by J.P. Jackson of MAC. He appears to be the same J.P. Jackson who was a member of the ANSI N45.2 Committee.)

R.B. Clements, TUGCO Vice President - Nuclear, one of the only TU management employees with previous nuclear experience (Navy experience, not commercial experience), testified in his deposition that he advised TU Management that the "At-Risk" approach violated the intent of 10CFR50 Appendix B. He further testified that he felt the decision to use the approach was irreversible, since it was "set in stone."

MAC's 1978 warning about "undue pressure on the designer to justify what has been done" proved to be remarkably accurate:

> "If the studies cannot be completed by August 1, 1981 and/or the studies require changes to the system as presently designed, then I will obtain outside A/E services for TUSI and G&H's use to provide engineering review and justification to use the systems as presently designed and installed."
> (J.T. Merritt letter to R.E. Ballard, dated June 15, 1981)

Mechanical/Electrical Drawings Problems

Lack of early engineering awareness of the magnitude of the subsequent detailed mechanical and electrical effort resulted in getting a very slow start on issuing construction installation drawings in both of these critical areas.

Assignment of engineering responsibility to others for pipe and pipe hangers resulted in a coordination burden. The engineering and design of pipe, pipe hangers, snubbers and restraints were split among several organizations including, G&H New York, G&H Dallas, Westinghouse, ITT Grinnell-Providence, ITT Grinnell-Industrial Pipe Division, NPSI, Brown & Root, and Comanche Peak Project Engineering (CPPE). The coordination burden was extensive, and the management of this effort was haphazardly implemented. Design changes in one organization often had cascading effects on the work of the other organizations. Problems with pipe and pipe hangers plagued Comanche Peak, and the inability to resolve associated technical issues led eventually to the Walsh/Doyle Allegations.

The decision to design conduit by system rather than area also created problems. In an effort to expedite conduit installation G&H abandoned their normal conduit design process of coordinating all conduit in an area onto one drawing. In 1978, G&H began to produce conduit drawings one system at a time. This allowed construction to start earlier, but it exacerbated problems with the installation of later systems. Those problems included redundant safety train separation criteria, difficulty with interdiscipline design review to identify and eliminate interferences, and conduit and support consolidation.

Interference Problems - Early Decision Not To Use Three Dimensional Model.

Interference problems between construction commodities arise when the attempted installation of one system (or component) in an area conflicts with the existing installation of another system (or component) in the same space. Interferences arise, for example, due to design inconsistencies, space limitations, or design changes.

Interferences can be identified in engineering/design by several different methods. One method involves interdiscipline design review, where the various design disciplines coordinate their efforts and review other discipline's drawings to identify conflicts. Another method involves the construction of a three-dimensional engineering scale model.

Although the three dimensional model may involve a substantial initial expense, it has many potential benefits. Other nuclear projects used three-dimensional scale models and found them very helpful. According to the notes of Mr. B.J Murray's interview with Cresap, McCormick & Paget (CMP), G&H proposed the use of a three-dimensional model. Mr. Murray had visited Duke Power Company's Catawba nuclear plant, and he had been favorably impressed with the benefits Duke had gained through use of their model. However, TU rejected the G&H and Murray recommendation because TU felt the model would be too expensive.

A scale model would have been very helpful to TU. Not only would it have been valuable in identifying and resolving interferences, but also it would have provided other benefits such as assisting in component location and placement.

Concrete Inserts

There was an inordinate number of problems at Comanche Peak associated with anchorages, embedments, Hilti fasteners and Richmond inserts. These items are all used to attach components to concrete walls and slabs.

Early problems with safety factors, strength and loading conditions, and questionable field construction practices raised serious and recurring questions about plant safety. More recently, questionable construction practices were still evident.

> "24. When necessary as a result of on site unavailability of bolts of the proper length, Hilti

> Kwik Bolts may be modified with proper QC witnessing, by shortening, rethreading, and stamping the new bolt length designation. Final Bolt length shall be the same as stock lengths as supplied by Hilti Corporation...This note constitutes engineering approval as per CEI-20."
>
> (Design Change Authorization 7974, Revision 13, dated 3/9/85)

This authorization does not define "proper QC witnessing", nor does it address the requirements of the Certificate of Conformance.

There is another example where an electrician reportedly cut the wedge section off of a Hilti Bolt and inserted the disabled bolt into a hole. The electrician had repeatedly encountered rebar as he drilled into concrete, so he was unable to obtain the correct concrete penetration depth. Instead of correctly installing the Hilti, he took an unsatisfactory and dangerous approach.

"As-Builts"

The NRC's IE Bulletin 79-14 required As-Built information to be factored into the final stress analysis. In the documents prepared for the CMP audit TU stated that the response to IE Bulletin 79-14 required a major effort by CPSES which had adverse cost and schedule implications. In their defense to the ASLB of the Iterative Design approach, TU also stated that the final design would not occur until an As-Built verification of the final installation was approved by the engineer to the final design. Therefore, it is inconsistent for the

79-14 As-Built effort to have had adverse and unexpected consequences if TU planned to implement the Iterative Design approach as described to the ASLB. The requirements of 79-14 appear to be similar to those described by TU required for Iterative Design, except for reporting to the NRC.

TU's response to 79-14 was done incorrectly. Consequently, TU had to hire Stone and Webster to perform a 100% reverification as part of the CPRT effort.

Control Room Ceiling

In 1984 TU had to change the design of the Control Room Ceiling because they could neither document the basis of the design nor could they prove to the NRC that the ceiling would not fall during an earthquake. If the Control Room Ceiling were to fall, it could cause an incapacitating injury to a control room operator. This issue first had been addressed in 1977; at that time, TU decided to take an unacceptable approach to resolve the problem.

Regulatory Guide 1.29 - Seismic Design Classification states:

> "The Control Room, including its associated vital equipment, cooling systems for vital equipment, and life support systems, and any structures or equipment inside or outside of the control room whose failure could result in incapacitating injury to the occupants of the control room...should be designed and constructed so that the SSE would not cause such failure."
>
> (Regulatory Guide 1.29)
>
> (Note: Regulatory Guide 1.29 was first issued in June 1972. The control room reference was appar-

ently added to Revision 2 of Regulatory Guide 1.29 which was issued in February 1976.)

In March 1977, Gibbs & Hill sent a letter to TU suggesting the design basis of the control room ceiling should be modified to incorporate seismic requirements. In April 1977, TU directed G&H to proceed with the original design basis but to include seismic embedments in the ceiling to allow for future conversion "if necessary". In 1981 TU sent G&H a set of detail drawings which proposed to strengthen the sloping gypsum ceiling and wall and requested comments and concurrence. G&H concurred with the design changes. In July 1984, the NRC began the Technical Review Team (TRT) inspection of Comanche Peak. The TRT found:

> "G&H could not provide backup calculations to support this modification, nor could TUEC provide justification for their position that the remaining suspended ceiling elements (i.e., the louvered and acoustic elements) would not fall and cause an incapacitating injury to operating personnel."
> (ISAP II.d)

The control room ceiling is another example where TU initially failed to modify the design in response to a safety concern identified by the NRC. When TU finally realized the importance of not having the control room ceiling susceptible to falling on a reactor operator during an accident, they decided to change the design. As a result of their earlier shortsightedness, TU had to accept the delay and added expense of replacing the control room ceiling.

Problems Uncovered Later in CPSES History o Unsatisfactory Pipe Support Design

The original design of pipe supports at Comanche Peak was unsatisfactory. (The words "hangers" and "supports" are used interchangeably.) TU was unable to prove to the ASLB the adequacy of the original pipe support design because questionable design practices and methods had been used. Consequently, the ASLB had doubts about the design quality of Comanche Peak, and they required an independent design verification.

> "However, based on our record, we consider design error to be sufficiently prevalent to require independent means of assuring ourselves of the quality of design of Comanche Peak."
>
> (ASLB Memorandum and Order, December 28, 1983.)

The original pipe support designs contained several types of problems. Some examples of these problems are the following.

- o Pipe Support Stability - (e.g. pipe displacement within a loose fitting hanger)
- o Cinched U-Bolts - (e.g. localized stress increase due to hanger)
- o Richmond Inserts - (e.g. inadequate safety factor)
- o Pipe Support Mass - (e.g. failure to consider weight of support in analyses)
- o Wall-to-Wall and Floor-to-Ceiling Supports - (e.g. increased stress due to wall and floor

displacement)

- Dual Strut/Snubber Design - (e.g. unequal load distribution between members)

The numerous pipe support design problems at Comanche Peak led to reanalysis of 100% of the pipe supports (a total of 19,261 supports). As a result of the reanalysis, over 25% (5,500) of the supports are being physically modified.

- <u>Unsatisfactory Cable Tray Hanger Design</u>

The original design of cable tray hangers at Comanche Peak was unsatisfactory. When the design of the cable tray hangers was reviewed during the Independent Assessment Program, numerous problems were identified with the design. As a result, TU decided in June 1985, to perform 100% design verification of nuclear cable tray hangers. TU selected Ebasco Services, Inc. (Ebasco) to verify the design and to reanalyze the cable tray hangers in Units #1 and #2; the Unit #1 effort was expanded to include Impell in late 1985.

The cable tray hanger designs contained several types of problems. Some examples of these problems are the following.

- Bending Stress - (e.g. offset loads due to cable and flame retardant weight)
- Design of Columns - (e.g. buckling due to inadequate slenderness ratio)
- Bolt Holes - (e.g. reduction in plate strength due to excessive bolt holes)

- o Cable Tray Hanger Weight - (e.g. failure to consider hanger weight in performing hanger analyses)
- o Similarity - (e.g. dissimilar components assumed to be similar for purposes of analysis)
- o Safe Shutdown Earthquake Loads - (e.g. inappropriate application of Operating Basis Earthquake (OBE) loads instead of SSE loads)
- o Natural Frequencies and Resonance - (e.g. incorrect calculation of natural frequencies invalidated earthquake analysis)

The numerous cable tray hanger design problems at Comanche Peak led to reanalysis of 100% of the cable tray hangers in Unit #1 (4,352 hangers); over 10% (512 hangers) are being modified. In Unit #2, comparable design analysis and modification may be required.

o Unsatisfactory Conduit/Conduit Support Design

The original design of conduit/conduit supports at Comanche Peak was unsatisfactory. When the design of the conduit/conduit supports was reviewed during the Independent Assessment Program, numerous problems were discovered in the design. As a result, TU decided in October 1986, to perform a 100% design verification of nuclear conduit supports. TU expanded the work scope of Ebasco to include verification of the design and reanalysis of 100% of the conduit supports in Units #1 and #2.

The conduit support designs contained several types of problems. Some examples of these problems are the following:

- o Torsional Stress in UNISTRUT - (e.g. failure to heed manufacturer's recommendation)
- o Thermolag on Conduit Supports - (e.g. failure to consider heavier weight of square insulation)
- o Grouted Penetrations - (e.g. failure to perform supporting calculations for assumptions)
- o Anchor Bolt Prying Force - (e.g. failure to consider prying forces on anchor bolts)
- o Safe Shutdown Earthquake Loads - (e.g. inappropriate application of OBE loads instead of SSE loads)
- o Rigid vs. Non-rigid Conduits - (e.g. substitution of small conduits for large conduits without addressing rigidity)
- o Dynamic Amplification Factor - (e.g. failure to apply correct earthquake forces)

The numerous conduit support design problems at Comanche Peak led to reanalysis of 100% of the conduit supports in Unit #1 (approximately 7,000 seismic conduit supports and approximately 75,000 non-seismic conduit supports). The number of conduit supports requiring modification is still being researched.

o Unsatisfactory HVAC Design

The original design of the heating, ventilating and air conditioning (HVAC) system and HVAC duct supports at Comanche Peak was unsatisfactory. When the design of the HVAC systems was reviewed during the Independent Assessment Program, numerous problems were discovered in the design. TERA identified HVAC system design problems; CYGNA identified HVAC structural problems. As a result, TU selected Ebasco to verify the design adequacy of the HVAC systems and to verify the design adequacy of 100% of seismic HVAC ducts and their supports.

The HVAC design contained several types of problems. Some examples of these problems are the following:

- o Heat Load Calculations - (e.g. failure to consider all heat sources)
- o Equipment Specifications - (e.g. HVAC equipment specifications conflicted with supporting design calculations)
- o Transverse Duct Joint Integrity - (e.g. failure to apply duct joint loading conditions)
- o Anchor Bolt Embedment Length - (e.g. incorrect consideration of embedded length due to concrete topping coat)
- o Similarity - (e.g. dissimilar components assumed to be similar for purposes of analysis)
- o Design of Columns - (e.g. buckling due to inadequate

slenderness ratio)

The numerous HVAC design problems reflect misapplication of basic design concepts; additionally, these problems led to reanalysis of 100% of the HVAC seismic duct supports in Unit #1 (approximately 4,000 supports). The number of modifications required is still being researched.

o <u>Unsatisfactory Electrical Systems Design</u>

The original design of electrical systems at Comanche Peak was unsatisfactory. Problems with electrical design were recognized as early as 1977, but the NRC Construction Appraisal Team (CAT) indicated the need for an independent assessment program in 1983 when the CAT identified cable separation problems. TU selected TERA to perform an independent review of the electrical systems. When TERA found numerous discrepancies in the design, TU selected Stone & Webster Engineering Corp. to verify the design adequacy of electrical systems.

The electrical systems design contained several types of problems. Some examples of these problems are the following:

- o Electrical System Design Calculations - (e.g. incorrect assumptions and numerous mathematical errors)
- o Computer Program Validation - (e.g. lack of validation procedures and improper identification of calculation printouts)

- o Equipment Specifications - (e.g. equipment specifications conflicted with calculations and with nameplate ratings)
- o Electrical Independence - (e.g. failure to satisfy single failure criterion and interaction with non-safety systems)
- o Electrical Penetrations - (e.g. electrical penetrations did not comply with design requirements)

Reverification of the electrical systems has required an extensive effort. The number of modifications required is still being researched.

Walsh/Doyle CASE Allegations

Mark Walsh and Jack Doyle, two engineers who worked in the site engineering organization, testified before the ASLB in the hearings on Comanche Peak. Messrs. Walsh and Doyle had the following 19 broad areas of concern:

1. Interface between pipe support design groups.
2. Interface between pipe support design groups and pipe stress analysis organizations.
3. Design analyses for Richmond inserts and Hilti bolts.
4. Differential thermal expansion effects in pipe supports.
5. Differential thermal expansion in wall-to-wall, floor-to

-ceiling, and floor-to-wall pipe supports.

6. Stability of pipe support designs.
7. Use of U-bolts in pipe support designs.
8. Loading due to seismic acceleration of pipe support structures.
9. Moment restraint and local pipe stress due to welded stanchions.
10. Deflections and local stresses in pipe support structures.
11. Consideration of friction loads.
12. Consideration of kick loads.
13. Modeling of wide flange members as infinitely rigid in torsion.
14. Effects of cold forming on ductility of tube steel.
15. Operating condition loads appear to be in error.
16. Welded stepped connections, fillet welds and skewed welds.
17. Section property values utilized by Pipe Support Engineering.
18. Support pads welded over girth welds.
19. Damage to pipe supports during hydrostatic testing.

The allegations brought up by Walsh and Doyle were a major motivating factor behind the reinspection/reverification effort. While not all of the allegations were judged to have merit, enough of them were unanswerable that TU's credibility was severely affected.

CAT, ASLB and TRT Findings

The allegations and a series of investigations raised serious questions about the adequacy of design and construction of Comanche Peak.

The NRC performed a CAT inspection in early 1983. The CAT team identified numerous problems and concluded:

> "It is the position of the Construction Appraisal Team that the results of this inspection indicate several construction program weaknesses."
>
> (NRC letter to TU dated 4/11/83)

The CAT team resul:s and the inability of TU to address the Walsh-Doyle allegations, contributed to the ASLB conclusion in December 1983 that an independent third-party review should be performed on Comanche Peak.

> "The Licensing Board finds that the applicant has not demonstrated the existence of a system that promptly corrects design deficiencies and has not satisfactorily explained several design questions raised by the intervenor. The Board suggests the need for an independent design review and requires applicant to file a plan that may help resolve the Board's doubts."
>
> (ASLB Memorandum and Order dated 12/28/83)

The Technical Review Team (TRT) established by the NRC began an intensive onsite review effort in July 1984. The purpose of the review was to allow the NRC to reach a decision regarding the licensing of Comanche Peak Unit #1. The onsite effort covered a number of areas, including allegations of improper construction practices.

The NRC issued a series of three reports (9/18/84, 11/29/84, and 1/3/85) which addressed the results of the TRT investigations. The number and severity of the problems identified by the TRT were a major influence on TU to conduct the CPRT and CAP.

CPRT findings

As a result of the issues raised by the external sources (i.e. SRT, SIT, CAT, CASE, ASLB, TRT, etc.), TU established the Comanche Peak Response Team and the Corrective Action Program . This effort eventually involved hiring several outside consulting firms to verify, reanalyze and/or redesign virtually every safety related design feature of Comanche Peak. Where items were found to be potentially deficient on a systematic basis, statistical verification techniques were used. Two significant results of these statistical techniques were the 100% engineering reanalysis of safety related piping systems and the necessity of the Post Construction Hardware Verification Program.

