SOUTH TEXAS PROJECT UNITS 1 AND 2

SAFETY EVALUATION FOR THE

ELIMINATION OF ARBITRARY

INTERMEDIATE PIPE BREAKS

Docket No. 50-498 AND 50-499

JULY 1985

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Division Of Engineering
Mechanical Engineering Branch

TABLE OF CONTENTS

ABSTRACT

The Draft Safety Evaluation Report for the application filed by Houston Lighting and Power Company, City Public Service Board of San Antonio, Central Power and Light Company, and the City of Austin, as applicants and owners, for licenses to operate the South Texas Project Units 1 and 2 (Docket Nos. 50-498 and 50-499) has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in Matagorda County, Texas, west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. Subject to resolution of the items discussed in this report, and other items pertaining to sections not included in this draft report, the staff will document the conclusions regarding the safety review in a Safety Evaluation Report scheduled for publication in December 1985.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

*Deleted from the July 1981 edition of the Standard Review Plan (NUREG-0800)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

*Deleted from the July 1981 edition of the Standard Review Plan (NUREG-0800)

TABLE OF CONTENTS (Continued)

*Deleted from the July 1981 edition of the Standard Review Plan (NUREG-0800)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

*Deleted from the July 1981 edition of the Standard Review Plan (NUREG-0800)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

LIST OF FIGURES

TABLE OF CONTENTS (Continued)

Page

LIST OF TABLES

1 INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT

1.1 Introduction

This report is the U.S. Nuclear Regulatory Commission (NRC) staff's draft Safety Evaluation Report (SER) on the application for an operating license (OL) for the South Texas Project Units 1 and 2, Docket Nos. 50-498 and 50-499, in Matagorda County, Texas. The NRC Project Manager assigned to the OL application for STP is N. Prasad Kadambi. Dr. Kadambi may be contacted by calling (301) 492-7272 or by writing to him at the Division of Licensing, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

The application to construct and operate the South Texas Project was filed by Houston Lighting and Power Company (HL&P, the applicant) on May 19, 1974, on behalf of itself and the other owners. They are

- City Public Service Board of San Antonio (CPS)
- Central Power and Light Company (CPL)
- City of Austin (COA)

The application was docketed July 5, 1974. Following a public hearing before an Atomic Safety and Licensing Board on November 12, 1975, Construction Permits (CPs) Nos. CPPR-128 and CPPR-129 were issued on December 22, 1975 by the NRC.

HL&P applied for an operating license on May 12, 1978, and the application was docketed on July 17, 1978. The NRC staff review of the applicant's Final Safety Analysis Report (FSAR) and the Environmental Report (ER) has been continuing since docketing despite a hiatus in construction when the architect-engineer and constructor were changed. Completion of the safety review in the form of issuance of an SER and completion of the environmental review by issuance of a Final Environmental Statement (FES) are required before an OL is issued. The final SER is scheduled for issue in December 1985, and the FES in March 1986.

All non-proprietary information used by the NRC staff in its evaluation is available to the public at the NRC Public Document Room at 1717 H Street, N.W., Washington DC, and at the Wharton Junior College Library, Wharton Texas.

During the course of the review the staff has met a number of times with the applicant, nuclear steam supply system vendors, other suppliers, and their consultants to discuss the design, construction, and proposed operation of the facility. Where necessary, the staff has requested additional information. This material has been or will be incorporated into the FSAR as appropriate.

The design of the plant was reviewed against Federal regulations, CP criteria, and the NRC "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP). Two versions of the SRP are in existence, NUREG-75/087 (March 1979) and NUREG-0800 (July 1981). Generally, the two versions contain very similar review criteria. Unless otherwise mentioned, reference to the SRP connotes the 1981 version. The SRP is written to cover a variety of site conditions and plant designs. Each section is written to provide the complete procedure and all acceptance criteria for that area. However, for any given application, the staff reviewers may select and emphasize particular aspects of each SRP section as appropriate for the application. In some cases, the major portion of the review of a plant feature may be done on a generic basis with the designer of that feature rather than in the context of reviews of particular applications from utilities. In other cases, a plant feature may be sufficiently similar to that of a previous plant so that a de novo review of the feature is not needed. For these and other similar reasons, the staff may not have carried out in detail all of the review steps listed in each SRP section in the review of every application.

Following the accident at Three Mile Island Unit 2 (TMI-2), the Commission paused in its licensing activities to assess the impact of the accident. During this pause, the recommendations of several groups established to investigate the lessons learned from the TMI-2 accident became available. These recommendations were correlated and assimilated into a TMI-2 Action Plan, published as NUREG-0660, "NRC Action Plan Developed As a Result of the TMI-2 Accident." Additional guidance relating to implementation of the Action Plan is in

NUREG-0737, "Clarification of TMI Action Plan Requirements," and in Supplement 1 to NUREG-0737. Licensing requirements based on the lessons learned from the TMI-2 accident have been established to provide additional safety margins. These have been incorporated into the design and operation of South Texas Units 1 and 2. Table 1.1 cross-references the TMI items to the sections in this SER where they are discussed, either in this draft or in the final SER.

Section 2 through 18 contain the results of the staff's radiological safety review and evaluation of safety-related issues that have been considered during the review of the OL application to the extent complete by the date of issue. Section 19 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). Section 20 will consider whether the operation of the plant will be inimical to the common defense and security. Section 21 will discuss the requirements for the review of the financial qualifications of the applicant. Section 22 will describe the financial protection and indemnity requirements for preoperational storage of nuclear fuel and operation of the station. Section 23 will present the staff's conclusions.

Appendix A will be a chronology of the staff's principal actions related to the safe (or radiological) review of the applicant. Letters to and from the applicant cited in the text will be listed in Appendix A. Appendix B will list the references used during the course of the review. Availability of all material cited in this report is described on the inside front cover of the final SER. Sections of Title 10 of the Code of Federal Regulations (10 CFR) (including the general design criteria (GDC) in Appendix A of 10 CFR 50), NRC regulatory guides (RGs), and sections of the SRP (including branch technical positions (BTPs)), will be identified as appropriate. They are not included in Appendix B. Appendix C will be a discussion of how various unresolved safety issues (USIs) relate to the application. Appendix D is a list of abbreviations and acronyms used in this report. Appendix E is a list of principal contributors to the document at the current stage of completion. Appendix F, "Control of Heavy Loads at Nuclear Power Plants, South Texas Project, Unit 1 and Unit 2," was prepared for the NRC at EG&G Idaho, Inc. Appendix G discusses the elimination of arbitrary intermediate pipe breaks.

As part of its review of the application insofar as NRC regulations apply, the staff will ask the applicant to certify that South Texas Units 1 and 2 meet the applicable requirements of 10 CFR 20, 50, 51, and 100. Following the applicant's response to this request, the staff will address its findings in this area in a supplement to this SER.

In accordance with the provisions of the National Environmental Policy Act (NEPA) of 1969, a Draft Environmental Statement (DES) that sets forth the environmental considerations related to the proposed construction and operation of South Texas Units 1 and 2 will be prepared by the staff and published in November 1985. The FES will be published in March 1986, as mentioned above, and will include a consideration of public comments received on the DES.

The review and evaluation of South Texas Units 1 and 2 for an operating license is only one of many stages at which the staff reviews the design, construction, and operating features of the facility. The facility design was extensively reviewed before the applicant was granted a construction permit for the facility. Construction of the facility has been monitored in accordance with a detailed monitoring and inspection program at the OL stage. The staff has reviewed the final design of the facility to determine that the Commission's regulations have been met. If an operating license is granted, the facility must be operated in accordance with the terms of the operating license and the Commission's regulations, and the facility will be subject to the staff's continuing inspection program.

In addition to the NRC staff review, the ACRS will review the application and will meet with both the applicant and the staff to discuss the final design and proposed operation of the plant. The Committee's report to the Chairman of the NRC will be included in a supplement to the SER.

1.2 General Plant Description

1.2.1 Site Characteristics

1.2.1.1 Location and Size of the Site

The site is located in south-central Matagorda County west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. It consists of approximately 12,220 acres of land and includes areas being used for a plant, a railroad, and a cooling reservoir. Centerline coordinates for the reactors of Units 1 and 2 are 28°47'41.772" latitude and 96°02'53.079" longitude, and 28°47'41.922" latitude and 96°02'59.820" longitude, respectively. The universal transverse mercator coordinates for Units 1 and 2 reactor centerlines are N-3188669.141 meters and E-788157.126 meters, and N-3188669.219 meters and E-787974.143 respectively. The plant is located about 12 miles south-southwest of Bay City.

1.2.1.2 Description of Plant Environs

The 7000-acre main cooling reservoir (MCR) is fully enclosed with an embankment; baffle dikes direct the flow of water. The station is located at the north end of the MCR with condenser cooling water being discharged into the western half of the reservoir and returned to the power plant intake through the eastern half of the reservoir. Blowdown to control reservoir water quality is discharged back to the Colorado River. A spillway is provided to release flood waters resulting from direct rainfall on the reservoir surface level.

1.2.2 Plant Description

The station is composed of two units, each having an identical pressurized water reactor (PWR) nuclear steam supply system (NSSS) and turbine generator (TG). The units are arranged using a "slide-along" concept. As a result, Unit 2 is similar to Unit 1 and 600 feet away, and the standby transformers are arranged using a "mirror-image" concept.

The NSSS is a Westinghouse Electric Corporation (W) four-loop PWR.

The reactor has a multi-region-cycled core. The fuel rods are Zircaloy that contain slightly enriched uranium dioxide fuel. The fuel assembly is of the canless type. It basically consists of guide thimbles attached to top and bottom grids and top and bottom nozzles. The fuel rods are held by spring clip grids that provide very stiff support. The integrity of the fuel rods is ensured because they are designed to prevent excessive fuel temperatures, excessive internal rod gas pressures as a result of fission gas releases, and excessive cladding stresses and strains. The control rods are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specified fuel design limits are not exceeded. A soluble neutron absorber is utilized for long-term reactivity control and refueling operations. The reactor core rated thermal power is 3800 MWt. An additional 17 MWt of energy is added to the coolant from nonreactor core sources, primarily reactor coolant pump (RCP) heat.

High-pressure light water serves as the coolant, neutron moderator, reflector, and solvent for the neutron absorber. The reactor coolant system (RCS), comprised of four parallel loops (each with an RCP and a steam generator (SG)), is used to transfer the heat generated in the core to the SGs using RCPs to circulate the water. RCS pressure is maintained by means of a pressurizer attached to the hot leg of one of the loops. The RCS is designed to circulate borated light water at temperatures, pressures, and flow rates consistent with the design thermal and hydraulic performance of the NSSS.

The residual heat removal system (RHRS) is used to cool down the RCS following reactor shutdown after the RCS temperature has been reduced below approximately 350°F by the auxiliary feedwater system (AFW) and by dumping steam. The entire system is located within the containment. Following cooldown, the RHRS removes decay heat from the reactor core to maintain the desired temperature. The system consists of three independent trains, each with its own pump and heat exchanger (HX).

The chemical and volume control system (CVCS) maintains the coolant inventory in the RCS. The functions of the CVCS are purification of the reactor coolant,

control of the RCS chemistry, regulation of the reactor coolant inventory, control of reactivity in the core, and seal water injection for the RCPs. The CVCS consists of charging pumps, boric acid transfer pumps, chiller pumps, regenerative HX, letdown HX, and other HXs, tanks, filters, and demineralizers.

The following systems are used to directly mitigate the consequences of postulated accidents up to and including the design-basis accident (DBA) and are classified as engineered safety features (ESF) systems:

(1) containment heat removal system (CHRS)

(2) containment isolation system (CIS)

(3) combustible gas control system

(4) emergency core cooling system (ECCS)

(5) fuel handling building (FHB) heating, ventilating and air conditioning (HVAC) exhaust subsystem

(6) control room habitability systems

(7) auxiliary feedwater system

The reactor containment provides a virtually leaktight barrier to prevent escape of fission products to the environment in the unlikely event of a loss-of-coolant accident (LOCA). The reactor containment is a post-tensioned concrete cylinder with a steel liner plate, hemispherical top, and flat bottom. The containment is designed to withstand the internal pressure and coincident temperature resulting from the mass and energy release of a LOCA.

Following the unlikely event of a LOCA, heat is removed from and pressure is reduced in the containment by the reactor containment fan coolers (RCFCs) and the containment spray system (CSS). Following a LOCA, component cooling water (CCW) is circulated through the RCFCs and borated water from the refueling

water storage tank (RWST) is sprayed into the containment atmosphere. Long-term post-LOCA cooling of the containment is provided by the CSS suction when it is switched to the containment sump and by the RCFCs.

Sodium hydroxide is added to the CSS to remove iodine from the containment atmosphere after a LOCA. Also after a LOCA, the CIS provides the capability to isolate the various system lines penetrating the containment and prevents the direct release of radioactivity to the environment. The combustible gas control system provides control of combustible gas concentrations in the containment following a LOCA by maintaining the hydrogen concentration below 4 volume percent. Redundant electric thermal recombiners are provided for this purpose.

The ECCS injects borated water into the RCS following a LOCA to limit core damage, metal/water reaction, and fission product release, and to provide, in conjunction with the control rods, sufficient negative reactivity to ensure safe shutdown of the reactor core. Borated water is injected from the accumulators and the RWST. The ECCS also provides long-term, post-accident cooling of the core by recirculating borated water from the containment sump to the core.

The system consists of three independent trains, each one capable of providing 100% of the required flow to the core in the unlikely event of a LOCA. Each train consists of one high-head safety injection pump and one low-head safety injection pump. Heat is removed from the system during recirculation by the residual heat removal HX. The piping and valving associated with each of the three subsystems are identical. In the event of a steam pipe rupture, the ECCS provides adequate shutdown capability.

The AFW system provides adequate cooling to the SGs in the event of a normal feedwater (FW) supply interruption. The system consists of redundant pumps. These pumps take suction from the auxiliary feedwater storage tank (AFST).

The component cooling water system (CCWS) acts as an intermediate fluid barrier between the radioactive systems and the essential cooling water system (ECWS) to reduce the possibility of leakage of radioactivity from the plant to the environment. The CCWS is designed to provide a continuous supply of cooling

water to remove residual and sensible heat from the reactor during normal shutdown, to cool the letdown flow to the CVCS during power operation, to cool the ESF heat loads after a postulated LOCA, and to remove heat from various other plant components during normal operation.

The ECWS supplies cooling for those loads that are necessary for the safe shutdown of the reactor and to mitigate the consequences of postulated accidents. The ECWS also supplies cooling water to various systems during normal operation and shutdown. Heat rejection to the ECWS during either normal operation, normal shutdown, or DBA conditions is accomplished by three redundant cooling water loops, each with its own pump and motor, piping, valves, and instrumentation. Each loop cools one diesel generator (DG) HX, one CCW HX, two sets of two essential chillers during normal operation and one set of two essential chillers during accident conditions, and the CCW pump supplementary cooler. The required cooling water is taken from the essential cooling pond (ECP) (ultimate heat sink).

Three standby DGs are the onsite standby power sources feeding the Class 1E loads if the offsite power sources become unavailable.

The primary purposes of the reactor control and protection systems are to provide indication of automatic protection, to exercise proper control to ensure safe and proper reactor operation during steady-state and transient power operations, and to provide initiating signals to mitigate the consequences of accident conditions. The reactor trip system (RTS) automatically prevents operation of the reactor in an unsafe region by shutting down the reactor whenever preset limits are approached. The safe operating region is defined by several considerations such as mechanical/hydraulic limitations on equipment and heat transfer phenomena. Therefore, the RTS keeps surveillance on process variables that are directly related to equipment mechanical limitations, such as pressure, pressurizer water level (to prevent water discharge through safety valves, and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Still other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or calculated variable exceeds a setpoint, the reactor will be shut down to protect against either

gross damage to fuel cladding or loss of system integrity, which could lead to release of radioactive fission products into the containment.

The reactor control system enables the nuclear plant to accept a step load increase or decrease of 10% and a ramp increase or decrease of 5% per minute within the load range of 15% to 100% without reactor trip, turbine bypass, or pressurizer relief actuation, and is subject to possible xenon limitations. The system also maintains reactor coolant average temperature (T_{avg}) within prescribed limits by creating the bank demand signals for moving groups of rod cluster control assemblies (RCCAs) during normal operation and operational transients. The T_{avg} control also supplies a signal to pressurizer water level control and steam dump control.

The rod control system provides reactor power modulation by manual or automatic control of control rod banks in a preselected sequence and manual operation of individual banks. Control rod position is displayed in the control room, and alarms are provided to alert the operator if the required core reactivity shutdown margin is not available because of excessive control rod insertion or if control rod deviation exceeds preset limits.

The turbine generator is a W tandem compound, six-flow, 40-inch, last-stage-blade, 1800-rpm machine. It is installed outdoors on a turbine pedestal. The turbine guaranteed rating is 1,311,838 kW at a backpressure of 3.5 inches of mercury absolute and 0% makeup. The rating of the electric generator is 1,504,800 kVA at 60 Hz and a 0.90 power factor.

The main steam (MS) system transfers the steam from the outlet of the SGs to the turbine, where it is converted into mechanical energy that drives the electric generator. The steam is also used for various other services, such as shaft steam seals and turbine drives for main and auxiliary FW pumps. SG safety and power-operated relief valves are provided to protect the SG and the MS system in the event of high steam pressure.

The condenser is a three-shell, single-pass type located below the turbine. Cooling water from the cooling reservoir passes through the tubes with the

condensing steam flowing outside the tubes. Condensate is collected in the hotwell where the condensate pumps take their suction and supply the FW system.

The turbine bypass system provides an artificial steam load in the steam and power conversion systems when necessary. The system is rated at 40% of plant design steam flow. This bypass flow allows the turbine to take a 50% load reduction without reactor trip or lifting of SG safety valves. The bypass steam is equally distributed to all condenser shells to prevent uneven turbine exhaust backpressures. The turbine bypass system is not required for any safety function, but it provides operational flexibility and minimizes steam relief to the atmosphere.

The condensate and FW systems convey condensed steam from the condenser hotwells and the drains from the regenerative feed heating cycle to the SG while maintaining the water inventories throughout the cycle. The condensate pumps take suction from the condenser hotwells and discharge through the FW heaters to the deaerator. Condensate flows to and from the secondary makeup tank (SMT) to maintain the proper inventory of water in the secondary cycle. Feedwater booster pumps draw deaerated water from the deaerator storage tank to provide ample net positive suction head (NPSH) to the feedwater pump suction. The three steam-driven FW pumps discharge through the highest pressure FW heater into the SGs.

The onsite electrical system of each unit consists of the unit auxiliary transformer, four 13.8-kV auxiliary buses, three 13.8-kV standby buses, five 4.16-kV auxiliary transformers, two normal 4.16-kV auxiliary buses, three ESF 4.16-kV auxiliary buses, and three DGs. The three ESF 4.16-kV auxiliary buses feed the Class 1E ac power loads. The Class 1E 125-V dc power system consists of four independent subsystems (channels); each subsystem consists of an inverter, battery, and battery chargers. The onsite electrical system is designed to supply the functional requirements of all auxiliary loads required for all modes of plant operation. Instrumentation and protective control devices are provided to ensure reliability and availability of the system.

The offsite electrical system consists of two (345/13.8/13.8-kV) standby transformers, the 138-kV emergency transformer (138/13.8-kV), two main generators,

two main power transformers (345/22-kV), the 345-kV lines connecting the main power transformers and the standby transformers to the switchyard and the 345-kV switchyard, and the eight 345-kV transmission circuits from the South Texas 345-kV switchyard to the plant's owners interconnecting grids, and the 138-kV radial line out of CPL's Blessing/substation circuit to the 138-kV emergency transformer. In addition to the eight 345-kV transmission circuits, there will be a connection from the 345-kV switchyard at the site to the southern terminal facilities of a high voltage direct current (HVDC) interconnection system located at the plant. The transmission system provides sources of offsite power for plant auxiliary power systems for plant startup, shutdown, or at any time that power is unavailable from the unit's main generator. The normal power supply to unit balance-of-plant (BOP) auxiliary loads is provided through the unit auxiliary transformer connected to the generator bus.

The circulating water system supplies 907,400 gpm of cooling water from the reservoir to the main condensers of each unit to transfer the steam cycle rejected heat to the reservoir. Four 25% capacity vertical wet pit circulating water pumps take suction from the intake structure and discharge to a common header. The pumps are located in each bay, oriented with respect to each other to exclude the adverse effects of vortices and to provide a proper flow path and suction velocities. The cooling water is then supplied to a common condenser distribution header by two lines. This arrangement allows equal cooling water flow to each of the three main condenser shells.

The reactor makeup water system (RMWS) provides distribution of demineralized water from the demineralized water tank to reactor plant systems requiring demineralized water, including the spent fuel pool, CCWS, decontamination facilities, laboratories, and liquid and solid waste systems. The RMWS also stores and distributes recyclable reactor grade water from the boron recycle system (BRS) and the liquid waste processing system (LWPS). The RMWST stores reactor grade water, which is transferred by the reactor makeup water pump to systems requiring reactor grade water. They include

(1) CCWS emergency makeup
(2) spent fuel pool emergency makeup
(3) BRS

The DG fuel storage and transfer system for each unit is furnished with three independent fuel trains, one for each emergency DG. Each fuel train consists of a storage tank and the necessary piping, valves, and instrumentation. Each DG fuel oil storage tank has a capacity of 70,000 gallons. A normally isolated line is connected to the storage tank truck fill line from the auxiliary boiler fuel storage system. This connection may be used for replenishing the fuel used for testing the DGs. Each tank is provided with a drain, vent with flame arrestor, truck fill, and inspection manhole cover.

The emergency response facilities data acquisition and display system (ERFDADS) operates as an integrated system to provide plant and environmental data to aid operators and management in the control room, technical support center (TSC), and emergency operations facility (EOF) to respond quickly to abnormal operating conditions and mitigate the consequences of an accident. The TSC is the onsite TSC facility for emergency response. When activated, the TSC is staffed by predesignated technical, engineering, senior management, and other applicant personnel, and five predesignated NRC staff members. When it is activated, the TSC operates without interruption to provide plant management and technical support to plant operations personnel, and to relieve the reactor operators of peripheral duties and communications not directly related to reactor system manipulations. The TSC performs the EOF functions for the alert emergency class and for the site area emergency class and general emergency class until the EOF is functional. The TSC is located in the electrical auxiliary building at elevation 72 feet.

When activated, the operational support center (OSC) is the onsite area separate from the control room where predesignated operations support personnel assemble. The OSC is located in the administration building.

The EOF will be controlled and operated by the applicant. The EOF provides for the management of the applicant's overall emergency response, coordination of radiological and environmental assessment, determination of recommended public protective actions, and coordination of emergency response activities with Federal, state, and local agencies. When the EOF is activated, it will be staffed by personnel to be identified in the applicant's emergency plan. A designated senior licensee official will manage the applicant's activities in

the EOF. Facilities are provided in the EOF for the acquisition, display, and evaluation of radiological and meteorological data and containment conditions necessary to determine protective measures. These facilities are used to evaluate the magnitude and effects of actual or potential radioactive releases from the plant and to determine dose projections. The EOF is a separate facility located approximately 1 mile east of the power block, adjacent to the training center.

1.3 Confirmatory and Open Items

This draft SER documents the status of the safety review of the South Texas FSAR in most, but not all, areas. The sections that are not included herein are open because the staff has not completed the review or is awaiting additional information. The sections that are included contain other confirmatory or open items, whose resolutions will be sought in the final SER or a supplement thereto. A detailed listing of each confirmatory or open item has not been included in this draft because the staff position is clearly indicated in the text. A summary of the principal areas requiring resolution is in Table 1.2.

The Table of Contents indicates the sections not addressed in this draft SER either by not listing the section or by showing a blank in the Page No. Column next to the section title. Table 1.2, in conjunction with the Table of Contents, indicates areas where open items may arise or where items may be awaiting resolution pending receipt of information from the applicant. For example, the Section 2.5.4, "Stability of Subsurface Materials and Foundations," does not appear in the Table of Contents; more information may be required in this area for resolution of this issue at a later date.

Table 1.1 TMI-2 action plan items

TMI item	Shortened title/Description	SER Section(s)
I.A.1.1	Shift technical advisor	13.2.2.2
I.A.1.2	Shift supervisor responsibilities	13.5
I.A.1.3	Shift staffing	13.1
I.A.2.1	Immediate upgrade of RO and SRO training and qualifications	13.2.1.3
I.A.2.3	Administration of training programs	13.2.1.3
I.A.3.1	Revised scope and criteria for licensing exams	13.2
I.B.1.2	Independent Safety Engineering Group	13.4
I.C.1	Short-term accident and procedure review	13.5
I.C.2	Shift and relief turnover procedures	13.5.1
I.C.3	Shift supervisor responsibility	13.5
I.C.4	Control room access	13.5.1
I.C.5	Feedback of operating experience	13.5.1
I.C.6	Verification of correct performance of operating activities	13.5.1
I.C.7	NSSS vendor review of procedures	13.5.2.1
I.C.8	Pilot monitoring of selected emergency procedures for NTOLs	13.5.2.1
I.D.1	Control room design reviews	18
I.D.2	Plant safety parameter display console	18
I.G.1	Training during low power testing	14
II.B.1	Reactor coolant system vents	5.4.12
II.B.2	Plant shielding	12.3.2
II.B.3	Post-accident sampling	9.3.2.2
II.B.4	Training for mitigating core damage	13.2.1.3

Table 1.1 (Continued)

TMI item	Shortened title/Description	SER Section(s)
II.D.1	Relief and safety valve test requirements	3.9.3.2, 5.2.2.1
II.D.3	Valve position indication	5.2.2.1, 7.5.2.3
II.E.1.1	Auxiliary feedwater system evaluation	10.4.9
II.E.1.2	Auxiliary feedwater system initiation and flow	7.3.3.1
II.E.3.1	Emergency power for pressurizer heaters	8.4.9
II.E.4.1	Dedicated hydrogen penetrations	6.2.5
II.E.4.2	Containment isolation dependability	6.2.4
II.F.1	Accident monitoring instrumentation	
	1. Noble gas monitor	11.5.3
	2. Sampling and analysis of plant effluents	11.5.3
	3. Containment high range monitor	12.3.4
	4. Containment pressure	7.5.2.2
	5. Containment water level	7.5.2.2
	6. Containment hydrogen	7.5.2.2, 6.2.5
II.F.2	Instrumentation for detection of inadequate core cooling	4.4.8
II.G.1	Power supplies for pressurizer relief valves, block valves, and level indicators	5.2.2.2, 8.4.10
II.K.1	IE Bulletins	
	5. Review of ESF valves	6.3.1
	10. Operability status	6.3.1
II.K.2	Orders on B&W plants	
	13. Thermal mechanical report: effect of HPI for small-break LOCA with no auxiliary feedwater	15.6.5
	17. Voiding in RCS	15.0
	19. Benchmark analysis sequential AFW flow	15.0

Table 1.1 (Continued)

TMI item	Shortened title/Description	SER Section(s)
II.K.3	Final recommendations, B&O task force	
	1. Automatic PORV isolation	7.6.2.2, 15.6.1
	2. Report on PORV failures	15.6.1
	3. Reporting SV and RV failures and challenges	5.2.2.1
	5. Automatic trip of RCPs	15.1.5.1
	9. PID controller	7.7.2.1
	10. Proposed anticipatory trip at high power	7.2.2.5
	12. Confirmation of anticipatory trip	7.2.2.6
	17. ECCS outages	15.9.4
	25. Power on pump seals	15.1.5.1
	30. Small break LOCA methods	15.6.5
	31. Compliance with 10 CFR 50.46	15.6.5
III.A.1.2	Upgrading of emergency support facilities	13.3
III.A.2	Emergency preparedness	13.3
III.D.1.1	Primary coolant outside containment	11.5.3
III.D.3.3	Inplant I_2 radiation monitoring	12.3.4.2
III.D.3.4	Control room habilitability	6.4

Table 1.2 Summary of open and confirmatory items

FSAR/SER Section	Open or Confirmatory Issue
2	Resolution of inconsistency in demographic data
	Meteorological data for the ultimate heat sink
	Design basis for the HVAC system
	Details of the meteorological measurements program
	Updated geologic information regarding the site
	Information on the seismic characteristics of the site
3	Vertical floor frequencies for seismic analysis
	Containment exceptions to ASME 1973 Code criteria
	Exceptions regarding anchor bolts
	Pipe rupture stress summaries and design information
	Roto-Lok stud design information
	Component support stress information
	Reactor internals flow-induced vibration assessment
	Pump and valve inservice testing program
	Seismic qualification review
	Pump and valve operability review
	Environmental qualification of appropriate electrical equipment
4	NUREG-0737 Item II.F.2
	Failed fuel detection system
	Irradiated fuel surveillance program
	Fuel design criteria

Table 1.2 (Continued)

FSAR/SER Section	Open or Confirmatory Issue
5	Pre-service inspection program
6	Inservice inspection program
	Water drain seals in filter systems
9	Post-accident sampling system
	Design of fire suppression features
	Adequacy of fire protection
10	Secondary water chemistry
	Radiation release from condenser offgas
11	Solid waste management system
	Steam generator blowdown design
12	ALARA program policy, procedures, and design features
	NUREG-0737 Items II.B.2, II.F.1.3
	Occupational dose assessment and protection
	Radiation protection facilities, equipment, and instrumentation
13	Conformance to SRP Section 13.1.1
	Conformance to SRP Section 13.1.2
	Independent safety engineering group
	Qualifications of preoperational and initial startup test personnel
	Conformance of simulator to Regulatory Guide 1.149
	Physical security plans

Table 1.2 (Continued)

FSAR/SER Section	Open or Confirmatory Issue
14	Unacceptable changes to FSAR Section 14.2
	Clarification, correction, or additional information on specific test descriptions
15	Cycle-specific accident analyses
	Steam generator tube rupture accident analysis
	Liquid tank rupture analysis
17	Satisfactory continuation of the Engineering Assurance Program
18	Results of V&V program for final EOPs
	Control room indicating lights
	Control room lighting, sound, meter, and communication surveys

2 SITE CHARACTERISTICS

2.1 Geography and Demography

The South Texas project was reviewed in accordance with SRP Sections 2.

2.1.1 Site Location and Description

The site for the South Texas project, which is a proposed two-unit plant, consists of 12,300 acres (4978 hectares) of land in the southwestern part of Matagorda County, Texas. A 7000-acre (2833-hectare) cooling water reservoir has been constructed in the southern portion of the site boundary. The exclusion area, low population zone, site layout, and the immediate area surrounding the site are shown in Figure 2.1. Figure 2.2, shows the area within approximately 15 miles (24.14 km) of the site. Figure 2.3 shows Matagorda County and the region within 75 miles (121.68 km) of the site. Air, water, rail, and highway transportation routes in the vicinity of the site are shown in Figure 2.4.

The site is about 8.5 miles (13.68 km) north-northwest of the town of Matagorda, Texas, 12 miles (19.31 km) south-southwest of Bay City, 13 miles (20.92 km) north-northwest of Palacios, and 89 miles (143.2 km) southwest of Houston. The coordinates of the plant are 28° 47' 42" north latitude and 96° 02' 53" west longitude. The universal transverse mercator (UTM) coordinates are 3, 188, 669 meters north, and 788, 157 meters east, in zone 14. The area in the vicinity of the site is rural and contains a considerable amount of agricultural activity. It is relatively flat, and lies within the Coastal Prairie, which runs parallel to the Texas Gulf Coast. Matagorda Bay separates the site from the Gulf of Mexico, which is about 14 miles (22.53 km) southeast. The site borders on the west bank of the Colorado River, and the west branch of the river traverses part of the southeast sector of the site property. On the river, there is some recreational activity as well as a small amount of barge traffic transporting material to the four industrial facilities within 6 miles of the site.

2.1.2 Exclusion Area Authority and Control

The applicant has defined the exclusion area for the South Texas project as oval shaped, encompassing both Units 1 and 2, with the center of the oval located 305 feet (93 m) directly west of the center of the Unit 2 containment building. The minimum distance from the center of either reactor containment building to the exclusion area boundary is 4692 feet (1430 m). The applicant owns and controls all of the land and mineral rights within the designated exclusion area; no one resides within this area.

There are no railroads, highways, or waterways traversing the exclusion area. Farm-to-Market (FM) road 521, which formerly cut across the exclusion area, has been relocated along the northern border of the exclusion area. Activities within the exclusion area unrelated to Unit 1 operations are limited primarily to activity associated with the maintenance and operation of the proposed high-voltage direct current (HVDC) terminal, and the final construction of Unit 2. The HVDC terminal is to be operated by Central Power and Light Company personnel. Arrangements have been made to control and, if necessary, evacuate the exclusion area in the event of an emergency. (See Section 13.3 of this report for more details of these arrangements.)

The staff has concluded that, by virtue of ownership of the land and control of the mineral rights within the exclusion area, and because suitable arrangements have been made to control all activity unrelated to plant operations, the applicant has the authority to determine all activities within the exclusion area, as required by 10 CFR 100. The staff further concludes that the activities unrelated to plant operation within the exclusion area will not interfere with normal plant operations.

2.1.3 Population Distribution

Table 2.1 shows the resident population at various distances from the South Texas site for the years 1980, 1990, and 2030, as reported by the applicant. The year 2030 is the nearest census year to the projected end-of-plant life.

The staff has informed the applicant of some inconsistencies in the 0 to 10-mile demographic statistics and requested verification of the data. The applicant

has assured the staff that the population in the area 0 to 10 miles from the plant is being recounted and new data will be submitted soon. The staff will review and evaluate the new data and amend this report if it is deemed necessary.

The applicant indicated that the nearest permanent resident lives about 15,000 feet (4572 m) from the reactor. During the staff environmental site visit, the possibility that the nearest resident may live closer than 15,000 feet was discussed, and the applicant was requested to verify the location. The applicant concurred, and the information will be submitted with the 0 to 10-mile demography. The staff will amend this report if needed.

The nearest community in the vicinity of the site that is projected to have more than 1000 persons at the time of startup, is Bay City, Texas. Bay City, about 12 miles (19.31 km) north-northeast, had a population of 17,837 in 1980. The closest community is Matagorda, about 8.5 miles (13.68 km) south-southeast, which had a 1980 population of about 700. The population within 5 miles of the site in 1980 was 488, and within 10 miles it was 4122. As can be seen in Table 2.1 the population within 5 miles of the site is expected to increase by only about 843 persons during the life of the plant. The applicant reported that there were 239,339 people living within 50 miles (80.45 km) of the site in 1980; the applicant expects this number to increase to 302,955 by 1990. By the year 2030, the population within 50 miles (80.45 km) is projected to reach 536,852. There are no major cities within 50 miles of the site. The closest major city, Houston, about 89 miles (143.2 km) northeast, had a 1980 population of 1,595,138. In the ER, the applicant predicted a population growth rate of about 1.5% per year for the area within 50 miles during the life of the plant. The staff, using the Bureau of Economic Analysis (BEA) projections, calculated the population for this area and determined that the population will increase about 1.0% per year for this same period.

The applicant has designated a low population zone (LPZ) for the site with a radius of 3 miles (4.83 km) measured from a point located 305 feet (93 m) directly west of the center of the Unit 2 containment building. The topography within the LPZ is generally flat and used mainly for agriculture, much the same as the rest of the area in the general vicinity of the site. In addition to the cooling water reservoir in the southern section of the site, several sloughs

and a 34-acre lake (Kelly Lake) lie within the LPZ. These areas are not used for recreational purposes. About 149 persons lived within the LPZ in 1980. This number is not expected to change appreciably during the life of the plant. The transient population in the LPZ is negligible, except for persons utilizing the plant visitors center and picnic area overlooking the plant just outside the exclusion area, and light traffic on FM 521, which crosses the LPZ. There are no migrant workers, hospitals, or prisons within 10 miles (16.09 km) of the site. There are three small, privately owned recreational areas in the vicinity of Matagorda Bay, about 10 miles south-southeast of the site, that provide boating and fishing facilities. Within 10 miles of the site there are three schools. The Tidehaven Intermediate and Tidehaven High Schools are both in Elmaton, and the Matagorda Elementary School is in Matagorda. The three schools, which are approximately 8 miles (12.87 km) from the site, had a combined 1977-78 enrollment of about 470 students. Four other schools located just over 10 miles from the site had a total of 1375 students. Two retirement communities located between 3 and 4 miles (4.83 km and 6.44 km) from the site (along the eastern boundary of the Colorado River) house about 1000 people. (Section 13.3 of this report discusses the emergency preparedness plans for protecting the public in this area.)

The nearest densely populated center of about 25,000 or more persons, as defined by 10 CFR 100, is Bay City, Texas. Although the population of Bay City was only 17,837 in 1980, the population is expected to exceed 25,000 persons before the end of plant life (2030). The distance from the site to Bay City is about 12 miles (19.31 km), which is at least one-and-one-third times the distance to the LPZ outer radius, as required by 10 CFR 100.

2.1.4 Conclusion

The staff review of FSAR Section 2.1 is based on the 10 CFR 100 definitions of the exclusion area, the LPZ, and the population center distance, as well as on the staff's analysis of the onsite meteorological data from which the relative concentration factors (χ/Q) were calculated (see Section 2.3 of this SER) and the calculated potential radiological dose consequences of design-basis accidents (see Section 15). The staff has concluded, subject to a satisfactory determination of the demography inconsistencies noted, that the exclusion area, LPZ, and population center distance satisfy the criteria of 10 CFR 100 and are acceptable.

2.2 Nearby Industrial, Transportation, and Military Facilities

The South Texas project was reviewed in regard to activities at nearby industrial, transportation, and military facilities in accordance with SRP Sections 2.2.1, 2.2.2, 2.2.3, 3.5.1.5 and 3.5.1.6.

2.2.1 Transportation Routes

No highways, railroads, or waterways traverse the South Texas exclusion area. FM 521, which formerly ran through the exclusion area, has been relocated around the northern boundary of the exclusion area. Its closest approach is at least 4699 feet (1432 m) from the plant. Three other roads pass within 5 miles (8.05 km) of the South Texas project. In the northeast, two of the roads, 3057 and 2668, are about 4.5 and 4.8 miles (7.24 km and 7.72 km) from the plant, respectively; 1095 passes about 4.2 miles (6.76 km) west of the plant. These roads are used primarily for local traffic. Access to the plant, the visitors center, and the picnic area is by way of FM 521. Two primary roads in the vicinity of the site are State Highway 60, which runs north-south about 7 miles (11.26 km) east of the site, and State Highway 35, which runs generally in a north-south direction about 9 miles (14.48 km) northwest of the site at its closest point. The only major highway reasonably close to the site is U.S. 59, about 30 miles (48.27 km) northwest. Essentially no hazardous material is transported on the roads in close proximity to the site, except for that used at the South Texas project. Because of the separation distances between the major highways and the site, accidents that may occur on these roads would not pose a threat to the safe operation of the plant.

No main railroad lines run within 5 miles (8.05 km) of the site. The applicant examined the potential hazards of materials shipped on the Missouri Pacific, the Santa Fe, and the Southern Pacific lines that operate within the general area. The Missouri Pacific and the Santa Fe are located about 7 miles (11.26 km) north and east of the site, respectively, and the Southern Pacific is about 10 miles (16.09 km) west. Both the Missouri Pacific and the Santa Fe have rail spurs that terminate at the Celanese Chemical Company plant about 4.8 miles (7.72 km) from the site. Smaller amounts of hazardous material are carried on the railroads than are stored at the Celanese plant, which is the rail line's

closest approach to the site. Only railroad cars consigned to the South Texas project, which are operated by the Missouri Pacific railroad, will be allowed on the rail spur leading into the South Texas site.

The Colorado River, which runs generally in a north-south direction and passes within 2.75 miles (4.42 km) east of the site, is the principal waterway in the area. There are no locks or dams on the river in the vicinity of the site. Approximately 1200 barges annually transport both raw and finished materials, including petroleum products, up the 15-mile (24.14-km) stretch of the river from the Intercoastal Waterway near the Gulf of Mexico to the turning basin in the vicinity of the Port of Bay City. The applicant analyzed the largest shipment of petroleum products expected to be transported on the river past the site. Assuming a 15,000-barrel-capacity barge with a 10% gasoline-air mixture, the applicant's calculations indicate that the peak overpressure at the plant from such an explosion would be less than 0.1 psi. The staff considered the possibility of such an accident, evaluated the potential consequences, and agrees with the applicant's conclusion that the risk associated with such an explosion does not present a hazard to the plant.

The Colorado River is the source of makeup water for the onsite reservoir used for cooling water. Accidents involving river traffic striking the intake structure or spilling corrosive chemicals or other material into the river would not prevent the safe shutdown of the plant because the available plant cooling water supplied by the onsite reservoir is sufficient for cooldown.

The applicant concludes that the separation distances of the railroads, highways, and waterways in the area, as well as the nature of the roads near the plant and the types and quantity of hazardous materials transported on these routes, are sufficient to preclude adverse effects on the plant in the event of an accidental explosion or release. After reviewing the data and evaluating the consequences, the staff agrees with the applicant's conclusion.

2.2.2 Nearby Facilities

There are no military bases, bombing ranges, munitions plants, or missile installations within 10 miles (16.09 km) of the site. No airports are located

within 5 miles (8.05 km) of the site, but there are two relatively small airports within 10 miles. C-Level Farm is 9.5 miles (15.29 km) west-northwest, and Collegeport Airfield, which is not in active use, is 8.5 miles (13.68 km) southwest of the site. A replacement airfield with a single runway has been built about 0.25 mile (0.4 km) east of the Collegeport runway. In addition, there are 18 individual runways within about 10 miles of the site. Except for the 3700-foot (1128 m) turf runway at C-Level Farm and the new 2800-foot (853 m) runway at Collegeport, practically all of the other runways are small 1800- to 2600-foot (549- to 793-m) grass strips. Essentially all of the aircraft utilizing the ground facilities in this area are light weight, used principally for crop dusting or other agriculatural purposes. During the peak growing season, there may be as many as 25 to 100 takeoffs and landings daily at these locations. The William P. Hobby Airport about 78 miles (125.5 km) northeast and the Houston Intercontinental Airport about 92 miles (148 km) east-northeast are the closest major airports near the plant.

There are no low-level military aircraft training routes near the site. A low-level route (OB-19), previously used for bombing and navigation training by the Air Force and Navy, is no longer used.

Two low-level Federal Airways (V-70 and V-20) are within a 10-mile radius of the site. At their closest points, the centerlines of V-70 and V-20 are approximately 5 and 9 miles (8.05 km and 14.48 km) northwest of the site, respectively. On the basis of its review of the applicant's assessment of aircraft hazards at the site, the staff has concluded that the probability of an aircraft crash causing radiological consequences in excess of the guidelines of 10 CFR 100 is within the acceptance criteria of SRP Section 2.2.3 (less than about 10^{-7} per year) and is, therefore, acceptable.

Several industrial facilities are within approximately 7 miles (11.26 km) of the site. Some of these facilities are operating and some have ceased operations or have shut down completely. The Celanese Chemical Company produces, stores, and ships chemicals from its plant, which is about 4.8 miles (7.72 km) north-northeast of the site. The Conoco Chemical Co. Hi Density Polyethylene Plant is about 6.5 miles (10.46 km) east of the site. The Crysen Terminal (formerly Bay Tex), about 4.8 miles (7.72 km) north-northeast, maintains a petroleum

products storage capability of 120,000 barrels. Both Crysen and Celanese utilize the public wharf at the Port of Bay City. This wharf, about 4.8 miles (7.72 km) from the site, handles barge shipments of gasoline, diesel oil, chemicals, and nylon salt. The production equipment at the K and K Compression facility (formerly the Big Three Industrial Gas and Equipment Co.) located 5.5 miles (8.85 km) north-northeast has been dismantled; there are no plans for future industrial production. Parker Brothers, a docking facility for handling clams and oyster shells, is 3.5 miles (5.63 km) east of the site. This facility has ceased operations, and no plans for its future are contemplated. Except for the Parker Brothers facility, all of these industries are located in the vicinity of the Port of Bay City, which is accessible to water, rail, and highway transportation, and the area is highly undeveloped. No large industrial expansion is planned for this area in the near future.

Because of the distances involved, there is no danger of explosions or toxic gas releases at these facilities affecting the safe operation of the plant. However, because of the anhydrous ammonia, ammonium hydroxide, and hydrazine that is stored on the site, redundant detectors for these chemicals will be located in the outside air intakes for the control room. When these chemicals are detected, an alarm will sound and the control room will be automatically isolated. (Section 6.4 of this SER provides more details on the control room habitability system.)

There are no liquified petroleum gas (LPG) or liquified natural gas (LNG) lines running within 5 miles (8.05 km) of the South Texas site, but there are five natural gas pipelines in this area that vary in size from 4 to 30 inches (10.16 to 76.2 cm) in diameter. The applicant analyzed the consequences of a potential accident involving each of these lines, and determined that the 16-inch (40.64-cm) (1000-psig) Dow Chemical Company pipeline 2.1 miles (3.38 km) from the plant, and the 30-inch (1100 psig) Texas Eastern Transmission Corp. pipeline located 45 miles (7.24 km) from the site would pose the greatest potential threat to the operation of the plant in the event of a pipe rupture. The applicant's analysis was based on a hypothetical accident involving the release and detonation of the entire volume of gas at the location of the break, and also the delayed detonation of the gas-air mixture in the plume as it drifts or is blown toward the plant. The applicant's analysis indicates that the release

and detonation of gas from an unconfined gas-air mixture is not considered to be a credible event and will not affect the safety of the plant. The staff concurs with the applicant's analysis. There is a 10-inch (25.4-cm) pipeline carrying nitrogen, a 12-inch (30.48-cm) line carrying oxygen, and a 6-inch (15.24-cm) line carrying hydrocarbons from Freeport, Texas, to the Celanese plant, which is 4.8 miles (7.72 km) from the site. Because of the distance involved, these pipelines do not present a hazard to the South Texas plant.

Several gas and oil production fields are within 5 miles (8.05 km) of the site. Based on geological and production data for this area, the applicant says no expansion is expected near the site. However, the applicant analyzed a hypothetical drilling accident adjacent to the site boundary to determine its effect on plant safety-related structures, and no adverse effects were evident. There are no plans to move any of these pipelines or transport any other products in them in the future. There are no mining or quarry operations within 5 miles (8.05 km) of the site. There is a liquid petroleum gas storage facility in a salt dome about 16 miles (25.74 km) north-northwest of the site, but the closest salt dome formation in the area is 10 miles (16.09 km) east-southeast of the site. Therefore, future storage of LPG in underground caverns is not considered a problem because of the separation distances involved.

2.2.3 Conclusions

On the basis of (1) the information provided by the applicant and (2) the staff's review based on GDC 4 and SRP Section 2.2.3, the staff has determined that the South Texas plant is adequately protected and the plant can be operated with an acceptable degree of safety, activities at nearby industrial, transportation, and military facilities notwithstanding.

2.3 Meteorology

The staff evaluates regional and local climatological information, including extremes of climate and severe weather occurrences that may affect the design and siting of a nuclear plant, to ensure that the plant can be designed and operated in conformance with Commission regulations. The staff must have information concerning atmospheric diffusion characteristics of a nuclear power plant

site in order to determine that radioactive effluents from postulated accidental releases, as well as routine operational releases, are within Commission guidelines. Sections 2.3.1 through 2.3.5 below have been prepared in accordance with the SRP (NUREG-0800), utilizing information in FSAR Section 2.3, the applicant's responses to staff requests for additional information, and generally available reference materials, as described in the SRP.

2.3.1 Regional Climatology

The plant is located in the flat coastal plains of Southern Texas, about 89 miles southwest of Houston, and about 15 miles inland from the Gulf of Mexico.

Maritime tropical air masses dominate the region with an occasional incursion of continental air masses in winter. The mean annual temperature in the area is about 70°F (21.1°C), ranging from about 54°F (12.2°C), in January to about 84°F (28.9°C), in July and August. Annual precipitation in the area is about 42 inches (1065 mm).

The site is near both the principal track of cyclonic storms that originate over the western Gulf of Mexico and move eastward along the coast, and the favored landfall for hurricanes along the Texas coast, resulting in a variety of severe weather phenomena affecting the site. About 65 thunderstorms can be expected on about 50 days each year; these storms are most frequent in August. Considering the frequency of thunderstorms in the region, the applicant has estimated less than one lightning strike per year to plant safety-related areas. Hail often accompanies severe thunderstorms. In the period 1955 to 1967, hail with diameters 3/4 inch (19 mm) or greater was reported an average of nine times in the 1-degree latitude-longitude squares surrounding the site.

Tornadoes, often spawned by degrading hurricanes, occur in the area. The staff has independently examined tornado occurrences in the site region (a 2-degree latitude square centered on the site). Because of the proximity of the site to the Gulf of Mexico, the area of consideration was limited to the land area contained in the 2-degree square, approximately two-thirds of the total area, or 10,939 mi^2. In the period 1954 to 1981, 250 tornadoes were reported in this

area, a mean annual frequency of 8.9 tornadoes per year. Considering the mean annual frequency, the geographic area, and the expected tornado path area (0.206 mi^2), the staff has computed the probability of a tornado strike at the plant site to be about 1.7×10^{-4} per year, which converts to a recurrence interval of about 5900 years. The applicant has computed a recurrence interval for a tornado strike at the plant site to be about 45,000 years. Tornadoes spawned by hurricanes move at the speed of winds in the parent storm. Maximum wind speeds associated with tornadoes reflect the contribution of both translational speed (storm movement) and rotational speed. An independent study of all violent tornadoes reported in the United States for the period 1880 to 1982 indicated that no tornado associated with any hurricane has exceeded a maximum wind speed (translational plus rotational speed) of 260 mph. The design-basis tornado parameters selected by the applicant conform to the recommendations of RG 1.76, "Design Basis Tornado for Nuclear Power Plants," for this region of the country. These characteristics are: rotational speed, 290 mph; translational speed, 70 mph; and, a total pressure drop of 3 psi, at a rate of 2 psi per second.

Hurricanes or remnants of hurricanes pass through the region occasionally. During the period 1871 to 1982, about 49 tropical cyclones (tropical depressions, tropical storms, and hurricanes) passed within 100 nautical miles of the site.

Occurrences of high wind speeds in the area are associated with severe thunderstorms, extratropical cyclones, tropical storms, and hurricanes. The applicant has evaluated extreme wind speed information from throughout the region of the plant and computed the "fastest mile" wind speed at a height of 30 feet with a return period of 100 years to be 125 mph. The staff has examined the applicant's analysis of extreme winds and independently reviewed extreme winds speeds, particularly those associated with occurrences of hurricanes along the Texas coast. The staff concludes that the selection of 125 mph as the operating-basis wind speed (a wind speed that could reasonably be expected to affect the plant site during the operating life of the plant) for the site is acceptable based on available information. Gust factors and vertical velocity profiles have been developed in accordance with the criteria of American National Standards Institute (ANSI) A58.1, "Building Code Requirements for Minimum Design Loads in Buildings and Other Structures" (1972).

To determine the meteorological conditions for maximum water loss and minimum water cooling for the essential cooling pond, which is the ultimate heat sink for the plant, the applicant examined data from the National Weather Service Station at Victoria, Texas. However, apparently two separate periods of record were examined. For maximum water loss, the applicant examined the maximum difference between the dry bulb temperature and the dew point temperature in combination with maximum wind speeds for 30-day averages for the summer seasons (defined by the applicant to be from June 15 to September 15) for the period 1951 to 1957. The combination of meteorological conditions producing maximum water loss were determined by the applicant to be for the period July 22 to August 20, 1954. Although these conditions appear to be reasonably conservative, the applicant apparently has not conformed to the recommendations of RG 1.27, "Ultimate Heat Sink for Nuclear Power Plants," to examine a representative climatological period of record. In contrast, to select the meteorological conditions that result in minimum water cooling, the applicant examined data from Victoria, Texas, for the period 1951 to 1970. For this analysis, the applicant selected the 1-day conditions (for July 28, 1957) that resulted in highest water temperature, followed by conditions observed from June 29, 1957 to July 27, 1957, to produce the highest 30-day water temperature. These conditions appear reasonably conservative, and the applicant appears to have examined an adequate period of record to satisfy the recommendations of RG 1.27. However, the applicant must confirm that the intent of RG 1.27 with respect to a representative climatological period of record was satisfied for the analysis of maximum water loss from the ultimate heat sink.

Snow and ice are uncommon in the area. Average annual snowfall is less than 0.5 inch (13 mm), although 15.4 inches (390 mm) was reported at Galveston, Texas, in February 1895. Ice storms, which can plug drains and scuppers as well as disrupt offsite power, are also rare, with glaze occurring less than 1 day each year, on the average. The accumulation of water on the roofs of safety-related structures is the most likely cause of severe and extreme environmental loads for design considerations. The adequacy of the design against such loads is discussed in Section 2.4.3 of the SER.

In the design of the heating ventilation and air conditioning (HVAC) systems for all safety-related buildings, the applicant used a maximum temperature of

96°F (35.5°C) and a minimum temperature of 29°F (-1.8°C). The bases for selection of the HVAC design temperatures were the 1% probability of occurrence per year (summer) and 99% (winter) probability of occurrence values per year from the distributions presented by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE). Extreme temperatures with return periods of 100-years in the site area are approximately 108°F (42.2°C) and 4°F (-15.6°C). An extreme maximum temperature of 110°F (43.3°C) was reported at Victoria (July 1939), and an extreme minimum temperature of 5°F (-15°C) has been reported at Houston (January 1940).

In response to staff questions, the applicant indicated that "because of thermal inertia and due to the conservative design of HVAC systems...persistent temperatures (e.g., on the order of several hours) greater than the design basis values will have no impact on the normal temperature ranges" expected for the operation of safety-related systems and components. If, in designing the HVAC systems, the applicant has considered the design-basis temperature values as long-term, steady-state values conservatively assumed to occur continuously, extreme temperatures that are transient and of short duration are not expected to affect the performance of such systems. The applicant must confirm the "conservative design of HVAC systems" as discussed above.

Large-scale episodes of atmospheric stagnation occur infrequently in the region. Only about four atmospheric stagnation cases totaling about 17 days were reported in the area in the period 1936 to 1970. None of these cases lasted 7 days or more.

On the basis of its review according to the SRP Section 2.3.1, the staff concludes that, with the exceptions of design-basis temperatures for auxiliary systems and components, and the period of record examined for maximum water loss from the ultimate heat sink, the applicant has identified and considered appropriate regional meteorological conditions in the design and siting of this plant, and therefore, meets 10 CFR 100.10 and GDC 2. The applicant selected design-basis tornado characteristics that conform to the position in RG 1.76, and, therefore, meets GDC 4 in determining an acceptable design-basis tornado for missile generation.

2.3.2 Local Meteorology

Climatological data from Bay City, Matagorda, and Victoria, Texas, and available onsite data have been used to assess local meteorological characteristics of the plant site.

Precipitation is well distributed throughout the year, ranging from about 2.3 inches (58 mm) in March to about 4.6 inches (115 mm) in September. Maximum and minimum monthly amounts of precipitation observed at Victoria have been 14.5 inches (370 mm) in September 1967 and 0 inches (0.0 mm) in November 1945. The maximum amount of precipitation in a 24-hour period at Victoria was 8.6 inches (220 mm) in April 1969; the greatest daily precipitation at Matagorda was 12.2 inches (310 mm) in May 1951. As noted above, snowfall is not common along the Texas coast, although snow has occurred in each month from December through March. The maximum monthly snowfall at Victoria was 5 inches (125 mm) in January 1940, and the maximum amount of snowfall in a 24-hour period at Bay City was 3.8 inches (97 mm) in February 1958. The annual total precipitation measured at the site for the period January to December 1976 is about 37.4 inches (950 mm) compared with the annual total at Victoria of 48.2 inches (1100 mm) for the same period of record. The staff's examination of the applicant's hourly precipitation data from the site indicates anomalous and inconsistent records, which suggest problems with the applicant's measurement of precipitation and data reduction techniques. These problems will be examined during the review of the upgraded meteorological measurements program (see Section 2.3.3 below).

Wind data taken from the 10-m level of the onsite meteorological tower for a 4-year period of record (January 1974 to December 1977) extracted from a magnetic tape containing hourly observations of meteorological parameters indicate prevailing winds from the southeast, south-southeast, and south, which occur together about 41% of the time. Winds from the west-southwest, west, and west-northwest occur least frequently, with a total annual frequency of only about 4%.

The average wind speed at the 10-m level is about 10.7 mph (4.8 m/sec). Calm conditions (defined as wind speeds less than the starting threshold of the anemometer) occur less than 0.2% of the time.

Neutral (Pasquill type D) conditions predominate at the site, occurring about 31% of the time, as defined by the vertical temperature gradient between the 60-m and 10-m levels. Moderately stable (Pasquill type F) and extremely stable (Pasquill type G) conditions occur about 14% and 10% of the time, respectively, for the same stability indicator.

As discussed above, the staff has reviewed available information relative to local meteorological conditions of importance to the safe design and siting of this plant in accordance with the criteria contained in SRP Section 2.3.2. Although the staff is concerned about precipitation measurements at the site, the staff concludes that the applicant has identified and considered appropriate local meteorological conditions in the design and siting of this plant and, therefore, meets 10 CFR 100.10 and GDC 2.

2.3.3 Onsite Meteorological Measurements Program

Meteorological measurements at the site were initiated in July 1973. The meteorological tower used to provide data to support both the construction permit and operating license applications is located about 5000 feet (1500 m) northeast of the reactor buildings. Wind speed and wind direction are measured at the 33-foot (10-m) and 195-foot (60-m) levels, and vertical temperature gradient is measured between the 10-m and 60-m levels. Ambient dry bulb temperature is measured at the 10-m, 30-m, and 60-m levels. Dew point temperature is measured at the 10-m level. Precipitation and solar radiation are measured near the ground. The applicant has analyzed the overall measurement system accuracies for each parameter, and concluded that the system accuracy for analog recording of vertical temperature difference are not within the specifications presented in RG 1.23. System accuracies for digital recording appear to comply with the specifications presented in RG 1.23. The meteorological data provided with the operating license application have been checked and found to compare reasonably with other data collected in the area.

The applicant provided over 4 years (July 21, 1972 to January 3, 1978) of meteorological data on magnetic tape with the operating license application. The data base differs somewhat from the period of record described in the FSAR, which ended September 20, 1977. The staff has utilized 4 calendar years of

onsite data (January 1974 to December 1977), combined into joint frequency distributions of wind speed and wind direction by atmospheric stability for use in the atmospheric dispersion assessments presented in Sections 2.3.4 and 2.3.5. Wind speed and wind direction data for these assessments were based on measurements at the 10-m level, and atmospheric stability was defined by the measurement of vertical temperature gradient between the 10-m and 60-m levels.

The meteorological measurements system was calibrated quarterly during the period of record from July 1973 to December 1977. Joint data recovery of wind speed and wind direction at the 10-m level by atmospheric stability (defined by the vertical temperature gradient between the 10-m and 60-m levels) was about 98% for the 4-calendar-year period described above. The data set is expected to reasonably reflect expected diurnal, seasonal, and annual airflow and stability patterns at the site. The 4-year period of record is also expected to reasonably represent occurrences of extreme atmospheric conditions of importance for assessments of local transport and diffusion characteristics. The frequencies of occurrence of moderately stable and extremely stable conditions at the site agree reasonably well with other sites in the region. Dose consequences assessments based on available onsite meteorological data are expected to be reasonably conservative. Extreme meteorological conditions for design of safety-related structures, systems, and components (discussed in Section 2.3.1) were based on long-term (typically 30 years or more) climatological data from nearby National Weather Service stations, and not directly on the 4 years of onsite data. However, the representativeness of long-term offsite data was determined by comparisons of concurrent offsite data with available onsite data.

The applicant has indicated that the meteorological measurements program will be upgraded for use during plant operation, although no specific information has been provided. One of the areas to be examined as part of the upgraded program is the measurement of precipitation to resolve anomalous and inconsistent records, as discussed in Section 2.3.2 of the SER. To address the meteorological considerations for emergency preparedness planning outlined in 10 CFR 50.47 and Appendix E to 10 CFR 50, the proposed upgraded operational meteorological measurements program will be reviewed for conformance with NUREG-0737, Item III.A.2; Supplement 1 to NUREG-0737; and NUREG-0654, Appendix 2, "Criteria for Preparation

and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The incorporation of current meteorological data into a real-time atmospheric dispersion model for dose assessments will also be considered as part of the upgraded capability.

The staff has reviewed the onsite meteorological measurements program in accordance with SRP Section 2.3.3. Although the applicant has indicated that some meteorological measurements, most notably vertical temperature difference, using analog recording do not conform to RG 1.23, "Onsite Meteorological Programs," the staff has examined the reasonableness of the data provided. The 4 years of data collected by the applicant appear reasonably representative of expected onsite meteorological conditions. However, the staff is continuing its evaluation in this matter, including the nature and timing of upgrades to the meteorological measurements program. Nevertheless, the staff concludes that the available site data provide a reasonable basis for making conservative estimates of atmospheric dispersion conditions for consequence assessments for design-basis accidents and routine radioactive releases from the plant.

2.3.4 Short-Term (Accident) Diffusion Estimates

To audit the applicant's estimates, the staff has performed an independent assessment of short-term (less than 30-day) accidental releases from buildings and vents using the direction-dependent atmospheric dispersion model described in RG 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," with consideration of increased lateral dispersion during stable conditions accompanied by low windspeeds. As described in Section 2.3.3, 4 years of onsite data were used for this evaluation. Wind speed and wind direction data were based on measurements at the 10-m level, and atmospheric stability was defined by the vertical temperature gradient measured between the 10-m and 60-m levels. A ground-level release with a building wake factor, CA, of 1320 m^2 was assumed. The relative concentration (χ/Q) value for the 0- to 2-hour time period was determined to be 1.4×10^{-4} sec/m^3 in the southwest sector at an assumed exclusion boundary distance of 1430 m. Similar χ/Q values were calculated at the exclusion area boundary in adjacent or nearby sectors. The χ/Q values for appropriate time periods at the low-popluation zone (LPZ) distance of 4800 m are

Time Period	χ/Q (sec/m^3)
0 to 8 hours	1.9×10^{-5}
8 to 24 hours	1.2×10^{-5}
1 to 4 days	4.8×10^{-6}
4 to 30 days	1.3×10^{-6}

The χ/Q values for the LPZ distance were calculated in the west sector, although similar values were calculated in adjacent or nearby sectors.