In light of the great numbers of problems which occurred over the history of Comanche Peak, and which ultimately led to the CPRT and CAP, it is astounding what was the perception of TU top management. As expressed by Mr. Brittain, both the CPRT and CAP were unnecessary for a functional, safe plant, although they were a practical necessity to get an operating license.

The Evolution of Field Engineering

An analysis of the evolution of the field support effort shows TU's lack of understanding of the breadth of the problems confronting them.

A project with engineering only slightly in front of construction requires a large coordination effort. TU did not anticipate that, nor did they anticipate the need for a large site engineering effort. They only reacted to the constructor's problems.

The History of the G&H Dallas Office

The Gibbs & Hill Dallas Office was opened in June 1977, to provide support to CPSES. G&H established a Field Design Support Group and a Small Bore Pipe Hanger Design Group in the Dallas Office.

Although the Dallas office was opened with the apparent approval of TU upper management, Mr. Joe B. George apparently disagreed with its establishment. On March 6, 1978, Mr. George wrote an interoffice memo outlining his trip to G&H in New York. In it he wrote:

> "...I have discussed in detail the G&H Dallas Group with Ken Schepple. I told Ken that if I were making the decision, today, I would not put the Design Support Group in Dallas, but instead at the Site... I have requested that G&H do not add any additional peopllle to the Dallas staff unless we concur that this is where we want them."

The need to increase the on-site engineering was becoming particularly acute in the summer of 1978. Mr. George sent a memo to

Roy Gordon, Gibbs & Hill President on August 26, 1978. In that memo, Mr. George stated:

> "I need immediate help and attention from all Gibbs & Hill officers and managers to staff our CPSES site engineering group and above all, Bob Murray's interference group is key to meeting schedule. I am attaching his needs as outlined in the attached letters. I have been informed today that G&H is having problems in getting heavy weight engineers to accept these positions due to our not furnishing transportation and lodging during their stay at CPSES. Please be informed that this is a negotiable item. For example, I would be willing to provide pool transportation and apartment lodging for one year to eighteen months for qualified candidates for the openings."
>
> "I am appealing to the top for help as time does not permit me to go through channels."

On September 14, 1978, Mr. George directed all field questions to be sent to New York, effectively eliminating the need for this Dallas group.

In responding to Mr. George, Mr. Ken Schepple, Gibbs & Hill Vice President, stated:

> "... We are concerned that the instructions issued in your memorandum will impact adversely our ability to support CPSES field operations. These instructions were issued without prior discussion with any of the G&H management and, therefore, gave us little opportunity to plan for the obvious concerns that members of our staff may now have. We request an early opportunity to review with you both the effectiveness of our Dallas office and the full significance of your requirements."
>
> "...this office has resolved over 1300 CPSES field questions referred to it, and this turnaround was accomplished with dispatch and at a lower billing

> rate than our New York office."
>
> "In our opinion, this matter is a policy decision that deserves further discussion..."

Mr. George did not reverse his decision, and several members of the Dallas Field Design Support Group were reassigned to the site. The Small Bore Pipe Support Hanger Design Group was described as "ineffective" in the CMP Audit response; it had been transferred to the site in October 1979.

Establishment of the Dallas Office was shortsighted. Twenty-eight months after it had been established, it was disbanded. The movement of the engineers to Dallas, and then to the jobsite, is another example where TU did not thoroughly evaluate and then follow through on a proposed corrective action.

In contrast to the Comanche Peak experience, in the mid to late 1970's the larger Architect/Engineers had developed site engineering capabilities in a deliberate and formal manner. Stone and Webster Engineering Corporation, for example, which also is playing a central role in the CPRT/CAP, developed a field engineering extension office known as the FXO; the FXO had complete Quality Assurance procedures as well as formal methods to effect field design changes expeditiously. Ebasco Services, Inc. had a similar organization, which was called Ebasco Site Support Engineering (ESSE).

Budget Directives and Impact upon the project

An analysis of the budget directives issued by TU shows adverse impact on G&H's ability to properly execute the engineering requirements of the project. Examples of these actions included: cash flow and budget restrictions; pressure to reduce computer usage including pipe stress analysis; refusal to recognize regulatory scope increases; reductions in G&H's scope by assigning responsibilities to others without adequate oversight; and interminable disagreements about personnel expenses such as relocation, transportation, per diem, etc.

TU's decisions to curtail the engineering budget contributed to the inability of G&H to provide sufficient numbers of engineers and to supervise them effectively in order to complete the engineering on time. Although TU's decisions are some of the root causes behind the many problems which exist at Comanche Peak, it is clear that they have not been so identified by TU.

VII. CONSTRUCTION OF COMANCHE PEAK

Prior to becoming the constructor on Comanche Peak, Brown & Root (B&R) had only very limited experience in nuclear construction. Although B&R had constructed fossil fuel power plants in the past utilizing their "open shop" contractor approach, the Brunswick project of Carolina Power & Light Co. (two Boiling Water Reactors each rated at 790 megawatts) represented their only nuclear experience.

A. Planning and Control of Construction

Evolution of Brown & Root (B&R) Contract

The original contract between TU and B&R was dated February 29, 1973. The contract was cost reimbursable plus a fixed fee in the amount of $5,746,000. The fixed fee was based on a projected total manhour expenditure by B&R of 12,500,000 manhours. Key milestone dates were stipulated in the contract as follows:

1) Start site grading	12/1/74
2) Start mobilization at site	5/1/75
3) Start foundations	8/1/75
4) Delivery of Unit 1 reactor vessel	4/1/77
5) Ready for Unit 1 cold functional test	2/1/79
6) Unit 1 fuel loading	5/1/79
7) Unit 1 Commercial Operation	1/1/80

8) Delivery of Unit 2 reactor vessel 4/1/79

9) Ready for Unit 2 cold functional test 2/1/81

10) Unit 2 fuel loading 5/1/81

11) Unit 2 Commercial Operation 1/1/82

The fixed fee covered B&R's profit, certain home office construction management services, other general overhead items, and the "cost of defective work to the extent described in Article C-5 of the General Conditions".

Contained within the contract were two incentive provisions for B&R. The first was a labor saving performance incentive based on an estimated base manhour target of 12,500,000 manhours. These manhours included both manual and non-manual labor. This should be particularly noted since manual labor was not segregated from non-manual for this incentive. It should also be noted that there is a potential danger in this type of incentive; if manual labor productivity is lower than expected, non-manual labor, including supervision, could be decreased as a percentage of total labor in an attempt to meet the manhour target. The penalty or bonus for this incentive was to be calculated outside of a 5% band of the final target manhour number. For actual manhour overruns in excess of 5% above the final base target manhour number, the base fee would be reduced by 25% of the cost of the overrun up to a total reduction of $2,000,000. The bonus side would be calculated in the same fashion for underruns below 5% of the final base target manhour number.

The second incentive was an escalation control incentive based on an average manhour dollar rate established for each calendar year. The actual cost for each year would be compared to the escalation control cost and the difference would be calculated based on the total number of manual manhours worked. If the difference represented an overrun in actual cost, B&R would credit TU with one-third of the difference. If the difference represented an underrun in actual costs, B&R would be credited with one-half of the difference. There were no limits established for either the bonus or penalty in this incentive.

Most of the supplements to B&R's contract were minor in nature and should have been of little or no consequence to their overall performance. The one exception to this was Contract Supplement Order Number 7 dated June 17, 1977. The base fee was increased to $11,500,00 based on a revised base manhour target of 28,860,890 manhours. It should be noted that this new manhour figure came out of the Definitive Estimate developed in December 1976. It should also be noted that the base manhour target more than doubled from the original contract. Contract Supplement Order Number 7 increased the bonus/penalty amount for the labor performance incentive to a maximum of $3,000,000, but it eliminated the escalation control incentive.

A B&R office memo dated November 17, 1976 indicated that B&R had earned an escalation control incentive credit of $821,385 to date in 1976 and had earned a credit of $341,191 in 1975 which had not been approved for payment by TU. TU requested that B&R stop spending time on scope and quantity changes in late 1977.

"Reducing cost and estimating group by 25% or redirecting their activities to productivity tracking...let's agree on how the estimate should be updated. I suggest we are trying to make the estimate too accurate and for what...B&R is still drawing up so called documented PBA's...They must stop wasting their time in this manner... please keep in mind that the target fee will be negotiated..."

(Memo from J.B. George to H.O. Kirkland dated December 29, 1977)

The change in the base manhour target authorized by Contract Supplement Order Number 7 was evidence that the scope of construction work had significantly increased on CPSES. There was also additional evidence that the base manhour target for B&R would increase.

"The project Definitive Estimate transmitted to us January 11, 1977, by Brown & Root has some problems of considerable magnitude...Generally the estimators used the project work experience and trends through late summer; since that time, the production has dramatically worsened to make the estimate unrealistic for the safety related work...I would expect the performance would worsen or remain the same rather than improve as the majority of the balance of concrete construction is more difficult...There is a credibility problem now for this area (piping and electrical) which is greater than the concrete work. The labor contingency in the estimate will not cover the anticipated concrete construction overrun which presents alarm for the rest of the plant. I also anticipate the allowance in the estimate for premium time and inefficiency is too low if we are to make schedule."

(G.B. Crane memo to L.F. Fikar, dated January 21, 1977)

In a cost reimbursable plus fixed fee contract, there is a correlation between the scope of work and the fee amount. Significant changes in scope normally result in adjustments to the fee, as demonstrated by Contract Supplement Order Number 7. Government construction contracts and most private sector commercial construction contracts allow the contractor to earn a fair profit and recover reasonable overhead costs on constructive changes. A prudent contractor would be expected to keep track of scope and manhour changes to its contract. This apparently was the intent of the contract between B&R and TU.

TU's actions and directives to B&R after June, 1977, strongly indicate that TU was not following the intent of the contract. J.B. George's desire to negotiate the target fee was clearly not in conformance with the intent of the contract. TU's actions relating to the implementation and control of B&R's contract could have contributed to the attitude problems and conflicts between TU and B&R.

Development and Implementation of Construction Schedules

The initial scheduling efforts on Comanche Peak were coordinated through Gibbs & Hill. Brown & Root provided the input for construction but did not control the development of the overall project schedule. It was not until after the Definitive Estimate was developed (December 1976) that an integrated project schedule was addressed in early 1978. The integrated project schedule apparently attempted to incorporate input from engineering, construction and start-up for the first time on the project.

> "On February 21, the integrated schedule for Unit 1 and Common was hand carried to TUSI. This schedule interfaces engineering, procurement, construction, and start-up. An analysis will be completed and a conclusive report issued on Unit 1 and Common around the middle of March, 1978."

(B&R Monthly Progress
Report, February 1978)

B&R coordinated the input for this schedule and was responsible for its creation and maintenance. It should be noted that the fuel load date for Unit #1 of August 1980, represented the extension made in October 1976. The Unit 2 fuel load date was extended to August 1982 in March 1977.

By late 1978, it had become apparent that Unit 1 was delayed.

> "On December 7, 1978 during the Mini-Summit Meeting it was discussed that the beginning of Start-up will be several months late...On December 8, 1978 Mr. Fikar discussed this and the possible delay in getting fuel loaded in Unit 1 in August, 1980 with the top Texas Utilities officers. The delay was unacceptable and direction was given to take all steps possible to avoid a delayed fuel load of Units 1 and 2."

(Memo from J.B. George to
H.O. Kirkland et al dated
December 16, 1978)

In early 1979, after TMPA had signed the Joint Ownership Agreement, the fuel load date for Unit 1 was extended to March, 1981. The fuel load date for Unit 2 remained unchanged at that time. In early 1979, the integrated project schedule was still in use. A major effort was made by TU from 1979 into 1980 to move into a systems completion and turnover mode.

> "Engineering should manage work priorities to support start-up schedule."

(Memo from J.B. George to
H.O. Kirkland et al dated
December 16, 1978)

This precipitated a decision in May, 1980 to abandon the project CPM schedule and proceed with a total start-up schedule.

> "The official startup schedule with system priorities and bogey for all critical commodities will set all work activities by 5/30/80 at the latest. There will be no need for further CPM activities after this date."

(Memo from J.B. George to Jim
Bazor et al dated May 1, 1980)

TU proceeded under this schedule format until May 1981 when TU management opted to develop a detailed project schedule once again.

> "To expedite system turnovers in an efficient, orderly fashion, it is recognized that a detailed project schedule for all groups is imperative."

(Memo from J.T. Merritt to
distribution dated May 20, 1981)

In September, 1981, the Unit 1 master schedule was accelerated by modifying logic and eliminating certain activities. Engineering buy-off and future pipe rework activities were deleted and other activities were overlapped.

> "The Unit 1 Master Schedule can be accelerated if specific assumptions are made...The Area Management Planning & Scheduling Group will identify the 'Tie Points' between Engineering/Construction Schedule and Start-up Schedule...During the identification of Tie points it may be necessary to use parallel logic...'Engineering Buy Off' and 'Piping future rework' will be deleted from the construction

logic."

(Nelson Smith memo to John Merritt dated September 11, 1981)

"The 'Accelerated Schedule' logic is based on the following specific conditions and assumptions...Deletion of 'Future Rework' for piping, large hangers, conduit and conduit supports; only 'Documented Future Rework' remains in the logic...wire and cable will be pulled when 20% of conduit is installed. Which means that the conduit will be installed on a selected basis...Hangers identified in the "HITS" by the following:

'...Material Shortage-Current Group'...will be deleted."

(Nelson Smith memo to John Merritt dated 9/18/81)

This schedule lasted until January 1982 when a "new" scheduling approach was developed.

"As discussed, B. J. Murray is responsible for communications, correspondence and development of the new scheduling approach which will include not only engineering, construction and procurement responses but also startup. The new schedule should have heavy involvement from R. E. Camp."

(Memo from J.T. Merritt to distribution dated January 11, 1982)

Prior to its abandonment in 1980, there had been a project schedule which attempted to integrate engineering, procurement and construction; the project master schedule developed in 1981 purportedly had heavy input from start-up.

Construction Status Versus Schedule

The Limited Work Authorization (LWA) was issued on October 17, 1974. The LWA allowed Brown & Root to begin work on temporary roads, facilities and communications. Through November 1974, soil and loose rock excavation was completed down to the surface of hard rock at the plant site and rock blasting started. Clearing, grubbing, and excavation had started in the area of the Squaw Creek Dam. The Construction Permit (CP) was issued in December, 1974, approximately three months ahead of schedule. This prompted TU to advance construction start dates for the reactor building, safeguard building, auxiliary building, turbine building, and service water intake structure.

> "Bob advised that TUGCO wishes to take maximum advantage of their early receipt of a construction permit...by advancing construction start dates for reactor building, safeguard building, auxiliary building, turbine building, and service water intake structure. TUSI requests that schedule be advanced two months in all of these areas...G&H felt that substantial improvement in the CPSES schedule could be achieved by initiating rebar fabrication on the basis of preliminary engineering drawings..."
>
> (Notes of telecon between Bob Hickman and R.E Hersperger dated December 20, 1974)

Excavation for the power block building foundations continued during early 1975. By May of that year, rebar placement had started for the Unit 1 Containment foundation. In the June, 1975 B&R progress report, it was noted that a new six month schedule would be developed to reflect the B&R adjusted plan of work incorporating the engineering slippages identified in a June 30, 1975 meeting with G&H. No official changes were made to the overall schedule, however, until

October 1976.

First safety-related concrete was placed during July 1975, in the reactor cavity foundation mat. Concrete work proceeded close to the overall cumulative placement targets until early 1976 when monthly progress began to fall behind schedule. Concrete progress faltered considerably in May, 1976 and by August, 1976, B&R was approximately seven months behind schedule. B&R experienced progress problems during the previous winter due to difficulties with the winter concrete mix. serious QA/QC problems with the Unit 1 Containment mat also significantly impacted progress. The progress of concrete was an important factor in acknowledging the Unit 1 fuel load delay in October, 1976.

During the latter part of 1976 and early 1977, structural progress continued with the erection of the containment liner, concrete walls and slabs in the auxiliary and safeguards building, and structural steel in the turbine building. In early 1977, B&R began listing piping and hanger delivery dates from ITT Grinnell as an area of concern. The need to finalize the cable tray support system was also being noted. At the same time, drawings being received from G&H were too illegible for construction use.

> "Drawings received from G&H that are too illegible for construction use."
>
> (B&R Monthly Progress Report January 1977)

In March 1977, the scheduled Unit 2 fuel load date was delayed until May 1982. Overall project completion stood at 28.9% with the actual progress line appearing close to the target on the percent of total job complete curve. However, Unit 1 progress against time was not isolated, which made it difficult to determine the exact schedule status of Unit 1. A review of the project mechanical and electrical status at that time indicates that process pipe installed on temporary hangers had only recently started in the Unit 1 turbine building.

By September of 1977, only minor pipe and lighting installation was in progress in the lower elevations of the auxiliary building. The project was still not close to going into a bulk mechanical and electrical installation mode. One basic reason for lack of expected progress was that B&R had reduced total manpower on the project in May 1977 in response to a TU request for a fiscal year 1978 $67,000,000 cut in the project budget. In November 1977, faced with a projected slip for the setting of the NSSS vessels in the Unit 1 containment from May 1978 until July 1978, TU directed an accelerated program of extended hours and two shift work to achieve NSSS vessel sets by May 1978.