The applicant has calculated somewhat higher (25% to 35%) values for the 0- to 2-hour period at the exclusion area boundary and for the 0- to 8-hour period at the LPZ distance. The applicant has calculated substantially lower (factors of 1.8 to 4.8) values for periods of 16 hours and longer at the LPZ distance. These differences are principally attributable to differences in modeling. The applicant used a direction-independent atmospheric dispersion model, such as that suggested in RG 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors."

On the basis of the above evaluation performed in accordance with SRP Section 2.3.4, the staff concludes that the applicant has considered appropriate atmospheric dispersion estimates for assessments of the consequences of radioactive releases at the exclusion area boundary in accordance with the requirements of 10 CFR 100.11, although the applicant's analysis of atmospheric dispersion for assessments at the LPZ distance may underestimate dose consequences for time periods longer than 8 hours. However, the staff used the atmospheric dispersion estimates provided in this section in an independent assessment of the consequences of radioactive releases for design-basis accidents. The results of this assessment are discussed in Section 15 of this SER.

2.3.5 Long-Term (Routine) Diffusion Estimates

To audit the applicant's estimates, the staff will perform an independent calculation of annual average relative concentration (χ/Q) and relative deposition

(D/Q) values using the straight-line Gaussian atmospheric dispersion model described in RG 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases From Light-Water-Cooled Reactors." The results of this model will be adjusted to reflect spatial and temporal variations in airflow using the correction factors contained in NUREG/CR-2919.

On the basis of the evaluation described above and in accordance with SRP Section 2.3.5, the staff will determine if the applicant has considered site-specific atmospheric dispersion conditions in demonstrating compliance with the numerical guides for doses contained in 10 CFR 50, Appendix I. The atmospheric dispersion estimates developed by the staff will be included in the assessment of the radiological impact to persons resulting from routine releases to the atmosphere contained in the staff's environmental statement.

2.5 Geology and Seismology

In this review, the staff considered information on geology and seismology obtained since the SER-CP was issued (August 1975). This information included (1) data gathered from both on-site and near-site investigations, including geologic and geophysical information acquired as a result of extensive oil/gas exploration in the site region; (2) material gathered in staff discussions with individuals knowledgeable of the geology and seismology of the site and region; (3) recently acquired literature; (4) an evaluation by the applicant of strain energy in Gulf Coast sediments; (5) an assessment of the significance of both groundwater use and oil/gas production in terms of site and regional subsidence; (6) an evaluation of the site-area subsurface model through comparison with copyrighted and proprietary structural contour maps; (7) verification, through detailed geologic mapping of site excavations, of the absence of faulting underlying the plant site area; and (8) a compilation of observed and instrumental seismicity of the site through 1983. As a result of this review, and assuming that the on-going investigations/analyses enumerated below result in favorable conclusions, the staff has determined that the SER-CP conclusions regarding the safety of the South Texas project from a geological and seismological standpoint remain valid.

FSAR Sections 2.5.1, 2.5.2, and 2.5.3 indicate that the applicant has satisfied 10 CFR 50, 10 CFR 100, and Appendix A to 10 CFR 100 by (1) performing post-CP site and near-site geological, seismological, and geophysical investigations/studies as needed and (2) consulting with individuals knowledgeable about the local geology and seismology.

In addition, the applicant is in conformance with applicable portions of the SRP and RGs 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"; 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 2; and 1.132, "Site Investigations for Foundations of Nuclear Power Plants."

As a result of rather recent post-SER-CP developments, the applicant is currently evaluating

(1) a hypothesis suggesting that the origin of the faults underlying and adjacent to the site may be the result of, or influenced by, the movement of a salt mass at unknown depths

(2) the impact, if any, such a hypothesis would have on FSAR conclusions on such subjects as possible movement of nearby faults, the possible age of these faults, and the effect at the plant site of ground motion resulting from movement of faults within 5 miles (8 km) of the site

(3) lineament analysis based on imagery developed after the SER-CP was issued

(4) identification and confirmation, through geophysical or other means, of the presence of continuous horizons overlying the regional east-west trending fault about 2.7 miles (4.3 km) north of the site

(5) the assignment of defensible ages to various geologic horizons underlying the site, at least to those geologic formations above a depth of 2000 feet (610 m)

The staff anticipates that the results of these studies will not affect its current position that the South Texas site is suitable for a nuclear power facility. The staff findings will be included in the final SER-OL.

The information on the South Texas project received after the SER-CP was issued is discussed in Sections 2.5.1, 2.5.2, and 2.5.3 below.

2.5.1 Basic Geologic and Seismic Information

Since the SER-CP was issued, the applicant has conducted geologic investigations both on and off the site and has evaluated geological and geophysical data obtained by others. These investigations and analyses have resulted in an increased understanding and confirmation of the surface and subsurface conditions of the South Texas site and vicinity.

Assuming that the applicant's on-going studies/investigations identified above produce favorable results, the staff finds that no new information has been developed that would indicate a need to modify the staff's earlier conclusions regarding the suitability of the South Texas site.

The principal new geologic and geophysical information in the FSAR regarding the site and the area within 5 miles (8 km) of the site has been derived from the following sources:

(1) acquisition and interpretation of several of the seismic reflection surveys conducted since the CP was issued

(2) an evaluation of site subsidence based upon horizontal and vertical ground movement data obtained through the applicant's subsidence monitoring network

(3) structural contour maps of geologic horizons underlying the site and vicinity prepared by Cambe Geological Services.*

(4) mapping and photographing of the excavations for the plant structures

The applicant is evaluating the geologic and geophysical information derived from the interpretation of four of the most relevant post-CP seismic reflection

---

*A Houston, Texas, firm, not associated with the applicant.

profiling surveys conducted within 5 miles (8 km) of the South Texas site. The applicant is evaluating these data to identify and confirm, through the seismic profiles (and possibly through hydrocarbon test well logs), the presence of defensible, continuous seismic reflectors or horizons overlying the east-west trending fault about 2.7 miles (4.3 km) north of the site. This evaluation will define the age of most recent movement of the fault where interpreted on several post-CP seismic reflection profiles and reconfirm the presence of the seismic reflector overlying the fault, as established during the CP investigations. Because of the applicant's reinterpretation and consequent relocation of the east-west trending fault to the north of the position presented in the Preliminary Safety Analysis Report (PSAR), the FSAR shows no seismic reflectors overlying the fault. The staff anticipates that the applicant will present information in an FSAR amendment to establish the noncapability of the fault.

As of May 1985, 18 post-CP petroleum test holes and nearly 53 miles (85 km) of seismic reflection profiling have been completed within 5 miles (8 km) of the site.

As determined by the applicant's site subsidence network, subsidence is negligible and is well below the rates predicted in the PSAR. The subsidence rates measured for 1976 through mid-1984 at the plant area ranged from 0.16 to 0.25 inch (0.41 to 0.64 cm) per year. The predicted annual rate was 0.60 to 0.80 inch (1.52 to 2.0 cm) per year. The net effect of subsidence, coupled with the heave and settlement associated with plant site construction activities (excavation, backfill, and embankments) on the critical structures, is discussed in Section 2.5.4 below. Considering current production depths and distance from the site, subsidence resulting from fluid/gas withdrawal associated with off-site hydrocarbon wells is unlikely.

Structural contour maps of two Tertiary horizons underlying the site area at depths in excess of 8000 feet (2438 m) have been obtained from Cambe Geological Services. The maps were prepared in June and November 1984. Although the sense of motion and attitude of the faults shown on the Cambe maps are not universally coincidental with those interpreted by the applicant, the Cambe interpretation is in general agreement with the trend (east-west) of faults shown in the FSAR. No implied hazard to the site is raised as a result of the staff's

evaluation of the Cambe subsurface interpretation. It should be noted that Cambe's structural contour maps are not as comprehensive as those prepared by the applicant, because the Cambe maps portray an evaluation of only electrically logged test holes. The applicant's interpretation included information obtained from the many deep and shallow seismic reflection surveys as well as the electric logs.

Geologic mapping of the plant excavations, including those for the essential cooling pond and attendant safety-related structures, coupled with complete photographic coverage, has confirmed the geologic integrity of the site area. As predicted by the applicant's pre-CP investigations, the South Texas excavations--as inspected, mapped, and photographed--show no evidence of either faulting or through-going deformation.

Only two linears identified through remote-sensing-imagery studies in the PSAR are located in the plant structures area. The alignment of these two linears--one trending to the northeast, the other to the northwest--passes through the essential cooling pond area. Geologic mapping of this area has demonstrated (1) that the soil stratification is coherent, with no indication of disturbance, and (2) that there is no known basis for assuming a structural origin for either of the two linears.

The staff inspected the plant excavations on March 31, 1976 and on March 17, 1977 and concluded that no structural abnormalities were visible within either the mapped or the then-visible portions of the excavations. A geological representative (Dr. David Patrick) of the U. S. Army Corps of Engineers accompanied the staff on the 1976 visit, Dr. Charles Kreitler of the Texas Bureau of Economic Geology was present at the 1977 site visit. Both representatives agreed with the staff regarding the absence of evidence suggesting faulting.

2.5.1.1 Regional Geology

The South Texas site is located within the Gulf Coastal Plain physiographic province on the northwest flank of the Gulf Coast geosyncline. The outer edge of the Gulf Coastal Plain physiographic province is defined by the Cretaceous, Tertiary, and Quaternary contact with the adjacent Paleozoic sediments some 230 miles (370 km) to the northwest.

Stratigraphically, the Gulf Coastal Plain is underlain by thousands of feet of unmetamorphosed Quaternary through Mesozoic sediments underlain presumably by Paleozoic basement. Sedimentary thicknesses exceed 50,000 feet (15,240 m) along the axis of the generally northeast-southwest trending Gulf Coast geosyncline. The sedimentary sequence beneath the site is estimated at 40,000 feet (12,192 m) of continental and marine deposits. Gulf Coastal Plain deposits are locally folded and faulted but are generally undeformed.

Structurally the site region is bounded by the Ouachita Tectonic Belt on the north as the Ouachita Mountains and on the west where the tectonic belt is found in the subsurface. The arcuate axis of the Gulf Coast geosyncline lies to the south and east of the site (see PSAR Figures 2.5.1-3 and 2.5.1-5). Subsidence of the Gulf Coast geosyncline began between Jurassic and late Cretaceous and was greatly accelerated during the Tertiary. True geosynclinal proportions were attained by the Oligocene.

The major near-surface structures in the West Gulf Coastal Plain are normal faults, some of which extend for many tens of miles. These have been called down-to-the-coast faults because the hanging wall is typically on the coastward side. Some of them have well-developed anthithetic faults.

Faulting in the West Gulf Coastal Plain can be divided into two groups--older and younger--based on the age of their formation. The older faults, located along the inner periphery of the province boundary (the Ouachita Tectonic Belt), form a belt or zone approximately 65 miles (104.6 km) wide at the nearest approach 85 miles (136.8 km northwest) of the site. The faulting is reportedly associated with the Ouachita Belt. In the site region the older, peripheral faulting is comprised of four fault zones: (1) the Balcones, (2) Luling, (3) Mexia-Talco, and (4) Charlotte-Jordanton. The Balcones is the most distant of these zones, while the Charlotte-Jordanton is the closest to the site. Coastward of these older faults is a second, younger group with similar characteristics. They are predominantly faults with a history of low-normal confining stress, termed growth faults. Such faults are found within the site and region. The growth faults are of non-tectonic origin and are characterized by steep near-surface dips, which become less steep with depth and eventually pass into bedding planes at great depth. Sediment has accumulated simultaneously with fault movement, resulting in thicker strata on the downthrown (coastward) side.

Growth faults are considered to be non-tectonic gravity-related features, formed contemporaneously with sediment deposition. They are characterized by steep, near-surface dips, which become less steep with depth and eventually pass into bedding planes at great depth. Movement on most known growth faults ceased in the Tertiary. As a result of subsequent deposition, these faults are under high lithostatic stress and, therefore, have no potential for surface displacement (for an exception see below.) Some, however, have continued to move, principally as a result of human activity (the withdrawal of groundwater and fluids associated with hydrocarbon production). Such active growth faults have not been recognized in the South Texas site region.

The applicant is assessing a recently identified alternative hypothesis suggesting deep-seated salt movement (rather than gravity inducement) as a possible causative mechanism for faulting in the site area. (See also Section 2.5.1.2 below.)

On the basis of its review, and subject to the anticipated favorable results of the applicant's on-going studies/investigations, the staff has concluded that no regional geologic hazards such as capable surface faulting, faulting reactivated by fluid extraction (groundwater or hydrocarbon) or other phenomena are a potential hazard to the South Texas project.

2.5.1.2 Site Geology

The South Texas project site is immediately adjacent to the Colorado River in Matagorda County, approximately 12 miles (19.3 km) southwest of Bay City, Texas, within the essentially featureless West Gulf Coastal Plain section of the Coastal Plain physiographic province. The Gulf of Mexico is nearly 15 miles (24 km) southeast of the site.

A Pleistocene deltaic sequence of interbedded, lenticular clays, silty clays and sands and gravels with clay interbeds of undetermined thickness underlies the critical structures area. The uppermost Pleistocene formation, the Beaumont, consists predominantly of stiff to hard clay with some silty clay layers as well as silty sand and some fine to medium sand. Total thickness of the Beaumont underlying the site has not yet been determined. The applicant is evaluating

stratigraphic studies published after the SER-CP was issued to assess the depth/age relationship of Pleistocene and older sediments underlying the plant site.

During both the CP and OL investigation phases, the applicant extensively utilized subsurface investigations--principally deep seismic reflection surveys and induction electric logs made in conjunction with hydrocarbon test wells--to define the geologic structure within 5 miles (8 km) of the plant site. Post-CP (1975) geological exploration within the site boundaries has been limited to one seismic reflection line, made in 1977, which follows the right-of-way of relocated FM 581. Because the applicant controls/owns the mineral rights, no hydrocarbon exploration wells have been made within the site boundaries. Within 5 miles of the plant site, post-CP subsurface investigations through 1984 consist of nine seismic reflection lines totaling 53 miles (85 km) in length and 18 hydrocarbon test wells with the hole depths of the successful wells generally ranging from 11,000 to 15,000 feet (3353 to 4572 m). Subsurface information obtained since the SER-CP issued, coupled with reinterpretation of selected pre-CP-SER seismic sections and well logs, has resulted in many modifications, generally minor, in the earlier (PSAR) interpretation of geologic structure within 5 miles of the plant site. For the most part, these modifications are confined to the area north and west of the site boundary where the preponderance of the recent exploration has been conducted; they consist principally of better definition of the trend (east-west) and depth (less than 1000 feet, 305 m) of the near-surface fault approximately 2.7 miles north of the plant site. Although additional faults have been identified to the west of the site boundary, no gross revisions have been made in the geologic structure within the site boundaries. Because the newly identified faults west of the site are not capable (they die out at depths exceeding 6000 feet (1,829 m) and do not project into the site area), they do not affect site safety.

To better define the age of last movement of the near-surface fault north of the site, the applicant is currently reassessing much of the existing geophysical data, principally that from the north and west of the site boundaries. Consequently, much of the information now in the FSAR relative to this area (principally figures and cross-sections) will be revised.

FSAR Figure 2.5.1-1A shows the nine post-CP seismic reflection lines and 18 hydrocarbon wells. The applicant had incorporated selected seismic reflection

records into the FSAR and is now re-reviewing at least two of the more significant seismic lines, as well as some geophysical records, acquired prior to and during the development of the PSAR (these have, for the most part, been incorporated into the PSAR). This is being done to better define the extent of the surfaceward projection of the east-west trending fault shown on FSAR Figure 2.5.1-6A. This fault approaches within at least 1000 feet (305 m) of the ground surface at about 2.7 miles north of the plant site. FSAR Figures 2.5.1-12 and 2.5.1-13, cross-sections along post-CP-SER seismic reflection lines Jaecon 2M and Jaecon 4M, respectively, show no seismic reflectors or other continuous horizons overlying this fault. Consequently, the applicant has presented no basis for determining the age of the last movement of the fault at these two locations.

The fault was initially identified through geophysical means (well logs and several seismic reflection lines) during the CP licensing investigations. At that time, the applicant's interpretation of both geophysical methods (well logs and seismic lines) indicated that the fault was capped by a well-defined seismic reflector at an approximate depth of 800 feet (244 m), as shown on PSAR Figure 2.5.1-42. The applicant reinterpreted the SER-CP data in conjunction with the post-CP-SER geophysical work (see FSAR Figure 2.5.1-7). This reinterpretation has resulted in the "flattening" of the slope of the fault so that its surfaceward projection is now some 2330 feet (711 m) north of its previously interpreted location and, as shown, it is no longer capped by the 800-foot (233 m) reflector. Because the resolution of seismic reflectors typically deteriorates as the lines approach the ground surface (this is particularly true of Jaecon Lines 2M and 4M), the applicant will examine, in great detail, the uppermost portions of well logs adjacent to the intersection of the fault with both pre- and post-CP seismic reflection lines to identify possible undisturbed horizons capping the fault along the trend of these seismic lines.

In addition to the possible identification of undisturbed horizons overlying the trend of the near-surface fault north of the site, the applicant will attempt to determine the geologic age of the horizons underlying the STP site by evaluating published stratigraphic relationships of the Pleistocene and older sediments.

In addition to the possible gravity (landslide) origin of the site area faults, as described in Section 2.5.1.1 above, another widely accepted hypothesis attempting to explain their origin suggests that the faulting developed as a consequence of the rise of salt bodies. In a 1982 report assessing the hydrocarbon potential at the site, Miller and Lents, Inc., a consultant to the applicant, indicated that, principally on the basis of gravity data, an east-west trending salt ridge south of the site may be the underlying cause of the structural features observed on and near the site. The suggestion may have merit, with salt most likely underlying the site, because three commercially exploited salt domes are located within 10 to 26 miles (16.1 to 41.8 km) of the site. Recognizing that salt masses are sporadically mobile and that this mobility has, in many cases, resulted in faulting of the overlying sediments (Jackson, 1982), the applicant is evaluating (1) the suggestion that the site area faulting may be induced by salt, which is potentially mobile, and (2) the effect of such potential movement on the integrity of the subsurface in the site area.

It is possible that the applicant will not identify any well-defined horizon of sufficient age (at least 35,000 years) demonstrating the noncapability of the fault north of the plant area. However, if this fault is determined to be capable, it would most likely present no known geologic (surface rupture) or seismologic hazard (ground motion) to the safety of the plant. If the plane of the fault is projected to the ground surface from the locations and depths presently identified through geophysical means, it is at least 2.7 miles north of the plant area, and will not outcrop at the plant site.

A small (antithetic) fault associated with this fault has been interpreted beneath the site area below the 6200-foot (1890-m) depth (as discussed in the SER-CP). This antithetic fault, well-defined by several high quality reflectors, shows no apparent offset of Oligocene strata (which is more than 20 million years old). In the extremely unlikely event that this small fault could move and propagate to the surface at or near the plant site during the life of the plant, such motion (ground movement) would be detected by the operational horizontal-vertical ground movement monitoring network established by the applicant. Such movement would be determined well in advance of any detrimental effects on the critical plant structures. (Anticipated seismic effects at the plant site resulting from the movement of this postulated fault are discussed in Section 2.5.2.3 below.)

The applicant has thoroughly investigated numerous linears, detected by a myriad of imagery systems available before the SER-CP was issued. Only two of the identified linears pass through the plant structures area. Many other linears were noted within and beyond the site boundaries and within a 5-mile (8-km) radius of the plant structures area. Extensive studies within this area, both surface and subsurface, suggested no evidence of structural control of the linears.

Where detailed post-SER-CP geologic mapping of the plant excavations coincided with the trend of the above two identified linears, the mapping confirmed the absence of structural control.

The applicant is conducting a supplemental lineament analysis, using pertinent imagery not available during the CP phase of investigations. The staff's evaluation of the results of this study will be presented in the final SER.

Regional subsidence, attributed mainly to concentrated groundwater use, has occurred, and is continuing to occur, in portions of Matagorda County (including the plant site), as well as in portions of adjacent Brazoria and Jackson Counties. Subsidence at the site and in the site region that can be attributed to the withdrawal of fluids/gasses associated with hydrocarbon production is unlikely as discussed below. In the PSAR, area subsidence in the site region was estimated to be approximately 1.3 feet (39.6 cm). This estimate was based upon 1951-1973 leveling surveys, coupled with a deep aquifer piezometric level decline of 34 feet (10.4 m) beneath the site during that time period. In 1975, the applicant estimated that the deep aquifer underlying the structures area may be subjected to an additional piezometric level decline of 87 feet (26.5 m), resulting in an approximate maximum subsidence of 3 feet (0.9 m) at the plant site between 1973 and 2020.

Considering the uncertainties associated with projections of future groundwater withdrawal, attendent gradients, and directional variability of the gradients, as well as the effect of onsite use of groundwater upon subsidence, the applicant has established a monitoring system capable of detecting both vertical and horizontal ground movements. These measurements are necessary to document subsidence and any tensional strain caused by subsidence during the life of the facility. The monitoring system--including piezometers, near-surface subsidence

monuments, and horizontal strain monuments--was fully operational by October 1976. Piezometers monitoring the deep aquifer were operational by October 1974. As of July 1984, measurements obtained through the monitoring system indicate that both net regional subsidence and net deep aquifer piezometric declines at the plant site are well below anticipated values. Horizontal strain movements have been negligible, with recorded movements falling within the accuracy limits of the survey. In the PSAR, subsidence rates at the plant site were predicted to range from 0.60 to 0.80 inch (1.52 to 2.0 cm) per year. Actual rates (measured from early 1976 through mid-1984) varied from 0.06 to 0.20 inch (0.15 to 0.5 cm) at the essential cooling pond and from 0.16 to 0.25 inch (0.41 to 0.64 cm) beneath Units 1 and 2. In the PSAR, the decline in the deep aquifer piezometric level for the 8-year period 1976 to 1984 was predicted to be 14 feet (4.27 m). However, actual readings at the plant site (Piezometer 029) indicate an increase 4 feet (1.22 m) from elevation -47 feet in July 1976 to elevation -43 in July 1984) in the deep aquifer piezometric level rather than a decline. (The net effect of subsidence and the heave and settlement associated with construction activities (excavation, backfill, and embankments) on the critical plant structures is discussed in Section 2.5.4 of this report.)

On the basis of its review, the staff has concluded that subsidence at the site resulting from the withdrawal of hydrocarbons and associated fluids from wells beyond the site boundaries is unlikely. Net subsidence (ground movements associated with groundwater withdrawal, petroleum production activities, and heave and settlement related to plant site construction activities through mid-1984) is assessed in Section 2.5.4 of this report. It is unlikely that there will be future hydrocarbon production immediately adjacent to the site boundaries, because there has been no production success over the past several years. Because the applicant has obtained all the mineral rights within the approximately 1800-acre exclusion area, there will be no hydrocarbon production within this area.

As of March 1984, 9 of the 18 post-CP hydrocarbon test wells were commercially successful. Eight of these nine commercial wells are west-northwest of the plant site, with the closest well 2.6 miles (4.2 km) from the site. The ninth well is 3.6 miles (5.8 km) east of the site. The most recent well was completed in April 1983. Because of the great depth of the wells (all are deeper than

11,000 feet (3636 m), consequent low hydrocarbon reservoir porosity, and distance to the nearest producing well (approximately 2.5 miles (4.0 km), the differential subsidence that is occasionally associated with hydrocarbon-related fluid extraction is not expected. Moreover, the plant monitoring system, which has been designed to detect both horizontal and vertical ground movements, is capable of reflecting any small movements resulting from hydrocarbon-related activities.

Hydrocarbon production closer to the site, particularly that at depths greater than 15,400 feet (5052 m) cannot be totally discounted. However, considering that a number of dry holes (one as close as 2.3 miles (3.7 km) to the west and others more distant to the southeast and south) have been completed adjacent to the site boundaries within the past several years (one as recently as November 1982), the prospects of near-site commercial production do not appear likely. Moreover, a September 1982 report by a consulting firm commissioned by the applicant, Miller and Lents, concluded that there was little likelihood that there are economically producible hydrocarbons beneath the site.

Subject to the considerations identified above, the staff has concluded that there are no identified geologic structures or other hazards at the site or in the near vicinity of the site that represent a known safety hazard to the facility or that would localize an earthquake in the proposed area.

2.5.2 Vibratory Ground Motion

In its review of the seismological aspects of the plant site, the staff has followed the tectonic province approach to determine the vibratory ground motion corresponding to the safe shutdown earthquake (SSE) (Appendix A of 10 CFR 100). The staff concluded in the SER-CP that the 0.10g acceleration used as the high frequency input to the RG 1.60 response spectrum was adequate for the South Texas site. Since the conclusion of the CP-review, more information pertaining to the geological character of the site has become available, including more detailed information on growth faults near the site. Pending the completion by the applicant's is ongoing analysis of the geological and geophysical data and a discussion of the potential influence of the growth faults identified at or near the site, the staff has maintained its original conclusions on the adequacy of the South Texas seismic design.

2.5.2.1 Seismicity

The Gulf Coastal Plain (PSAR Figure 2.5.1-5) in which the site is located is an area of infrequent and low seismicity. This observation is substantiated by the work of Barstow et al. (1981), which contains an earthquake frequency map of the U. S. east of the Rocky Mountains. This map indicates that there have been less than four earthquakes with a Modified Mercalli Intensity (MMI) greater than III within an area of 4517 mi^2 (11,700 km^2) and a time span of 177 years (1800 to 1977). Barstow et al., Dewey and Gordon (1984), and others have relocated and/or reevaluated many historical events. In response to a staff request, the applicant has provided an updated listing of historical earthquakes making use of the most recent sources. This listing includes more earthquakes than originally listed in the FSAR. However, it does not appreciably change the seismicity of the region in which the site is located. The applicant's Table 230.05N-1 indicates that within a 200-mile (321.9-km) radius of the site only 23 earthquakes were reported from 1873 to 1983. None of these occurred within 50 miles (80.5 km) of the site (applicant's Figure Q230.05N-2). Table 230.05N-2 lists earthquakes from 1699 to 1983 and within 600 miles (965.6 km) of the site that had an MMI equal to or greater than V (MMI) and/or body wave magnitudes (m_b) equal to or greater than 3.5 (m_b). In many cases, the intensities and magnitudes listed are a result of re-evaluations based on geophysical and seismological data that have become available as a result of recent studies pertaining specifically to eastern U. S. seismicity.

2.5.2.2 Tectonic Province

At the CP review, the staff discussed the characteristics of the tectonic province (Gulf Coastal Plain Tectonic Province) in which the South Texas site is located. In particular, the staff recognized four seismic zones: (1) the Mississippi Embayment Earthquake zone, (2) the Southern Cordilleran Front zone, (3) the zone at the intersection of the Ouachita Tectonic Belt and the Wichita Structural System, and (4) the Gulf Coastal Seismic Zone.

The tectonic provinces discussed in the FSAR were identical to those discussed in the PSAR (PSAR Figure 2.5.2-4). These include the Gulf Coast seismotectonic province in which the site is located, the Southern Cordillera seismotectonic

province to the west, the Llano seismotectonic province and the Ouachita seismotectonic province to the west and north, the Wichita seismotectonic province to the north, and the Sigsbee Abyssal Plain to the south. In his discussion of the tectonic map of North America, King (1969) defines the Gulf Coastal Plain as a platform deposit (Mesozoic and younger) that was laid over the deformed Paleozoic and older rocks of the Ouachita foldbelts. The platform deposits thicken and slope seaward from the exposed parts of the foldbelts, the basement descending beneath them. The continental shelves that border this extensive coastal plain are its submerged extension.

The staff recognizes that within or intersecting with the Gulf Coastal Plain tectonic province there are different regions that exhibit vastly different levels of seismicity (Comanche Peak SER, NUREG-0797; Waterford SER, NUREG-0787; and River Bend SER, NUREG-0989). These regions are: (1) The Mississippi Embayment (New Madrid) Earthquake Zone, (2) the Ouachita-Wichita belt of seismicity, and (3) the Gulf Coastal Plain tectonic province south of the buried Ouachita thrust front. A discussion of the characteristics of each of these regions follows.

2.5.2.2.1 Mississippi Earthquake Zone

Although this zone has experienced the most damaging earthquakes ever recorded in the United States (the 1811 and 1812 New Madrid, Missouri earthquakes), it need not be considered for the South Texas site because of the large distance between its southwesternmost boundary and the site. For purposes of licensing nuclear power plants, the staff adopted a conservative approach by assuming Memphis, Tennessee as the most southern termination of the Mississippi Earthquake Zone (NUREG-0989). Hence, the ground motion, induced by a recurrence of the 1812, magnitude 7.4 (m_b) New Madrid earthquake, is substantially less than the SSE ground motion, as discussed in Section 2.5.2.5.1 below.

2.5.2.2.2 Ouachita-Wichita Belt of Seismicity

The boundaries of the east-west Ouachita-Wichita belt of seismicity are subject to interpretation by various investigators. Nuttli and Brill (1981) show this east-west trending area overlapping the Nemaha Ridge Seismic Zone; the applicant's tectonic features maps show both the front of the Ouachita tectonic

belt (PSAR Figure 2.5.1-5) and the Ouachita seismotectonic province (PSAR Figure 2.5.2-4). Both maps show that the Ouachita-Wichita belt (Ouachita seismotectonic province) intersect and overlap the Gulf Coastal Plain tectonic province. Although the boundaries are somewhat ambiguous, the largest historic earthquake in the Ouachita-Wichita belt of seismicity is the October 22, 1882, earthquake that, reportedly, occurred near Paris, Texas. Estimates of its intensity range from those of Coffman and Von Hake (1973), who estimated MMI VI-VII and placed the epicenter near Fort Smith, Arkansas, to those of Docekal (1970), who estimated that it approached or possibly even reached MMI VIII and who, upon reevaluation of the data, relocated the epicenter near Paris, Texas.

A recent study of this event by Carlson (1984) both relocates the event to southern Oklahoma (34°N, 96°W) and downgrades its intensity to MMI VI. On the basis of available data, it is the staff's position that the earthquake occurred in or near the southern Oklahoma region and that its intensity was no higher than MMI VII (NUREGs-0797 and -0989). An evaluation of the event by Stover et al. (1982) corroborates this conclusion. Because this event has not been associated with a specific geologic structure, the staff assumes its occurrence at the closest approach of the Ouachita-Wichita zone to the site, which is approximately 300 miles (480 km) from the site.

2.5.2.2.3 Gulf Coastal Plain Seismicity

Seismicity in the Gulf Coastal Plain tectonic province south of the buried Ouachita tectonic belt is relatively uniform. The largest historical intensity earthquake that has not been associated with known geologic structure is the MMI VI event that was centered near Donaldsonville, Louisiana, on October 19, 1930. Carlson (1984) discusses the 1964 Hemphill-Pineland earthquake swarm and concludes that the maximum intensity of the swarm was an MMI VI event. The largest instrumentally recorded earthquake that has not been associated with known geologic structure is the m_b = 4.9 event that occurred approximately 450 miles (720 km) offshore in the Gulf of Mexico on July 24, 1978. Frohlich (1982) discusses this offshore seismicity and concludes that this and other earthquakes may be related to stresses associated with the downwarping of the lithosphere caused by the accumulation of sediments from the Mississippi River. The staff assumes that an earthquake similar to those that occurred in

Donaldsonville and the Gulf of Mexico could occur near the plant site. (Ground motion estimates from the above events are discussed in Section 2.5.2.5.3 of this report). Although the January 8, 1891, Rusk, Texas, earthquake is reported as MMI VII (Coffman and Von Hake, 1973), the area over which this event was felt is very small (it was felt only at Rusk). This led Nuttli and Brill (1981) to interpret this event as a very small magnitude ($m_b = 3.8$), shallow earthquake. The staff concurs with Nuttli and Brill and has concluded that this event should be considered as a random, shallow, small magnitude earthquake (NUREGs-0787 and -0797) that presents no significant strong motion hazard to the South Texas site.

2.5.2.3 Correlation of Earthquake Activity with Geologic Structure

The applicant has stated, and the staff concurs, that the earthquakes that have occurred in the Gulf Coastal Plain, as discussed in Section 2.5.2.2.3, cannot be associated with specific tectonic structures.

There are a number of faults identified near the South Texas site (see, for example, FSAR Figure 2.5.1-7) that are considered to be growth faults of nontectonic origin. That is, these faults are probably a result of gravity slumping or a result of fluid withdrawal.

Growth faulting has been discussed extensively in the FSAR Section 2.5.1.1.6.3.2.1, wherein the applicant concluded that, by inference, the materials in which these faults are observed are incapable of storing sufficient strain energy to cause significant ground motion upon release (fracture). The staff has requested the applicant to elaborate on the potential of the faults underneath and in the vicinity of the site by either demonstrating (1) that these faults are ancient faults overlain by undisturbed layers of material and thus considered inactive, or (2) that the materials in which the faults are identified have such geophysical properties that failure along the faults as a result of accumulated strain would not cause significant ground motion.

The issue of growth faults, the manner in which they were identified, and the evaluation of their potential for movement at or near the site is discussed in detail in Section 2.5.1.2 above.

2.5.2.4 Maximum Earthquake Potential

In addressing the maximum earthquake potential, the staff relied on the historical earthquake record provided by the applicant and the tectonic provinces discussed in Section 2.5.2.2. Because no active faults have been identified in these zones, it can be assumed (following the guidance in 10 CFR 100, Appendix A) that, for the purpose of assessing maximum earthquake potential, the maximum historical earthquake within a given tectonic province may occur anywhere in that province. The historical earthquakes, considered to be maximum events for the different tectonic provinces, are as follows:

(1) For the Mississippi Earthquake Zone, the February 7, 1812, New Madrid Missouri earthquake with MMI XI-XII and magnitude 7.4 (m_b) will be evaluated as having occurred 500 miles (880 km) from the site. (Memphis, Tennessee is conservatively considered the most southern extension of the Mississippi Earthquake Zone.)

(2) For the Ouachita-Wichita seismic zone, the October 22, 1882, Paris, Texas (or southern Oklahoma) earthquake with MMI VII MMI will be evaluated as having occurred 300 miles (480 km) from the site (the closest proximity of the adjacent tectonic province to the site).

(3) For the Gulf Coastal Plain tectonic province in which the site is located, two earthquakes are conisdered: (1) the October 19, 1930, Donaldsonville, Louisiana, earthquake with MMI VI and (2) the July 24, 1978, Gulf of Mexico event with magnitude 4.9 (m_b). The influence of these events will be evaluated as if they had occurred near the site.

2.5.2.5 Safe Shutdown Earthquake

In determining the SSE, the staff has followed the tectonic province approach described in Appendix A to 10 CFR 100. The applicant's proposed SSE acceleration level of 0.10g is used as the high frequency anchor point for an RG 1.60 response spectrum. As discussed below, this is an adequate representation of the SSE response spectra.

2.5.2.5.1 Ground Motion from New Madrid-Type Earthquake

Because of the differences in attenuation of seismic energy in the central United States in relation to the western United States, the staff places more confidence in the relationships developed by Nuttli and Herrmann (1984) because they are derived from the most recent and more complete earthquake information data set. The Nuttli and Herrmann (1984) relationships predict an average peak horizontal acceleration of 0.017g from a magnitude 7.4 (m_b) earthquake at a distance of approximately 550 miles (880 km), which is substantially less than the SSE seismic design zero period acceleration (ZPA) of 0.10g.

It should be noted that the intensity/distance relationship developed much earlier by Gupta and Nuttli (1976) predicts an intensity VI at a distance of 550 miles (880 km), which, translated into acceleration, would result in high frequency acceleration of 0.08g (Trifunac and Brady, 1976). This result, however, appears to be overly conservative in light of another study by Nuttli (1974) that contains a table summarizing the intensities recorded during the 1811 and 1812 events showing the New Orleans area having experienced an intensity V. Hence, the South Texas site would experience this level of ground motion or less from a recurrence of these events. Both the above estimates of intensity at the site would result in ground motion that is less than the SSE seismic design of 0.10g ZPA.

2.5.2.5.2 Ground Motion from the Ouachita-Wichita Belt of Seismicity

Because the largest event in the tectonic province (that on October 22, 1882) has not been correlated with a known geologic structure, the staff assumed it occurred at the closest approach of the tectonic province to the site, which is approximately 300 miles (480 km) from the site. Using the Gupta and Nuttli (1976) intensity/distance relationship, the intensity estimated at the site is equal to MMI III as a result of a recurrence of an intensity VII event in the Ouachita-Wichita zone. The resulting ground motion of 0.008g is substantially less than the SSE seismic design of 0.10g ZPA.

2.5.2.5.3 Ground Motion from the Gulf Coastal Plain Seismicity

As discussed in Section 2.5.2.2.3, the largest historical earthquake not associated with a particular geologic structure within the tectonic province is the July 24, 1978, m_b = 4.9 event, when maximum magnitude is considered, or the October 19, 1930, MMI=VI event, when maximum intensity is considered.

The applicant proposed an acceleration level for the SSE of 0.10g as the high frequency (anchor) acceleration to the RG 1.60 seismic design response spectrum. A high frequency acceleration level of 0.10g corresponds roughly to an MMI VI-VII earthquake occurring near the site, using the intensity acceleration relationship suggested by Trifunac and Brady (1975). An MMI VI-VII intensity is more conservative than the largest historical intensity of MMI VI in the Gulf Coastal Plain.

Several investigators have proposed relationships between magnitude and acceleration levels that have been recently updated. For instance, the Nuttli and Hermann (1984) relationships for a 4.9 (m_b) near-field earthquake predict an acceleration of 0.09g, assuming a Gulf Coastal Plain Q_o of 400. The Campbell (1983) relationship predicts a 50th percentile acceleration of 0.04g. In addition, the SSE seismic design of the 0.10g RG 1.60 response spectrum has been considered adequate for several other nuclear power plants situated in the Gulf Coastal Plain (Waterford SER, NUREG-0787, and River Bend SER, NUREG-0984).

On the basis of the above analyses, the staff considers the RG 1.60 response spectrum using a high frequency anchor acceleration of 0.10g adequate for the South Texas plant seismic design SSE.

2.5.2.6 Operating Basis Earthquake

The applicant has proposed an RG 1.60 response spectrum anchored to a high frequency acceleration of 0.05g for the OBE. Thus, the design vibratory ground acceleration for the OBE is one-half of the SSE design acceleration, which is consistent with the Appendix A to 10 CFR 100.

2.5.3 Surface Faulting

Post-CP site and regional subsurface information presented to date by the applicant reinforces the staff's opinion that there is no known evidence to indicate surface faulting at either the South Texas site or within 5 miles (8 km) of the plant site. The staff expects that the applicant's on-going studies will reinforce this conclusion.

The post-CP information consists of (1) the applicant's site mapping efforts; (2) the results of the examination of site excavations by geologists representing the NRC, U. S. Army Corps of Engineers, and Texas Bureau of Economic Geology; (3) structural contour maps of deep geologic horizons prepared by an independent consulting firm; and (4) the applicant's acquisition and interpretation of geophysical information developed as a result of extensive petroleum exploration.

The post-CP geophysical data within and beyond a 5-mile (8-km) radius of the South Texas project interpreted by the applicant includes (1) the reinterpretation of many previously examined electric logs and (2) approximately 23 miles (37 km) of seismic reflection profiling, as shown on FSAR Figure 2.5.2-1A. The applicant has identified an additional approximately 30 miles (40.3 km) of seismic reflection profiling within a 5-mile (8-km) radius of the plant by the applicant (FSAR Figure 2.5.1-1A). These additional data have not been acquired because, in the opinion of the staff, the extensive, high-quality geophysical information (both electric well logs and seismic reflection lines) on conditions immediately adjacent to the plant itself previously interpreted both by the applicant and by the staff adequately defined the geologic conditions in the site vicinity. A survey of all available information, both surface and subsurface, shows no evidence to support the existence of surface faulting within 5 miles (8 km) of the site. The applicant is evaluating both pre- and post-CP SER geophysical data to verify the continuity (and geologic age) of horizons overlying the projections of the near-surface growth fault about 3 miles (4.8 km) north of the plant site.

As mentioned above, one of the growth faults in the site area projects to within at least 1000 feet (305 m) of the surface about 3 miles (4.8 km) north of the plant site. An antithetic fault that intersects it at a depth of approximately

11,000 feet (3353 m) and terminates at a depth of more than 6200 feet (1840 m) would project surfaceward into the plant site area. During the CP investigations, the applicant used state-of-the-art seismic reflection methods to determine that this fault does not project above a depth of 6200 feet (1190 m). Several high quality reflection horizons were identified at and above this depth in the geologic section. These horizons are continuous, with no apparent offsets indicative of fault displacement. On this basis, the staff concluded that the antithetic fault identified in the subsurface below the site has a maximum upward extent that is approximately 6200 feet (1890 m) below the ground surface immediately beneath the site. In response to a staff request at the CP stage, the applicant projected the plane of this fault to the ground surface. Assuming a conservative range of dips for the antithetic fault plane, the projection that showed the surface intersection would be several hundred feet south of the nearest seismic Category I structure (the emergency cooling pond). This antithetic growth fault is considered to be noncapable because there is no indication, either in the geophysical records (seismic profiling and electric well logs) or in the surficial deposits to suggest a surfaceward continuation of the identified faulting above the 6200-foot (1890-m) depth. The fault is not known to cut deposits younger than the Tertiary Miocene (24 million years old).

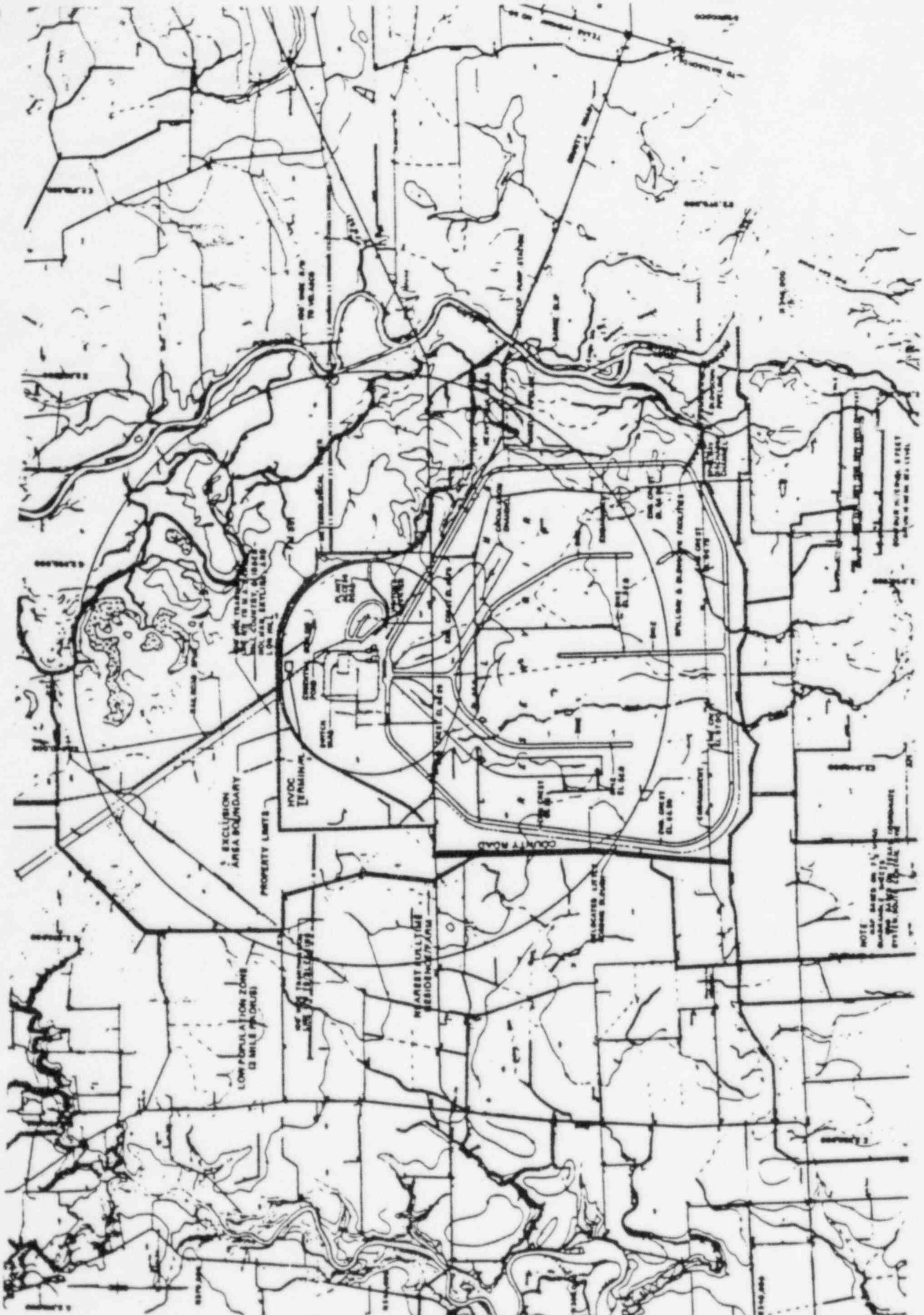

Figure 2.1 Site layout, exclusion area, low population zone, and surrounding area

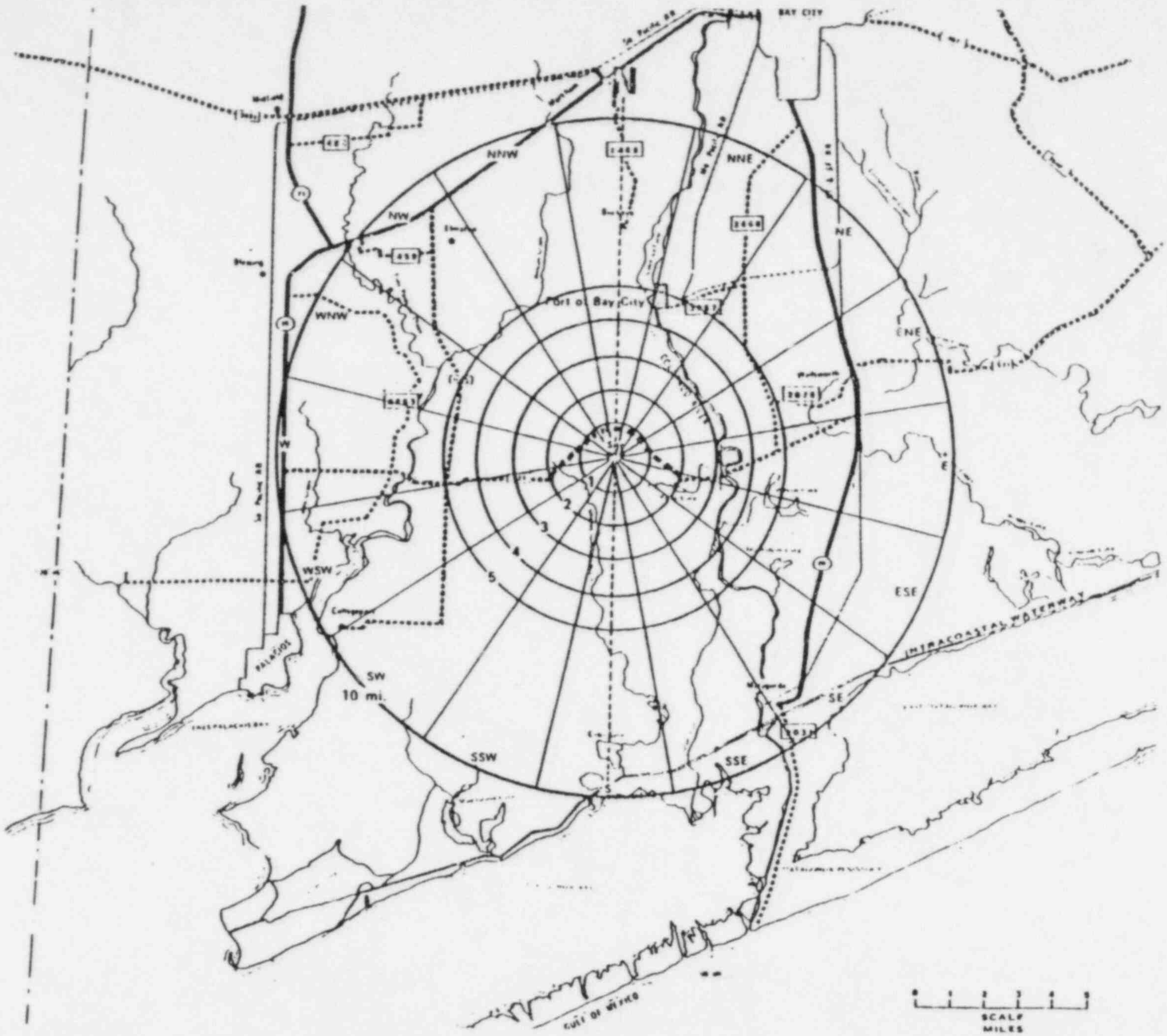

Figure 2.2 Area within 15 miles of the site

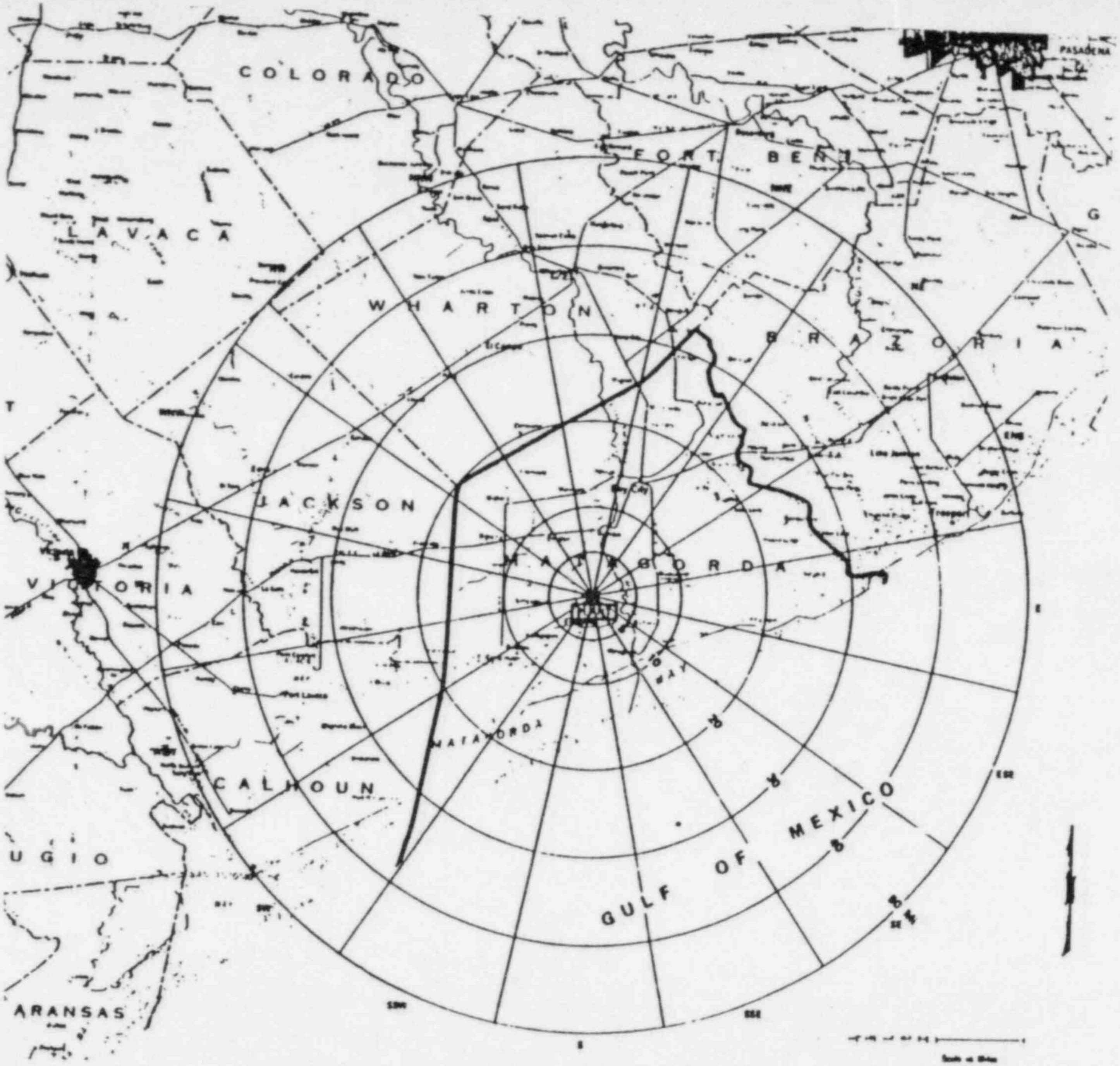

Figure 2.3 Matagorda County and the region within 75 miles of the site

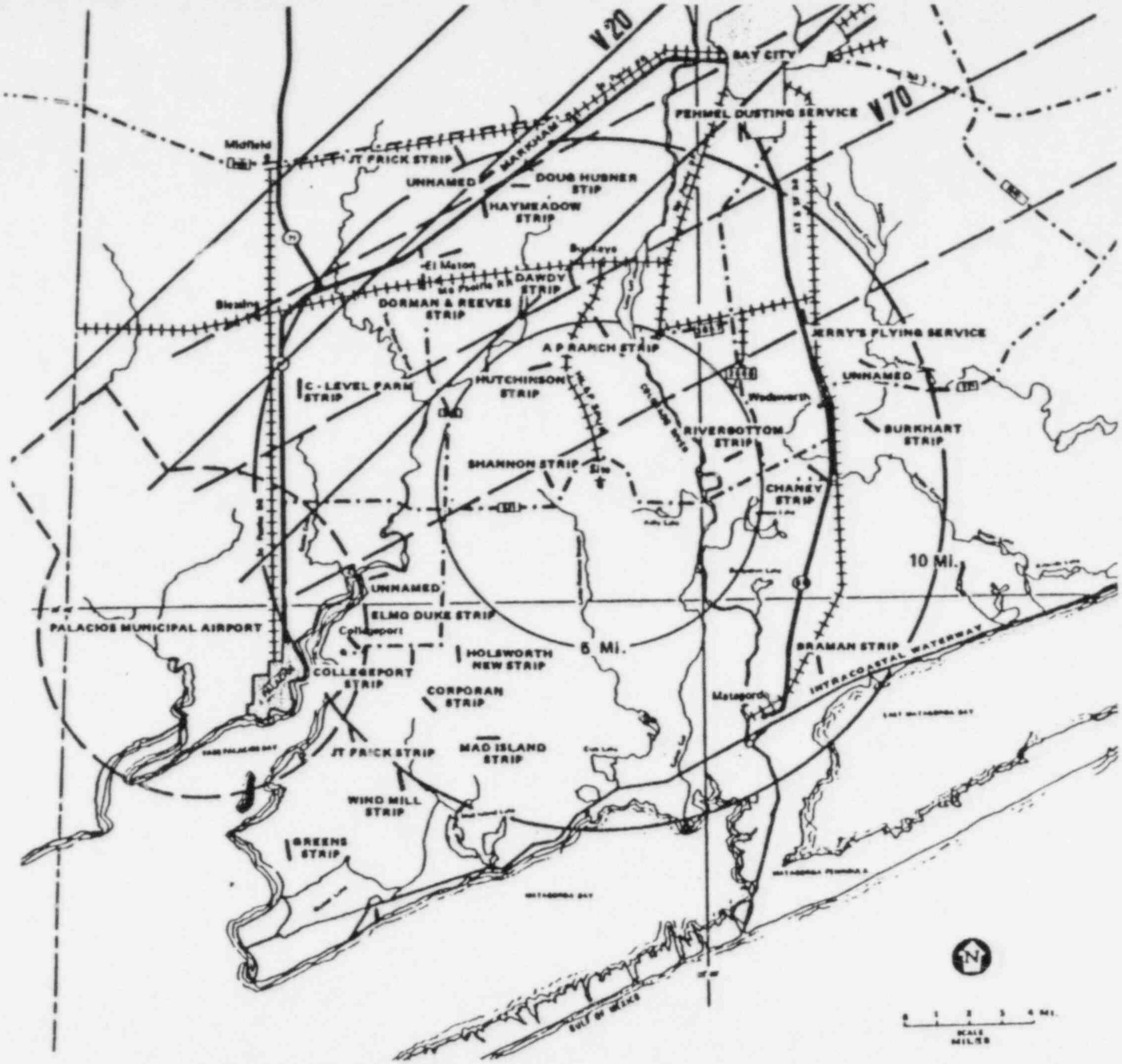

Figure 2.4 Air, water, rail, and highway transportation routes in the vicinity of the site

Table 2.1 Resident population in the site vicinity

Year	Distance from site					
	0 to 1 miles	0 to 2 miles	0 to 3 miles	0 to 4 miles	0 to 5 miles	5 to 10 miles
1980	0	28	149	273	488	3,634
1990	0	40	205	394	737	5,553
2030	0	92	468	875	1,580	12,826

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.1 General

FSAR Section 3.1 discusses conformance of structures, components, equipment, and systems to the GDC. Using this information, the staff has reviewed the final design and design criteria to verify that South Texas has been designed to meet the GDC.

The staff review of structures, components, equipment, and systems relies heavily on the application of industry codes and standards that have been used as accepted industry practice. The codes and standards cited in this report have been previously reviewed by the staff, found acceptable, and incorporated into the SRP.

3.2 Classification of Structures, Systems, and Components

TO COME

3.3 Wind and Tornado Criteria and Loadings

3.3.1 Wind Design Criteria

All seismic Category I structures exposed to wind forces were designed to withstand the effects of the design wind. The design wind specified has a velocity of 125 mph based on a 100-year mean recurrence interval.

The procedures that were used to transform the wind velocity into pressure loadings on structures and the associated vertical distribution of wind pressures and gust factors are in accordance with ANSI A58.1 and ASCE paper 3269, which are acceptable to the staff.

On the basis of its review, the staff concludes that the plant design is acceptable. It meets SRP Section 3.3.1 and GDC 2 with respect to the capability of the structures to withstand design wind loading so that their design reflects

(1) appropriate consideration for the most severe wind recorded for the site with an appropriate margin

(2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena

(3) the importance of the safety function to be performed

The applicant has met these requirements by using ANSI A58.1 and ASCE paper 3269, which the staff has reviewed and found acceptable, to transform the wind velocity into an effective pressure on structures and for selecting pressure coefficients corresponding to the structures' geometry and physical configuration.

The applicant has designed the plant structures with sufficient margin to prevent structural damage during the most severe wind loadings that have been determined appropriate for the site so that the requirements of item 1 above are met. In addition, the design of seismic Category 1 structures, as required by item 2 above, has included in an acceptable manner, load combinations that occur as a result of the most severe wind load and the loads resulting from normal and accident conditions.

The procedures used to determine the loadings on structures induced by the design wind specified for the plant are acceptable because these procedures have been used in the design of conventional structures and proven to provide a conservative basis that, together with other engineering design considerations ensures that the structures will withstand such environmental forces. The use of these procedures provides reasonable assurance that, in the event of design basis winds, the structural integrity of the plant structures that have to be designed for the design wind will not be impaired and, in consequence, safety-related systems and components located within these structures are adequately protected and will perform their intended safety functions if needed. This satisfies the requirement of item 3 above.

3.3.2 Tornado Design Criteria

All seismic Category I structures exposed to tornado forces and needed for the safe shutdown of the plant were designed to resist a tornado of 290 mph tangential wind velocity and a 70 mph translational wind velocity. The simultaneous atmospheric pressure drop was assumed to be 3 psi in 1.5 seconds. Tornado missiles are also considered in the design as discussed in Section 3.5 of this report.

The staff concludes that the plant design is acceptable and meets SRP Section 3.3.2 and GDC 2 with respect to the structure capability to withstand design tornado wind loading and tornado missiles so that their design reflects

(1) appropriate consideration for the most severe tornado recorded for the site with an appropriate margin

(2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena

(3) the importance of the safety function to be performed

The applicant has met these requirements by using ANSI A58.1 and ASCE paper No. 3269, which the staff has reviewed and found acceptable, to transform the wind velocity generated by the tornado into an effective pressure on structures and for selecting pressure coefficients corresponding to the structures geometry and physical configuration.

The applicant has designed the plant structures with sufficient margin to prevent structural damage during the most severe tornado loadings that have been determined appropriate for the site so that the requirements of item 1 above are met. In addition, the design of seismic Category I structures, as required by item 2 above, has included in an acceptable manner load combinations that occur as a result of the most severe tornado wind load and the loads resulting from normal and accident conditions.

The procedures utilized to determine the loadings on structures induced by the design-basis tornado specified for the plant are acceptable because these procedures have been used in the design of conventional structures and proven to provide a conservative basis that, together with other engineering design considerations, ensures that the structures will withstand such environmental forces.

The use of these procedures provides reasonable assurance that in the event of design-basis tornado, the structural integrity of the plant structures that have to be designed for tornados will not be impaired and, in consequence, safety-related systems and components located within these structures will be adequately protected and may be expected to perform necessary safety functions as required. This satisfies the requirement of item 3 above.

3.4 Water Level (Flood) Design

3.4.1 Floor Protection (to come)

3.4.2 Water Level (Flood) Design Procedures

The design flood level resulting from the most unfavorable condition or combination of conditions that produce the maximum water level at the site is discussed in Section 2.4 above. The hydrostatic effect of the flood was considered in the design of all seismic Category I structures exposed to the water head.

On the basis of its review, the staff concludes that the plant design is acceptable and meets SRP Section 3.4.2 and GDC 2 with respect to the capability to withstand the effects of the floor or highest groundwater level so that their design reflects

(1) appropriate consideration for the most severe flood recorded for the site with an appropriate margin

(2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena

(3) the importance of the safety function to be performed

The applicant has designed the plant structures with sufficient margin to prevent structural damage during the most severe flood or ground water and the associated dynamic effects that have been determined appropriate for the site so that the requirements of item 1 above are met. In addition, the design of seismic Category 1 structures, as required by item 2 above, has included in an acceptable manner load combinations that occur as a result of the most severe flood or groundwater-related loads and the loads resulting from normal and accident conditions.