> "Effective November 14, 1977 the construction effort will be expanded to two shifts, six days per week, ten hours per shift."
>
> (Memo from J.T. Merritt, J.B. George and H.O. Kirkland to TUSI/B&R/G&H dated November 7, 1977)

The Unit 1 containment acceleration was necessary to expedite structural progress in order to be ready for the NSSS vessel sets. The Unit 1 NSSS vessel sets were made in May 1978. From late 1977 into 1978, severe problems were encountered with the receipt of large bore pipe spools and hangers from ITT Grinnell, and with the receipt of cable tray support drawings from G&H. By August 1978, process pipe and electrical installation were still less than 10% complete. A decision to go to a double shift operation across the entire project in April 1978 had minimal effect on expediting mechanical and electrical completion.

By late 1978, the scheduled fuel load for Unit 1 was less than two years away. The B&R monthly progress report for December 1978 indicated that cable tray hanger fabrication was curtailed due to the lack of available drawings. At a summit meeting on December 8, 1978, L. F. Fikar discussed a possible delay in getting fuel loaded in Unit 1 by August, 1980 with top TU officers. The delay was deemed unacceptable and direction was given to take all steps possible to avoid a delayed fuel load of Units 1 and 2.

In December, 1978, TU informed TMPA of the purported status of the project.

> "All facets of design, construction and preparation for start-up are moving toward the anticipated successful and reliable operation of the plant <u>according to schedule</u>..."(emphasis added).
>
> (Letter from L.F. Fikar to Joel T. Rodgers dated December 19, 1978)

TU attempted to qualify their assurance, however, in the next to last paragraph of that letter by stating that causes beyond their control could have substantial impact on completion dates and costs for the project. The letter did not reveal the information on project delay discussed by TU officials.

In March 1979, the fuel load date for Unit 1 was changed to March 1981; the Unit 2 fuel load date, however, was not modified. Critical items which were evaluated as part of the schedule analysis included late equipment deliveries, piping and hanger delivery rate, moment and pipe whip restraints, and delivery of small pipe material.

Actual physical progress in 1979 was significant for both electrical and mechanical installation work. The following list shows the percent complete at the beginning of 1979 compared to the end of 1979 for several key commodities. The information was taken from an analysis chart prepared by TU in November, 1981.

Large pipe >= 8"	52% to 90%
Medium pipe 2.5-6"	36% to 80%
Cable tray	32% to 87%
Conduit	10% to 65%

From this same chart, wire and cable pulling stood at approximately 15% complete at the end of 1979. Subsystem turnovers stood at 7% complete. Based on the project status in late 1979, B&R advised TU that it was virtually impossible to expect to achieve fuel loading of Unit 1 by March 1981. J.G. Munisteri of B&R had instructed his staff to analyze the overall situation and to advise him of what a realistic date should be for fuel loading of Unit #1 as well as the effect on overall cost.

A response letter was written by L. F. Fikar on December 17, 1979 stating that TU was not yet ready to give up on trying to achieve the Unit 1 fuel load date.

> "As I told you at the meeting last week, we are not yet ready to give up on trying to achieve our Unit #1 fuel load date. As I also said, Joe B. George, as Project General Manager, is the person directly responsible for cost and schedule for the project. He currently has under study the issues and concerns you have expressed and will involve your Houston group at the appropriate time for their inputs...Please ask your people not to initiate any work along these lines until they have heard from him."
>
> (L.F. Fikar letter to J.G. Munisteri dated December 17, 1979)

It is clear that TU did not want B&R evaluating revisions to the existing schedule or estimate. Closing estimates were given to Brazos based on the existing estimates.

In July 1980, the fuel load dates for Unit 1 and 2 were changed to December 1981 and September 1983, respectively. The reasons cited by TU management for this slip were regulation changes and project scope revision. It was during this same time frame that TU dropped the overall project schedule in favor of a start-up only schedule program. The field as-built verification and design review program required by IE Bulletin 79-14 was scheduled to start in mid-1980.

At the end of 1980, Unit 1 progress was reported as 87% complete. In January 1982, Unit 1 progress was reported as 86% complete. Concurrently, Unit 2 progress decreased from 51% to 46% over the same period. Based on a document provided to Cresap, McCormick and Paget (CMP), B&R expended over 7,500,000 manhours in 1981. This manhour expenditure represents over 25% of the Definitive Estimate base target manhours for construction. This time frame also would coincide with the period for the as-built reinspection program for pipe.

New fuel load date projections were made by TU in September, 1981.

> "This will transmit to you our current revised estimate of Comanche Peak Steam Electric Station completion dates and the associated cost. It is now projected that fuel will be loaded in Unit #1 in mid 1983 and in Unit #2 in late 1984...Finally, the accuracy of this present estimate on schedule and cost is subject to question since our track record has been less than desirable."
>
> (J.B. George letter to L. F. Fikar, dated September 18, 1981).

In October 1981, B&R underwent a routine ASME survey. The survey identified several deficiencies regarding the B&R QA manual. ASME decided to allow B&R's NA and NPT Certificates to expire on January 8, 1982. Loss of those certificates prevented B&R from performing ASME code work on the project. The certificates were re-issued on March 15, 1982, after B&R revised their QA manual and ASME performed a re-survey.

Other schedule slippages were made after this point in time on the project; further evaluation of these delays is continuing.

Construction Budget and Schedule Objectives

It is noteworthy that only $350,000,000 of the estimated project cost was unspent by September 1979. This balance of funds to be spent hinged on substantial construction completion by B&R in 1980 and a winding down of both B&R's and G&H's efforts in 1980. A proper evaluation of remaining scope was not used to determine this $350,000,000 figure. It simply resulted from calculation of what remained out of the $1.7 billion estimate. TU declared that the project would be completed with this amount, and indirect and overhead costs which were not needed were to be eliminated (memos dated September 24 and December 26, 1979). The project estimate was modified to $2.235 billion in August 1980, and to $3.44 billion in October 1981.

The original schedule was maintained until October 1976, when the fuel load date for Unit 1 was slipped from May 1979 to August 1980. This meant that at that time there were only 46 months remaining until fuel load. Major Unit 1 station buildings were statused as 28% complete in October 1976, but no significant mechanical or electrical work had yet started in the power block. If 30 months were required for a reasonable start-up period, only 16 months remained to complete all Unit 1 and common structural concrete plus virtually 100% of the power block mechanical and electrical installation work. As in the original schedule, a longer allowance for construction would result in an unrealistically short timetable for start-up.

From October 1976, until early 1979, the Unit 1 schedule remained the same, although the B&R monthly status reports indicated that the required schedule progress was not occurring. This was the basis for the decisions to accelerate work inside the Unit 1 containment in November 1977, and across the job in April 1978. These accelerations did allow them to set the vessels beginning in May 1978, but did not compensate for the lack of sufficient electrical and mechanical design.

A look at the time interval between the Unit 1 NSSS vessel sets and fuel load is in order here. TU was able to meet the target date of May 1978, for the Unit 1 NSSS vessel sets per the revised project schedule. As noted previously, this milestone serves as the kick-off point for mechanical (and then electrical) bulk commodity installation. What this required, however, was that in a 27-month period the bulk of all mechanical and electrical work would be completed, the design would be verified, systems completion and turnovers would be accomplished, the entire preoperational testing program would be completed, and fuel would be loaded. This was not possible!

The April 1978, CPM schedule indicated that the overall project was approximately 30 weeks behind schedule due to engineering and procurement problems (Memo from J.B. George to H.C. Kirkland et al dated December 16, 1978). What this meant was that the project had to make up approximately 7 months of schedule delay in 28 months. Under the unrealistic and unachievable Comanche Peak schedule, this was an impossible task.

By December 1978, when it had become clearly obvious that the Unit 1 fuel load date of August 1980, could not be met, TU upper management refused to allow a revision to be made to the fuel load date. In early 1979, however, after TMPA had executed the JOA, the Unit 1 fuel load date was changed to March 1981. This was at a point in time when total process pipe was less than 50% complete and total electrical was approximately 20-30% complete.

By December 1978, the project should have been into systems completion/turnover and should have been beginning preoperational testing in order to support the then-existing fuel load date. TU did try to drive the project into this mode, but mechanical and electrical progress were not sufficient to support such a transition. Subsystem turnovers, which did not begin until July/August 1979, were only 7% complete at the end of 1979, and were making little progress. In fact, the premature transition from bulk construction to systems completion impeded progress. At that time only 15 months remained to the scheduled fuel load.

<u>Construction Interaction Requirements With Engineering and Start-up</u>.

As a result of the fast-track approach, the success of the Comanche Peak project construction schedule rested on the ability of TU to closely coordinate and manage the interactions between engineering and construction, and between construction and start-up. The At-Risk approach to pipe and hanger design and installation required additional coordination and time to complete the design review.

Many references in the B&R monthly project reports indicate problems with timely receipt of engineering documents and material. There were many meetings where these problems were discussed. For example:

> "During the review it was made clear that there were construction progress problems in the following

> areas... Process pipe hangers - engineering and fabrication...Process pipe delivery...Instrumentation engineering and material delivery...Electrical engineering and material delivery."
>
> (Summit Meeting Minutes, February 21, 1978)

Furthermore, the requirements of testing must be the driving factor in determining construction priorities during the systems completion and turnover period. TU attempted to make up schedule losses in engineering and procurement by making a premature transition into systems completion and turnover without having made sufficient progress on bulk mechanical and electrical installation to support the transition.

B. Execution/Implementation of Construction

Actions Taken by Brown & Root to Perform Construction

o Manual and Non-Manual Staffing

Until the budgetary cutback in April 1977, it appears that B&R was allowed to staff the project as needed to meet schedule requirements. Prior to this initial round of budget cuts, total B&R personnel on the project numbered approximately 3,000. The budget cut imposed a cap of 2,500 personnel until the Unit 1 containment schedule acceleration in November 1977. This acceleration increased manpower to a peak of slightly over 3,000. The project-wide move to a double shift operation in April 1978, increased manpower totals to almost 4,000. Total B&R manpower levels fluctuated between 4,000 and 4,300 until January, 1980. (The B&R progress report was stopped at that time, so manpower figures were not available for review and analysis after 1/80.)

The ratio of manual to non-manual personnel may be reviewed after further discovery.

o Personnel Training

B&R had a chronic problem recruiting skilled craft labor and certain non-manual personnel such as engineers. There is also evidence that the lack of adequate numbers of skilled craftsmen resulted in the hiring of lesser skilled personnel:

> "We have experienced a high rate of failure by new hires in our present pipe welding test." (January 1977) "A problem still exists in procuring qualified reinforcing iron workers in numbers sufficient enough to meet the demands of the work schedule through 1981...The RIW superintendent has been requisitioning RIW helpers and has been transferring laborers into his department for training. These helpers and laborers are expected to develop into leadermen and possibly journeymen within the next year." (September 1977)
>
> "There is a shortage of laborers due to terminations for various reasons and move-up to craft helpers." (February 1979)

B&R established a procedural training program which focused on the understanding by craft personnel of construction requirements contained in procedures. Due to the limited experience level of craft personnel being hired, B&R also had to institute a skills training program to enhance the ability of laborers and helpers in becoming craft journeymen. As part of the project QA commitments, B&R also had training and certification programs for QC inspectors, both ASME and non-ASME. Although B&R had instituted training programs, the NRC Technical Review Team (TRT) identified numerous deficiencies in the training, qualification and certification of QC, Document Control Center (DCC) and craft personnel.

o <u>Measurement of Percent Complete</u>

Brown & Root established a target percent complete curve and reported the actual progress compared to planned progress for the total project in the monthly progress report. The target percent complete curve was based on a weighted percentage of the following thirteen commodities:

1. Excavation
2. Backfill
3. Structural Concrete
4. Steelwork
5. Process pipe hangers
6. Process pipe - 2" & under
7. Process pipe - 2.5-12"

8. Process pipe - over 12"
9. Instrumentation
10. Cable pull
11. Cable terminate
12. Conduit
13. Cable tray

The usage of a single S-curve to measure total project progress makes it virtually impossible to properly evaluate unit progress.

o Feedback on Problems to TU

Problem identification and resolution are necessary in order to mitigate the downstream impact of problems and to enhance the ability of the project to meet its goals and objectives.

There are several examples where TU was notified of problem areas which required resolution and failed to adequately address these problems in a timely manner. The most obvious of these are the problem areas listed at the end of each B&R monthly progress report. B&R provided a compilation of some of the typical problems which were encountered on the project. Among these problems were:

> "Construction continues to have an immediate need for delivery of pipe hangers." (September 1977 Progress Report)
>
> "Electrical design drawings are late in arriving from the engineer and are expected to retard con-

> struction in the areas of conduit, cable tray, cable tray supports, permanent lighting supports, and cable and conduit schedules." (September 1977 Progress Report)

> "The following items mentioned in the last twelve issues of this report are repeated with emphasis again this month... pipe whip restraint drawings...installation of cable tray hangers..." (January 1979 Progress Report) (emphasis added).

The same types of problems were identified in routine correspondence between B&R and TU.

> "The major area of concern for the Unit 1 and Common schedule is in the category of the overall status of supports and pipe restraint systems...Combining all of the above concerns we see the potential for major impacts to the cost and schedule of CPSES." (Memo from L.E. Hancock to Joe George dated May 17, 1979)

Another example of B&R's identification of a project problem appeared in a letter from Joseph Munisteri to L.F. Fikar dated September 7, 1977. In this letter, B&R responded to the TU request for steps to be taken to improve labor productivity. Munisteri requested TU to reduce the construction effort in order to let engineering and material support catch up. (TU's response was to accelerate construction.)

o Performance of Work Out of Sequence

Faced with pressure from TU management to be productive and to meet installation quotas, B&R opted to perform installation work in areas out of the desired construction sequence for mechanical and electrical commodities.

> "We have removed the restraint that goes from erection of pipe hangers three months (prior) to the erection of cable tray supports due to the fact that if the redesign by Gibbs & Hill of all cable tray supports is completed on time, we will be hanging cable tray, especially in the Auxiliary and Safeguard, prior to any piping and hanger deliveries." (Memo from H.C. Dodd to L.A. Ashley dated April 25, 1977)

<u>Actions Taken by TU</u>

o <u>Organizational Staffing</u>

From the beginning of the project until the establishment of the Construction Manager position in 1980, TU did not have a formal construction management group. Based on information taken from CPSES organization charts dated December, 1976 through 1983, The B&R Project Manager reported organizationally to the Office of the Project General Manager or Resident Manager.

The office of the Project General Manager was established about September 1977, and consisted of J.B. George and his B&R counterpart, Henry Kirkland. The main decision-making responsibility regarding B&R was placed in this office. Although there were no direct lines of functional responsibility placed between TU and B&R, the various TU engineering and quality organizations had daily interaction opportunities with B&R. Other than procedural responsibilities and the implicit authority this bestowed, these TU support groups had no direct functional management responsibility for B&R.

In early 1980, R. Murray was named construction manager, and the B&R Project Manager reported directly to him. Under Mr. Murray, an area management concept was started but it required using United Engineers & Constructors personnel and other contract personnel to staff the positions.

o <u>Budget control</u>

The total Definitive Estimate budget remained the same from June 1977 until August 1980. A "Financial Status of Project" report issued in July 1978, showed that currently estimated project direct costs and escalation had increased by $135 million over the Definitive Estimate. TU accommodated this increase by transferring funds from the project contingency account to the project direct cost and escalation accounts. TU also attempted to maintain the project budget by directing cuts in the area of overheads and indirects.

> "...a number of things I would like you to investigate... indirect manhours and dollars that Brown & Root has in the project...QA/QC manhours and salaries looks entirely too high."
>
> (Memo from L.F. Fikar to Joe George dated May 4, 1977)

> "...find activities that could be entirely eliminated."
>
> (Summit Meeting Minutes, December 13, 1977)

> "I then plan to direct each group as to what activities to eliminate..." (Memo from J.B. George to distribution dated December 26, 1979)
>
> "Review all overhead and indirect cost for duplication and necessity of work done with objective of reducing 25% by 6/80."
>
> (CPSES Consolidated Business Planning Review, March 1980)

TU sought further overhead and indirect budget cuts in March 1980, by directing B&R to stop certain estimating and cost accounting activities. That directive led B&R to warn TU:

> "Certain changes you have set forth would destroy and make useless the documentation we have compiled at CPSES. It would cause us to be without control data necessary to properly manage the project. These changes would flagrantly violate minimum standards of management for a project the size of CPSES."
>
> (B&R letter to J.B. George dated April 14, 1980)

TU attempts to maintain unrealistic budgets by cutting overhead and indirect manpower were counterproductive, since they adversely affected B&R's ability to support the field construction effort.

o <u>Non-ASME QA/QC Takeover</u>

Initial documentation review indicates that this is an issue which may have had significant impact on the project. Further analysis may be performed to address this subject.

o <u>Problem Feedback Responsiveness</u>

B&R notified TU of p oblems. The manner in which TU handled this notification indicated lack of recognition or delayed recognition by TU. B&R was aware in April 1977, for example, that published delays to pipe and hanger deliveries would have schedule impact. The B&R progress report for September 1977, stated that construction continued to have an immediate need for delivery of pipe hangers. The meeting minutes for the December 1977, summit meeting, however, stated that:

> "No major problems with procurement to support construction seem to exist at this time."