The procedures used to determined the loads on seismic Category I structures induced by the design flood or highest groundwater level specified for the plant are acceptable because these procedures have been used in the design of conventional structures and proven to provide a conservative basis that, together with other engineering design considerations, ensures that the structures will withstand such environmental forces.

The use of these procedures provides reasonable assurance that, in the event of floods or high groundwater, the structural integrity of the plant seismic Category I structures will not be impaired and, in consequence, seismic Category I systems and components located within these structures will be adequately protected and may be expected to perform necessary safety functions, as required. This satisfies item 3 above.

3.5. Missile Protection

3.5.1 Missile Selection and Description

3.5.1.1

3.5.1.2

3.5.1.3 Turbine Missiles

The staff has reviewed South Texas Units 1 and 2 with regard to turbine missiles and concludes that the probability of unacceptable damage to safety-related systems and components due to turbine missiles to acceptably low (i.e., less than 10^{-7} per year) provided that the turbine missile generation probability is maintained to be 10^{-4} per reactor year or less for the life of the plant by an acceptable maintenance program. In reaching this conclusion, the staff has factored into consideration the favorable orientation of the turbine generator.

The staff considers the turbine missile issue as a confirmatory item if the applicant agrees to:

(1) submit for NRC approval, within 3 years of obtaining an operating license, a turbine system maintenance program based on the manufacturer's calculations of missile generation probabilities, or

(2) volumetrically inspect all low pressure turbine rotors at the second refueling outage and every other (alternate) refueling outage thereafter until a maintenance program is approved by the staff, and conduct turbine steam valve maintenance (following initiation of power output) in accordance with present NRC recommendations in SRP Section 10.2.

3.5.2 Structures, Systems, and Components To Be Protected from Externally Generated Missiles

3.5.3 Barrier Design Procedures

The seismic Category I structures, systems, and components are shielded from, or designed for, various postulated missiles. Missiles considered in the design of structures include tornado-generated missiles and various containment internal missiles, such as those associated with a loss-of-coolant accident.

The applicant has provided information indicating that the procedures that were used in the design of the structures, shields, and barriers to resist the effect of missiles are adequate. The analysis of structures, shields, and barriers to

determine the effects of missile impact was accomplished in two steps. In the first step, the potential damage that could be done by the missile in the immediate vicinity of impact was investigated. This was done by estimating the depth of penetration of the missile into the impacted structure. (Secondary missiles are prevented by fixing the target thickness well above that determined for penetration.) In the second step of the analysis, the overall structural response of the target's being impacted by a missile is determined using established methods of impact analysis. The equivalent loads of missile impact, whether the missile is environmentally generated or accidentally generated within the plant, are combined with other applicable loads, as discussed in Section 3.8 of this report.

The staff finds that the use of the modified Petry formula to evaluate local effects such as penetration is consistent with Section 3.5.3 of NUREG-75/087. Furthermore, the minimum thicknesses of missile barriers are greater than those delineated in the current SRP Section 3.5.3 (NUREG-0800).

Procedures used by the applicant to evaluate the overall response of a barrier's being impacted by a missile is based on the energy and momentum transfer considerations. These procedures are comparable to the acceptable procedure delineated in SRP Section 3.5.3 (NUREG-0800).

On the basis of its review, the staff concludes that the procedures used to determine the effects and loading on seismic Category I structures and missile shields and barriers induced by design-basis missiles selected for the plant provide a conservative basis for engineering design. These procedures, therefore, are acceptable to ensure that structures or barriers are adequately resistant to and will withstand the effects of such forces. Conformance with these procedures is an acceptable basis for satisfying, in part, GDC 2 and 4.

3.6 <u>Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping</u>

3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

3.6.2 Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping

GDC 4, "Environmental and Missile Design Bases," requires that structures, systems, and components important to safety be designed to be compatible with and to accommodate the effects of the environmental conditions as a result of normal operations, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be adequately protected against dynamic effects--including the effects of missiles, pipe whipping, and discharging fluids--that may result from equipment failures and from events and conditions outside the nuclear power plant.

The staff's review in accordance with SRP Section 3.6.2 pertains to the methodology used for protecting safety-related structures, systems, and components against the effects of postulated pipe breaks both inside and outside containment. The staff has used the review procedures identified in SRP Section 3.6.2 to evaluate the effect that breaks in high-energy fluid systems would have on adjacent safety-related structures, systems, or components with respect to jet impingement and pipe whip. The staff also reviewed the location, size, and orientation of postulated failures and the methodology used to calculate the resultant pipe whip and jet impingement loads that might affect nearby safety-related structures, systems, or components. The details of the staff's review follow.

Pipe whip need only be considered in those high-energy piping systems having fluid reservoirs with sufficient capacity to develop a jet stream. The criteria for determining high- and moderate-energy lines are in Branch Technical Position (BTP) ASB 3-1 in SRP Section 3.6.1. These criteria have been used correctly by the applicant. A list of all high-energy systems is in the FSAR.

For high-energy piping within the containment penetration area where breaks are not postulated, SRP Section 3.6.2 sets forth certain criteria for the analysis and subsequent augmented inservice inspection requirements. Breaks need not be postulated in those portions of piping within the containment penetration region that meet the requirements of the ASME Code Section III, Subarticle NE-1120

and the additional requirements outlined in BTP MEB 3-1 in SRP Section 3.6.2. Augmented inservice inspection is required for those portions of piping within the break exclusion region.

For ASME Section III Class 1 high-energy fluid system piping not in the containment penetration area, SRP Section 3.6.2 states that breaks are to be postulated at every location where the fatigue cumulative usage factor, as determined by the ASME Code, is greater than 0.1. Breaks are also to be postulated at terminal ends of piping runs and at those ASME Class 1 piping locations where the primary or secondary stress intensity range (including the zero load set) as calculated by equation (10) and either equation (12) or (13) in Paragraph NB-3653 of ASME Section III exceeds 2.4 S_m for normal and upset conditions including the OBE.

For additional environmental and mechanical protection, MEB 3-1 further requires that breaks be postulated at two locations between the terminal ends of the pipe, even if the calculated stresses and usage factors of the entire run of pipe are within the above acceptance criteria. These two locations are selected at the two highest stress locations between terminal ends of a pipe run and are identified as arbitrary intermediate breaks (AIB).

Several utilities have proposed eliminating AIB locations, citing many disadvantages. As a result of reviewing these proposals, the staff has determined that pipe rupture protection devices that are required to protect against the dynamic effects of arbitrary intermediate breaks may introduce negative effects on plant operations, and do not contribute to the plant safety as originally intended. The staff concluded that elimination of the AIB requirement for certain specified systems is warranted. All safety-related equipment near the eliminated break locations is environmentally qualified for the non-dynamic effects of a non-mechanistic pipe break with the greatest consequences on the equipment. In addition, all of the applicable piping systems will be included in the piping preoperational testing program for each plant. These systems will be monitored for vibration and thermal expansion responses as a result of startup and operational transients. The staff has approved the applicant's proposal for eliminating arbitrary intermediate breaks, as discussed in Appendix G of this SER.

The staff requires additional information on the following:

- More information and clarification are required on the criteria used for selecting postulated break locations and break types in ASME Class 1, 2 and 3 piping.

On the basis of its review of FSAR Section 3.6.2 and contingent upon the resolution of the unresolved item, the staff concludes that the pipe rupture postulation and the associated effects are adequately considered in the plant design, and, therefore, are acceptable and meet GDC 4.

The proposed pipe rupture locations have been adequately assumed and the design of piping restraints and measures to deal with the subsequent dynamic effects of pipe whip and jet impingement provide adequate protection to the structural integrity of safety-related structures, systems and components.

The provision for protection against dynamic effects associated with pipe ruptures of the reactor coolant pressure boundary inside containment and the resulting discharging fluid provide adequate assurance that design-basis loss-of-coolant accidents will not be aggravated by the sequential failures of safety-related piping, and emergency core cooling system performance will not be degraded by these dynamic effects.

The proposed piping and restraint arrangement and applicable design considerations for high- and moderate-energy fluid systems inside and outside of containment, including the reactor coolant pressure boundary, will provide adequate assurance that the structures, systems, and components important to safety that are in close proximity to the postulated pipe ruptures will be protected. The design will be of a nature to mitigate the consequences of pipe ruptures so that the reactor can be safely shut down and maintained in a safe shutdown condition in the event of a postulated rupture of a high- or moderate-energy piping system inside or outside of containment.

3.7 Seismic Design

3.7.1 Seismic Input

The horizontal peak acceleration value for the safe shutdown earthquake (SSE) chosen is 0.1g. The corresponding peak acceleration for the operating basis earthquake (OBE) is 0.05g. The vertical peak accelerations are taken as

two-thirds of the peak horizontal accelerations. Both the horizontal and vertical design response spectra comply with RG 1.60, "Design Response Spectra for Seismic Design for Nuclear Power Plants."

The specific percentage of critical damping values used in the seismic analysis of seismic Category I structures, systems, and components complies with those specified in RG 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." The only exceptions are values to be used in seismic analysis of some of the cable tray systems.

The applicant informed the staff that the seismic analysis and design of cable trays and support as an integrated structural system will incorporate damping values ranging from 7% to 15% (as opposed to maximum of 7% specified in RG 1.61 for bolted steel structures) depending on the zero-period acceleration at the locations within structures. The applicant cited a test program report, "Cable Tray & Conduit Raceway Seismic Test Program, Text Report-Release 4," dated December 15, 1978, as a basis for this position. The tests were conducted by ANCO Engineers, Inc. with Bechtel Power Corporation.

At an audit meeting during the week of January 7, 1985, the staff requested that the applicant provide information to demonstrate that the cable tray and support system is like the cable tray/support system used in the Bechtel/ANCO testing program. In a letter dated May 16, 1985, the applicant compared the following parameters for the two systems: (1) seismic input motion, (2) natural frequencies of cable tray and supports, (3) material and connections for supports, (4) type of tray, (5) method of securing cables, (6) cable tray loading, (7) configuration of supports, and (8) types of fire proofing. The staff has reviewed these comparisons between the tested parameters and the South Texas cable tray and support system parameters and finds that the South Texas cable tray system is well represented by the test program. Therefore, the use of 7% to 15% damping is acceptable. (The staff has adopted similar positions for cable tray systems of other plants when a similarity between the tested system and the plant system has been demonstrated).

The synthetic time history used for seismic design of Category I plant structures, systems, and components is adjusted in amplitude and frequency content

to obtain response spectra that envelope the response spectra specified for the site.

The seismic Category I structures at South Texas are founded on the support media consisting of alternating layers of stiff to hard clays and dense silts and sand which extend to depths of several thousand feet. The embedment depths of various Category I structures ranges from approximately 4 feet to 59 feet.

On the basis of its review, the staff concludes that the seismic design parameters used in the plant structure design are acceptable and meet SRP Section 3.7.1, GDC 2, and Appendix A to 10 CFR 100.

3.7.2 Seismic System Analysis

This review is combined with that in Section 3.7.3 below.

3.7.3 Seismic Subsystem Analysis

The scope of review of the seismic system and subsystem analysis for the plant included the seismic analysis methods for all Category I structures, systems, and components. It included review of procedures for modeling, seismic soil-structure interaction, development of floor response spectra, inclusion of torsional effects, evaluation of Category I structure overturning, and determination of composite damping. The review has included design criteria and procedures for evaluation of interaction of nonseismic Category I structures with seismic Category I structures and effects of parameter variations on floor response spectra. The review has also included criteria and seismic analysis procedures for reactor internals and Category I buried structures outside the containment.

The system and subsystem analyses were performed by the applicant on an elastic and linear basis. Modal time history multidegree of freedom methods form the bases for the analyses of all major Category I structures, systems, and components. When the modal response spectrum method was used, governing response parameters were combined in conformance with the position of RG 1.92, "Combining

Modal Responses and Spatial Components in Seismic Response Analyses." The square root of the sum of the squares of the maximum codirectional responses was used in accounting for three components of the earthquake motion. (The component factor method has also been used for this purpose).

Floor spectra inputs used for design and test verifications of structures, systems, and components were generated from the time history method, taking into account variation of parameters by peak widening. A vertical seismic system dynamic analysis is employed for all structures, systems, and components where analyses show significant structural amplification in the vertical direction. Torsional effects and stability against overturning are considered.

The inertial effects of an earthquake on buried systems and tunnels have been adequately accounted for in the analysis. The principles used to account for the effects of static resistance of the surrounding soil on buried system deformations were based on the theory of structures on elastic foundations and they are acceptable.

The applicant has used two-step finite element analysis to account for the soil-structure interaction (SSI) effects for the major Category I structures. In the first step, translational and rotational responses (acceleration) at the soil/foundation interface are obtained through a use of two-dimensional plane-strain finite element model. In the second step, the interface accelerations are applied to a fixed-base, detailed, 3-dimensional structural models to obtain the floor spectra and responses for the structural design. The applicant performed additional SSI analysis using elastic half-space methodology and a single-step finite element analysis to achieve the following objectives:

(1) to comply with the staff position that requires that the SSI analysis include both elastic half-space (EHS) and finite element approaches for all seismic Category I structures founded on soil (SRP Section 3.7.1, NUREG-0800). Further, these seismic Category I structures should be designed to responses obtained by any of the following methods:

    (a) an envelope of results of the two methods

(b) the results of one method with conservative design considerations of impact from use of the other methods

(c) a combination of (a) and (b) with provision of adequate conservatism in design

(2) to evaluate the effect of structural configuration changes on the floor spectra

(3) to evaluate the effect of the floor flexibility on the vertical responses

The results of the EHS analysis indicate that the two-step finite element model (FEM) vertical spectra envelope EHS vertical spectra for all buildings. For the horizontal direction, FEM spectra envelope EHS spectra, except in the low frequency range. The applicant has investigated the structures, components, and equipment falling in the low frequency range, and has noted that the affected components have been able to comply with options 1(a), (b), or (c) above. On this basis, the staff concludes that the STP design has complied with SRP Section 3.7.1 (item (1) above).

Both the EHS and single-step FEM analyses indicate that the two-step FEM results are artificially sensitive to changes in structural configuration and are overly conservative. Therefore, the staff concludes that two-step FEM spectra are adequate and need not be revised to reflect changes in the structural configuration.

The vertical response analyses based on EHS method indicates that the vertical response spectra are not affected if the fundamental vertical frequency of the floor subsystem exceeds 12 Hz. The applicant expects to confirm that frequencies of floor subsystems in each building are higher than the corresponding limit. The staff reviewed and discussed the applicant's vertical analysis at the structural audit and found that the applicant's approach to account for the vertical floor flexibility is adequate and reasonable. Pending the confirmation of the frequencies of the floor systems in seismic Category I buildings, the staff considers the issue regarding the vertical floor flexibility resolved.

The current staff position requires that an additional eccentricity effect based on a consideration of ± 5% of the maximum building dimension at the level under consideration shall be assumed to account for accidental torsion. The applicant's original analysis of seismic Category I structures did not account for the accidental torsional effects. However, the applicant has now analyzed all seismic Category I structures to assess effects on the plant structures that might result from the implementation of the staff position. The results of the applicant's analyses (provided by a letter dated May 16, 1985) indicate that the critical wall sections for all structures have adequate capacity and/or reinforcement to resist additional shear forces resulting from the consideration of the accidental torsion. On the basis of this information, the staff concludes that the applicant has met the intent of the current staff requirement and, therefore, this issue is resolved.

The applicant's seismic analysis of the turbine building indicates that the turbine building remains elastic when subject to SSE loads (RG 1.60 spectra anchored at 0.1g). The resultant members forces are within the allowable loads. The staff discussed the applicant's analysis and reviewed results during the structural audit. The staff finds that the turbine building has been shown to be safe against collapse during the postulated SSE event and, therefore, this issue is considered resolved.

During the audit (on January 7, 1985), the staff reviewed the seismic analysis of the reactor water storage tank (RWST) in detail. The staff found that the RWST is adequate to withstand hydrodynamic loads resulting from seismic excitation including the tank wall flexibility effects.

Pending the confirmation of the vertical floor flexibilities, the staff concludes that the plant design is acceptable and meets SRP Sections 3.7.2 and 3.7.3, GDC 2, and Appendix A to 10 CFR 100 with respect to the capability of the structures to withstand the effects of the earthquakes. The plant design reflects

(1) appropriate consideration for the most severe earthquake recorded for the site with an appropriate margin (GDC 2), and consideration of two levels of earthquakes (Appendix A, 10 CFR 100)

(2) appropriate combination of the effects of normal and accident conditions with the effect of the national phenomena

(3) the importance of the safety functions to be performed (GDC 2), and the use of a suitable dynamic analysis or a suitable qualification test to demonstrate that structures, systems, and components can withstand the seismic and other concurrent loads, except where it can be demonstrated that the use of an equivalent static load method provides adequate consideration (Appendix A, 10 CFR 100).

The applicant has met the requirements of item 1 above by use of the acceptable seismic design parameters, per SRP Section 3.7.1. The combination of earthquake-resultant loads with those resulting from normal and accident conditions in the design of seismic Category I structures, as specified in SRP Sections 3.8.1 through 3.8.5, will conform with item 2 above.

3.7.4 Seismic Instrumentation Program

The type, number, location, and utilization of strong motion accelerographs to record seismic events and to provide data on the frequency, amplitude and phase relationship of the seismic response of the containment structure comply with the intent of RG 1.12, "Instrumentation for Earthquakes." The staff is currently reviewing a minor deviation from RG 1.12 and will report its findings. Instrumentation is being installed on Category I structures, systems, and components to provide data for the verification of the seismic responses determined analytically for such Category I items.

The applicant has met the intent of SRP Section 3.7.4 except that a seismic instrumentation surveillance scheme has not yet been provided. However, in accordance with stated staff requirements, such a scheme will be incorporated in the Technical Specifications. The applicant has met 10 CFR 100, Appendix A by providing the instrumentation that is capable of measuring the effects of an earthquake, which meets GDC 2. The applicant will meet 10 CFR 50.55a by providing an inservice inspection program that will verify operability by performing channel checks, calibrations, and functional tests at acceptable intervals. In addition, the installation of the specific seismic instrumentation on

the reactor containment structure and at other seismic Category I structures, systems, and components constitutes an acceptable program to record data on seismic ground motion as well as data on the frequency and amplitude relationship of the seismic response of major structures and systems. A prompt readout of pertinent data at the control room can be expected to yield sufficient information to guide the operator on a timely basis for the purpose of evaluating the seismic response in the event of an earthquake. Data obtained from such installed seismic instrumentation will be sufficient to determine that the seismic analysis assumptions and the analytical model used for the design of the plant are adequate and that allowable stresses are not exceeded under conditions where continuity of operation is intended. Provision of such seismic instrumentation complies with the intent of RG 1.12.

3.8 Design of Seismic Category I Structures

3.8.1 Concrete Containment

The reactor coolant system is enclosed in a steel-lined, post-tensioned reinforced-concrete containment, as described in FSAR Section 3.8.1. The containment structure was designed, primarily, in accordance with the American Concrete Institute (ACI) "Proposed Standard Code for Concrete Reactor Vessels and Containments," ACI 359-ASME Code, Section III, Division 2, issued for trial use and comments in 1973 and, with ASC-1969. It was designed to resist various combinations of dead loads; live loads; environmental loads including those resulting from wind, tornadoes, the OBE, and the SSE; and loads generated by the design-basis accident, including pressure, temperature, and associated pipe rupture effects.

A continuous-weld, steel liner plate is provided on the entire inside face of the containment to limit the release of radioactive materials into the environment. The thickness of the liner in the wall and dome is 3/8 inch. A 3/8-inch-thick plate is used on top of the foundation mat and is covered with a 24-inch concrete fill slab.

The cylindrical portion and the hemispherical dome of the containment are prestressed by a post-tensioning system that consists of horizontal and vertical

tendons. Three buttresses are equally spaced 120 degrees apart, around the containment. The cylinder and the lower half of the dome are prestressed by horizontal tendons anchored 360 degrees apart, bypassing the intermediate buttresses. Each successive hoop tendon is progressively offset 120 degrees from the one beneath it. The vertical U-shaped tendons are continuous over the dome, forming a two-way system for the dome. These tendons are anchored in the continuous gallery beneath the base mat.

The staff position in Section 3.8.1 of NUREG-75/087 accepts the proposed ACI Code with some exceptions. These exceptions are related to the tangential shear criteria, principal tensile stress criteria, and allowable increase in stresses for wind and OBE load conditions. The applicant has indicated that the tangential shear design is in accordance with ASME Code Case N-250 for a prestressed concrete containment. The staff finds the use of Code Case N-250 acceptable. The applicant has complied with the allowable stress requirement specified by the staff in NUREG-75/087 regarding OBE and wind load conditions. The applicant has not relied on concrete tensile strength.

The applicant has taken several exceptions to the proposed code in the area of authorization and stamping requirement, personnel qualifications for Level III inspection engineers, criteria for radial stress, and testing frequency for cadweld splices. The staff is currently reviewing these exceptions.

The staff is also reviewing the applicant's exceptions to criteria for MC component design.

Pending the satisfactory review of the above exceptions, the staff concludes that the applicant has met 10 CFR 50.55a and GDC 1 with respect to ensuring that the concrete containment is designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with its safety function by meeting the regulatory guides and industry standards indicated below.

The applicant has met GDC 2 by designing the concrete containment to withstand the most severe earthquake that has been established for the site with sufficient margin and the combinations of the effects of normal and accident conditions

with the effects of environmental loadings such as earthquakes and other natural phenomena.

The applicant has met GDC 4 by ensuring that the design of the concrete containment is capable of withstanding the dynamic effects associated with missiles, pipe whipping, and discharging fluids.

The applicant has met GDC 16 by designing the concrete containment so that it is an essentially leaktight barrier to prevent the uncontrolled release of radioactive effluents to the environment.

The applicant has met GDC 50 by designing the concrete containment to accommodate, with sufficient margin, the design leakage rate, calculated pressure and temperature conditions resulting from accident conditions, and by ensuring that the design conditions are not exceeded during the full course of the accident condition. In meeting these design requirements, the applicant has used the recommendations of regulatory guides and industry standards.

The criteria used in analysis, design, and construction of the concrete containment structure to account for anticipated loadings and postulated conditions that may be imposed upon the structure during its service life-time are in conformance with established criteria, and with codes, stan-dards, guides, and specifications acceptable to the Regulatory staff. These include meeting the intent of positions of RGs <u>1.10</u>; <u>1.15</u>; <u>1.18</u>; <u>1.19</u>; <u>1.35</u>; "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures"; 1.55; and <u>1.103</u>; and ASME Code Section III, Division 2, 1973 (proposed code).

The use of criteria as defined above provides reasonable assurance that, in the event of winds, tornadoes, earthquakes and various postulated accidents occurring within and outside of the con-tainment, the structure will withstand the specified design conditions without impairment of structural integrity or safety function of limiting the release of radioactive material.

3.8.2 Steel Containment

Because the South Texas units have concrete containments, this SRP Section is not applicable.

3.8.3 Concrete and Structural Steel Internal Structures

The containment interior structures consist of reinforced concrete and steel framed walls, compartments and floors. The major code used in the design of concrete internal structures was ACI 318-71, "Building Code Requirements for Reinforced Concrete."

Steel internal structures were designed in accordance with the AISC, "Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings," 1969 edition.

The current staff position requires that the concrete internal structure should be designed in accordance with the ACI-349, "Requirements for Nuclear Safety-related Structures," as amplified by RG 1.142, "Safety-Related Concrete Structures for Nuclear Power Plants." By a letter dated May 16, 1985, the applicant provided a comparison between South Texas design criteria (ACI 318-71) and ACI 349-76 and RG 1.142 to assess the impact of the current staff position on STP structural design (other than containments).

These comparisons indicate that the South Texas design, in general, meets the intent of the current staff requirement. In particular, the controlling load combinations for the design are same as those currently required by the staff. How-ever, the applicant's criteria for welded anchor studs, grouted rock-bolts, and anchor bolts for certain applications are being reviewed.

Pending the satisfactory resolution of the unresolved items, the staff concludes that the design of the containment internal structures is acceptable and meets the relevant requirements of 10 CFR 50.55a and GDC 1, 2, 4, 5, and 50.

The applicant has met 10 CFR 50.55a and GDC 1 with respect to ensuring that the containment internal structures are designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with their safety function to be performed by meeting regulatory guides and industry standards.

The applicant has met GDC 2 by designing the containment internal structure to withstand the most severe earthquake that has been established for the site with sufficient margin and the combinations of the effects of normal and accident conditions with the effects of environmental loadings such as earthquakes and other natural phenomena.

The applicant has met GDC 4 by ensuring that the design of the internal structures are capable of withstanding the dynamic effects associated with missiles, pipe whipping, and discharging fluids.

The applicant has met GDC 5 by demonstrating that structure systems and components are not shared between units or that if shared they have demonstrated that sharing will not impair their ability to perform their intended safety function.

The applicant has met GDC 50 by designing the containment internal structures to accommodate, with sufficient margin, the design leakage rate and calculated pressure and temperature conditions resulting from accident conditions and by ensuring that the design conditions are not exceeded during the full course of the accident condition. In meeting these design requirements, the applicant has used the recommendations of regulatory guides and industry standards. The applicant has also performed appropriate analyses that demonstrate that the ultimate capacity of the structures will not be exceeded and establish the minimum margin of safety for the design.

The criteria used in the design, analysis, and construction of the containment internal structures to account for anticipated loadings and postulated conditions that may be imposed during their service lifetime are in conformance with established criteria, codes, standards, and specifications acceptable to the staff. These include meeting the intent of positions of RGs 1.57, "Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components,"

and 1.142 and the following industry standards: ACI-349; ASME Code Section III, Division 2, "Code for Concrete Reactor Vessels and Containments"; ASME Code Section III, Subsections NE and NF"; AISC "Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings"; and ANSI N45.2.5.

The use of criteria as defined or described above provides reasonable assurance that, in the event of earthquakes and various postulated accidents occurring within the containment, the interior structures will withstand the specified design conditions without impairment of structural integrity or the performance of required safety functions.

3.8.4 Other Seismic Category I Structures

The other seismic Category I structures at the South Texas project are

(1) mechanical-electrical auxiliaries building

(2) diesel generator building

(3) fuel handling building

(4) essential cooling water intake structure

(5) essential cooling water discharge structure

(6) Class 1E underground electrical raceway system

(7) auxiliary feedwater storage tank

The seismic Category I structures other than the containment and its interior structures are structural steel and/or concrete. The structural components consist of slabs, walls, beams, and columns. The major code used in the design of concrete seismic Category I structures was ACI 318-71. For steel seismic Category I structures, the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings" was used.

The concrete and steel Category I structures were designed to resist various combinations of dead and live loads; environmental loads including winds, tornadoes, the OBE, and the SSE; and loads generated by postulated ruptures of high-energy pipes such as reaction and jet impingement forces, compartment pressures, and the impact of whipping pipes.

The current staff positions requires that the concrete internal structure should be designed in accordance with ACI-349, "Requirements for Nuclear Safety-Related Structures," as amplified by RG 1.142. By letter dated May 16, 1985, the applicant compared the South Texas design criteria (ACI 318-71) and ACI 349-76 and RG 1.142 to assess the impact of the current staff position on structural design (other than containments).

These comparisons indicated that the South Texas design, in general, has met the intent of the current staff requirements. In particular, the controlling load combinations for the design are same as those currently required by the staff. However, the applicant's criteria for welded anchor studs, grouted rock-bolts, and anchor bolts for certain applications are currently under review.

Pending the satisfactory resolution of the unresolved items, the staff concludes that the design of the containment internal structures is acceptable and meets the relevant requirements of 10 CFR 50.55a and GDC 1, 2, 4, 5, and 50.

The applicant has met 10 CFR 50.55a and GDC 1 with respect to ensuring that the containment internal structures are designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with their safety function to be performed by meeting the regulatory guides and industry standards indicated below.

The applicant has met GDC 2 by designing the safety-related structures other than the containment to withstand the most severe earthquake that has been established for the site with sufficient margin and the combinations of the effects of normal and accident conditions with the effects of environmental loadings such as earthquakes and other natural phenomena.

The applicant has met GDC 4 by ensuring that the design of the safety-related structures is capable of withstanding the dynamic effects associated with missiles, pipe whipping and discharging fluids.

The applicant has met GDC 5 by demonstrating that structures, systems, and components are not shared between units or that, if shared, they have demonstrated that sharing will not impair their ability to perform their intended safety function.

The applicant has met the requirements of 10 CFR 50, Appendix B in this area because the quality assurance program provides adequate measures for implementing guidelines relating to structural design audits.

The criteria used in the analysis, design, and construction of all the plant's seismic Category I structures to account for anticipated loadings and postulated conditions that may be imposed upon each structure during its service lifetime are in conformance with established criteria, codes, standards, and specifications acceptable to the staff. These include meeting the positions of RG 1.142, ACI-349, and the AISC "Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings."

The use of these criteria as defined or described above provides reasonable assurance that, in the event of winds, tornadoes, earthquakes, and various postulated accidents occurring within the structures, the structures will withstand the specified design conditions without impairment of structural integrity or the performance of required safety functions.

3.8.5 Foundations

Foundations of seismic Category I structures are described in FSAR Section 3.8.5. Primarily, these foundations are reinforced concrete of the mat type. The major code used in the design of these concrete mat foundations was ACI 318-71. These concrete foundations have been designed to resist various combinations of dead loads; live loads; environmental loads resulting from wind, tornado, and seismic effects; and the loads postulated by ruptures of nigh-energy pipes.

The current staff position requires that the concrete internal structure be designed in accordance with the ACI-349, as amplified by RG 1.142. By a letter dated May 16, 1985, the applicant compared the South Texas design criteria (ACI 318-71) and ACI 349-76 and RG 1.142 to assess the impact of the current staff position on the South Texas structural design (other than containments).

These comparisons indicate that the South Texas design, in general, has met the intent of the current staff requirement. In particular, the controlling load combinations for the design are same as those currently required by the staff. However, the applicant's criteria for welded anchor studs, grouted rock-bolts, and anchor bolts for certain applications are currently under review.

Pending the satisfactory resolution of the unresolved items, the staff concludes that the design of the containment internal structures is acceptable and meets the relevant requirements of 10 CFR 50.55a and GDC 1, 2, 4, 5, and 50.

The applicant has met 10 CFR 50.55a and GDC 1 with respect to ensuring that the containment internal structures are designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with their safety function to be performed by meeting the guidelines of regulatory guides and industry standards indicated below.

The applicant has met GDC 2 by designing the seismic Category I foundation to withstand the most severe earthquake that has been established for the site with sufficient margin and the combinations of the effects of normal and accident conditions with the effects of environmental loadings such as earthquakes and other natural phenomena.

The applicant has met GDC 4 by ensuring that the design of seismic Category I foundations is capable of withstanding the dynamic effects associated with missiles, pipe whipping, and discharging fluids.