TU finally mounted a program to expedite pipe spool and hanger deliveries from ITT Grinnell during the first half of 1978 (one year later) with mixed results.

During the summit meeting of February 1978, it was pointed out that it would not be economical to add substantially to the work forces in the areas of piping, pipe welding, electrical and instrumentation without having the resources to support additional work forces. Contrary to this advice, TU management directed B&R to implement a double shift effort in April, 1978. Observations made subsequent to this decision were:

> "...quite a bit of idleness in all crafts...Also I noted one group of idle electric workers and of course you would expect this as they are the majority(?) of the work force." (Memo from Joe B. George to Henry Kirkland dated July 27, 1978)

> "...in the pipe and electrical activities, materials and design information were not available to support the acceleration and realize the improvements that

> were anticipated." (Analysis of construction acceleration attached to Summit Meeting Agenda, August 1980)

o <u>Construction Manager/Area Manager Decisions</u>

Initial document reviews in this area indicate that decisions were made which may have had impact on the project. Further analysis may be performed to address this subject.

o <u>Coordination of Design Documents and Material Deliveries</u>

In order to meet the aggressive schedule objectives set by TU management, close coordination of the design, fabrication and delivery of material was required. Timely receipt of engineering documents and material was necessary to properly support construction progress. Several references indicate that the required coordination did not materialize. Among these are:

> "As you can see, all of these areas have slipped considerably...Grinnell spools are not being received in any consecutive sequence...At present, Grinnell is shipping spools at random." (Memo from H.C. Dodd to L.A. Ashley dated April 25, 1977)

> "...there were construction progress problems in the following areas... process pipe hangers - engineering and fabrication...electrical engineering and material delivery." (Summit Meeting Minutes, February 21, 1978)

o <u>Establishment of Commodity Quotas/System Completion Requirements</u>

TU management was determined to meet their unrealistic schedule even in light of flagging production. They made a decision to leave the bulk installation mode and enter into the systems completion and turnover mode while still requiring that commodity targets be met.

> "Further production unit rates are of no value to TUSI. The only production rates that we care about are the meeting of the weekly bogey for pipe, welds, hangers, HVAC, conduit, W/C set out on the official startup schedule...The official startup schedule with system priorities and bogey for all critical commodities will set all work activities by 5/30/80 at the latest." (Memo from J.B. George to Jim Bazor et al dated May 1, 1980)

Reaction by field personnel is summarized in an NUS interview performed during the latter half of 1980. Some of the findings were:

> "The attempt to make system turnovers appears to be roughly six months early...This quota system will cause every group to go against their better judgment in order to make "numbers"...Management priorities to the number of hangers per week conflicts with long range design and construction considerations."

o <u>Establishment of Procedures to Handle Field Changes</u>

TU established procedure P-2 to handle design changes/deviations in the field. Revision 2 for this procedure was issued on August 17, 1977. The component modification card system (CMC) was implemented at that time to handle the as-built documentation of field pipe support changes. Some cogent observations of TU's design change control system are as follows:

> "Mr. Stewart emphasized concern about lack of engineering justification for acceptance or recommendations (regarding DC/DDA's)" (NRC Exit Interview Conference Memo dated October 14,1977)
>
> "...the design change documents are not handled in a consistent manner in the field." (B&R QA audit CP-15 dated April 11-13, 1979)
>
> "This system is completely confusing...A review of Brown & Root and ANI records indicate excessive errors and/or lack of information." (Letter from Hartford Steam Boiler Inspection and Insurance Company to Tom Gamon, B&R QA Manager Power Division, dated August 22, 1979)
>
> "Because of the complexity of using so many documents to determine what design conditions are valid, there is a high likelihood the QC inspections may not have produced an exact representation of the as-built condition." (EDS Pipe Support Program/Documentation Review, September 17, 1980)

C. Major Problems in Construction of Comanche Peak

Unrealistic Budgets and Schedules

The original schedule for the project was unrealistic. This schedule had a duration of 45 months from first nuclear concrete to fuel load for Unit 1. The commodity trend curves prepared in April 1977, by B&R demonstrated how B&R planned to meet this schedule. These trend curves included the commodities of concrete, structural steel, pipe, cable tray, conduit, cable and terminations.

The 90% completion point for each of the commodities from the trend curves was estimated as shown below:

1. Concrete - May 1978
2. Structural steel - March 1977
3. Pipe over 12" - March 1978
4. Pipe 2.5" to 12" - February 1979
5. Pipe under 2.5" - November 1979
6. Cable tray - August 1979
7. Conduit - September 1978
8. Cable - November 1979
9. Terminations - November 1979

While the cable tray curve appears to be at least one year out of phase, the curves appear supportive of an August 1980 fuel load date for Unit 1, assuming the unrealistic start-up time period.

These curves are inconsistent with the overall project schedule. The NSSS vessel sets were scheduled for May 1978, 27 months prior to fuel load. This milestone usually signals the start of bulk installation activities on the project. According to the trend curves, however, large bore pipe over twelve inches would have to be substantially completed prior to the setting of the NSSS vessels. B&R realized that sustained bulk installation had to start in 1977 in order to meet schedule objectives.

> "I told Mr. Austin that drawing delays and incomplete drawings have already had a very definite schedule impact on piping and electrical -that we could be in full swing in three areas, piping,

electrical conduit and cable tray if drawings and material were available." (Memo from H.C. Dodd to L.A. Ashley dated June 2, 1977)

In an opinion provided in June 1978, the NRC Caseload Forecast Panel, based on information provided by TU, stated that they felt the fuel load date for Unit 1 would be between April 1981, and September 1981. In December 1978, the project was 20 months from the then-scheduled fuel load date for Unit #1. TU upper management had just rejected the request to revise the Unit 1 fuel load date. Based on commodity progress, and using the trend curves as a guide, the project was up to 44 months from fuel load. This would have placed Unit #1 fuel load in August 1982. Due to the short start-up duration implied in the curves, a fuel load date of August 1982, or later, might have been reasonable. It is noteworthy that TU only extended the fuel load date in early 1979 for Unit #1 to March 1981.

At the end of 1979, wire and cable pulling was only approximately 15% complete. Based on the cable trend curve, fuel load was at least 23 months away. This would place fuel load no earlier than November 1981, which was still an overly optimistic date. It was in December 1979, that L. F. Fikar stated that TU was not ready to give up on the March 1981, fuel load date for Unit #1. By March 1980, systems turnovers were only 11% complete. Furthermore, in a May 29, 1980, memo to J.T. Merritt, et al, J.B. George stated that the scheduled Unit #1 Fuel Load was March 1, 1981, and was showing approximately six months slip. TU slipped the Unit #1 fuel load date to December 1981, in July 1980.

The project estimate remained the same from June 1977, until approximately August 1980, when it was increased from $1.7 billion to $2.235 billion. That the estimate could remain unchanged through documented periods of lower than anticipated productivity, construction commodity quantity increases, schedule delays and significant schedule accelerations is evidence that it did not reflect the cost of remaining scope. TU tried to decrease the budget growth by directing several rounds of overhead and indirect cost cuts. This reflected the fact that TU realized that direct construction costs were increasing as a percent of the total budget.

Evidence of this is found in the "Financial Status of Project" report issued in July 1978. This report shows that estimated construction manhours had increased from 28,860,890 to 36,2̣2,851, and estimated direct labor costs had increased by 55%. According to information provided by TU to Cresap, McCormick and Paget, B&R had expended slightly over 30,000,000 manhours by the end of 1979. This expenditure was greater than the target manhour figure from the Definitive Estimate, and was approximately 81% of the "current" estimate developed in January 1979. The December 1979 B&R Monthly Progress Report showed a total project percent complete of 66%. Rather than acknowledge the problems which were the cause of construction cost escalation, however, TU looked to reduce other areas in order to compensate for this increase.

From December 1979, through March 1980, B&R had expended approximately $5.2 million per month on direct labor. At this rate of expenditure, B&R would have exhausted its entire direct labor budget by September 1980. In July 1980, TU revised the CPSES cost estimate to $2.235 billion.

Due to significant increases in the cost of site engineering, construction labor, design engineering, major purchase orders and construction materials, TU increased the estimate for CPSES to $3.44 billion in October 1981. That estimate revision represented a 102% increase over the $1.7 billion estimate and came only 24 months after J.B. George's "$350 million left" statement. The October 1981 estimate was also 54% higher than the $2.235 billion estimate of July 1980.

The large increases in the CPSES estimate in such a relatively short time frame leads to the following conclusions:

1) The $1.7 billion and $2.235 billion estimates were unrealistic and were too low.
2) TU did not accurately project the final cost of CPSES in the 1977-1981 time frame due to their failure to properly define remaining work scope and to understand and incorporate the impact of problems at CPSES.
3) TU had lost control of the cost at CPSES and had no confidence in their estimates.

Lack of Adequate Engineering and Material Coordination to Support Construction

The Comanche Peak project schedule required that close coordination be maintained of the engineering and procurement phases of the project to support construction. Engineering and design documents normally are sent to the field with adequate lead time to allow construction personnel time to review the documents, check for installation problems, and have any problems resolved prior to starting installation in an area. Early receipt of documents also allows construction to better plan and coordinate their overall work effort and maximize the efficiency of manual labor. In the "fast-track" approach, additional coordination is necessary because engineering documents are issued to the field before engineering is complete. This also requires that engineering documents undergo interdisciplinary coordination and review since there may no longer be adequate time to field check the documents for constructibility. Whenever engineering documents are issued with errors, construction work in progress is delayed or substantial rework may be encountered.

TU did not recognize the importance of coordination. One of the earlier indications that coordination was a potential major problem area was in Dodd's memo to Ashley in April 1977. There were numerous references in the B&R monthly progress reports concerning engineering and material restraints, and J. Munisteri recommended in September 1977, that B&R slow down production so that engineering could catch up in order to improve construction productivity. This advice was not heeded by TU. Instead, the Unit 1 containment schedule was accelerated in November 1977, and the project was put on a double shift, extended work week in April 1978, apparently ignoring the following:

> "...it would not be economical to add substantially to the work forces in the areas of piping, pipe welding, electrical and instrumentation without having the resources to support additional work forces."
>
> (Summit Meeting Minutes, February 21, 1978)

The schedule acceleration evaluation performed in August 1978, concluded that the acceleration did not pay off for mechanical or electrical commodities due to the unavailability of materials and design information.

Nagging engineering and procurement problems were noted in a March 29, 1979, memo from J.B. George to distribution. L.E. Hancock's memo of May 17, 1979, to J.B. George further stated that there was potential for major cost and schedule impacts due to the status of pipe supports and restraints.

The lack of engineering and material coordination had an impact on construction; it delayed installation work, which resulted in extended schedules and production inefficiencies.

Compounding of Interference Problems

The inability of TU to control the inter-discipline coordination of G&H's engineering and design efforts would have resulted in interference problems by itself. The following additional factors caused directly or indirectly by TU actions and decisions aggravated the situation, compounded the interference problems on the project, and made cost and schedule estimates less realistic.

1. Abandonment of any viable attempts to coordinate the design, fabrication and delivery of pipe and pipe hangers and adoption of the At-Risk approach to expedite installation of pipe and hangers.
2. The installation of commodities out of the desired sequence.
3. The premature conversion to a systems completion and turnover mode.

Project documents do not indicate that TU originally planned to use the At-Risk approach in the design, fabrication and installation of pipe and pipe hangers. The At-Risk approach evolved over time. Due to the overriding pressure to meet schedule and the failure to provide pipe and hangers to the field in a timely manner to support construction, TU decided that the only way to meet schedule was to shortcut the formal design coordination and review process.

Instead of adequately reviewing the design before issuance of drawings to vendors and to the field, TU intended to review the as-built pipe and hanger configurations to determine if the installation was adequate. In addition to violating the intent of regulatory requirements, there was a risk that this after-the-fact design analysis would require reworking pipe and hangers to meet design considerations (hence "At-Risk"). This rework could lead to further interference problems. The creation of the mechanical interference group was necessitated by the lack of necessary coordination and the usage of the At-Risk approach.

"I submit to you and to all concerned with CPSES that we have only started in resolving our support system and interference problems...I need immediate help and attention from all Gibbs & Hill officers and managers to staff our CPSES site engineering group and above all, Bob Murray's interference group is key to meet schedule." (Memo from J.B. George to Roy Gordon dated August 26,1978)

"...we got a problem out there right now out there with hangers...[I]n 2 weeks we have created a backlog of RFIC's in excess of 250, somewhere between 250-300 hangers as a result of that backlog, that going through Murray's interference group, we have brought out Routenaro's group, that's the Grinnell hanger people of Dallas, 4 individuals in here this morning which they are going to work extended hours, straight through until we can clear out this backlog." (J.T. Merritt comments, staff meeting October 9, 1978)

"When you have completed an area or system and have it bought off by QC, you are vulnerable to future design changes that may cause rework...piping lines installed off location are causing a great deal of feedback to engineering for reanalysis." (Problem summaries from NUS interviews circa late 1980)

The problems experienced with mechanical and electrical material deliveries led B&R to install commodities out of the desired sequence. This problem was noted in the October 1978, staff meeting.

"We now have a (interference) problem with hangers...Bumping into other disciplines, drilling holes, cutting rebar, trying to pick up Hilti-Kwiks, something else being where the hangers were scheduled to go." (John Merritt comment, October, 1978 staff meeting)

TU was pushing for system turnovers in 1979 in order to meet the fuel load date of March 1981, for Unit 1. The project should have been in a systems completion and turnover phase before 1979 in order to have any chance of meeting that fuel load date. However, the project actually was still in the bulk installation mode. TU tried to resolve this problem by prematurely going to the systems completion mode and by requiring commodity quotas, or bogeys, to be met. Some pertinent observations were made in the NUS interviews conducted in the latter part of 1980:

> "The attempt to make system turnovers appears to be roughly six months early...This quota system will cause every group to go against their better judgment in order to make "numbers"...Craft morale problem is a major concern with the amount of rework being experienced...Different crafts are taking down each other's pipe, duct, conduit, etc., to get their systems installed."

The combination of these three factors greatly increased the interference problems experienced on the project. Further analysis is needed to determine the extent of the rework performed to resolve interference problems.

Inadequate System to Handle Field Changes

All nuclear projects are required to have procedures to guide the installation and inspection of construction work and to identify and resolve non-conforming conditions. At Comanche Peak, the volume of problems caused by lack of coordination, by at-risk design and installation, by work performed out of sequence and by the premature systems completion orientation overloaded the field change system.

"A generic control problem was also noted in regards to CMC's. However, the problem with CMC control is...one brought about by the large volume of CMC's currently issued as controlled documents (approximately 10,000)." (Letter from B&R to Hartford Steam Boiler Inspection & Insurance Company dated October 4, 1979)

The overloading of the field change control process may also have been exacerbated by the hiring of lesser qualified manual, non-manual, and QC personnel who were not adequately trained.

> "During discussions with QC Mechanical Inspectors it was learned that these inspectors rely upon construction personnel to determine what is the latest revision to a drawing including all applicable design changes." (B&R QA audit CP-15 dated April 11-13, 1979)

> "The lack of experienced and trained personnel is a significant problem. Extensive training is required to achieve a common understanding of how the system works." (NUS Interviews circa latter 1980.)

> "The training and qualification of QA/QC, craft and other personnel were not administered and monitored effectively. (Comanche Peak SSER Supplement 11, Appendix P)

The NRC TRT QA/QC group commented on the entire process in the Comanche Peak SSER Supplement 11, Appendix P:

> "The TRT found examples of ineffective interaction among the engineering, construction and quality control groups that was evident because of...design acceptance of questionable construction practices, inadequate design analyses of field changes"

> "The control of documents, and subsequently of records, was replete with recurrent deficiencies."

<u>Additional Problems During Construction of CPSES</u>

o Incorrect Alignment of Unit #2 Reactor Vessel Supports

Due to inadequate interdiscipline engineering coordination, B&R installed the Unit #2 reactor vessel supports incorrectly. The supports were rotated 45 degrees from the correct positions which were necessary to properly align the reactor vessel with the other NSSS components. This problem required significant rework to correct (drilling holes in concrete, addition of tie bolts and reinforcing steel, rerouting of HVAC ducts) and provides strong evidence that very serious coordination problems existed at CPSES. This same problem is also addressed in Section VI of this report.

o Improper Switchgear Operation Due to Unlevel Floors

Construction deficiencies were identified involving the structural embedments and concrete floor supporting the Unit #1 and #2 safety-related 6.9 kv switchgear. The concrete floor and structural embedments were not level, which caused gaps between the switchgear and the floor. These gaps could have caused the metal switchgear floors to distort because of circuit breaker weight resulting in misalignment between the 6.9 kv breaker tulips and cabinet stabs.

If these deficiencies had remained uncorrected, the reliable performance of the Unit #1 and #2 safety-related 6.9 kv switchgear could not have been assured under normal operating and accident conditions. It is noteworthy that this deficiency was not identified until preoperational testing of the Unit #2 safety-related switchgear. This provides strong evidence of poor quality construction work and TU's inability to identify and resolve construction non-conformances.