The applicant has met GDC 5 by demonstrating that structure systems and components either are not shared between units or that, if shared, they have demonstrated that sharing will not impair their ability to perform their intended safety function.

The use of these criteria as defined or described above provides reasonable assurance that, in the event of winds, tornadoes, earthquakes, and various postulated events, seismic Category I foundations will withstand the specified design conditions without impairment of structural integrity and stability or the performance of required safety functions.

3.8.6 Structural Audit

From January 7 through January 11, 1985, the staff met with the applicant and the applicant's consultants to conduct the seismic and structural audit. The audit covered major safety-related structures.

The staff conducted the audit to

(1) investigate in detail the implementation of the structural and seismic design criteria committed to by the applicant before construction permits were issued for the facility

(2) verify that the key structural and seismic design and the related calculations have been done in an acceptable way.

(3) identify and assess the safety significance of the areas where the plant structures were designed and analyzed using methods other than those recommended by the NRC Standard Review Plan (NURG-0800).

As a result of the audit, the staff identified several action items consolidating all the outstanding issues relative to the adequacy of the South Texas structural design. The review and evaluation of the information resulting from these action items provided a basis for the conclusions discussed above.

3.9 Mechnical Systems and Components

The review performed under SRP Sections 3.9.1 through 3.9.6 (NUREG-0800) pertains to the structural integrity and functional capability of various safety-related mechanical components in the plant. The staff's review is not limited to ASME Code components and supports, but is extended to other components such as control rod drive mechanisms, certain reactor internals, and any safety-

related piping designed to industry standards other than the ASME Code. The staff reviews such issues as load combinations, allowable stresses, methods of analysis, summary of results, and preoperational testing. The staff's review must arrive at the conclusion that there is adequate assurance of a mechanical component performing its safety-related function under all postulated combinations of normal operating conditions, system operating transients, postulated pipe breaks, and seismic events.

3.9.1 Special Topics for Mechanical Components

The staff has reviewed the design transients and methods of analysis used for all seismic Category I components, component supports, core support structures, and reactor internals designated as Class 1 and CS under the ASME Code, Section III, and those not covered by the Code. The assumptions and procedures used for the inclusion of transients in the fatigue evaluation of ASME Code Class 1 and CS have been reviewed. The staff's review also covered the computer programs used in the design and analysis of seismic Category I components and their supports, as well as experimental and inelastic analytical techniques.

The applicant has provided a list of the design transients and the number of cycles for each of the design transients.

The applicant used computed codes to analyze mechanical components. A list showing all computer programs used by the applicant for static and dynamic analyses to determine the structural integrity and functional integrity of seismic Category I Code and non-Code items, and the analyses to determine stresses, along with a description of the program, is included in the FSAR. Design control measures to verify the adequacy of the design of safety-related components are required by 10 CFR 50, Appendix B.

An experimental stress analysis method is used for essential cooling water underground aluminum bronze piping by the applicant.

On the basis of its review of FSAR Section 3.9.1, the staff concludes that the design transients and resulting loads and load combinations with appropriate

specificed design and service limits for mechanical components and supports are acceptable and meet GDC 1, 2, 14, and 15; 10 CFR 50, Appendix B; and 10 CFR 50, Appendix A.

The applicant has met GDC 14 and 15 by demonstrating that the design transients and resulting loads and load combinations with appropriate specified design and service limits that the applicant has used for designing Code Class 1 and CS components and supports and reactor internals provide a complete basis for design of the reactor coolant pressure boundary for all conditions and events expected over the service lifetime of the plant.

The applicant has met GDC 2 and 10 CFR 100, Appendix A by including seismic events in design transients that serve as design bases to withstand the effects of natural phenomena.

The applicant has met 10 CFR 50, Appendix B and GDC 1 by having submitted information that demonstrates the applicability and validity of the design methods and computer programs used for the design and analysis of seismic Category I Code Class 1, 2, 3, and CS structures and non-Code structures within the present state-of-the-art limits and by having design control measures that are acceptable to ensure the quality of the computer programs.

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

The staff has reviewed the methodology, testing procedures, and dynamic analyses employed by the applicant to ensure the structural integrity and functionality of piping systems, mechanical equipment, and their supports under vibratory loadings. The staff's review included (1) the piping vibration, thermal expansion, and dynamic effect testing; (2) the seismic system analysis methods; (3) the dynamic responses of structural components within the ractor caused by steady-state and operational flow transient conditions for nonprototype reactors; (4) flow-induced vibration testing of reactor internals to be conducted during the preoperational and startup test program; and (5) the dynamic analysis methods used to confirm the structural design adequacy and functional capability of the reactor internals and piping attached to the reactor vessel when subjected to loads from a loss-of-coolant-accident (LOCA) in combination with a safe shutdown earthquake (SSE).

3.9.2.1 Piping Preoperational Vibration and Dynamic Effects Testing

Piping vibration, thermal expansion, and dynamic effects testing will be conducted during a preoperational testing program. The purpose of these tests is to ensure that the piping vibrations are within acceptable limits and that the piping system can expand thermally in a manner consistent with the design intent. During the plant's preoperational and startup testing program, the applicant will test various piping systems for abnormal, steady-state, or transient vibration and for restraint of thermal growth. Systems to be monitored will include (1) ASME Code Class 1, 2 and 3 piping systems; (2) high energy piping systems inside seismic Category I structures; (3) high energy portions of systems whose failure could reduce the functioning of seismic Category I plant features to an unacceptable safety level; and (4) seismic Category I portions of moderate energy piping systems located outside containment. Steady-state vibration, whether flow-induced or caused by nearby vibrating machinery, could cause 10^8 or 10^9 cycles of stress in the pipe during the 40-year life of the plant. For this reason, the staff requires that the stresses associated with steady-state vibration be minimized and limited to acceptable levels. The test program will consist of a mixture of instrumented measurements and visual observations by qualified personnel.

On the basis of its review of FSAR Section 3.9.2.1, the staff concludes that the applicant has met GDC 14 and 15 with respect to the design and testing of the reactor coolant pressure boundary. This provides reasonable assurance that rapidly propagating failure and gross rupture will not occur as a result of vibratory loadings. In addition, the testing ensures that design conditions are not exceeded during normal operation -- including anticipated operational occurrences -- by having an acceptable vibration, thermal expansion, and dynamic effects test program that will be conducted during startup and initial operation of specified high and moderate energy piping, including all associated restraints and supports. The tests provide adequate assurance that the piping and piping supports have been designed to withstand vibrational dynamic effects as a result of valve closures, pump trips, and other operating modes associated with the design-basis flow conditions. In addition, the tests provide assurance that adequate clearances and free movement of snubbers exist for unrestrained thermal movement of

piping and supports during normal system heatup and cooldown operations. The planned test will develop loads similar to those experienced during reactor operations.

3.9.2.2 Seismic Subsystem Analysis

Areas reviewed were seismic analyses methods, determination of the number of earthquake cycles, basis for selection of frequencies, the combination of modal responses and spatial components of an earthquake, criteria used for damping, torsional effects of eccentric masses, interaction of other piping with seismic Category I piping, and Category I buried piping systems.

The scope of the review of the seismic system and subsystem analysis includes the seismic analysis methods for all seismic Category I piping systems and components. The staff has reviewed the manner in which the dynamic system analysis is performed, the method of selection of significant modes, whether the number of masses or degrees of freedom is adequate, and how consideration is given to maximum relative displacements. The review included design methodologies and procedures used for the evaluation of the interaction of nonseismic Category I piping with seismic Category I piping, and the seismic methods that consider the effect of movement at support points, penetration, and anchors for seismic Category I buried piping systems. In addition, the staff reviewed seismic analysis procedures for reactor internals. The system and subsystem analyses are performed by the applicant on an elastic basis. Modal response spectrum, multi-degree of freedom, and time history methods form the basis for the analyses of all major seismic Category I systems and components. When the response spectrum method is used, modal responses are combined by the square-root-sum-of-the-squares (SRSS) rule.

For the dynamic analysis of seismic Category I piping, each piping system was idealized as a mathematical model consisting of lumped masses connected by elastic members. The stiffness matrix for the piping system was determined using the elastic properties of the pipe. This includes the effects of torsional, bending, shear, and axial deformations as well as change in stiffness due to curved members. Next, the mode shapes and the undamped natural frequencies were obtained.

The dynamic response of the system was calculated by using the response spectrum method of analysis. For a piping system that was supported at points with different dynamic excitations, the response analysis was performed using an enveloped response spectrum.

On the basis of its review of FSAR Sections 3.7.3A and 3.7.3B, the staff concludes that the applicant has met GDC 2 with respect to demonstrating the design adequacy of all seismic Category I piping systems, components, and their supports to withstand earthquakes by meeting the regulatory positions of RGs 1.61 and 1.92 and by providing acceptable seismic analysis procedures and criteria. The scope of review of the seismic system analysis included the seismic analysis methods of all Category I piping systems, components, and their supports. It included review of procedures for modeling, and inclusion of torsional effects, seismic analysis of multiply supported equipment and components with distinct inputs, and determination of composite damping. The review has included design criteria and procedures for evaluation of the interaction of non-Category I piping with Category I piping. The review has also included criteria and seismic analysis procedures for reactor internals.

3.9.2.3 Preoperational Flow-Induced Vibration Testing of Reactor Internals

Flow-induced vibration testing of reactor internals will be conducted during the preoperational and startup test program. The purpose of this test is to demonstrate that flow-induced vibrations similar to those expected during operation will not cause unanticipated structural damage or flow-induced vibrations.

The Indian Point 2 reactor has been established as the prototype for the Westinghouse four-loop plant internals verification program. The only significant difference between the South Texas Units 1 and 2 internals and the Indian Point internals is the substitution of 17x17 fuel assemblies for 15x15 assemblies, the replacement of the annular thermal shield with neutron shielding panels, and
UHI the change to the UHI-style inverted-top-hat support structure configuration.

The change to the neutron shield panels and 17x17 fuel assemblies has been tested at the Trojan plant. The change to the UHI-style inverted-top-hat support structure configuration has been tested at Sequoyah 1 plant. The four-loop internals

assurance program conducted on Indian Point 2--supplemented by the Trojan and Sequoyah Unit 1 data--satisfies RG 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Start-up Testing," Revision 2, for nonprototype Category I plants.

The staff requires more information on the differences between the lower internals design of the South Texas units and the design of Comanche Peak.

The applicant has committed to test the reactor internals in accordance with RG 1.20. The applicant will conduct a visual inspection before hot functional testing. The internals will then be subjected to an operating time of sufficient duration to ensure that a minimum of 10^6 cycles of vibration will be experienced by the critical components. At completion of the flow test, the vessel head will be removed and the internals will be inspected for evidence of wear and loose parts. All major load-bearing surfaces; torsional, lateral, and vertical restraints; locking and bolting devices whose failure could adversely affect the structural integrity of the internals; and all other locations examined on the prototype design will be inspected. The inside of the vessel will be inspected with all the internals removed both before and after hot functional testing to verify that no loose parts or foreign material is present. Important welds, bearing surfaces, and alignment and locking devices in the internals will be inspected with the aid of 5x or 10x magnifying glass. The staff finds the inspection program sufficient and the hot functional test of adequate length.

On the basis of its review and contingent on the satisfactory resolution of the unresolved issue, the staff concludes that the applicant has met GDC 1 and 4 with respect to the reactor internals being designed and tested to quality standards commensurate with the importance of the safety functions being performed and being appropriately protected against dynamic effects (1) by meeting RG 1.20 for the conduct of preoperational vibration tests and (2) by having a preoperational vibration program planned for the reactor internals that provides an acceptable basis for verifying the design adequacy of these internals under test loading conditions comparable to those that will be experienced during operation. The combination of tests, predictive analysis, and post-test inspection provides adequate assurance that the reactor internals will, during their service life, withstand the flow-induced vibrations of the reactor without loss of structural

integrity. The integrity of the reactor internals in service is essential to ensure the proper positioning of reactor fuel assemblies and unimpaired operation of the control rod assemblies to permit safe reactor operation and shutdown.

3.9.2.4 Dynamic System Analysis of Reactor Internals Under Faulted Conditions

The applicant has analyzed the reactors internals and unbroken loops of the reactor coolant pressure boundary, including the supports, for the combined loads due to a simultaneous LOCA and SSE. In FSAR Section 3.9.2.5, the applicant has described the methodology used in developing the dynamic loads resulting from an asymmetric load from a postulated pipe break at the reactor pressure vessel nozzle safe-end.

On the basis of its review of FSAR Section 3.9.2.5 and the load combinations and stress limits in FSAR Section 3.9.3, the staff concludes that the applicant has met GDC 2 and 4 with respect to the design of systems and components important to safety to withstand the effects of earthquakes and the appropriate combinations of the effects of normal and postulated accident conditions with the effects of the SSE by performing a dynamic system analysis that provides an acceptable basis for confirming the structural design adequacy of the reactor internals and unbroken piping loops to withstand the combined dynamic loads of a postulated LOCA and SSE. The analysis provides adequate assurance that the combined stresses and strains in the components of the reactor coolant system and reactor internals will not exceed the allowable design stress and strain limits for the materials of construction, and that the resulting deflections or displacements at any structural element of the reactor internals will not distort the reactor internals geometry to the extent that core cooling may be impaired. The methods used for component analysis have been found to be compatible with those used for the system analysis. The proposed combination of component and system analyses are, therefore, acceptable. The assurance of structural integrity of the reactor internals under LOCA conditions for the most adverse postulated loading event provides added confidence that the design will withstand a spectrum of lesser pipe breaks and seismic loading events.

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

The review under SRP Section 3.9.3 is concerned with the structural integrity and functional capability of pressure-retaining components, their supports, and core support structures that are designed in accordance with ASME Code Section III, or earlier industrial standards. The staff has reviewed loading combinations and their respective stress limits, the design and installation of pressure-relief devices, and the design and structural integrity of ASME Code Class 1, 2, and 3 components and components supports.

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

The staff has reviewed the methodology used for load combinations and the selected values of allowable stress limits. The applicant has evaluated all ASME Code Class 1, 2, and 3 components, component supports, core support components, control rod drive components, and other reactor internals using the load combinations and stress limits in FSAR Section 3.9.3. The staff has reviewed this information and has concluded that, with the exception of one item, it conforms to SRP Section 3.9.3. More information is required on the results of the final design and analysis of the Roto-Lok closure system used for the reactor vessels.

The ASME Code requires that a design specification be prepared for Class 1, 2, and 3 components such as pumps, valves, and piping systems. The design specification is intended to become a principal document governing design and construction of these components and should include specification of loading combinations, design data, and other design data inputs. The code also requires a design report of ASME Code Class 1, 2, and 3 piping and components. The staff will audit design documents for selected pumps, valves, and piping systems and review the selected design specifications and design reports for compliance with ASME Code requirements. The staff will discuss the results of this review in the SER.

On the basis of its review of FSAR Sections 3.9.3.1 and contingent on the satisfactory resolution of the open item, the staff finds that the applicant has met 10 CFR 50.55a and GDC 1, 2, and 4 with respect to the design and service load combinations and associated stress and deformation limits specified for ASME

Code Class 1, 2, and 3 components by ensuring (1) that systems and components important to safety are design to quality standards commensurate with their importance to safety and (2) that these systems can accommodate the effects of normal operation as well as postulated events such as LOCAs and the dynamic effects resulting from earthquakes. The specified design and service combinations of loading as applied to ASME Code Class 1, 2, and 3 pressure-retaining components in systems designed to meet seismic Category I standards provide assurance that in the event of an earthquake affecting the site for other service loading caused by postulated events or system operating transients, the resulting combined stresses imposed on system components will not exceed allowable stress and strain limits for the materials of construction. Limiting the stresses under such loading combinations provides a conservative basis for the design of system components to withstand the most adverse combination of loading events without loss of structural integrity.

3.9.3.2 Design and Installation of Pressure Relief Devices

The staff has reviewed FSAR Section 3.9.3.3 with respect to the design, installation, and testing criteria applicable to the mounting of pressure-relief devices used for the overpressure protection of ASME Code Class 1, 2, and 3 components. This review, conducted in accordance with SRP Section 3.9.3, includes evaluation of the applicable loading combinations and stress criteria. The design review extends to consideration of the means provided to accommodate the rapidly applied reaction force when a safety valve or relief valve opens, and the transient fluid-induced loads applied to the piping downstream of a safety or relief valve in a closed discharge piping system.

In accordance with Item II.D.1 of NUREG-0737, pressurized water reactor and boiling water reactor licensees and applicants are required to conduct testing to qualify the reactor coolant system relief and safety valves, block valves, and associated piping and supports under expected operating conditions for design-basis transients and accidents.

The Electric Power Research Institute (EPRI) was contracted by the PWR Owners Group to develop and carry out a generic test program and to provide the generic

test data to be used by the PWR utilities to satisfy NUREG-0737 Item II.D.1. Testing of valves in the EPRI program was completed by December 31, 1981.

By a letter dated April 1, 1982, from D. P. Hoffman, Chairman of the PWR Safety and Relief Valve Test Program Subcommitte, the EPRI/PWR Owners Group transmitted the following reports to NRC:

(1) Valve Selection/Justification Report
(2) Valve Inlet Fluid Condition for Pressurizer Safety and Relief Valves in Westinghouse-Designed Plants (note: two other NSSS vendor reports were also received)
(3) Test Condition Justification Report
(4) Safety and Relief Valve Test Report
(5) Application of RELAP5/MOD 1 for Calculation of Safety and Relief Valve Discharge Piping Hydrodynamic Loads

Additionally, by letter dated June 1, 1982, from R. C. Youngdahl to H. Denton, reports documenting block valve testing performed by EPRI were transmitted to the staff. These generic reports are currently being reviewed. On the basis of a preliminary review of the EPRI generic reports, the staff has concluded that they contain data that can be used by the applicant to prepare an Item II.D.1 plant-specific response for the valves and associated piping for South Texas Units 1 and 2.

The staff requires that these plant-specific submittals be made before fuel load, in accordance with the schedule of NUREG-0737 and the September 29, 1981, clarification letter on this matter.

On the basis of its review of FSAR Section 3.9.3.3, and contingent upon an acceptable resolution of the open item, the staff finds that the applicant has met 10 CFR 50.55a and GDC 1, 2, and 3 with respect to the criteria used for design and installation of ASME Code Class 1, 2, and 3 overpressure relief devices by ensuring that safety and relief valves and their installations are designed to standards that are commensurate with their safety functions, and that they can accommodate the effects of discharge caused by normal operation as well as postulated events such as LOCAs and the dynamic effects resulting from the SSE. The

applicant also has met the relevant requirements of GDC 14 and 15 with respect to ensuring that the reactor coolant pressure boundary design limits for normal operation, including anticipated operational occurrences, are not exceeded. The criteria used by the applicant in the design and installation of ASME Code Class 1, 2, and 3 safety and relief valves provide adequate assurance that, under discharging conditions, the resulting stresses will not exceed allowable stress and strain limits for the materials of construction. Limiting the stresses under the loading combinations associated with the actuation of these pressure relief devices provides a conservative basis for the design and installation of the devices to withstand these loads without loss of structural integrity or impairment of the overpressure protection function.

3.9.3.3 Component Supports

The staff's review of FSAR Section 3.9.3.4 relates to the methodology used in the design of ASME Class 1, 2, and 3 component supports. The review includes assessment of design and structural integrity of the supports. The review addresses three types of supports: plate and shell, linear, and component standard types. In a letter from M. Wisenburg to H. Thompson dated February 25, 1985, the applicant provided a definition of the boundary between pipe supports and supplemental structure steel that is a part of the building structure. Pipe supports that are within the support boundary are designed and constructed in accordance with subsection NF of the ASME Code Section III, 1974 edition, with Winter 1975 addenda. Support members within the supplementary structures steel boundary are designed to the AISC standard. AISC requirements for construction has been augmented for support members outside the NF boundary to provide a continuity of equivalent quality between the NF and AISC portions. Full penetration welds on ASME Class 1 piping system support structures outside the NF boundary will be examined both visually and by the dye penetrant (PT) examination techniques. The staff finds the jurisdictional boundaries for pipe supports to be in conformance with standard industry practice and acceptable. More information regarding the design of NSSS ASME Class 1, 2, and 3 component supports is required.

On the basis of its review of FSAR Section 3.9.3.4 and contingent on the resolution of the open item, the staff finds that the applicant has met 10 CFR 50.55a

and GDC 1, 2, and 4 with respect to the design and service load combinations and associated stress and deformation limits specified for ASME Code Class 1, 2, and 3 component supports by ensuring (1) that component supports important to safety are designed to quality standards commensurate with their importance to safety, and (2) that these supports can accommodate the effects of normal operation as well as postulated events such as LOCAs and the dynamic effects resulting from the SSE. The combination of loadings (including system operating transients) considered for each component support within a system, including the designation of the appropriate service stress limit for each loading combination, has met RGs 1.124 and 1.130 and is in accordance with NUREG-0484, Revision 1. The specified design and service loading combinations used for the design of ASME Code Class 1, 2, and 3 component supports in systems classified as seismic Category I provide assurance that in the event of an earthquake or other service loadings caused by postulated events or system operating transients, the resulting combined stresses imposed on system components will not exceed allowable stress and strain limits for the materials of construction. Limiting the stresses under such loading combinations provides a conservative basis for the design and support components to withstand the most adverse combination of loading events without loss of structural integrity.

Class CS component evaluation findings are addressed in SER Section 3.9.5.

3.9.4 Control Rod Drive Systems

The staff's review under SRP Section 3.9.4 covers the design of the control rod drive system up to its interface with the control rods. The rods and drive mechanism shall be capable of reliably controlling reactivity changes either under conditions of anticipated normal plant operational occurrences, or under postulated accident conditions. The staff reviewed the information in FSAR Section 3.9.4 relative to the analyses and tests performed to ensure the structural integrity and functionally of this system during normal operation and under accident conditions. The staff also reviewed the life-cycle testing performed to demonstrate the reliability of the control rod drive system over its 40-year life.

A detailed review of the design of the control rod drive system with respect to its capability of controlling reactivity and cooling the reactor core with appropriate margin in conjunction with either the emergency core cooling system or the reactor protection system was not performed because of the system's similarity to those in other Westinghouse plants that were found to be acceptable. The staff is not aware of any significant design changes in the control rod drive system for South Texas Units 1 and 2.

On the basis of its review, the staff concluded that the design of the control rod drive system is acceptable and meets GDC 1, 2, 14, 26, 27, and 29, and 10 CFR 50.55a.

The applicant has met GDC 1 and 10 CFR 50.55a with respect to designing components important to safety to quality standards commensurate with the importance of the safety functions to be performed. The design procedures and criteria used for control rod drive systems are in conformance with appropriate ANSI and ASME codes.

The applicant has met GDC 2, 14, and 26 with respect to designing the control rod drive system to withstand effects of earthquakes and anticipated normal operation occurrences with adequate margins to ensure its structural integrity and functional capability and with extremely low probability of leakage or gross rupture of reactor coolant pressure boundary. The specified design transients, design and service loadings, combinations of loads, and limiting the stresses and deformations under such loading combinations are in conformance with the appropriate ANSI and ASME codes and acceptable regulatory positions specified in SRP Section 3.9.3.

The applicant has met GDC 27 and 29 with respect to designing the control rod drive system to ensure its capability to control reactivity and cool the reactor core with appropriate margin, in conjunction with either the emergency core cooling system or the reactor protection system. The operability assurance program is acceptable with respect to meeting system design requirements in observed performance as to wear, functioning times, latching, and overcoming a stuck rod.

3.9.5 Reactor Pressure Vessel Internals

The staff's review under SRP Section 3.9.5 is concerned with the load combinations, allowable stress limits, and other criteria used in the design of the reactor internals. The staff has limited its review under SRP Section 3.9.5 to include the design and analysis of the reactor internals and the deformation limits specified for those components. A detailed review of the configuration and general arrangement of the mechanical and structural internal elements was not performed because of the plant's similarity to other Westinghouse plants that were found acceptable. The staff is not aware of any significant design changes in the reactor internals for South Texas Units 1 and 2.

On the basis of its review of FSAR Section 3.9.5, the staff concludes that the design of reactor internals is acceptable and meets GDC 1, 2, 4, and 10 and 10 CFR 50.55a.

The applicant has met GDC 1 and 10 CFR 50.55a with respect to designing the reactor internals to quality standards commensurate with the importance of the safety functions to be performed. The design procedures and criteria used for the reactor internals are in conformance with the requirements of subsection NG of the ASME Code, Section III.

The applicant has met GDC 2, 4, and 10 with respect to designing components important to safety to withstand to effects of earthquake and the effects of normal operation, maintenance, testing, and postulated LOCAs with sufficient margin to ensure that their capability to perform their safety functions is maintained and the specified acceptance fuel design limits are not exceeded.

The specified design transients, design and service loadings, and combinations of loading as applied to the design of the reactor internals structures and components provide reasonable assurance that, in the event of an earthquake or of a system transient during normal plant operation, the resulting deflections and associated stresses imposed on these structures and components would not exceed allowable stresses and deformations under such loading combinations. This provides an acceptable basis for the design of these structures and components to withstand the most adverse loading events that have been postulated

to occur during service lifetime without loss of structural integrity or impairment of function.

3.9.6 Inservice Testing of Pumps and Valves

The staff review under SRP Section 3.9.6 is concerned with the inservice testing of certain safety-related pumps and valves typically designated as ASME Code Class 1, 2, or 3. Other pumps and valves not categorized as Code Class 1, 2, or 3 may be included if they are considered to be safety-related by the staff. In SER Sections 3.9.2 and 3.9.3, the staff discusses the design of safety-related pumps and valves in the South Texas plant. The load combinations and stress limits used in the design of pumps and valves ensure that the component pressure boundary integrity is maintained. In addition, the applicant will periodically test and perform periodic measurements of all safety-related pumps and valves. These tests and measurements are performed in accordance with Section XI of the ASME Code. The tests verify that these pumps and valves operate successfully when called on. Periodic measurements of various parameters are compared to baseline measurements to detect long-term degradation of the pump or valve performance. The staff reviews the applicant's program for preservice and inservice testing of pumps and valves according to SRP Section 3.9.6, and gives particular attention to those areas of the test program for which the applicant requests relief from the requirements of Section XI of the ASME Code. The applicant must provide a commitment that the inservice testing of ASME Class 1, 2, and 3 components will be in accordance with the revised rules of 10 CFR 50.55a(g).

The applicant has not yet submitted its program of the preservice and inservice testing of pumps and valves; therefore, the staff has not yet completed its review. The staff will report the resolution of these issues in a supplement to this SER.

Several safety systems connected to the reactor coolant pressure boundary have design pressure below the rated reactor coolant system (RCS) pressure. Also some systems that are rated at full reactor pressure on the discharge side of pumps have pump suction below RCS pressure. To protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high pressure RCS and the low pressure system. The leak-tight

integrity of these valves must be ensured by periodic leak testing to prevent exceeding the design pressure of the low pressure systems.

Pressure isolation valves must be Category A or AC per IWV-2000 and meet the IWV-3420 of Section XI of the ASME Code, except as discussed below.

Limiting Conditions for Operation (LCO) must be added to the Technical Specifications to require corrective action (shutdown or system isolation) when the finally approved leakage limits are not met. The Technical Specifications also must include surveillance requirements that will state the acceptable leak rate testing frequency.

Periodic leak testing of each pressure isolation valve must be performed at least once each refueling outage, after valve maintenance and before return to service. Such testing also must be done for systems rated as less than 50% of RCS design pressure each time the valve has moved from its fully closed position unless justification is given. The testing interval should average once a year. Leak testing should also be performed after all disturbances to the valves are complete, before power operation after a refueling outage, maintenance, etc.

The staff's position on leak-rate LCO is that leak rates must be equal to or less than 1 gpm for each valve to ensure the integrity of the valve, demonstrate the adequacy of the redundant pressure isolation function, and give an indication of valve degradation over a finite period of time. Significant increases over this limiting valve would be an indication of valve degradation from one test to another.

The Class 1 to Class 2 boundary will be considered the isolation point that must be protected by redundant isolation valves. In cases where pressure isolation is provided by two valves, both will be independently leak tested. When three or more valves provide isolation, only two of the valves must be leak tested.

The staff will complete the review of this issue as a part of its review of the Technical Specifications.

3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

The staff evaluation of the adequacy of the applicant's program for qualification of safety-related electrical and mechanical equipment for seismic and dynamic loads consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an onsite audit of selected equipment items to develop the basis for the staff judgment on the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program.

The Seismic Qualification Review Team (SQRT), consisting of staff engineers and engineers from the Idaho National Engineering Laboratory (INEL), has reviewed the methodology and procedures of the seismic and dynamic equipment qualification program in FSAR Sections 3.9.2, 3.9.3, and 3.10. The SQRT has concluded that the information in the FSAR meets the intent of the current licensing criteria as described in IEEE 344-1975; RGs 1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis," and 1.100, "Seismic Qualification of Electric Equipment for Nuclear Power Plants"; and SRP Section 3.10, with several exceptions. The FSAR did not address surveillance and maintenance programs that would ensure that all safety-related Class 1E and age-sensitive mechanical components in both harsh and mild environments will be functional throughout the entire life of the plant. In addition, the FSAR did not discuss the qualified life of these equipment items. The staff also found that the FSAR does not include a commitment to establish, before plant operation, a central filing system from which qualification documentation can be retrieved in an auditable manner.

The staff has informed the applicant that a substantial portion (85% to 90%) of the equipment should be qualified, documented in an auditable manner, and installed on the site before an onsite audit by the SQRT can be performed. The staff also indicated to the applicant the type of information necessary for SQRT to select the equipment items for a detailed onsite review. The staff is waiting for information from the applicant necessary to determine a target

- Some valves listed in Table 3.9-1.2 no longer appear to be used. For example, containment purge valves HA002 and HA004, as well as radiation monitoring valves RP002 and RP005, have been deleted from Table 7.3-9 (Amendment 43).

- For all active BOP valves, the applicant should list the function, ANS safety class, and active status in a manner similar to the way Table 3.9-1.2A lists NSSS valves.

(3) Table 3.9-1.2A (Amendment 41) lists active NSSS valves. However, several valves are flagged with the footnote "*BOP scope of supply." The applicant must clarify the purpose of the footnote.

(4) The applicant must clearly show the extent to which RG 1.148, ANSI/ASME N551.1 draft standards, and ANSI B16.11 are met.

(5) The applicant must clarify the methods used for qualification. Specific information should be presented in the FSAR, and be available for review at the site. The applicant must demonstrate

- the extent to which operational testing is performed at design basis conditions (full flow, pressure, temperature etc.)

- the technical basis for qualifying equipment by similarity analysis and prototype testing

- qualification of the equipment as an assembly rather than individual components

- the extent to which qualification by analysis, as presented in Table 3.9-10, was supplemented by correlated test results and documented operating data

(6) The applicant should clearly show how implementation of the initial test program, maintenance and surveillance, inservice inspection, and quality

assurance programs will maintain equipment operability throughout the 40-year plant life. Specific criteria should be presented in the FSAR, and be available for review at the site.