- <u>Air Gaps Between Concrete Structures</u>

The Comanche Peak FSAR required a separation of Seismic Category I buildings to prevent interaction of these structures during an earthquake. For the seismic analysis of these buildings, it was assumed that there would be a clear air gap between the buildings and that they would not interact during an earthquake. Failure to maintain the integrity of this air gap between the buildings would invalidate the seismic analyses that were performed. Interaction between the buildings would require more complex seismic analyses to be performed to determine if the buildings could withstand earthquakes.

Field investigations by B&R QC inspectors originally identified the problem with rotofoam left in the air gaps. This problem was resolved by requiring that the rotofoam debris be removed from the air gap. The resolution was not successful because not all of the rotofoam was removed. Subsequent inspections performed after the initial rotofoam removal effort identified additional rotofoam plus other types of debris such as wood wedges, rocks and clumps of concrete in the gaps. These inspections were performed in 1978 but were not reported as a non-conformance until 1983. The disposition of the non-conformance included an analysis which did not address the applicable FSAR load case combination.

The NRC Technical Review Team (TRT) could not determine whether an adequate air gap had been maintained between the buildings. As part of the CPRT effort, TU had to perform an as-built inspection of the air gap, remove accessible debris, and perform an analysis to demonstrate that any material or debris left in the gaps would not significantly effect the seismic response of Seismic Category I structures. If the air gap had been properly maintained and kept clean during construction, the additional costs incurred to resolve the problem would not have been required.

o <u>Problems with Batching and Placement of Concrete</u>

Concrete is one of the most important construction materials used at a nuclear project. Concrete is used for building foundations, floors and walls, as well as for radiation shielding. Quality control of both the batch mixing and placing of concrete on a nuclear project is important since poor quality concrete could result in problems ranging from cracking to structural failure. During the construction of CPSES, numerous problems occurred regarding the batch mixing and placement of concrete. Some of these problems were:

1) A hoist was left in an area where concrete was poured and became permanently embedded in the concrete.
2) Concrete pours were made in cold or freezing temperatures without taking the necessary precautions for cold weather concrete pours.
3) Concrete pours were made with inadequate numbers of craft and QC personnel, which resulted in poorly placed concrete

and which caused other problems such as voids.

4) The NRC CAT identified that mix uniformity tests for concrete had not been performed as required by the Comanche Peak FSAR.

The numerous problems involving concrete have led TU to implement an extensive program to verify the quality of poured concrete at CPSES. This program includes extensive testing of concrete, as well as physical removal of concrete to check reinforcing steel. If proper quality control had been used during the batching and placement of concrete at CPSES, these additional costs would not have been necessary.

o Omitted Reinforcing Steel

Reinforcing steel is used to strengthen concrete for tensile forces. Since concrete is very strong under compressive forces, the reinforcing steel helps concrete maintain a balanced strength for both compressive and tensile forces. The size, number and location of reinforcing steel bars in concrete is very important in determining the strength of the concrete under specified loading conditions. Improper size, number or location of reinforcing steel rods in concrete could lessen the strength of the concrete and allow failure under adverse loading conditions.

There were several reported omissions of reinforcing steel from concrete pours at CPSES. One of those pours involved the omission of 112 #9 reinforcing bars in a Unit #1 reactor cavity pour. The reinforcing steel for this pour was installed and inspected in accordance with Revision 2 of a drawing. Revision 3 to the drawing, which included the additional #9 reinforcing bars, was issued shortly after the concrete was poured. The additional reinforcing steel had been added as a precaution against cracking in the vicinity of the neutron detector slots should a loss of coolant accident (LOCA) occur. Gibbs & Hill had violated a procedure to be followed by the engineer which required that a "Construction Hold Notice" be issued for pending revisions affecting work. This was not done. Gibbs & Hill later stated that the omission of reinforcing steel was acceptable without performing the necessary analysis. This is an example of both a procedure violation by the engineer and the acceptance of a "use-as-is" disposition without any engineering justification.

o <u>Cutting of Reinforcing Steel in Fuel Handling Building</u>

The strength of concrete under tensile forces is dependent on the size, number and location of reinforcing steel bars in the concrete. If the reinforcing steel is cut, it may not provide the necessary reinforcement to the concrete and can result in a weakened concrete structure.

In January 1983, a construction crew core drilled approximately 10 holes about nine inches deep into the concrete during the installation of the trolley rails in the Fuel Handling Building. The crew had been authorized to cut the first layer of reinforcing steel bars but it was reported that additional layers were also cut.

Subsequently, the NRC Technical Review Team requested TU to determine if any layers beyond the first layer were cut. If additional layers were cut, TU had to perform an analysis to demonstrate that the design integrity of the building was not compromised. This is an example of poor control of construction work.

o <u>Pipe Support Deficiencies</u>

Pipe supports are necessary to hold plant piping in place during normal and emergency conditions. Failure to properly install pipe supports per design requirements can seriously affect the ability of the supports to hold the pipe in place.

The NRC CAT and TRT inspection teams both identified numerous deficiencies in the installation of pipe supports at Comanche Peak. Some of these deficiencies were:

1) U-bolt configuration not per drawings.
2) Dimensions not per drawing.
3) Load pin locking devices missing.
4) Loose strut locknuts.
5) Missing/broken cotter pins.
6) Hilti Bolts not meeting minimum embedment requirements.

Configuration control problems may be attributed to the inadequate design control system used at CPSES and to the failure of construction crews to pay attention to drawing detail. Missing/loose locknuts, cotter pins, etc. are due to poor construction practices and lack of attention to detail.

o HVAC Duct and Duct Supports

The NRC CAT team inspected HVAC ducts and supports for conformance to design drawings in 1983. Five of nine supports inspected did not conform to as-built sketches or design drawings. A further check of HVAC as-built drawings in late 1985 and early 1986 found additional deviations from design drawings. Ducts had not been bolted or welded to supports as required by the design drawings. This led TU to terminate the HVAC contractor (Bahnson) in early 1987 and to replace them with another contractor. Bahnson had been fabricating and installing HVAC duct and duct supports at CPSES since early 1978.

This is an example of poor quality control inspections and lack of attention to detail by construction crews.

o Cold Springing of Pipe

Cold springing of pipe is a method to force pipe into proper alignment if it has been installed incorrectly; cold springing is done by using jacks, "come-alongs", and other types of construction tools or equipment. This is normally an unauthorized method for correcting pipe installation problems on nuclear projects since it adds stress to the pipe. This additional stress can increase total stress on a pipe beyond its design failure limits. During flushing operations in Unit #1, the main steam piping had shifted due to the weight of the added water and sagging of temporary supports. The polar crane and "come-alongs" were used to force the main steam line into proper alignment and the permanent pipe supports were modified to provide proper support to the pipe in its restored position.

The NRC TRT cited this as a violation of Criterion V of Appendix B to 10 CFR 50 and requested that TU perform several assessments including evaluation of stresses in the affected portion of the main steam piping. This is an example of poor construction practices and inadequate supervision of construction work since an unauthorized methodology was used to correct a field problem without notifying engineering.

o <u>Cable Termination Problems</u>

There can be on the order of 100,000 individual wire-end terminations on a single nuclear unit. Many of these terminations are in safety-related systems where it is absolutely essential that electrical circuit integrity and continuity be maintained. A single loose termination can cause a system malfunction and failure due to inadequate contact between the wire lug and termination. Certain wire terminations require additional protection due to possible exposure to water or steam. This can be accomplished by wrapping the termination with insulation tape or by using heat shrinkable cable insulation sleeves.

The NRC TRT identified several problems with cable terminations and splices at CPSES. Among those problems were:

1) Lack of awareness on the part of QC inspectors who were supposed to document in inspection reports when the instal-

lation of "nuclear heat-shrinkable cable insulation sleeves" was required to be witnessed.

2) Inspection reports that did not indicate the required witnessing of splice installations.

3) Cable terminations were found which did not agree with their locations or drawings. Due to this, TU was requested to reinspect all safety-related and associated terminations in the control room panels.

o Improper Cable Tray and Conduit Support Installation

Design analysis of plant components is based on the design drawings. Plant components should be fabricated and installed in accordance with these design drawings. If plant components are not fabricated and installed in accordance with the design drawings, the design analysis will not be valid.

In a relatively small inspection sample, the NRC TRT found numerous discrepancies in several cable tray and conduit supports. In the inspection of one particular cable tray hanger, for example, over 40 stiffeners and 80 welds were found in addition to those which appeared on the design drawings. This hanger had been already inspected and accepted by QC.

This example provides further evidence that construction by craftsmen to other than the approved design contributed to the serious breakdown in configuration control and design change control at CPSES.

Expiration of NA and NPT Certificates

Programmatic deficiencies found in the B&R QA Manual by an ASME survey team in October 1981, led to an ASME decision to allow B&R's NA and NPT Certificates to expire. B&R revised their QA manual and ASME performed a re-survey before the NA and NPT stamps and certificates were re-issued. The impact of this event on the CPSES construction program may be evaluated.

VIII. PREOPERATIONAL TESTING OF COMANCHE PEAK

A. Planning & Control of Preoperational Testing

In reviewing the preoperational testing program at Comanche Peak, our review and analysis concentrated on the planning and control aspects of the program. The execution/ implementation of the preoperational testing program was not reviewed in detail. More specifically, we did not review or analyze whether or not the performance of the various tests conducted in the testing program was adequate. Consequently our remarks pertain to the planning and control aspects of the testing program, and to the management actions taken by TU relative to planning and control. If our review is expanded in the future to include execution/implementation of the testing program, this report will be amended.

B. Actions Taken by TU to Manage Preoperational Testing

TU decided quite early in the project not to conduct preoperational testing activities utilizing TU personnel exclusively. Their original intent was to staff approximately 50% of the testing personnel needs utilizing contractor personnel, and the remaining 50% utilizing TU personnel.

Impell was awarded the startup services contract in August, 1975. Separate contracts were maintained with several other suppliers of startup personnel in addition to Impell.

Mr. Richard E. Camp was the first Impell employee to be assigned to Comanche Peak. He served as the lead startup engineer from his assignment in August, 1975 until July, 1983. At that time, Mr. Camp was named startup manager reporting to John Merritt.

From early in the project until August, 1982, responsibility for performance of the preoperational testing and startup program resided within the TU operations organization. Within the operations organization, testing reported to Mr. J. Kuykendall. It should be noted that Mr. Kuykendall's previous experience was in coal plant operations; he had no prior nuclear experience. (It should be noted also that Mr. Camp's prior startup experience was 2 years at the Cooper Nuclear Station, a boiling water reactor (BWR), and at Washington Nuclear Project No. 2 for approximately 18 months, another BWR, early in the construction of that unit.)

The startup program plan was issued by Texas Utilities in May, 1977. In that manual, TU acknowledged that,

> Title 10, Part 50, Appendix B of the Code of Federal Regulations (10 CFR 50 App. B) requires that a test program be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures. Thereby the purpose of this plan is to describe the administrative organization, methods and procedures to be used by TUGCO to implement, control and document the test program.
>
> (CPSES Startup Program Plan)

The manual then goes on to describe the various testing activities to be performed during the testing program. When Texas Utilities submitted the Final Safety Analysis Report (FSAR) in 1978 the FSAR included Chapter 14.0 entitled "Initial Test Program." That chapter described the test program and included the various commitments made by Texas Utilities to the NRC pertaining to the test program.

In August 1982, responsibility for the test program was transferred from the operations group to the assistant project general manager (J. Merritt); Mr. Merritt was named startup manager at that time. It should be noted that Mr. Merritt had no prior nuclear experience before his assignment at Comanche Peak. Furthermore, he had no prior nuclear testing experience before his assignment as startup manager.

In July 1983, Mr. Merritt was given broader responsibilities. He retained responsibility for startup testing, however, and Mr. Camp became startup manager reporting to Mr. Merritt.

C. Preoperational Testing Interaction with Construction and Fuel Loading

The following wording from the Startup Program Plan describes the responsibility of TUGCO Nuclear Operations:

> "The TUGCO Nuclear Operations Group is responsible for conducting the Startup Program for CPSES.
>
> "...This responsibility includes:
>
> "...provide scheduling input to the Constructor for the completion of station systems in support of

testing activities;"

(CPSES Startup Program Plan)

This identifies the requirement for startup testing program personnel to describe system completion needs to construction, whereby construction is expected to complete the desired systems in the appropriate order as needed by testing.

In January, 1978, with fuel loading scheduled for August, 1980, the required system turnovers were to begin in December, 1978. These requirements were described in a January 27, 1978 TU/Brown & Root memorandum:

> "If we consider now...the startup requirements with turnover starting on December, 1978 and completion on March, 1980..."
>
> (B&R memo dated 1/9/78; Page 7 as attached to the TUSI memo dated 1/27/78.)

The FSAR described the relationship between preoperational testing and fuel load.

> "Preoperational testing will be completed prior to fuel load with certain limited exceptions where tests or parts of tests will be deferred to the Initial Startup Test Program."
>
> (FSAR Chapter 14)

One minor exception is then described as an example in the FSAR. What this means is that TU recognized that the preoperational testing program was to be completed prior to loading fuel. Furthermore for non-nuclear safety related systems the following pertained:

> "for systems and components which have no nuclear

safety related requirements, acceptance testing will be performed to verify proper system performance and to insure reliable and efficient operation of the plant."

(FSAR, Chapter 14)

It thus was envisioned that the acceptance testing program would also be accomplished as an adjunct to the preoperational tests prior to fuel loading.

D. Status of Preoperational Testing vs. Time

There were approximately 325 systems which required turnover from construction to testing (and to operations). It should be pointed out that the total of 325 systems represented Unit #1 (and common facilities) turnovers only.

The first system was turned over for acceptance in July 1979. By the end of December 1979, only 21 systems had been turned over. By December 1980, 63 systems had been turned over. By December 1981, 185 of the 325 systems had been turned over.

In information provided to Cresap, McCormick and Paget (CMP), TU implied that the overall startup program for Unit 1 and Common began in August or September 1979. The program was only 20% complete by August 1981, and did not reach 50% completion until September, 1982.

The following milestones were identified as accomplishments of the testing program in other CMP documents:

- o Unit 1 control room manned for first time - 1/80

- Startup transformers energized (138KV) - 1/80
- First major mechanical system run at Comanche Peak (Service water system) - 3/81
- Unit 1 steam turbine and electrical generator ready for rotation - 9/81
- Successful completion of Unit 1 RCS cold hydro - 7/82
- Unit 1 diesel generators first run and tested to 110% electrical load - 9-10/82
- Hot functional testing of Unit 1 completed - 5/83

IX. PROJECT STATUS - 1977 TO 1979

The entire time period for the project, from initiation in 1972 through 1987, was reviewed for preparation of this report. Separation of the time period from 1977 to 1982 into two segments (1977 to 1979; 1980 to 1982) was done for convenience.

In evaluating any given time period, however, it is impossible to look at progress and status without recognizing that poor progress may be the result of earlier improper management decisions and practices. Although many such cause and effect relationships are described within this report, the relationships are meant to serve as typical examples, not an exhaustive listing.

In October 1976, TU changed the scheduled completion date for Unit #1; the Unit #2 schedule remained unchanged. As a result of the October 1976 change, the completion dates became the following:

	Fuel Load	Commercial Operation
Unit #1	8/80	1/81
Unit #2	8/81 (no change)	1/82 (no change)

Mr. James L. Ghiotto of TU cited the following as the primary reason for the schedule change:

> "The primary reason for this change is a reduction in the System estimates of growth and the future demands for electric energy."

(Ghiotto by cover note to Burl B. Hulsey, et al, dated 10/5/76)

The acknowledgement of the one-year delay on Unit #1 reflected the lack of sufficient progress up to that time to meet the earlier schedule. It did not adequately reflect the lack of realism or the unachievability of the schedule after the Reactor Vessel set milestone. Mr. Ghiotto expressed that as follows:

> "The Comanche Peak unit was chosen for deferral because the delay fits the present rate of construction progress. The work on Unit No. 1 has been delayed because of difficulties in meeting the extremely stringent criteria for design and construction. The most serious difficulties have been in the placing of reinforcing steel in the pouring of high strength concrete.
>
> (Ghiotto by cover note to Burl B. Hulsey, et al, dated 10/5/76)

The Definitive Estimate was prepared for Comanche Peak in December 1976. Since there was a higher degree of completion of engineering/design at that time, the estimate better (although still inadequately) reflected the size of the project. Gibbs & Hill reported engineering and design at 37% and 44% complete, respectively, in December 1976; engineering and design had been substantially less complete when the earlier estimate was prepared. It should be noted that the Definitive Estimate was based on design and information available on a cut-off date of 8/28/76. Furthermore, it was based on Commercial Operation dates of 1/1/81 for Unit #1 and 1/1/83 for Unit #2.

As a result of the Definitive Estimate, the B&R contract was amended in June, 1977. The base manhour target for B&R's work scope increased from 12,500,000 manhours to nearly 29,000,000 manhours. The project clearly was substantially larger in scope than

TU originally contemplated. Furthermore, in a meeting between TU and B&R in June 1977, B&R indicated that:

> "...I was very confident that Brown & Root could perform the requirements for the project within the estimated total manhours and unit cost, BUT that some changes would be required by Gibbs & Hill to support the budget and the schedule." (emphasis in original)
>
> (H.C. Dodd, Jr. Memo to L.A. Ashley dated June 2, 1977.)

Mr. Dodd cited some specific examples of Gibbs & Hill impact on the construction schedule, such as the following:

> "...drawing delays and incomplete drawings have already had a very definite schedule impact on piping and electrical..."
>
> (H.C. Dodd, Jr. Memo to L.A. Ashley dated June 2, 1977.)

Despite the fact that engineering was behind, and had already impacted construction, TU imposed their 1977 spending limitations on engineering (G&H) as well as on construction (B&R). The limitation resulted in G&H decreasing its manhour expenditure for 1977 to approximately 513,000 mhrs, compared to more than 671,000 mhrs in 1976. (It should be noted, also, that G&H was expending substantial numbers of manhours in preparation of the FSAR, which was submitted to the NRC in February 1978, with the application for the Operating License.)

In June 1977, TU also had introduced a Manhour Target Incentive/Penalty clause into the G&H contract. (Supplement No. 8.) Mr. Dodd (B&R) indicated his concern and asked about this clause and its potential impact in the site meeting with TU's upper management:

"I asked if Gibbs & Hill in fact was now operating on a target manhours incentive bonus penalty program. Mr. Brittain informed me that this was true. I then asked if this would give Gibbs and Hill another excuse not to solve field related problems but to only push through for construction drawings."

(H.C. Dodd, Jr. Memo to L.A. Ashley dated June 2, 1977)

In August 1977, B&R once again called TU's attention to critical problems areas at the site, and asked for assistance from TU.

"<u>TUSI</u>...

TUSI needs to take an active part in expediting ITT Grinnell Hangers and Pipe...

<u>B&R Construction</u>...
More direct communication between G&H and B&R...

<u>B&R QA/C</u>...
Strive to have qualified inspectors...

<u>Gibbs & Hill</u>...
Legibility of G&H and vendor drawings is still a big problem...Timely release of drawings to meet the construction schedule...B&R needs to be installing cable tray supports, cable tray and conduit now in safety related areas. Need drawings out already too late to meet schedule...
There appears to be very little review between G&H disciplines, such as electrical vs. pipe vs. structural."

(H.C. Dodd, Jr. letter to J.T. Merritt, Jr. dated August 8, 1977)

Also in August, 1977, Homer C. Schmidt, the TU Project Manager, indicated that TU felt G&H should not further reduce its staff, but instead increase it.

"We concur that G&H should not further reduce its staff to achieve 1977 budget restraints. We further concur that additional G&H staffing is necessary to meet project objective."

(H.C. Schmidt letter to R.E. Hersperger dated August 9, 1977.)

At a Management Meeting in September 1977, the preliminary milestones for the Unit #1 and Unit #2 Critical Path Method (CPM) schedules were addressed. A partial listing of those milestones was the following:

Unit #1 -

Set Vessel	May 1978
Begin Startup	December 1978
Fuel Load	August 1980

Unit #2 -

Set Vessel	September 1979
Begin Startup	February 1981
Fuel Load	August 1982

In assessing the critical path for Unit #1, the importance of the electrical commodities was highlighted.

> "The electrical installation (raceway, wire and cable, termination) being at the end 'of the line' is the most critical activity on the job. Any delay (concrete or piping) will impact the electrical installation in the plant because of the electrical interconnection of the startup systems. (First electrical startup system must be ready by December, 1978.)"

(J.J. Moorhead letter to H.C. Schmidt dated September 15, 1977.)

In October, 1977, with the issuance of their Monthly Progress Report for the month of September 1977, Gibbs & Hill acknowledged to TU that they were significantly behind schedule in issuance of drawings.

> Project status:
> "Drawings schedule to be issued for B&R construction - 1743
>
> Drawings actually issued for B&R construction - 1207"
>
> (G&H Monthly Progress Report)

Gibbs & Hill also was behind schedule in issuing specifications for bidding and construction.

Despite the fact that G&H was behind schedule in performing engineering/design work, TU directed expansion of the construction efforts to meet the Unit #1 Steam Generator set milestone of May 15, 1978. (The projected date had slipped to July 24, 1978.)

> "On November 4, 1977 B&R presented an accelerated program of extended hours and two shift work...
>
> ...Effective November 14, 1977 the construction effort will be expanded to two shifts, six days per week, ten hours per shift...
>
> 'Reactor Building Unit 1 Only.'"
>
> (TUSI Office Memo dated November 7, 1977 from J.T. Merritt, Jr., et al. to TUSI/B&R/G&H)

By January 1978, concerns about meeting the schedule had increased. Not only were the electrical commodities a major concern, but also pipe hangers were a major concern.

> "Hanger Logic...We do not know when (and if) ITT will be able to furnish the required hangers. We do know this delivery will be very, very late. If we

think of Start-up beginning in December, 1978 and

the first Mechanical Systems to be turned over around February-April, 1979, we realize that the hanger delivery causes us a problem, a very big problem."

"We also are waiting for definite data about the total amount of wire and cable on the project."

"Again, we feel that the total of 5,801,379 LF officially given by G&H is too low (Total wire and cable for Unit 1-2 - Common.)"

"The piping and hanger delivery is now a real problem."

"The electrical work is also critical,..."

"The situation is very serious and grave and if we consider the start-up requirements, we must ring an alarm bell for the piping and electrical situation."

"Practically all piping, HVAC, instrumentation and electrical installation has not started...
The situation is very, very critical because we do not have a serious commitment yet for hanger and piping delivery."

"Construction is behind in the fabrication and installation of cable tray hangers...In general, electrical work that could and should be in progress is being delayed as much as six months for want of either engineering information, client-furnished materials, or both."

(1/27/78 Summary of TUGCO Meeting with attachments held on 1/11/78.)

Also in January 1978, TU assumed direct management of QA/QC operations at the site. There was no indication that TU considered potential impact to the schedule since the expected impact of this action on the construction schedule and progress was not reported. Organizational and responsibility changes of this nature often have a detrimental impact on the schedule, at least in the short term. (It should also be noted that the B&R and G&H Project Managers were changed in January 1978, too.)

In analyzing the critical path for Unit #1 (actually analyzed in December 1977), it was concluded by the project that setting the NSSS vessels was a necessary, but not sufficient, condition to meeting the schedule.

> "The Set Vessel Date is the controid (sic) of the whole schedule. If we meet this date we will complete the job in time provided construction is supported by engineering and procurement. If we do not meet this date, we may not meet the final target."
>
> (1/27/78 Summary of TUGCO Meeting with attachments held on 1/11/78)

In February 1978, B&R stated that they had developed an integrated schedule for Unit #1 and Common and they provided it to TU for review. The schedule purportedly integrated engineering, procurement, construction and startup, although the Definitive Target Startup Schedule was not issued until October 1978. Review of the integrated schedule prompted another acceleration in the efforts of construction.

> "The Integrated Schedule was formally presented to management on April 10, 1978. The criticality of the schedule, based on working a standard single shift, 40-hour week was defined...
> From this analysis, a management decision was reached to accelerate to a 2-shift, 10-hour, 5 day work week."
>
> (B&R Monthly Construction Progress Report No. 42 for period ending 4/30/78.)

In their Monthly Progress Report No. 44 for the period ending June 30, 1978, B&R reiterated to TU some of their serious concerns about meeting schedule requirements:

> "The following items mentioned in the last five issues of the report are repeated with emphasis this month:...
> Construction is behind in the fabrication and installation of cable tray hangers...In general, electrical work that could and should be in progress is being delayed as much as ten months for want of either G&H engineering information, drawings, or clarification, receipt of G&H purchased material, raceway schedules, client-furnished material, or all...
> Listed below are equipment items which are needed to meet the fuel load target date. The float column indicates the number of weeks which expected receipt of each item deviates from the scheduled latest finish date for installing the item."
>
> (B&R Monthly Construction Progress Report No. 44)

There then followed a list of 64 items with negative float up to 51 weeks.

In the meantime, the NRC Caseload Forecast Panel had visited the Comanche Peak site on April 18-19, 1978. The purpose of the visit was to assess the Fuel Load Date in order to allow the NRC staff to allocate personnel resources for FSAR/OL review. The NRC confirmed that TU could not meet its then-existing schedule.

> "As a result of our review of construction activities and the other information provided by the applicant, we stated that we estimated the fuel load date for Unit 1 as being between April 1981 and September 1981 or eight to twelve months after their current date of August 1980."
>
> (NRC Trip Report -Site Visit to Assess Fuel Load Date - April 18-19, 1978 dated 6/9/78.)

The NSSS Vessels were set beginning in May 1978. This should have provided clear indication to TU that the then-existing schedule was neither realistic nor achievable. For the Westinghouse plants which had been placed into Commercial Operation most recently prior to that time, the average duration from setting the reactor vessel to commercial operation was approximately 45 months. That would imply a Commercial Operation date for Unit #1 of February 1982.

Finally, in December 1978, although TU realized they could not meet their schedule, they refused to acknowledge that fact.

> "On December 7, 1978 during the Mini-Summit Meeting it was discussed that the beginning of Start-up will be several months late. Further it was determined that the cause was mostly due to late engineering information. The most critical engineering information is presently in the Electrical Discipline.
>
> "On December 8, 1978 Mr. Fikar discussed this and the possible delay in getting fuel loaded in Unit #1 in August 1980 with the top Texas Utilities officers. The delay was unacceptable..."
>
> (J.B. George Memo to H.C. Kirkland, et al dated 12/16/78.)

Although the first system turnover was supposed to have occurred in December 1978, it did not actually occur until July, 1979. We did not determine whether the systems turned over subsequent to July 1979 were in the proper sequence as needed by the Preoperational Testing and Startup personnel. The initial energization of the start-up transformer, however, which is customarily the beginning of the testing program, did not occur until January 1980. This would normally indicate fuel load approximately 30 months (2 1/2 years) later, i.e. July 1982, but that did not occur.

X. PROJECT STATUS - 1980 TO 1982

One of the major work efforts at the Comanche Peak jobsite from 1980 through 1982 related to pipe hangers. (The words "pipe hangers" and "pipe supports" are used interchangeably.) Other commodities such as conduit (including conduit supports) and cable tray (including cable tray hangers) also received much attention, but a major focal point was pipe hangers.

Although a great deal of work was devoted to pipe hangers in the 1980 to 1982 time period, B&R had emphasized the pipe hanger problem to TU in April 1979. (The need for hanger drawings and materials to support construction had been a problem earlier.)

> "A new area of great concern is the possibility that about 5,000 pipe supports may have to be redesigned as a result of re-analysis of the design criteria. This may affect supports in all stages from design through fabrication and installation."
>
> (B&R Monthly Construction Progress Report No. 54; Period ending 4/30/79)

B&R further amplified their concern to TU the following month.

> "The quantity of pipe supports that will have to be redesigned and either revised, refabricated and/or reinstalled is currently estimated as approaching 3,000. These redesigns are the result of:
>
> a. Reclassification of certain non-nuclear piping from non-seismic to seismic category.
>
> b. Higher G-loads used in the final computer analysis than were utilized in the nomographs.
>
> c. Designs being released for fabrication and construction that were not (in) accordance with the latest engineering information.
>
> "The total quantity of pipe supports that remain to be designed and fabricated for Unit 1 and Common...is esti-

mated at 6,800. Completion of this design effort at present rates...will have significant impact on construction progress."

(B&R Monthly Construction Progress Report No. 55; Period Ending 5/31/79)

Redesign was not the only problem related to pipe supports, however. The construction estimate also was extremely low, and it did not include the latest information on the total number of supports;

"Pipe supports continue to be an area of major concern. The most recent estimates for quantity requirements of supports 2 1/2 inches and larger is 18,416 which is significantly greater than the construction estimate of 13,165. ...very low probability is assessed to the necessary completion by December, 1979."

(B&R Monthly Construction Progress Report No. 56; Period Ending 6/30/79)

There was no apparent progress in pipe support design from June to August 1979. The quantity of pipe supports that remained to be designed and fabricated as of August 31, 1979, remained the same as it had been in June 1979: 7,469.

In response to the major concern with pipe supports, a design team was formed on-site to address the pipe support problems. This was the origination of what eventually became the Pipe Support Engineering (PSE) group.

In the meantime, the NRC issued Inspection and Enforcement IE Bulletin 79-14 - Seismic Analysis for As-Built Safety-Related Piping Systems - in July 1979. In the Bulletin, the NRC explained the potential jeopardy to plant safety associated with safety-related piping systems:

> "Recently two issues were identified which can cause seismic analysis of safety-related piping systems to yield non-conservative results. One issue involved the algebraic summation of loads in some seismic analyses...The other issue involves the accuracy of the information input for seismic analyses...inspection by IE and by licensees of the as-built configuration of several piping systems revealed a number of nonconformances to design documents which could potentially affect the validity of seismic analysis."
>
> (N.C. Moseley memo to NRC Region Directors dated 7/2/79)

IE Bulletin 79-14, often referred to simply as 79-14, called attention to the need to re-evaluate seismic analyses to consider the as-built configuration. This was especially important if modifications to safety-related piping systems affected the condition or configuration of the piping and pipe supports as described in documents from which seismic analysis input information had been obtained. In 79-14, the NRC described a series of actions to be taken by holders of Construction Permits (such as TU) to verify that their seismic analysis was adequate, and to report that information to the NRC staff.

Comanche Peak project status as of the end of 1979 (12/29/79) was reported as follows:

Unit 1	77.3% complete
Unit 2	41.2% complete
Total Project	66.2% complete

(Comanche Peak Progress Report #12 dated 1/22/80)

Initial Energization of the startup transformer had not yet occurred; that milestone was accomplished in January 1980. (Note: Under the circumstances described earlier in subsection IV.C, fuel load would follow initial energization by approximately 2 1/2 years.

Given initial energization in January 1980, fuel load theoretically could have occurred in July 1982, provided that all other project actions prerequisite to fuel load had been completed.) However, only approximately 20 system turnovers from construction to TUGCO operations had been completed at that time. Furthermore, the work force at the site exceeded 4,000 people.

> "For the week ending January 26, 1980, there were 4,339 personnel total on the job. The reason this number has increased somewhat recently is because of the increased effort in the piping/piping hanger and electrical areas for Unit 1 - both engineering support and construction workforce."
>
> (Comanche Peak Progress Report #14 dated 1/31/80)

Consequently, it appears that initial energization may not have been as meaningful as it would be under more normal circumstances.

TU took some actions in early 1980 apparently in an attempt to reduce project expenditures and to force a transition from the bulk installation mode of construction to the systems completion and turnover mode. Some of these actions interrupted the necessary flow of information for project control.

> "The Monthly Construction Status Report has been suspended..."
>
> (B&R letter to J.B. George dated 4/14/80)
>
> "All work on the existing CPM (both units) has ceased."
>
> "Attached is the April 15, 1980 Analysis of the CPM for your information and distribution. No further updates are anticipated."
>
> "The scheduling group will be totally dispersed by June 1, 1980."

(D.C. Frankum memo to J. B. George/J.T. Merritt dated 5/27/80)

B&R expressed their concern about the actions taken by TU. In particular, they disagreed with abandonment of B&R's control group.

> "...we cannot agree that it is in the best interest of TUSI and cost effectiveness to dissolve the cost accounting control data and records you have addressed."
>
> "If, after consideration of the above, TUSI decides that the directives should be carried out, Brown and Root has no choice but to ask for the following conditions in a Supplemental Order to the Contract.
> 1. Indemnification from all cost accounting and scheduling data and control at CPSES.
> 2. Settlement of Final Fee amount for CPSES."

(B&R letter to J.B. George dated 4/14/80)

In May 1980, J.B. George acknowledged some of the schedule delay which was being experienced by the project. He did not acknowledge it all, however.

> "This will restate that the CPSES scheduled Unit #1 Fuel Load is 3-1-81 and at the present is showing approximately 6 months slip...The total cost estimate is 1.7 billion."

(J.B. George memo to J.T. Merritt Jr., et al dated 5/29/80)

It was only a short time later that TU acknowledged some additional schedule delay. The additional delay accompanied a revised estimate for total project cost of $2.235 billion.

> "It is now projected that fuel will be loaded in Unit #1 in December 1981 and in Unit #2 in the third quarter of 1983."

(J.B. George letter to L.F.

Fikar dated 7/17/80)

As of August 31, 1980, the Comanche Peak project was reported as 75% complete. Unit #1 was reported as 86% complete and Unit #2 was reported as 50% complete.

In October 1980, TU changed the official scheduled completion dates for Unit #1 and Unit #2; the completion dates were changed to the dates identified previously by Mr. George:

	Fuel Load	Commercial Operation
Unit #1	12/81	6/82
Unit #2	9/83	3/84

The corresponding estimated total project cost for these completion dates officially changed to $2.235 billion, an increase of $535 million over the previous estimate.