(7) The following actions by the applicant would enhance PVORT understanding of the plant:

- The applicant should identify any pumps and valves that are considered to be functional accessories for active safety-related equipment. (The diesel generator lubrication system described in FSAR Section 9.5.7 is safety related and is designed to seismic Category I, SC3 requirements. The system includes one engine-driven and two motor-driven pumps, which are not listed in any of the tables in FSAR Section 3.9).

- FSAR Tables 3.9-4 and -4C provide the stress criteria for Class 2 and 3, non-active, BOP and NSSS pumps, respectively. The applicant should identify these non-active pumps.

- FSAR Section 3.9.3.2.1.2 describes an NSSS program for testing various valve designs and sizes during a simulated faulted event. The applicant must describe the criteria used to select the valves for testing and specify the range of sizes that are covered.

- FSAR Sections 3.9.3.2.2 and 3.9.3.2.3 describe the methodology used to demonstrate operability of BOP pumps and valves, respectively. The applicant must identify the seismic accelerations and describe how they were applied to qualify "rigid" and "flexible" BOP equipment.

- The applicant must specify the range of sizes of BOP valves that are covered by program 1 in FSAR Section 3.9.3.2.3. Also, the applicant must confirm that the evaluation of the BOP check valves will include "stress analysis of critical parts, which may affect operability including the faulted condition loads," as is the case for NSSS check valves.

- The PVORT is interested in examining the lists of pumps and valves that are designated for inservice testing per FSAR Section 3.9.6.

The applicant must submit FSAR amendments to resolve the identified FSAR deficiencies. In addition, the PVORT, which consists of NRC staff members and consultants from Idaho National Engineering Laboratory (INEL), will follow the applicant's effort closely, and will confirm its implementation during the onsite audit. During the plant site audit, the staff will review in detail the applicant's implementation of the qualification program to confirm that all applicable loads and combinations of loads have been defined, operability has been verified through appropriate tests and analyses, that assemblies rather than individual components have been verified operable, and that operability can be ensured for all safety-related equipment throughout the plant life. A substantial portion (85% to 90%) of the equipment must be qualified, documented in an auditable manner, and installed onsite before an onsite audit by the PVORT can be performed. Whenever the applicant indicates that the work is substantially complete, the PVORT will conduct an onsite audit shortly thereafter. The staff will report the results of the audit and the followup and resolution of the concerns described above in a future supplement to the SER.

3.11 Environmental Qualification of Electric Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

The applicant must demonstrate that equipment that is used to perform a necessary safety function is capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is in GDC 1 and 4 and in Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment are in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," and NUREG-0588, "Interim Staff Position on Environmental Qualification of

Safety-Related Electrical Equipment." NUREG-0588 supplements IEEE Standard 323 and various NRC regulatory guides and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of electrical equipment qualification programs by industry and to provide guidance to the NRC staff for use in ongoing licensing reviews. The positions below provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other factors such as margin, aging, and documentation.

In February 1980, the staff asked the applicant to review and evaluate the environmental qualification documentation for each item of safety-related electric equipment that could be exposed to a harsh environment and to identify the degree to which the applicant's qualification program complies with the staff positions described in NUREG-0588. IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to the applicant for consideration in the review.

A final rule on environmental qualification of electric equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for the South Texas project may be qualified to the criteria specified in Category I of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

In response to the above requirements, the applicant has provided some preliminary equipment qualification information in Section 3.11 of the FSAR.

3.11.3 Completeness of the Environmental Qualification Program.

The applicant must demonstrate compliance with the final rule, 10 CFR 50.49 before an operating license can be granted.

In accordance with the scope defined in 10 CFR 50.49, the applicant must provide

(1) A list of all nonsafety-related electrical equipment located in a harsh environment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions by the safety-related equipment. A description of the method used to identify this equipment must be included. The nonsafety-related equipment identified must be included in the environmental qualification program.

(2) A statement that all safety-related electric equipment in a harsh environment, as defined in the scope of 10 CFR 50.49, is included in the equipment qualification program (including equipment required for moderate energy line break, fuel handling accident, etc.)

(3) A list of all Category 1 and 2 post-accident monitoring equipment currently installed, or to be installed before plant operation, in response to RG 1.97, Revision 2. The equipment identified must be included in the environmental qualification program.

The applicant also must provide information demonstrating qualification of all equipment in a harsh environment within the scope of 10 CFR 50.49. This material should be submitted to allow the staff sufficient time for review and approval before issuance of an operating license.

Although there are no detailed requirements for mechanical equipment, GDC 1 and 4; Sections III and XVII of Appendix B to 10 CFR 50; and SRP Section 3.11, Revision 2, contain the following requirements and guidance related to equipment qualification:

(1) Components shall be designed to be compatible with the postulated environmental conditions, including those associated with loss-of-coolant accidents.

(2) Measure shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.

(3) Design control measures shall be established for verifying the adequacy of design.

(4) Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

To demonstrate compliance with GDC 4 for mechanical equipment, the staff requires that the applicant perform a review and evaluation that includes the following:

(1) Identification of safety-related mechanical equipment located in harsh environmental areas, including required operating time.

(2) Identification of the nonmetallic subcomponents of this equipment.

(3) Identification of the environmental conditions for which this equipment must be qualified. The environments defined in the electrical equipment program are also applicable to mechanical equipment.

(4) Identification of nonmetallic material capabilities.

(5) Evaluation of environmental effects.

The list of equipment identified should be submitted. From this list, the staff will select approximately three items of mechanical equipment for which documentation of environmental qualification should be provided for staff review. Also, the results of the review should be provided for all mechanical equipment in harsh environment areas and corrective actions identified.

For mechanical equipment, the staff review will concentrate on materials that are sensitive to environmental effects, such as seals, gaskets, lubricants, fluids for hydraulic systems, diaphragms, etc.

Additionally, all safety-related equipment should be subjected to a maintenance, surveillance, and periodic testing program in accordance with RG 1.33, to detect any age-related degradation that could affect the qualification of the equipment in regard to its being maintained in a qualified condition.

Upon receipt of the applicant's submittal, the staff will review the environmental qualification program for compliance and request any additional information needed to establish its acceptability. The staff will then perform an audit review of electrical equipment, environmental qualification files, and associated installed equipment.

After the staff completes this audit, it will document its results in an SER supplement. Before an operating license is issued, the staff must be able to conclude that the applicant has demonstrated full compliance with 10 CFR 50.49 and all applicable rules and regulations.

4 REACTOR

4.1 Introduction (To Come)

4.2 Fuel Design

The fuel assembly described in the FSAR is a 17 x 17 array of fuel rods. Each fuel rod has an outside diameter of 0.374 inch, an active fuel length of 168 inches, and a length of 176.69 inches.

FSAR Section 4.2 gives the design bases for the fuel assembly. For the Westinghouse (W) analysis, plant design conditions are divided into four categories of operation that are consistent with traditional industry classification (ANSI Standards N18.2-1973 and N-212-1974): Condition I is Normal Operation, Condition II is Incidents of Moderate Frequency, Condition III is Infrequent Incidents, and Condition IV is Limiting Faults. Fuel damage is then related to these conditions of operation, which are coupled to the fuel design bases and design limits. The FSAR subsections of the FSAR design bases section address topics such as cladding, fuel material, fuel rod performance, spacer grids, fuel assembly, incore control components, and surveillance program. Thus, as part of the discussion of the cladding design bases, cladding material and mechanical properties, stress-strain limits, vibration and fatigue, and cladding chemical properties are also presented. A similar approach is taken for the other major subtopics.

The staff's review follows SRP Section 4.2 (NUREG-0800). The objectives of this review are to ensure that (1) the fuel system is not damaged as a result of normal operation and anticipated operational occurrences, (2) fuel system damage is never so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. "Not damaged" means that fuel rods do not fail, that fuel system dimensions remain within operational tolerances, and that functional capabilities are not reduced below those assumed in the safety analysis. This objective implements GDC 10, and the design limits that accomplish

this are called specified acceptable fuel design limits (SAFDLs). "Fuel rod failure" means that the fuel rod leaks and that the first fission product barrier (the cladding) has, therefore, been breached. Fuel rod failures must be accounted for in the dose analysis required by 10 CFR 100 for postulated accidents. "Coolability," which is sometimes termed "coolable geometry," means, in general, that the fuel assembly retains its rod-bundle geometrical configuration with adequate coolant channels to permit removal of residual heat after a severe accident. The general requirements to maintain control rod insertability and core coolability appear in the GDC (27 and 35). Specific coolability requirements for loss-of-coolant accidents are given in 10 CFR 50.46 ("Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors").

To meet the above-stated objectives of the fuel system review, the staff examines the following specific areas: design bases, description and design drawings, design evaluation, and testing, inspection, and surveillance plans. In assessing the adequacy of the design, several items involving operating experience, prototype testing, and analytical predictions are weighed in terms of specific acceptance criteria for fuel system damage, fuel rod failure, and fuel coolability.

Recently, Westinghouse developed the optimized fuel assembly (OFA), which is described in WCAP-9500; that report was approved by the staff (Rubenstein, May 15, 1981, and Tedesco, May 22, 1981). The OFA design also consists of a 17 x 17 array of fuel rods; however, the rods have a diameter of 0.360 inch, which is somewhat smaller than the rod diameter in the standard fuel assembly (SFA). The fuel assembly for South Texas Units 1 and 2 is the same as the SFA except that the active fuel length is 2 feet longer. Because the format of WCAP-9500 followed RG 1.70 ("Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants"), some of the fuel design bases and design limits for the OFA were not presented in WCAP-9500 in a form that permitted cross-checking with the acceptable criteria provided in SRP Section 4.2. Therefore, several questions were issued (Rubenstein, August 8, 1980) to clarify the design bases and limits. Responses to those questions are contained in letters from Westinghouse (Anderson, January 12, 1981, and April 21, 1981). These responses are applicable to the SFA to be used in other plants (Petrick, September 9, 1981). The applicant has specified the applicablity of those responses that apply to the fuel assembly for South Texas in Amendment 45 to the FSAR.

4.2.1 Design Bases

Design bases for the safety analysis address fuel system damage mechanisms and suggest limiting values for important parameters so that damage will be limited to acceptable levels. For convenience, acceptance criteria for these design limits are grouped into three categories in the SRP: (1) fuel system damage criteria, which are most applicable to normal operation (W Condition I), including anticipated operational occurrences (W Condition II); (2) fuel rod failure criteria, which apply to normal operation (W Condition I) anticipated operational occurrences (W Condition II), and postulated accidents (W Conditions III and IV); and (3) fuel coolability criteria, which apply to postulated accidents (W Conditions III and IV).

4.2.1.1 Fuel System Damage Criteria

The following paragraphs discuss the evaluation of the design bases and corresponding design limits for the damage mechanisms listed in the SRP. These design limits, along with certain criteria that define failure (see Section 4.2.1.2 of this report), constitute the SAFDLs required by GDC 10. The design limits in this section should not be exceeded during normal operation including anticipated operational occurrences.

(1) Cladding Design Stress

FSAR Section 4.2.1.1(b,1) indicates that the cladding stresses under Conditions I and II are less than the Zircaloy yield stress, with due consideration of temperature and irradiation effects. This is a traditional limit consistent with previous Westinghouse design practice, but with credit being taken by Westinghouse for irradiation-induced strengthening. The staff has approved (Thomas, July 21, 1983) WCAP-9179, Revision 1, which includes approval for taking such credit. The applicant has incorporated this reference in FSAR Amendment 45.

(2) Cladding Design Strain

With regard to cladding strain, FSAR Section 4.2.1.1(b,2) gives a design limit for fuel rod cladding plastic tensile creep (as a result of uniform cladding

creep and uniform cylindrical fuel pellet swelling and thermal expansion) of less than 1% from the unirradiated condition. The applicant indicates (in FSAR Section 4.2.1.1) that this limit is consistent with proven practice. Although the supporting data for normal operation (Condition I) has not been explicitly reviewed, that value appears to be consistent with past practice (the SRP gives no numerical value for normal operation cladding strain as an acceptance criterion). Thus there is reasonable assurance that 1% total plastic creep strain is an acceptable design limit for normal operation, including Condition I power changes (load following). For transient-induced deformation, the SRP indicates that 1% uniform cladding strain is an acceptable damage limit that should preclude some types of pellet/cladding interaction (PCI) failures. However, while such a limit is consistent with past practice, it should not be construed to be a broadly applicable PCI damage limit because there is ample evidence (Tokar, November 14, 1979) that PCI failures can occur at less than 1% uniform cladding strain. Nevertheless, the 1% cladding transient plastic strain criterion appears to be an acceptable design limit for the type of application indicated in SRP Section 4.2. For fuel assembly structural design, Westinghouse set design limits on stresses and deformations that result from various nonoperational, operational, and accident loads. As indicated in FSAR Section 4.2.1.5, the stress categories and strength theory in ASME Code Section III are used as a general guide. This is consistent with acceptance criterion II.A.1(a) of SRP Section 4.2 and is acceptable.

(3) Strain Fatigue

According to FSAR Section 4.2.1(c,1), the cumulative strain fatigue cycles are less than the design strain fatigue life, which the applicant states is consistent with proven practice. The strain fatigue criteria in FSAR Section 4.2.3.3(1.) of the FSAR are the same as those described in SRP Section 4.2, (a safety factor of 2 on stress amplitude or of 20 of the number of cycles) that are, therefore, acceptable.

(4) Fretting Wear

Although the SRP does not provide numerical bounding-value acceptance criteria for fretting wear, it does stipulate that the allowable fretting wear should be

stated in the FSAR and that the stress and fatigue limits should presume the existence of this wear.

FSAR Sections 4.2.1.1(c,2), 4.2.1.4(b), 4.2.2.2.4, and 4.4.4.7 indicate that potential fretting wear as a result of vibration is maintained within acceptable limits, ensuring that the stress-strain limits are not exceeded during the design life. In response to questions related to the SFA review (Anderson, January 12, 1981, and April 21, 1981), Westinghouse noted that the design basis for fretting wear is that fuel rods shall not fail during Condition I and Condition II events. Westinghouse does not use an explicit fretting wear limit in the stress and fatigue analysis for fuel rods; however, Westinghouse does use a value (proprietary) of wall thickness as a general guide in evaluating cladding imperfections, including fretting wear. Cladding imperfections, including fretting wear, are thus considered in the stress and fatigue analysis, albeit in a qualitative manner. In view of the apparently small effects of these defects and large stress and fatigue margins (see Section 4.2.3.1(4) of this report), this design method is acceptable.

Westinghouse has stated that the design basis for guide thimble tubes (Anderson, January 12, 1981, and April 21, 1981) is that the thinning of the guide thimble tube walls should not result in the failure of the fuel assembly structural integrity or functionability of the guide thimble tubes. The staff finds this acceptable.

With regard to a design limit for guide thimble tube wear, Westinghouse uses a design criterion of 6 g, as noted in FSAR Section 4.2.1.5(1,). This design limit was accepted for Westinghouse fuels at other plants in the analysis of an accident involving the most limiting load on a fuel assembly structure with guide thimble tubes that have been degraded by wear. This design limit is acceptable.

(5) <u>Oxidation and Crud Buildup</u>

The design basis for cladding oxidation and crud buildup is that the increase in cladding temperature as a result of cladding oxidation and crud buildup is not excessive (see Section 4.2.1.2(3), below, as well as FSAR Sections 4.4.2.9.1 and 4.4.2.11.5).

SRP Section 4.2 identifies cladding oxidation, hydriding, and crud buildup as potential fuel system damage mechanisms. Hydriding is discussed in Section 4.2.1.2(1), below. Because of the increased thermal resistance of the crud layers, there is an increased potential for elevated temperature within the fuel as well as the cladding. Because the effect of oxidation and crud layers on fuel and cladding temperature is a function of several different parameters (such as heat flux and thermal-hydraulic boundary conditions), a design limit on oxide or crud layer thickness does not, per se, preclude fuel damage as a result of these layers. Rather, it is necessary that these layers be appropriately considered in other temperature-related fuel system damage and failure analyses. Westinghouse has taken this approach (see FSAR Sections 4.4.2.9.1, 4.4.2.11, 4.4.2.11.5 and 4.4.4.5.2) in the design of the fuel assembly, and the staff finds it acceptable.

(6) Rod Bowing

Fuel rod bowing is a phenomenon that alters the pitch dimensions between adjacent fuel rods. Bowing affects local nuclear power peaking and the local heat transfer to the coolant. Rather than placing design limits on the amount of bowing that is permitted, the applicant has included the effects of bowing in the safety analysis (see FSAR Sections 4.2.3.1.4 and 4.2.3.3.5). This is consistent with the SRP and is acceptable. The methods used for predicting the degree of rod bowing are evaluated in Section 4.2.3.1(6) of this report, and the impact of the resulting bow magnitude is evaluated in Section 4.4.

(7) Axial Growth

In the fuel assembly design, the core components requiring axial-dimensional analyses are the control rods, neutron source rods, burnable poison rods, fuel rods, and fuel assemblies. (Thimble plugging rods are omitted because they are short and not axial-growth limited.) The axial growth of the first three of these components is primarily dependent upon the behavior of poison, source, or spacer pellets and their Type 304 stainless-steel cladding. The growth of the last two is mainly governed by the behavior of fuel pellets, Zircaloy-4 cladding, and Zircaloy-4 guide thimble tubes.

The Westinghouse design bases for core component rods are that (1) dimensional stability and cladding integrity are maintained during Condition I and Condition II events and (2) these components do not interfere with shutdown during Condition III and Condition IV events.

Westinghouse does not, per se, have design limits on the axial growth of control, source, and burnable poison rods. However, allowances are made to accommodate (1) pellet swelling as a result of gas production and (2) relative thermal expansion between the stainless-steel cladding and the encapsulated material. Westinghouse does not account for irradiation growth of the stainless-steel cladding and has cited experiments (Foster and Strain, October 1974) as justification for the insignificance of irradiation growth of stainless-steel at PWR operating conditions.

For the Zircaloy cladding and fuel assembly components, the axial-dimensional behavior is governed by creep (as a result of mechanical or hydraulic loading) and irradiation growth. The critical tolerances that require controlling are (1) the spacing between the fuel rods and the fuel assembly (shoulder gap) and (2) the spacing between the fuel assemblies and the core internals. Failure to adequately design for the former may result in fuel rod bowing, and for the latter may result in collapse of the holddown springs. With regard to inadequately designed shoulder gaps, problems have been reported (Schenk, October 1973; Kuffer and Lutz, 1973; R. E. Ginna Unit 1 FSAR, Rochester, 1972; Clark, July 24, 1983; Rubenstein, June 17, 1983; and Nerses, April 28, 1983) in foreign (Obrigheim and Beznau) and domestic (Arkansas 2, Ginna, and St. Lucie 2) plants that have necessitated predischarge modifications to fuel assemblies.

With regard to a design basis for shoulder gap spacing, FSAR Section 4.2.3.5.1 indicates that interference is precluded by having clearance between the fuel rod end and the top and bottom nozzles. The design clearance accommodates the differences in growth, fabrication tolerances, and the differences in thermal expansion between the fuel cladding and the thimble tubes. Westinghouse does not have specific limits on growth, but uses a gap spacing that is equal to or greater than a certain fraction of the fuel rod length.

With regard to fuel assembly growth, the Westinghouse design basis is that there shall be no axial interference between the fuel assembly and upper and lower

core plates caused by temperature or irradiation. As a design limit, Westinghouse use a minimum gap, which is a fraction of the fuel assembly length, between the fuel assembly and the reactor internals.

The staff finds the design bases and limits dealing with axial growth acceptable.

(8) Fuel Rod and Nonfuel Rod Pressures

For Condition I and Condition II events, the mechanical design basis for core component rods described in the FSAR is that dimensional stability and cladding integrity are maintained. A necessary corollary of this design basis is that the driving force, rod internal pressure, is never so great as to result in loss of dimensional stability and cladding integrity.

SRP Section 4.2 identifies rod internal pressure as a potential fuel system damage mechanism. In this sense, damage is defined as an increased potential for elevated temperatures within the rod as well as an increased potential for cladding failure. Although the SRP mentions only fuel and burnable poison rods, the mechanism also applies to control rods, neutron source rods, and other core component rods. Because rod internal pressure is a driving force for, rather than a direct mechanism of, fuel system damage, it is not necessary that a damage limit be specified. It is only necessary that the phenomenon be appropriately considered in other fuel system damage and fuel failure analyses. In other words, rod internal pressure must be considered in calculating the temperature of the rod internals, cladding deformation, and cladding bursting.

To simplify the analysis of fuel system damage resulting from excessive rod internal pressure, the SRP states that rod internal gas pressure should remain below the nominal system pressure during normal operation unless otherwise justified. Westinghouse has elected to justify limits other than that provided in the SRP.

The internal rod pressure criteria used by Westinghouse are shown in FSAR Section 4.2.1.3,b and allow the fuel rod internal pressure to exceed the system pressure under certain conditions: (1) the internal pressure is limited so that the fuel-to-cladding gap does not increase during steady-state operation, and

(2) extensive departure from nucleate boiling (DNB) propagation does not occur during normal operation and any accident event. These criteria have been previously approved by the staff and remain acceptable.

The design bases for the absorber rods, burnable poison rods, and neutron source rods are described in FSAR Section 4.2.1.6. The burnable poison rod cladding is designed under Article NB-3000 of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III, for Conditions I and II. The neutron source rods are designed to withstand an internal pressure equal to the pressure generated by released gases over the source life. A stress intensity limit of two-thirds of the material yield stress is stated for the absorber rods. A strain limit of 1% is stated in FSAR Section 4.2.1.1(b,2). The limits are unchanged from previously approved Westinghouse fuel designs and remain acceptable for the South Texas plant.

(9) Assembly Liftoff

The SRP calls for the fuel assembly holddown capability (gravity and springs) to exceed worst case hydraulic loads for normal operation, including anticipated operational occurrences. The fuel assembly design basis provides for positive holddown for Condition I, but allows momentary liftoff during one Condition II event (FSAR Section 4.4.2.6.2). This design basis is acceptable, if the applicant can show that the affected fuel assemblies will reseat properly, without damage and without other adverse effects during the event. The ability of the affected fuel assemblies to satisfy this provision is discussed in Section 4.2.3.1, below.

(10) Control Material Leaching

The SRP and GDC require that control rod reactivity be maintained. Control rod reactivity can sometimes be lost by leaching of certain poison materials if the control rod cladding has been breached. The mechanical design basis for the control rods, given in FSAR Section 4.2.1.6, is to maintain cladding integrity. Because cladding integrity would ensure that reactivity is maintained, this design basis might appear to be acceptable. However, under some circumstances, unexpected breaches might go undetected, so the staff does not normally accept

control rod cladding integrity as a sufficient design basis. Section 4.2.3.1 addresses on the adequacy of the control rod design to ensure maintenance of reactivity.

4.2.1.2 Fuel Rod Failure Criteria

The evaluation of fuel rod failure thresholds for the failure mechanisms listed in the SRP is presented in the following paragraphs. When these failure thresholds are applied to normal or transient operation, they are used as limits (the specified acceptable fuel design limits of GDC 10), because fuel failures under those conditions should not occur (according to the traditional conservative interpretation of GDC 10). When these thresholds are applied to accident analyses, the number of fuel failures must be determined for input to the radiological dose calculations required by 10 CFR 100. The basis or reason for establishing these failure thresholds is thus predetermined, and only the threshold values are reviewed below.

(1) Internal Hydriding

Hydriding as a cladding failure mechanism is precluded by controlling the level of moisture and other hydrogenous impurities during fabrication. As described in the applicant's revised response (Anderson, January 12 and April 21, 1981) to a staff question, the moisture levels in the uranium dioxide fuel are limited by Westinghouse to less than or equal to 20 ppm. This specification is compatible with the ASTM specification for sintered uranium dioxide pellets, which allows 2 micrograms of hydrogen per gram of uranium (2 ppm). The applicant must confirm if this criterion applies to South Texas, or, if other criteria were used to control moisture in the uranium dioxide, the applicant must provide them.

(2) Cladding Collapse

If axial gaps in the fuel pellet column were to occur as a result of densification, the cladding would have the potential of collapsing into a gap (flattening). Because of the large local strains that would result from collapse, the cladding is assumed to fail. As indicated in FSAR Section 4.2.1.3, cladding collapse shall be precluded during the fuel rod design lifetime. This design basis is the same as that in the SRP and is therefore acceptable.

(3) Overheating of Cladding

The design basis as given in FSAR Section 4.4.1.1 for preventing fuel failures as a result of overheating is that there will be at least a 95% probability that DNB will not occur on the limiting fuel rods during normal operation or any transient conditions arising from faults of moderate frequency (Condition I and Condition II events) at a 95% confidence level. This design basis is consistent with the thermal margin criterion of SRP Section 4.2 and is, thus, acceptable. The specific departure from nucleate boiling ratio (DNBR) limits and methods of analysis are reviewed in Section 4.4 of this report.

(4) Overheating of Fuel Pellets

As a second method of avoiding cladding failure due to overheating, Westinghouse avoids centerline fuel pellet melting as a design basis. This design basis is the same as given in the SRP and is thus acceptable.

The design limit (FSAR Sections 4.2.1.2 and 4.4.1.2) corresponding to the design basis given above is that, during modes of operation associated with Condition I and Condition II events, there is at least a 95% probability that the peak kW/ft fuel rod will not exceed the uranium dioxide melting temperature. This design limit is an acceptable representation of the design basis given previously.

(5) Pellet/Cladding Interaction

As indicated in SRP Section 4.2, there are no generally applicable criteria for PCI failure. However, the SRP series two acceptance criteria of limited application for PCI: (a) less than 1% transient-induced cladding strain and (b) no centerline fuel melting. The same criteria also are in SRP Sections 4.2.1.1, 4.2.1.2, and 4.4.1.2. Thus, they are acceptable.

(6) Cladding Rupture

In the LOCA analysis for SFA-designed plants, an empirical model is used to predict the occurrence of cladding rupture. The failure temperature is expressed

as a function of differential pressure across the cladding wall. There are no specific design limits associated with cladding rupture, and the rupture model is a portion of the emergency core cooling system (ECCS) evaluation model, which is documented in Revision 1 of WCAP-9220-P-A and WCAP-9221-A. The FSAR must reference the Revision 1 versions of these two documents.

4.2.1.3 Fuel Coolability Criteria

For major accidents in which severe fuel damage might occur, core coolability must be maintained, as required by several GDC (27 and 35). The following paragraphs discuss the evaluation of limits that will ensure that coolability is maintained for the severe damage mechanisms listed in SRP Section 4.2.

(1) Fragmentation of Embrittled Cladding

For LOCA analysis (FSAR Section 15.6.5.1), Westinghouse uses the acceptance criteria of 2200°F on peak cladding temperature and 17% on maximum cladding oxidation, as prescribed by 10 CFR 50.46.

For events other than the LOCA, the staff has not established separate temperature or oxidation criteria. Yet it is clear that for short-term events such as locked rotor, the 2200°F peak cladding temperature and 17% oxidation LOCA criteria are not really meaningful, because the temperature history for such an event is much shorter than that of a LOCA. For events such as locked rotor, therefore, Westinghouse uses a unique peak-cladding-temperature (PCT) criterion of 2700°F (see FSAR Section 15.3.3.2 and Section 15.4.8.1.2).

The Westinghouse 2700°F PCT limit was selected taking into consideration the short time (a few seconds) that the fuel is calculated to be in DNB for a locked-rotor type event and the fact that the PCT and total metal-water reaction at the fuel hot spot would not be expected to impact fuel coolable geometry. Although this limit has been used by Westinghouse for several years, the basis for the limit has only recently been reviewed. However, a staff assessment (Van Houten, February 23, 1981) of the available experimental information indicates that fuel rod cladding will, indeed, retain its rod-like geometry after exposure to a short-term (a few seconds) PCT of 2700°F. That conclusion is based on four Japanese reports (Shiozawa, March 1979; Hoshi, May

1980; JAERI-M-9011, September 1980; and Fukishiro, October 1980) that describe experimental results for reactor test programs reported since 1979. Thus, the staff concludes that there is reasonable assurance that the 2700°F PCT limit for short-term events such as locked rotor is an acceptable coolability limit for the Westinghouse fuel assembly design.

It should be noted that acceptance of the 2700°F PCT limit for fuel rod coolability is currently restricted to undercooling events such as locked rotor. For overpower events such as control rod ejection, which involve a pellet-to-cladding mechanical interaction, the staff has not determined the applicability of a PCT limit and currently uses a fuel rod enthalpy criterion of 280 cal/g for coolability of a rod-ejection accident.

(2) Violent Expulsion of Fuel Material

The design bases given in FSAR Section 15.4.8.1.2 state that there should be little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These are equivalent to those in the SRP.

The FSAR design limits are

- Average fuel pellet enthalpy at the hot spot will be below 225 cal/g for unirradiated fuel.

- Average cladding temperature at the hot spot will be below the temperature at which cladding embrittlement may be expected (2700°F).

- Peak reactor coolant pressure will be less than that which could cause pressures to exceed the faulted condition stress limits.

- Fuel melting will be limited to less than 10% of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits given above.

These limits are more conservative than the single 280 cal/g limit given in RG 1.77. They were approved in the review of WCAP-7588, and they remain

acceptable; however, the FSAR does not provide an enthalpy limit for irradiated fuel. The enthalpy criteria for irradiated fuel must be provided.

(3) Cladding Ballooning and Flow Blockage

In the LOCA analyses for SFA-designed plants, empirical models are used to predict the degree of cladding circumferential strain and assembly flow blockage at the time of hot-rod and hot-assembly burst. These models are each expressed as functions of differential pressure across the cladding wall. There are no specific design limits associated with ballooning and blockage. The ballooning and blockage models are portions of the ECCS evaluation model, which is documented in Revision 1 of WCAP-9220-P-A and WCAP-9221-A.

(4) Structural Damage from External Forces

FSAR Sections 4.2 and 4.2.1.5 state that the fuel assembly will maintain a geometry that is capable of being cooled under the worst case accident Condition IV event and that no interference between control rods and thimble tubes will occur during a safe shutdown earthquake. This is equivalent to the design basis in the SRP and is, therefore, acceptable.

4.2.2 Description and Design Drawings

The description of the fuel assembly, fuel rods, fuel assembly structure, and incore control components, is in FSAR Section 4.2.2. In addition, FSAR Tables 4.1-1 and 4.3-1 provide numerical values for various core component parameters. Although the FSAR does not provide values for each parameter listed in SRP Subsection 4.2.2, the FSAR includes enough information in sufficient detail to provide a reasonably accurate representation of the fuel assembly design; this information is thus acceptable.

4.2.3 Design Evaluation

Section 4.2.1 presents the design bases and limits. This section corresponds, point by point, to Section 4.2.1, to evaluate the Westinghouse methods of

demonstrating that the design criteria have been met. These methods include operating experience, prototype testing, and analytical predictions.

4.2.3.1 Fuel System Damage Evaluation

The following paragraphs discuss the evaluation of the ability of the applicant to meet the fuel system damage criteria described in Section 4.2.1.1 above. Those criteria apply only to normal operations and anticipated transients.