In describing the reasons for the increased cost estimate, J.B. George stated:

> "...difference between the present estimate and the January 1977 estimate. As can be seen, construction and engineering manhour cost constitute the major difference between the estimates."
>
> (J.B. George letter to L.F. Fikar dated 7/17/80)

Mr. George stated further:

> "...I cannot guarantee schedule on a project of this magnitude. It is my view that our present cost estimate is reasonably accurate as to manhours and material required to finish the job provided we meet schedule. Our big risk here depends on how close we can build the plant as it is presently designed."
>
> (J.B. George letter to L.F. Fikar dated 7/17/80)

In responding to a request from TU's Mr. M. Hall, Mr. D.C.

Frankum of B&R later provided additional insight into why the construction and manhour costs increased substantially. He felt engineering had not been sufficiently complete in 1977 to support development of an accurate estimate.

> "1977 Revision - ...This estimate was prepared by our Houston estimating group with an August, 1976 cutoff date for drawing takeoffs. At that time (Aug. 1976) construction was 12 percent complete and engineering was approximately 20 percent complete - not the 75-90 percent needed for a true definitive estimate."
>
> (D.C. Frankum, memo to M. Hall dated 4/23/82)

It is noteworthy that B&R earlier had expressed their opinion that the electrical commodities were underestimated:

> "...we feel that the total of 5,801,379 LF (of wire and cable) officially given by G&H is too low."
>
> (B&R letter to TU dated 1/9/78)

The pipe and pipe support problems at Comanche Peak were considered so serious that TU requested EDS Nuclear, Inc. to review and evaluate their program. EDS Nuclear submitted their report on September 17, 1980; in the report, EDS Nuclear described the scope of their evaluation as follows:

> "The intent of this review is to evaluate for TUSI the adequacy of the pipe and pipe support program at CPSES...The investigation concentrated primarily upon the pipe support program."
>
> (EDS Nuclear Inc. Pipe Support Program/Documentation Review, dated 9/17/80)

In the report, EDS Nuclear made several recommendations; two examples indicated existing problems and possible pitfalls for TU's program.

> "...the high rate of current QA rejections indicates that when the review responsibility is transferred, QA should monitor the hanger packages regularly for completeness and compliance to review procedures."
>
> "...management is advised to place an emphasis on the effectiveness of the program as opposed to production goals during the earlier stages of the new implementation."
>
> (EDS Nuclear Inc., Pipe Support Program/Documentation Review submitted to TUSI 9/17/80)

TU acknowledged once again the severity of their pipe hanger problem shortly thereafter. They also described some of the reasons for their problems.

> "As pointed out in a Fort Worth Star Telegram article on Friday, October 24:
> A Nuclear Regulatory Commission panel, which inspected the plant Wednesday, and Texas Utilities officials agree that the major stumbling block in plant construction is installation of hangers that support piping."
>
> "In the past, installation of piping hangers had fallen behind schedule due to procurement, engineering and construction problems. More recently, the problem has been that a hanger, for example, could not be installed as called for because other equipment was in the way...Further aggravating the problem at present,...is the task of going back and looking at several thousand Class 5 piping hangers located in areas with safety-related equipment...[W]hen their failure in a seismic event could result in a loss of capability of a safety-related function, they must be under the control of a quality assurance program. This was not done adequately and a number of Class 5 hangers must be looked at and, in some cases, reworked."
>
> (Comanche Peak Progress Report #22 dated 11/12/80)

The pipe hanger problems continued to be severe through the remainder of 1980, and the problem placed a heavy demand on the engineering (and construction) forces at the site.

> "...it has meant that close to 100 percent of the plant's piping hangers needed to be re-engineered and re-designed."
>
> "Of the approximately 400 engineering personnel on site (engineers, draftsmen, clerks), a full one-half - 200 or more personnel - are involved in the piping hanger re-design and fabrication effort."
>
> (Comanche Peak Progress Report #23 dated 1/14/81)

The NRC Caseload Forecast Panel toured the Comanche Peak site again in October 1980. In their report issued in January 1981, after reviewing information provided by TU, they advised TU that they did not feel TU would meet their then-scheduled fuel load date for Unit #1.

> "In conclusion, the applicant's target date for fuel loading Unit #1 is December 1981. We believe that date to be optomistic (sic) based on the identified items remaining and our estimates of the degree of difficulty to complete this work. Based on our meetings and tour, we project the fuel loading date to be December 1982."
>
> "...when the applicant has completed substantial fractions of the presently outstanding pipe hangers and cable installations we will reevaluate and adjust our projections accordingly."
>
> (NRC letter to TUGCO dated 7/14/81)

In late 1981, the American Society of Mechanical Engineers (ASME) decided they would allow the N-Stamp certificates of B&R for the Comanche Peak Project to expire on January 8, 1982. Since this action by ASME could potentially have had a serious effect on the project, the circumstances surrounding this action may be researched further. Furthermore, the impact to this action to the project also may be reviewed.

In October of 1981 the project announced a delay in the schedules for both Unit #1 and Unit #2. The scheduled commercial operation dates became the following:

Unit 1	January 1984
Unit 2	June 1985

The 1981 project cost estimate was also revised upward by over $1.2 billion to $3.44 billion.

A significant portion of the cost overrun was caused by the problems with hanger design and installation.

> "There are literally tens of thousands of these hangers located throughout the plant - over 40 thousand in both units."
>
> "The re-engineering of piping hangers has become necessary...These 8,000 hangers are being re-engineered and redesigned on site because they could not be installed as originally designed." (P. 12)
>
> "$300 million out of the $1.2 billion is estimated to go toward all aspects of redesigning and installing hangers. The 8,000 hangers in Unit 1 and common facilities account for a majority of the $300 million."
>
> (Comanche Peak Progress Report #27 dated 1/22/82)

In February 1982, Mr. F.B. Lobbin, a consultant hired by TU to review the quality assurance program for the design and construction of Comanche Peak, identified a serious problem with the quality assurance program.

> "The design and construction audit program is an area which, in the opinion of the author, requires considerable attention and improvement." p. 10
>
> (Final Report - Review of the Quality

Assurance Program for the Design and Construction of the Comanche Peak Steam Electric Station for TUGCO by F.B. Lobbin dated 2/4/82)

Very little, if any, progress was made in completion of the project from August 1980 to April 1982. The status of the project as of August 31, 1980 was mentioned earlier. When this is compared to the reported status as of April 24, 1982, the lack of progress is evident.

	8/31/80	4/24/82
Unit #1	86%	87%
Unit #2	50%	49%
Total Project	75%	76%

(Comanche Peak Progress Reports #21 dated 10/7/80 and #30 dated 5/28/82)

In the schedule adopted in October 1981, Cold Hydrostatic Testing (Cold Hydro) of the Unit #1 Reactor Coolant System was scheduled for June 1982. Performance of Cold Hydro at that time was supposed to support a scheduled fuel load of Unit #1 in June 1983. Although Unit #1 Cold Hydro was actually performed in July 1982, it is unclear whether or not the full test as originally planned was performed at that time. Further research may be performed to determine the status of the project at Cold Hydro, and to determine to what extent Cold Hydro prerequisites were satisfied.

In September 1982, J.B. George notified Gibbs & Hill (G&H)

of his displeasure with their previous performance. Not only did he describe a long-term dissatisfaction, but also he cited several examples of areas in which he had lost confidence in G&H.

> "During the past six years, I have had a reduction of confidence in G&H engineering."
>
> (J.B. George memo to K. Scheppele dated 9/27/82)

Several of the issues identified by Mr. George had been problems for a long time.

> "Interface problems with entire piping and supports. From beginning with stress analysis, now as-built overloads. Cannot be installed as designed."
>
> "Plant design not taking damage study problems down stream into account."
>
> (J.B. George memo to K. Scheppele dated 9/17/82)

In December 1982, the Comanche Peak project was six months from the then-scheduled fuel load date for Unit #1. As of 12/10/82, however, only 239 out of 325 systems/subsystems had been released by construction to the TU startup group. This meant that since February 1982, when 187 systems/subsystems had been turned over, only an additional 52 systems (or approximately 5 systems per month) had been completed. At this rate, turnover of the remaining 86 systems/subsystems would require an additional 17 months. It is noteworthy that Hot Functional Testing of Unit #1 was scheduled for December 1982.

It is also noteworthy that as of mid-December 1982, the design review certification process for hangers was far from completion.

2/12/88

"At Comanche Peak as of mid-December 1982, about [illegible] the approximately 10,500 hangers for Unit #1 and co[illegible] facilities have gone through the entire design review certification process."

(Comanche Peak Progress Report #32 dated 12/28/82)

XI. CONCLUSIONS

A. Texas Utilities did not act properly with regard to engineering/design, construction and preoperational testing/startup as the Project Manager of Comanche Peak.

The Comanche Peak Steam Electric Station has not been a successful nuclear project. Not only has the project been plagued with schedule delays and cost overruns, but also the quality of the design and construction is so questionable that a complete verification and validation has been required.

TU addressed NRC regulatory requirements as if these represented a maximum level of performance. TU failed to realize that instead they should view the requirements as representing minimum levels of performance, and that they should strive to meet higher, self-imposed goals.

The severe problems which existed over the course of the project were known to TU. TU knew that the project could not be completed in accordance with existing schedules and budgets. Furthermore, TU adopted approaches such as the At-Risk approach which unacceptably compromised quality.

Despite their knowledge of the existing problems, of the unrealistic and unachievable schedules and budgets, and of the sacrifices of quality, TU failed to take the necessary management actions to correct the troubles and to turn the project around. Such failure constitutes mismanagement.

Engineering/Design

The planning for engineering/design was not done properly. TU's decisions to establish and to extend the on-site engineering effort reflected poor initial planning as well as subsequent failures to comprehend the extent of the previous engineering/design inadequacies.

TU selected an Architect/Engineer with limited U.S. nuclear experience. TU also hired a Constructor with limited nuclear construction experience. TU then compounded the potential problems associated with having contractors with limited experience by failing to plan and implement the coordination required of the architect/engineer with the constructor.

TU failed to understand and implement the engineering quality assurance requirements embodied in regulations and industry standards; they also failed to understand the importance of quality assurance for engineering/design. TU failed to understand that the NRC used safety regulations to convey their intent and to satisfy their primary mission of assuring public safety. TU incorrectly attempted to justify their actions to the NRC as satisfying the letter of the safety regulations; TU failed to satisfy the intent of the safety regulations. As TU experienced the increasing safety emphasis by the NRC staff through the PSAR/FSAR review process, they complained of the effects of regulatory "racheting", but they failed to incorporate within their plans the impacts of such increasing emphasis.

TU failed to recognize the magnitude of the evolving engineering/design effort. TU did not comprehend the need for adequate engineering to support construction, so they failed to comprehend and to mitigate the negative effects of minimizing the engineering budget in the face of increasing requirements. TU also failed to understand the cause and effect relationships between sufficient engineering/design, productive construction implementation, and credible quality assurance documentation.

TU also failed to understand the risks of proceeding with personnel on their staff with limited nuclear experience. Their inexperience led to ignoring the recommendations of external parties which had been hired by TU to provide recommendations based on their experience.

TU failed to execute/implement the engineering/design of Comanche Peak properly. TU imposed cash flow restrictions on Gibbs & Hill without anticipating the impact of such restrictions.

TU failed to understand the significance of quality assurance audits of Gibbs & Hill. Some of these audits raised concerns of inadequate vendor drawing review by Gibbs & Hill. TU also failed to recognize the significance of inadequate Gibbs & Hill interdiscipline design review.

TU's decision to minimize revisions to construction drawings and not to incorporate previously approved design change documents resulted in predictable confusion of the engineers' design intent and subsequent deviations and non-conformance reports, as well as failure to verify construction against the approved drawings. The decision to allow "At Risk" engineering resolution without full engineering analysis and review further confused the engineers' design configuration. Furthermore, the decision to use the "At Risk" approach to allow construction to build from unanalyzed design change documents further added confusion to the design intent. TU failed to realize that use of other than current design information as reflected in drawings and design changes would lead to serious document control problems in construction and quality control.

As TU's role in engineering/design evolved from oversight and monitoring of Gibbs & Hill to day-to-day direction of the site engineering organization, TU acted without a preconceived plan, and without an understanding of the need to provide adequate and experienced technical supervision and personnel.

TU failed to control the engineering/design process properly on the Comanche Peak project. TU failed to accept and to respond on a timely basis to feedback information that engineering was not proceeding properly. TU failed to respond to information on lack of schedule performance, on increasing scope due to safety and regulatory requirements, to cost increases resulting from lack of productivity, and to problems identified by the Quality Assurance/Quality Control program.

TU failed to respond to questions and concerns raised by project employees. Instead, TU either ignored the concerns or antagonized the employees who raised those concerns. TU failed to understand the importance of having sufficient engineering complete in advance of construction, and continued construction with inadequate and insufficient engineering.

Although TU claims to have properly managed Comanche Peak, their management practices reveal unwillingness to accept unfavorable information, and reaction to project problems by removing quality assurance requirements and by otherwise cutting corners. It is not surprising that these failures later led to disastrous impacts when TU attempted to obtain its operating license from the NRC.

Construction

The planning for construction was not done properly. It resulted in schedule durations which were unrealistic and unachievable, especially when compared to previous projects. The initial schedule of 45 months from first nuclear concrete to fuel load was unachievable. A schedule of such duration required either an unrealistically short construction duration, an unrealistically short testing duration, or an unachievable degree of overlap between the two phases. CPSES documents also reveal strong inconsistencies between schedule objectives and supporting construction work (e.g. reflected in the commodity installation curves).

Actual construction progress was not properly factored into updated and revised schedules. This resulted in schedules that became increasingly unrealistic and impossible to meet. Project documents indicate that projected fuel load dates in late 1978 and late 1979 could not be met.

Construction estimates and budgets were prepared based on achievement of the unrealistic and unachievable schedules, and on incomplete engineering information.

Actions taken by TU to execute and implement construction resulted in significant schedule delays and budget overruns. Attempted implementation of the unrealistic and unachievable schedules resulted in decisions which caused substantial interference problems and subsequent rework. This was compounded by use of the "At-Risk" approach, by installation of work out of sequence, and by premature transition into the systems completion/turnover mode. Failure by TU to coordinate engineering and material/equipment support for construction caused schedule extensions and budget increases significantly greater than those which would have occurred if engineering initially had been sufficiently ahead of construction, or if construction had been slowed and engineering had been allowed to get ahead.

The cost estimate had become unrealistic by 1979. Increases in labor and material costs due to schedule delays and due to increases in costs of capital, as well as significant increases in commodities, had increased the project cost above the total described in the Definitive Estimate. B&R already had exceeded their base manhour target by the end of 1979, and they still had substantial mechanical and electrical work to complete on Unit #1. Even more substantial mechanical and electrical work remained on Unit #2.

TU failed to control construction. They were unable to recognize root causes of problems, and they failed to take appropriate corrective actions to solve those problems. TU consistently ignored the warnings of others, including Brown & Root, J.M. Varela, Management Analysis Company, F.B. Lobbin, the NRC and the Authorized Nuclear

Inspector.

Preoperational Testing/Startup

The planning for preoperational testing/startup was not done properly. Since TU retained performance responsibility as well as management responsibility for testing, this failure in planning is more directly attributable to TU.

From the start of the project, an insufficient duration was allocated for completion of testing. According to R.E. Camp, the initial duration for preoperational testing of 6-7 months was too short. By 1978, TU claims the scheduled duration for the program had become 21 months; that was still too short.

The TU executives with direct responsibility for testing had no nuclear experience. Through August 1982, preoperational testing and startup was the responsibility of Mr. J. Kuykendall. Mr. Kuykendall's previous experience was in coal plant operations; he had no prior nuclear experience. Subsequent to August 1982, preoperational testing and startup was the responsibility of Mr. J.T. Merritt; when he reported to Comanche Peak in mid-1977, Mr. Merritt also lacked nuclear experience.

The preoperational testing program was not integrated into the overall project schedule prior to 197?. Although B&R developed an integrated schedule for Unit #1 and Common and provided it to TU in February 1978, the Definitive Target Startup Schedule was not issued until October 1978.

The control of preoperational testing/startup was not done properly. TU forced the transition from bulk construction into systems completion too early in order to maintain their unrealistic schedule; this increased the difficulty in performing engineering and construction, created rework problems, and added to the cost and schedule duration. In fact, the performance of the testing program was not controlled. The scheduled duration for the preoperational testing program was not changed to reflect industry experience. Although R.E. Camp claimed the industry norm was 28-34 months, the schedule duration was not increased to reflect that norm.

Furthermore, the testing program schedule was not modified to reflect the project's experience. Although system turnovers to support testing did not begin in December 1978 as they were supposed to, the program schedule was not changed to reflect actual turnover experience; system turnovers did not begin until July 1979.

Initial energization did not occur until January, 1980, The schedule was not modified in a timely fashion to reflect that.

Some major testing milestones (e.g. Hot Functional) had to be performed twice. Modifications were made to equipment which already had been tested. Consequently, in order to verify satisfactory performance of the equipment after the modification, the tests had to be performed again.

B. <u>TU's improper actions as Project Manager of Comanche Peak were significant and caused cost overruns and schedule delays of the project</u>.

From the beginning, TU tried to impose on the project schedules which were unrealistic and unachievable. As a result, they commenced construction in 1974 without sufficient completion of engineering and design. Furthermore, they attempted to accelerate construction in 1977 and 1978, while at the same time limiting G&H's capability to perform engineering through budget limitations.

The fact that engineering was never far enough ahead of construction contributed to several problems. For example, improper sequencing of the construction commodity installation was a direct result.

The At-Risk approach to design change review, which TU utilized in order to minimize the impact on construction of design changes, violated the intent of 10 CFR 50 Appendix B. TU utilized At-Risk nonetheless, and the CPRT and CAP were direct results.

TU began the project in 1972, with an expected cost of $779 million and scheduled completion dates of January 1980 for Unit #1 and January 1982 for Unit #2. Now, nearly sixteen years later, the plant is expected to cost more than $8 billion; neither Unit #1 nor Unit #2 is yet on-line.

TU claimed that construction of Unit #1 was complete in 1984. Since the CPRT and CAP resulted from TU's improper actions, the delays and overruns resulting from these programs are attributable to TU.

Two other examples can be cited to illustrate TU's culpability. As Project Manager, TU established schedule goals which were unrealistic and unachievable. This contributed, among other things, to low morale among project personnel, and to performance of construction work out of sequence. Performance of the work out of sequence contributed to a massive interferences problem, which was costly and required a lot of time to resolve.

The unrealistic and unachievable schedules also prompted use of the At-Risk approach to design change control, and this approach was a major contributor to the present programs for identification and correction of design and construction deficiencies.

C. The Comanche Peak Response Team and Corrective Action Program and the failure to obtain an Operating License for Comanche Peak resulted from TU's improper actions.

The CPRT and CAP had their genesis in the external source issues. The external source issues raised enough questions about the design and construction of Comanche Peak that such programs as CPRT and CAP were required. The ASLB, for example, indicated that they had sufficient doubt about the design quality of the project that there was a need for an independent design review. TU had the responsibility to demonstrate to the ASLB that a system existed at Comanche Peak which promptly corrected design deficiencies; TU was unable to so demonstrate.

In their June 28, 1985 submittal to the ASLB, TU acknowledged that they had established the CPRT, composed of third-party experts with extensive experience in the design and construction of nuclear power plants to address the TRT's findings and to develop and implement a program which would identify and correct deficiencies in safety-related structures, systems, and components. TU further acknowledged that discrepancies had been identified which were of concern to them, as well; TU already had begun to take corrective action to correct them.

The discrepancies were the result of previous improper actions taken by TU. Several examples have been cited earlier.

Finally, TU stated in the Current Management Views section of their June 28, 1985 submittal:

> "TUGCO management is not satisfied with the status of the plant and would not proceed to operate it, even if authority were to be granted, until all of the outstanding concerns have been addressed, their safety significance determined, generic implications and collective significance considered, and necessary corrective actions have been completed."
>
> (TU submittal to ASLB dated 6/28/85)

For TU to have to undergo such programs as the CPRT and CAP in order to be able to operate its nuclear plant reflects the severity of TU's problems and the extent of its mismanagement.

D. By December 1978, it was clear that the project could not be placed into Commercial Operation in January 1981 (Unit #1) and January 1983 (Unit #2).

The Unit #1 Reactor Vessel was not set until May 1978. A realistic and achievable schedule would not have reflected Commercial

Operation of Unit #1 32 months later.

In order to meet the schedule, system turnovers were to have started in December, 1978. System turnovers had not yet started.

Preoperational testing had not yet started. A realistic, achievable schedule would have reflected approximately 30 months for completing preoperational testing prior to Fuel Load, assuming that design had been verified (as it had not) and that construction was in accordance with design. Commercial operation of Unit #1 could not be attained in January 1981.

When TU revised the Unit #2 schedule in June 1977, the revised startup logic indicated that a period of 18 to 24 months between startup of the two units was necessary. The project personnel decided on a 24 month difference at that time. Consequently, given the status of Unit #1, commercial operation of Unit #2 could not be attained in January 1983.

E. <u>TU knew that the January 1981 (Unit #1) and January 1983 (Unit #2) commercial operation dates could not be attained</u>.

TU knew in December 1978 that the beginning of start-up would be late. TU also knew that the cause was mostly due to late engineering information. TU had committed to the NRC in the FSAR that the preoperational testing program would be completed before fuel load. Preoperational testing could be expected to take approximately 2 1/2 years.

Rather than acknowledge the delay, however, TU's top officers declared the delay unacceptable. Declaration that the delay was unacceptable did not make it disappear. By that time, the delay had occurred.

Furthermore, the NRC had confirmed to TU nearly six months earlier that their estimate for the Unit #1 fuel load date was eight to twelve months later than TU's. Although TU could not be expected to schedule their activities based solely on NRC information, it would have been proper for TU to re-evaluate their own schedule based on the external information from NRC. Such a truthful re-evaluation would have acknowledged the delay.

In light of TU's understanding that a period of 18 to 24 months between startup of the two units was necessary, and in light of TU's selection of a 24 month separation, TU also knew that the Unit #2 commercial operation date could not be attained.

F. <u>By December 1979, the Definitive Estimate of $1.7 billion was not realistic.</u>

B&R already had exceeded their base manhour target. The estimate had not been revised to reflect the additional costs of schedule delays or the loss of construction efficiency due to sustained overtime, the need for rework, and lack of engineering and material support.

TU knew that the contingency in the project estimate had been used up. Consequently, with the project reportedly about 66%

complete, with the most complex work (mechanical and electrical, and testing) yet to come, there was no contingency left with which to address unknowns.

Furthermore, the project had been delayed beyond the completion dates utilized in developing the $1.7 billion estimate, and such delays are expensive.

G. By December 1979, it was clear that the project could not be placed into Commercial Operation in July 1981 (Unit #1) and January 1983 (Unit #2).

A reasonable preoperational testing/startup schedule would have projected fuel loading of Unit #1 approximately 2 1/2 years after initial energization of the startup transformer; initial energization did not occur until January 1980. That would have indicated a commercial operation date for Unit #1 no earlier than January 1983.

There were other severe problems to be dealt with which would further delay the schedule. One major example is the pipe support problem. As of late 1979, there was a substantially higher quantity of pipe supports to install than the quantity contained in the construction estimate. Additionally, pipe hanger redesign was recognized as a significant requirement.

H. By May 1982, the project was in such serious trouble that it clearly could not be placed into Commercial Operation in January 1984 (Unit #1) and June 1985 (Unit

#2).

Very little progress had been made in completion of the project for nearly two years. The project was stagnant.

Most of the pipe hangers had not yet gone through the entire design review certification process. The backlog was growing; by December 1982, only approximately 2,500 of the approximately 10,500 total for Unit #1 and common had been done. The At-Risk design change approach was presenting significant administrative and control problems. Documentation requirements for the craftsmen to install and for the QC inspector to inspect had become unwieldy.

The Lobbin report pointed out serious problems in the design and construction audit program, reiterating similar problems to those pointed out by MAC in 1978. In fact, the audit program required considerable attention and improvement.

TU had lost confidence in Gibbs & Hill. Dissatisfaction with G&H, which had started at least six years earlier, was reaching a culmination.

I. There was sufficient evidence available in 1982 that TU knew or should have known that the project was in serious trouble and could not be placed into Commercial Operation in January 1984 (Unit #1) and June 1985 (Unit #2).

Several occurrences in late 1981 and continuing into 1982 provided clear evidence that the project was in serious trouble. B&R was notified by the ASME that their certification would not be renewed upon expiration due to QA program deficiencies.

Mr. F. B. Lobbin, the consultant hired by TU, identified a serious problem with the quality assurance program. TU earlier had been made aware of serious quality assurance program deficiencies by their own personnel, by the NRC, and by Management Analysis Company (MAC) among others.

TU's own monthly Progress Reports indicated the project was stagnant. Although manual and non-manual manhours were being spent at a high rate, the project was not moving ahead.

The problems with pipe hangers, in particular, were overwhelming. TU knew, for example, that approximately 8,000 hangers for Unit #1 and common still had to go through the design review process; only 2,500 had gone through by the end of 1982.

Finally, the completion and turnover of plant systems was not on track. Only 52 systems had been turned over in the previous eight months; 86 systems still remained to be turned over. Furthermore, Hot Functional Testing, which was to have been performed in December 1982, was not completed the first time until May 1983; the test had to be performed again at a later date.

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SUMMARY

Nearly twenty-five years of experience in the nuclear industry in construction and project management, engineering, testing, operations, administration, contracting and consulting. Record of increasing management responsibility based on achievement. Experience in projects of national importance, including experience as Project General Manager of the St. Lucie Nuclear Plant Project, the most successful nuclear project in recent history.

EXPERIENCE

- 1984 to the present: RANDEL Associates, Inc.

  - CONSULTANT

    Business executive and management consultant in heavy construction project management, with specialization in commercial nuclear power plants.

    - Project management review, and cost and schedule performance analysis in nuclear construction project litigation, including preparation and presentation of testimony as an expert witness.

    - Retained as the expert in commercial nuclear construction project management by The Dow Chemical Company and Kirkland and Ellis, its attorneys, to provide xpert testimony in the Midland Nuclear Project litigation.

    - Retained as the expert in nuclear project engineering management and implementation by the City of Austin, Texas and by Miller, Canfield, Paddock & Stone, their attorneys, to provide expert testimony in the South Texas Project litigation.

    - Retained as a subcontractor in nuclear project management, and in engineering and construction management, by the Arizona Corporation Commission in their prudence review of Arizona Public Service Company on the Palo Verde Nuclear Generating Station.

    - Retained as an experienced nuclear project executive and expert by the minority owners of Comanche Peak Steam Electric Station to review the management of engineering/design, construction and preoperational testing in their litigation with Texas Utilities.

o 1978 to 1984: Washington Public Power Supply System

- DIRECTOR, WNP-1 Program

Reported directly to the Chief Executive Officer with responsibility for directing and managing all program activities required to preserve the assets and licenses of a 63% complete "mothballed" nuclear power plant. This required directing a total project staff of 600 people, with a monthly cash flow of $7.5 million.

o Developed a Project Enhancement Program and obtained Board of Directors' approval for implementation. The program involved utility decision-makers of national stature.

o Acted as principal company spokesman for Emergency Drills for WNP-2. The drill was praised by the Federal Emergency Management Agency and the Nuclear Regulatory Commission as the most successful to date.

- DIRECTOR, WNP-4/5 TERMINATION PROGRAM

Managed all activities related to the termination of two nuclear plants, one 17% complete and one 23% complete. Reported to the Chief Executive Officer; responsible for interface with Board of Directors' committees to keep them informed and to obtain specific approval for politically and legally sensitive actions.

o Successfully developed and implemented a management plan for terminating nuclear plant construction projects, a plan which has been referenced by others in the industry.

o Served as primary media and public interface to obtain public acceptance of the program. Guest speaker engagement at a Public Utilities Executive Course featuring other prominent Northwest and national energy figures as speakers.

- PROJECT ENGINEERING MANAGER and MANAGER OF ENGINEERING

Responsible for providing technical and administrative direction to Supply System engineering personnel in electrical, mechanical and civil engineering disciplines, as well as for nuclear licensing.

o 1977 to 1978: TERA Corporation

- SENIOR PROJECT MANAGER

Management Consultant for a management systems consulting firm specializing in advanced technology applications to utilities.

o 1974 to 1977: Florida Power & Light Co.

- PROJECT GENERAL MANAGER, St. Lucie Project

Senior line manager on a two-unit nuclear plant construction project, with full responsibility for the cost, schedule and quality of the $1.4 billion project, consisting of approximately 3500 employees.

o Completed the final St. Lucie #1 activities in 13 months, compared to 14 months for other similar projects. Accomplished fuel loading and comercial operation "on schedule".

o Developed the project plan for St. Lucie #2, and began construction. That project, which has since been completed, has become the model project for the industry.

o 1971 to 1974: General Dynamics Corp., Electric Boat Division.

- DEPUTY PROGRAM MANAGER

Responsible for directing and coordinating the overhaul and refueling of one nuclear submarine and the construction of another. Initiated a new approach to overhaul preparation which shortened the first year's schedule by two months.

EDUCATION

M.B.A.	1974	University of New Haven Areas of study: Gen'l Business & Management
M.S.	1971	University of Connecticut Field of Study: Electrical Engineering
B.S.E.	1964	Brown University Major: Electrical Engineering
	1966	Naval Nuclear Power Training Program. Equivalent to M.S. in Nuclear Engineering.

November, 1987.

APPENDIX B

LIST OF ACRONYMS

ACRS	Advisory Committee on Reactor Safeguards (NRC)
A/E or A-E	Architect Engineer
AEC	Atomic Energy Commission
ANI	Authorized Nuclear Inspector (ASME)
ANSI	American National Standards Institute
ASLB	Atomic Safety and Licensing Board (NRC)
ASME	American Society of Mechanical Engineers
BOP	Balance of Plant
BRAZOS	Brazos Electric Power Cooperative, Inc.
B&R	Brown & Root
BWR	Boiling Water Reactor
CASE	Citizens Association for Sound Energy
CAP	Corrective Action Program
CAT	Construction Appraisal Team (NRC)
CFP	Caseload Forecast Panel (NRC)
CFR	Code of Federal Regulations

CMC	Component Modification Card
CO	Commercial Operation
CP	Construction Permit
CPM	Critical Path Method
CPPE	Comanche Peak Project Engineering
CPRT	Comanche Peak Response Team
CPSES	Comanche Peak Steam Electric Station
DAP	Design Adequacy Program (CPRT)
DBA	Design Basis Accident
DCA	Design Change Authorization
DCC	Document Control Center
DC/DD	Design Change/Design Deviation (Request)
DCRP	Design Change Request to Proceed
DDR	Drawing Deficiency Report
DE/CD	Design Engineering/Change Deviation (Request)
DIR	Discrepancy/Issue Resolution (Reports) (From DAP)
DP&L	Dallas Power & Light (Company)
DSAP	Discipline Specific Action Plan (CPRT)

ECN	Engineering Change Notice
EPA	Environmental Protection Agency
ER	Environmental Report
ESI	External Source Issues
FEMA	Federal Emergency Management Agency
FL	Fuel Load
FSAR	Final Safety Analysis Report
G&H	Gibbs & Hill
GA	General Arrangement Drawing
GAP	Government Accountability Project
HFT	Hot Functional Testing
HVAC	Heating, Ventilating & Air Conditioning
IAP	Independent Assessment Program (CYGNA)
I&C	Instrument & Control
IDI	Integrated Design Inspection
IDVP	Independent Design Verification Program
IE	Inspection & Enforcement (NRC)
IEEE	Institute of Electrical and Electronic Engineers

ILRT	Integrated Leak Rate Test
INPO	Institute for Nuclear Power Operations
ISAP	Issue Specific Action Plan (CPRT)
ISI	In-Service Inspection
ISO	Isometric Drawing (Piping)
JOA	Joint Ownership Agreement
KV	Kilovolts (thousand volts)
LOCA	Loss of Coolant Accident
LWA	Limited Work Authorization
MAC	Management Analysis Company
MIS	Management Information System (data base)
NCR	Nonconformance Report
NDE	Nondestructive Examination
NEPA	National Environmental Policy Act
NF	(ASME B&PV Code Section III, Division I, Subsection NF - Pipe Supports)
NOV	Notice of Violation (NRC)
NPSI	Nuclear Power Services, Inc.
NRC	Nuclear Regulatory Commission

NRR	(Office of) Nuclear Reactor Regulation (NRC)
NSSS	Nuclear Steam Supply System
OBE	Operating Basis Earthquake
OI	Office of Investigations (NRC)
OIA	Office of Inspector and Auditor (NRC)
OL	Operating License
PCHVP	Post Construction Hardware Validation Program
P&ID	Process & Instrument Diagram
PSAR	Preliminary Safety Analysis Report
PSE	Pipe Support Engineering
PSI	Pre-Service Inspection
PWR	Pressurized Water Reactor
QA	Quality Assurance
QC	Quality Control
QCC	Quality of Construction; QA/QC Adequacy Program
RCS	Reactor Coolant System
REA	Rural Electrification Administration
RIL	Review Issues List (CYGNA/IAP)

RIV	Region IV (NRC)
RPV	Reactor Pressure Vessel
SALP	Systematic Assessment of Licensee Performance (NRC)
SAR	Safety Analysis Report
SDAR	Significant Deficiency Analysis Report
SEC	Securities and Exchange Commission
SER	Safety Evaluation Report
SIT	Special Inspection Team (NRC)
SRT	Special Review Team (NRC)
SSE	Safe Shutdown Earthquake
SSER	Supplemental Safety Evaluation Report (NRC)
SU	Startup
S&W	Stone & Webster
SWO	Stop Work Order
TESCO	Texas Electric Service Company
TEX-LA	Tex-La Electric Cooperative of Texas, Inc.
T/G	Turbine/Generator
TMI	Three Mile Island

TMPA	Texas Municipal Power Agency
TP&L	Texas Power & Light (Company)
TRT	Technical Review Team (NRC)
TU	Any and/or all of the companies within the Texas Utilities group of companies
TUEC	Texas Utilities Electric Company
TUGCO	Texas Utilities Generating Company
TUMCO	Texas Utilities and Mining Company
TUSI	Texas Utilities Services, Inc.
<u>W</u>	Westinghouse Electric Company