(1) <u>Cladding Design Stress</u>

As indicated in FSAR Section 4.2.3.1.2, Westinghouse used its performance-analysis and design (PAD) code. WCAP-8720 and WCAP-8785, which is the only one shown in the reference list in FSAR Section 4.2) to analyze cladding stress. That code has been reviewed and found acceptable (Stolz, February 9, 1979, and Rubenstein, June 30, 1982). Addendum No. 1 to WCAP-8720 has also been approved (NUREG-0390, Vol. 7) by the staff. In response to a staff question the applicant stated that typical calculated design values for cladding effective stress (Anderson, January 12, and April 21, 1981) are considerably below the 0.2% offset yield stress design limit. This response is incorporated into FSAR Amendment 45.

(2) <u>Cladding Design Strain</u>

The approved Westinghouse fuel performance code (PAD) was used in the strain analysis (Anderson, January 12 and April 21, 1981, and FSAR Section 4.2.3.1.2). Typical design values of steady-state and transient creep strain, as calculated by that code, are below the 1% strain criterion. Hence, the staff concludes that the cladding strain design limits have been met.

(3) <u>Strain Fatigue</u>

As indicated in FSAR Section 4.2.3.3.1, Westinghouse uses PAD code for the strain range and strain fatigue life usage analysis. Experimental data obtained from Westinghouse testing programs (see FSAR Section 4.2.3.3.1) were used by Westinghouse to derive the Zircaloy fatigue design curve, (Anderson, January 12,

and April 12, 1981, incorporated into the FSAR by Amendment 45. For a given strain range, the number of fatigue cycles is less than that required for failure, considering a minimum safety factor of 2 on stress amplitude or a minimum safety factor of 20 on the number of cycles (the fatigue usage factor is less than 1.0). The computations were performed with an approved code. Thus, the staff concludes that the fatique design basis has been met.

(4) Fretting Wear

With regard to the Westinghouse fretting analysis of the fuel cladding, cladding fretting and fuel vibration have been experimentally investigated, as shown in WCAP-8278 (and nonproprietary version WCAP-8279, as noted in FSAR Section 4.2.3.1.1). WCAP-8278 (and WCAP-8279) has been approved by the staff (Tedesco, April 2, 1981).

The out-of-pile flow tests and analyses (WCAP-9401) to determine the magnitude of fretting wear that is anticipated for the optimized fuel assembly (OFA) design have been previously reviewed and found acceptable (Tedesco, May 7, 1981). These analyses are also acceptably conservative for SFA applications (see discussion in Section 4.2.1.1(4) of this report). The applicant has indicated that these analyses also apply to the South Texas fuel, and this information has been incorporated into the FSAR by Amendment 44.

LWR operating experience demonstrates that the number of fretting-induced fuel failures is insignificant.

There should be only a small dependence of cladding stresses on fretting wear because this type of wear is local at grid-contact locations and relatively shallow in depth.

The built-in conservatisms (that is, safety factors of 2 on the stress amplitudes and 20 on the number of cycles) in the strain fatigue analysis as well as the calculated margin to fatigue life limit adequately offset the effect of fretting wear degradation.

Therefore, the staff concludes that the fuel rods will perform adequately with respect to fretting wear.

Fretting wear has also been observed on the inner surfaces of guide thimble tubes where the fully withdrawn control rods reside. Significant wear is limited to the relatively soft Zircaloy-4 guide thimble tubes because the stainless steel control rod cladding is relatively wear resistant. The extent of the wear is both time dependent and plant dependent and has, in some non-Westinghouse cases, extended completely through the guide thimble tube wall.

Westinghouse has predicted that a 17x17 SFA can operate under a rod cluster control assembly (RCCA) for a period of time that exceeds the amount of rodded time expected with current three-cycle fuel schemes before fretting wear degradation would result in exceeding the present margin to the 6g load criterion. However, the staff required several applicants to perform a surveillance program because of the uncertainties in predicting wear rates for the standard 17x17 fuel assembly design. The objective of this program was to demonstrate that there was no occurrence of hole formation in rodded guide thimble tubes, thus providing some confidence that the ability to scram is ensured. These applicants formed an owners' group, which submitted a generic report (Leasburg, March 1, 1982) that provides post-irradiation examination results on guide thimble tube wear in the Westinghouse standard 17x17 fuel assembly design. On the basis of this report, the staff has concluded (Rubenstein, April 19, 1982) that the Westinghouse standard 17x17 fuel assembly design is resistant to guide thimble tube wear. In FSAR Amendment 3, the applicant provided confirmatory information that the South Texas fuel assembly design is also resistant to guide thimble tube wear.

(5) Oxidation and Crud Buildup

The FSAR does not provide an explicit discussion of cladding oxidation, hydriding, and crud buildup; crud and oxide are mentioned in FSAR Sections 4.4.2.9.1, 4.4.2.11, 4.4.2.11.5, and 4.4.4.5.2. FSAR Section 4.2.3 states that the approved temperature-dependent cladding oxidation model in WCAP-9179 was used. The model affects the cladding-to-coolant heat transfer coefficient and the temperature drop across the cladding wall. Mechanical properties and analyses of the cladding are not significantly impacted by oxide and crud buildup. On the basis of its review of the oxidation and crud buildup models, the staff concludes that these effects have been adequately accounted for in the fuel design.

(6) Rod Bowing

The applicant has indicated that the fuel rod bowing analyis for the South Texas reactor cores was performed with the approved methods described in WCAP-8691, Revision 1. The DNB analysis in the FSAR indicates there are sufficient DNBR margins available to offset rod bow penalties.

(7) Axial Growth

Relative to the discussion in Section 4.2.1.1(7) above, on stainless steel growth of poison and control rods, the staff is aware of supporting information (Bloom, April 1972, and Appleby, April 1972) that was not cited by Westinghouse, but that also implies that irradiation growth of stainless steel should not be significant at the temperatures and fluences that are associated with PWR operation. Furthermore, because the staff is unaware of any operating experience that indicates axial-growth-related problems exist in Westinghouse NSSS plants, the staff can conclude that Westinghouse has made sufficient accommodations for control, source, and burnable poison rod axial rod growth in the NSSS designs.

The axial clearances in the South Texas fuel assembly are discussed in FSAR Sections 4.2.2 and 4.2.3.5.1. The applicant has incorporated into the FSAR in Amendment 45 material to confirm that the analysis of shoulder gap spacing between fuel rods and fuel assembly and the spacing between the fuel assemblies and core internals shows that interference will not occur until there are burnups beyond expected fuel design lifetimes. For extended-burnup applications, the adequacy of the spacing should be reverified. Furthermore, because stress-free irradiation growth of zirconium-bearing alloys is sensitive to texture (preferred cystallographic orientation) and retained cold work--which, in turn, are strongly dependent on the specific fabrication techniques that are employed during component production--the design shoulder gap should be reverified if Westinghouse current fabrication specifications are significantly altered.

(8) Fuel Rod and Nonfuel Rod Pressures

FSAR Section 4.2.3.1(2) indicates that WCAP-8720 (and WCAP-8785) was used to determine the internal gas pressures as a function of irradiation time. The

applicant must state that the fuel rods conform to the revised internal rod pressure design basis described in WCAP-8963 (and WCAP-8964), taking into account the longer fuel stack length of this design.

Absorber rod, burnable poison rod, and neutron source rod cladding is cold-worked Type 304 stainless steel, which is not covered by the ASME Code. Westinghouse, therefore, defines as the stress limit an intensity value S_m equal to two-thirds of the material yield stress. The yield stress for this material is approximately 62,000 psi. A strain limit of 1% probably also applies to the cladding, although FSAR Section 4.2.1.6 does not state this. FSAR Section 4.2.3.6(1.) states that internal pressures in the absorber rods, burnable poison rods, and neutron source rods satisfy the applicant's design criteria given in FSAR Section 4.2.1.6. The applicant has incorporated the analyses into the FSAR in Amendment 45.

Thus, the staff concludes that there is adequate assurance that nonfueled core component rods can operate safely during Conditions I and II because appropriate stress and strain limits are met even though the maximum internal rod pressure may exceed system pressure.

(9) Assembly Liftoff

Momentary liftoff will occur only during a turbine overspeed transient, as stated in FSAR Section 4.4.2.6.2. FSAR Section 4.4.2.6.2 states that proper reseating will occur after momentary liftoff. The applicant must confirm (1) that damage to adjacent assemblies will not occur even if one assembly is fully lifted and the adjacent ones remain seated and (2) that no ill consequences of momentary liftoff are expected, taking into account the additional assembly weight of this design.

(10) Control Material Leaching

Although the design basis for the control and burnable poison rods is to maintain cladding integrity and the probability of control and burnable poison rod cladding failures appears to be quite low, the staff has considered the corrosion behavior of control material and burnable poison. The staff concludes that a breach in the cladding should not result in serious consequences because the

Ag-In-Cd or hafnium absorber material and the poison material (borosilicate glass) are relatively inert.

4.2.3.2 Fuel Rod Failure Evaluation

The following paragraphs discuss the ability of the South Texas fuel to operate without failure during normal operation and anticipated transients and the accounting for fuel rod failures in the applicant's accident analysis. The fuel rod failure criteria described in Section 4.2.1.2, above, were used for this evaluation.

(1) Internal Hydriding

The criteria used to control the moisture level in the uranium dioxide fuel to prevent internal cladding hydriding must be confirmed (see Section 4.2.1.2(1) of this report).

(2) Cladding Collapse

In calculating when cladding collapse will occur, Westinghouse uses the generic methods described in WCAP-8377, which has been approved (Stello, January 14, 1975) for licensing applications. Inputs to the analysis include cladding ovality, helium prepressurization, free volume of the fuel rod, and limiting power histories.

However, the applicant has not demonstrated that the cladding collapse time for the fuel rods using WCAP-8377 methods exceeds the expected lifetime of these rods. The applicant must confirm that cladding collapse times exceeds the expected lifetime of the fuel.

(3) Overheating of Cladding

As stated in SRP Section 4.2, adequate cooling is assumed to exist when the thermal margin criterion to limit DNB or boiling transition in the core is satisfied. The method employed to meet the DNB design basis is reviewed in Section 4.4 of this report.

(4) Overheating of Fuel Pellets

The design evaluation of the fuel centerline melt limit is performed with the Westinghouse fuel performance code, PAD-3.3 (WCAP-8720, proprietary version and WCAP-8785, nonproprietary version). This code, which has been approved by the staff (Stolz, February 9, 1979, and Rubenstein, June 30, 1982), is also used to calculate initial conditions for transients and accidents described in SRP Chapter 15 (see Section 4.2.3.3(1), below, for further comments on PAD-3.3).

In applying the PAD-3.3 code to the centerline melting analysis, the melting temperature of the uranium dioxide is assumed to be 5080°F unirradiated and is decreased by 58°F per 10,000 MWd/t. This relation has been almost universally adopted by the industry and has been accepted by the staff. The expressions for thermal conductivity and gap conductance described in FSAR Section 4.4.2.11 are unchanged from those originally described in the PAD code. Thus the staff considers it unnecessary to further review these models.

The peak linear heat rating resulting from overpower transients/operator errors (assuming a maximum overpower of 118%) for South Texas is 18.0 kW/ft. As noted in FSAR Section 4.4.2.11.6, the centerline temperature at this peak linear heat rating is below that required to produce fuel melting.

Consequently, the staff concludes that the criterion for the prevention of fuel centerline melting is satisfied.

(5) Pellet/Cladding Interaction

Although the only two PCI criteria in current use in licensing (1% cladding strain and no fuel melting) are not broadly applicable, they are easily satisfied. As noted in the discussion of the cladding stress and strain evaluation, Westinghouse uses an approved code (PAD) to calculate creep strain, and the values calculated by that code for most Westinghouse designs are found to be below the 1% strain criterion. The applicability of these analyses to the South Texas fuel rods is discussed in Section 4.2.3.1 (3 and 4) above. And, as indicated in the discussion on overheating failures (in FSAR Section 4.4.2.11.6), the no-centerline-melt criterion is satisfied.

In addition to the SRP-type treatment of PCI, however, the applicant has addressed PCI from the standpoint of its effect on fatigue life (Anderson, January 12, and April 21, 1981, and FSAR Section 4.2.3.3(1)). PCI produces cyclic stresses and strains that can affect fatigue life of the cladding. Furthermore, gradual compressive creep of the cladding onto the fuel pellet occurs as a result of the differential pressure exerted on the fuel rod by the coolant.

Westinghouse contends that by using prepressurized fuel rods the rate of cladding creep is reduced, thus delaying the time at which fuel-to-cladding contact first occurs. The staff agrees that fuel rod prepressurization should improve PCI resistance, albeit in a presently unquantified amount.

In conclusion, the staff finds that Westinghouse has used approved methods in past analyses to demonstrate that the present PCI acceptance criteria have been met.

(6) Cladding Rupture

In the LOCA analysis for South Texas, the applicant has used an empirical model to predict the occurrence of cladding rupture. FSAR Section 15.6.5.4.1 states that the rupture model utilized for the large break analysis is the 1978 version of the LOCA evaluation model (WCAP-9220-P-A and WCAP-9221-A). This does not appear to be the latest model (Revision 1 of WCAP-9220-P-A and WCAP-9221-A), approved by the NRC. The updated LOCA evaluation model must be provided.

The rupture model utilized for the small-break analysis was the approved October 1975 version of the ECCS evaluation model (see FSAR Section 15.6.5.3.1.2). This model has been found acceptable for this analysis.

The appropriate references for the large-break LOCA analysis must be confirmed. The overall impact of cladding rupture on the response of the South Texas design to the LOCA is evaluated in Section 15.6.5 below.

4.2.3.3 Fuel Coolability Evaluation

The following paragraphs discuss the evaluation of the ability of the South Texas fuel to meet the fuel coolability criteria described in Section 4.2.1.3, above. Those criteria apply to postulated accidents.

(1) <u>Fragmentation of Embrittled Cladding</u>

The primary degrading effect of a significant degree of cladding oxidation is embrittlement of the cladding. Such embrittled cladding will have a reduced ductility and resistance to fragmentation. The most severe occurrence of such embrittlement is during a LOCA. The overall effects of cladding embrittlement on the South Texas design for the LOCA are analyzed in Section 15.6.5 below.

One of the most significant analytical methods that is used to provide input to the analysis in Section 15.6.5 of this report is the steady-state fuel performance code, which is reviewed in Section 4.2. This code provides fuel pellet temperatures (stored energy) and fuel rod gas inventories for the ECCS evaluation model as prescribed by Appendix K to 10 CFR 50. The code accounts for fuel thermal conductivity, fuel densification, gap conductance, fuel swelling, cladding creep, and other phenomena that affect the initial stored energy. For this purpose, Westinghouse uses a relatively new fuel performance code called PAD-3.3 (WCAP-8720). This code was approved by the staff (Stolz, February 9, 1979, and Rubenstein, June 30, 1982).

For non-LOCA events, the locked rotor accident (one-pump seizure with three loops operating) is the most severe undercooling event analyzed. This event is analyzed in FSAR Section 15.3.3, where the peak cladding temperature is found to be 1833°F, which is well below the 2700°F design limit. The analysis of this event is reviewed in Section 15.3.3 below, however, it is clear that the South Texas design meets the non-LOCA peak cladding temperature design limit.

(2) <u>Violent Expulsion of Fuel Material</u>

The analysis that demonstrates that the design limits are met for this event for South Texas is in FSAR Section 15.4.8 and is reviewed in the corresponding

section of this report. As noted in Section 4.2.1.3(2) of this report, no enthalpy limit is provided in the FSAR for irradiated fuel.

The applicant must provide this enthalpy criteria along with the calculated enthalpy for the limiting event.

(3) Cladding Ballooning and Flow Blockage

The cladding ballooning and flow blockage models for the large-break LOCA are integral parts of the Westinghouse ECCS evaluation model. Consequently, the concern expressed in Section 4.2.3.2(6) of this report as to the use of the appropriate Westinghouse ECCS model for the large-break LOCA analysis must be addressed before this analysis can be approved.

The cladding ballooning and flow blockage analysis for the small-break LOCA was performed with correlations from the approved October 1975 ECCS evaluation model (see FSAR Section 15.6.5.3.1.2). This model has been found to be acceptable for this analysis.

The appropriate references for the large-break LOCA analysis must be confirmed. The overall impact of cladding ballooning and assembly flow blockage models on the response of the fuel design to the LOCA is evaluated in Section 15.6.5 below.

(4) Structural Damage from External Forces

FSAR Sections 4.2.3.4, 4.2.3.5 and 4.2.3.6 state that Westinghouse has performed these analyses utilizing models described in WCAP-8236 (and WCAP-8288). The staff has reviewed and approved (Rubenstein, April 23, 1981) another report, WCAP-9401 (and WCAP-9402), which essentially augments the information presented in WCAP-8236 because both reports apply to similar assemblies. For South Texas, the applicant must demonstrate compliance with Appendix A of SRP Section 4.2 and Appendix E of NUREG-0609, taking into account the longer fuel assembly length of this particular design. The applicant may reference to WCAP-8236 and WCAP-9401, where appropriate, to accomplish this.

4.2.4 Testing, Inspection, and Surveillance Plans

4.2.4.1 Testing and Inspection of New Fuel

As required by SRP Section 4.2, testing and inspection plans for new fuel must include verification of significant fuel design parameters. Although details of the manufacturer's testing and inspection programs should be documented in quality control reports, the FSAR also should describe the programs for onsite inspection of new fuel and control assemblies after they have been delivered to the plant.

The Westinghouse quality control program that will be applied to South Texas fuel is discussed in FSAR Section 4.2.4, which addresses fuel system components and parts, pellets, rod inspection, assemblies, other inspections, and process control. Fuel system component inspection depends on the component parts and includes dimensions, visual appearance, audits of test reports, material certification, and nondestructive examinations. Pellet inspections, for example, are performed for dimensional characteristics such as diameter, density, length, and squareness of ends. Fuel rod, control rodlet, burnable poison rod, and source rod inspections reportedly include nondestructive examination techniques such as leak testing, weld inspection, and dimensional measurements. Process control procedures are described in detail. Incore control component testing and inspection is described in FSAR Section 4.2.4.3. In addition, in FSAR Section 4.2.4.4 states that if any tests and inspections are to be performed by others on behalf of Westinghouse, Westinghouse will review and approve the quality control procedures, inspection plans, and so forth, to ensure that they are equivalent to those described in FSAR Sections 4.2.4.1 through 4.2.4.3 and are performed properly to meet all Westinghouse requirements.

On the basis of information provided in FSAR Section 4.2.4 and the commitment by Westinghouse to ensure the acceptability of any tests and inspections performed by others on behalf of Westinghouse, the staff concludes that the fuel testing and inspection program for new fuel is acceptable.

4.2.4.2 Online Fuel Failure Monitoring

FSAR Section 4.2.5 does not include a description of the chemical volume and control system (CVCS) letdown monitor for online fuel rod failure detection nor

is there an indication that this description can be found elsewhere in the FSAR. A commitment to use the fuel failure detection instruments is required to meet the guidelines of II.D.2 of SRP Section 4.2. The sensitivity of the instruments to detect fuel rod failures also must be confirmed, as stipulated in II.D.2 of SRP Section 4.2.

4.2.4.3 Postirradiation Surveillance

Westinghouse has extensive experience with the use of 17 x 17 SFA in other operating plants. As noted in FSAR Section 4.2.3.3.2, this experience is summarized in WCAP-8183, which is periodically updated to provide the most recent information on operating plants. As noted in FSAR Sections 4.2.1.7 and 4.2.3.3.2, additional test assembly and test rod experience is given in Sections 8 and 23 of a Westinghouse report (Eggleston, current version); however, FSAR Section 4.2.3.3.2 refers to the wrong reference.

The applicant must include a post-irradiation surveillance program in the FSAR because the South Texas fuel assembly, though similar in some ways to the SFA is considerably longer (e.g., active fuel lengths are 168 and 144 inches, respectively). If the fuel design was like that in other operating plants, the minimum acceptable surveillance program would include a qualitative visual examination of some discharged fuel assemblies from each refueling to satisfy part of II.D.3 of SRP Section 4.2. Hence, the FSAR must include a more detailed surveillance program that is commensurate with the nature of the changes, as stated in II.D.3 of SRP Section 4.2. To satisfy the remaining part of II.D.3, the applicant must also (1) make a commitment in the surveillance program to perform additional surveillance if unusual behavior is noticed in the visual examination or if plant instrumentation indicates gross fuel failures and (2) address the disposition of failed fuel in the postirradiation fuel surveillance program.

4.2.5 Evaluation Findings

The following have not yet been provided by the applicant:

(1) A commitment to use the online fuel failure detection methods (see Section 4.2.4.2 in this report).

(2) A statement about the sensitivity of the CVCS letdown monitor for detecting fuel rod failures (see Section 4.2.4.2 in this report).

(3) A statement describing the postirradiation surveillance program (see Section 4.2.4.3 in this report).

(4) A commitment in the post-irradiation fuel surveillance program to perform additional surveillance if unusual behavior is noted in the visual examination or if plant instrumentation indicates gross fuel failures (see Section 4.2.4.3 in this report).

(5) A statement in the post-irradiation fuel surveillance program that addresses the disposition of failed fuel (see Section 4.2.4.3 in this report).

(6) The enthalpy criteria for irradiated fuel (see Section 4.2.1.3(2) of this report).

(7) A statement that the South Texas fuel rods conform to the revised internal rod pressure design basis described in WCAP-8963 (and WCAP-8964) (see Section 4.2.3.1(8) of this report).

(8) Confirmation that an analysis of the accident involving the most limiting load on a South Texas fuel assembly structure with guide thimble tubes degraded by wear was performed using the design criterion of 6 g (see Section 4.2.1(4) of this report).

(9) Confirmation that cladding collapse time exceeds the expected lifetime of the fuel (see Section 4.2.3.2(2) of this report).

(10) Confirmation that the moisture criterion provided in a previous response (see Section 4.2.1.2.(1) in this report) applies to South Texas, or if some other criteria were used to control moisture in the uranium dioxide, these need to be provided.

(11) Confirmation that the Revision 1 versions of WCAP-9220-P-A and WCAP-9221-A are referenced in the FSAR (see Sections 4.2.1.2(6), 4.2.3.2(6) and 4.2.3.3(3) of this report).

(12) Confirmation that in the event of momentary fuel assembly liftoff that damage to adjacent assemblies will not occur and that no ill consequences of momentary liftoff are expected (see Section 4.2.3.1(9) of this report).

(13) Confirmation that the incorrect reference (Reference 4.2-10) in Section 4.2.3.3(2) of the FSAR is replaced by the correct reference (Reference 4.2-8).

(14) A determination that the fuel assembly mechanical response to seismic and LOCA forces meets the reqirements of Appendix A of SRP Section 4.2 (see Section 4.2.3.3(4) of this report)

When the above are provided, the staff will conclude that the South Texas fuel has been designed so that (1) the fuel system will not be damaged as a result of normal operation and anticipated operational occurrences, (2) fuel damage during postulated accidents would not be severe enough to prevent control rod insertion when it is required, and (3) core coolability will always be maintained, even after severe postulated accidents. Thus, the plan will meet the related requirements of 10 CFR 50.46; GDC 10, 27, and 35; 10 CFR 50, Appendix K; and 10 CFR 100.

4.3 Nuclear Design

Each South Texas Units 1 and 2 power plant has a reactor core consisting of 193 fuel assemblies of the Westinghouse standard 17x17 design (except for length). The core has a design heat output of 3800 MWt, and, except for the power level and the core length, is similar in most respects in nuclear design to the Callaway reactor and other recent Westinghouse four-loop reactors. The staff has reviewed the nuclear design of the South Texas reactors in accordance with SRP Section 4.3.

In the areas of significance to the nuclear design there are two primary and several secondary differences in the design relative to standard four-loop

Westinghouse reactors with SFAs (e.g., Callaway or Seabrook). The primary differences are the power level increase from 3411 to 3800 MWt and an active core length increase from a 12-foot core to a 14-foot core. Largely as a result of the length increase and the resulting potential for increased axial power peaking, the design total power density peaking factor, F_Q, has been increased from the normal 2.32 to 2.50.

In a change not directly related to the primary design changes, the design enthalpy rise peaking factor, $F_{\Delta H}$, has been decreased from 1.55 to 1.52. Also the design required shutdown margin (in modes 1, 2, 3, and 4) has been increased from the usual 1.30 or 1.60 to 1.75% Δk. As a result of the power level, length, and peaking factor changes, the core average power density is down from 104.3 to 99.8 kW/l, the average linear power density is down from 5.44 to 5.20 kW/ft, and the peak linear power density is up from 12.6 to 13.0 kW/ft.

Other nuclear design parameters are the same as, or fall within, the normal range for standard Westinghouse reactors. This includes both the input parameters (radial core geometry, number of control rods, control rod material, number of burnable poison rods, fuel enrichments, etc.) and the parameters that are the results of design calculations (moderator temperature reactivity coefficient, Doppler coefficient, control rod worths).

The only novel design parameter that is of potential significance to the nuclear design review and evaluation is the increase in length. The increased total power level is of little significance, primarily because of the increased core length and resulting lower average power density. The slightly larger (3%) than normal peak power density (13.0 kW/ft) has no significant effect on the nuclear design. The larger length results in a slightly less axially stable power distribution during power changes and resulting xenon transients, which produces a potential for a larger axial peaking factor. This is accounted for by the larger design total peaking factor, F_Q. However, apart from a small increase in axial peaking, the increased instability is not significant and the methodology of operational power distribution control and related analyses are not changed.

Thus the South Texas reactors retain in their nuclear design, analysis, and parameters a close similarity to standard Westinghouse reactors with no adverse deviation, which is significant to a nuclear design safety evaluation. The nuclear design parameters that were developed and used for transient and accident analyses fall within (or very close to) ranges previously used and reviewed for other Westinghouse reactors. The discussion which follows is, therefore, very similar to the evaluations previously presented for other Westinghouse (standard) reactors.

4.3.1 Design Bases

The FSAR presents design bases that comply with the applicable GDC. Acceptable fuel design limits are specified (GDC 10), a negative prompt feedback coefficient is specified (GDC 11), and tendency toward divergent operation (power oscillation) is not permitted (GDC 12). Design bases are presented that require a control and monitoring system (GDC 13) that automatically initiates a rapid reactivity insertion to prevent exceeding fuel design limits in normal operation or anticipated transients (GDC 20). The control system must be designed so that a single malfunction or single operator error will cause no violation of fuel design limits (GDC 25). A reactor coolant boration system is provided which is capable of bringing the reactor to cold shutdown conditions (GDC 26) and the control system is required to control reactivity changes during accident conditions when combined with the engineered safety features (GDC 27). Reactivity accident conditions are required to be limited so that no damage to the reactor coolant system boundary occurs (GDC 28).

The staff finds the design bases in the FSAR acceptable.

4.3.2 Design Description

The FSAR describes the first-cycle fuel loading, which consists of three different enrichments and has a first-cycle length of approximately 1 year. The enrichment distribution, burnable poison distribution, soluble poison concentration, and higher isotope (actinide) content as a function of core exposure are presented. These are within normal ranges and are acceptable. Values presented for the delayed neutron fraction and prompt neutron lifetime at beginning and end of cycle are consistent with those normally used and are acceptable.

(1) Power Distribution

The design bases affecting power distribution are

- The peaking factor in the core will not be greater than 2.50 during normal operation of full power to meet the initial conditions assumed in the LOCA analysis.

- Under normal conditions (including maximum overpower) the peak fuel power will not produce fuel centerline melting.

- The core will not operate during normal operation or anticipated operational occurrences with a power distribution that will cause the departure from nucleate boiling ratio to fall below 1.3 (W-3 correlation with modified spacer factor).

The 2.50 F_Q peaking factor is determined and maintained via calculations of extremes of allowed transient power distributions and periodically measured radial power distributions and radial peaking factors F_{xy} and $F_{\Delta H}$. These also provide maximum initial conditions for events described in Section 15 that ensure that peak full power does not cause centerline fuel melting or result in departure from nucleate boiling during anticipated operational occurrences.

The applicant has described how the core will be operated and power distribution monitored to ensure that these limits are met. The core will be operated in the constant axial offset control (CAOC) mode, which has been shown to result in peaking factors less than 2.50 for this 14-foot core design for both constant power and load following operation. The applicant has elected to use an improved load following package, developed by Westinghouse, in South Texas Units 1 and 2.

CAOC is described in WCAP-8385 (proprietary) and WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures." This report contains methodology for operation with and without part length control rods. The former mode allows better return to power capability than the latter. Use of part-length rods has been withdrawn from Westinghouse reactors. The

improved load-follow strategy provides a return to power capability during operation without part-length rods comparable to the level previously obtainable from operation with part-length rods.

The improved load-follow strategy involves a redesignated control rod bank and modified overlap that allows greater reactivity insertion than the former design bank within the constraints of a widened, asymmetric CAOC band. The control bank has been changed from eight to four rods. The four rods removed from the control bank have been reassigned as a shutdown bank, thus maintaining shutdown margins. The CAOC band has been changed from ±5 to +3, -12 delta flux difference. The greater inserted reactivity is available for return to power capability upon control rod withdrawal. Another element in the load-follow strategy is the use of moderator temperature reductions to augment return to power capability. The temperature reduction adds reactivity during rapid return to power through the inherently negative moderator temperature coefficient.

The analysis used to calculate the maximum peaking factor that can occur using the improved strategy expands the set in the CAOC topical report to 18 calculational cases. However, with the reassigned control bank, maneuvers resulting in greater control rod insertion for a longer duration become operationally practical but tend to become slightly more limiting in terms of total peaking factors. Therefore, simulated load-follow maneuvers that return the flux difference to the target value (and thereby reduce control rod insertion) have been replaced by load-follow strategies that maintain the deeper rod insertion. As a result of its evaluation, the staff agrees with Westinghouse's conclusion that substitution of these more conservative cases will maintain the limiting nature of the 18-case load-following analysis.

Unlike reactors with 12-foot cores and a design F_Q of 2.32, the analyses show that the South Texas reactors can maintain the required peaking factor, 2.50, even at beginning of cycle conditions, with the +3, -12 delta flux difference, and thus do not require special first-cycle Technical Specification limits.

The staff concludes, for the reasons stated above, that the improved load-follow package will continue to prevent the 2.50 peaking factor limit from being exceeded in normal operation of the power plant, and, therefore, is acceptable.

South Texas has used a design $F_{\Delta H}$ value of 1.52, slightly less than the more usual value of 1.55. The usual nominal value is 1.44 and an 8% design uncertainty value is added. South Texas has used a 6% value. Because the expected uncertainty is about 4%, the use of 6% is still acceptable. The value of $F_{\Delta H}$ in operation is confirmed by the incore instrumentation and the 1.52 value will be required by Technical Specifications. It is acceptable as a design value.

Two types of instrumentation systems are normally provided to monitor core power distribution. Excore detectors with two axial sections are used to monitor core power, axial offset and azimuthal tilt for the 2.50 F_Q limit, and movable incore detectors permit detailed power distributions to be measured, particularly F_{xy} and $F_{\Delta H}$, to ensure that Technical Specification limits are met. These systems are used in operating reactors supplied by Westinghouse, and the staff finds their use acceptable for South Texas Units 1 and 2 when a 2.50 limit is the minimum requirement (or possibly lower when cycle specific 18-case or equivalent analyses so indicate).

(2) <u>Reactivity Coefficients</u>

The reactivity coefficients are expressions of the effect on core reactivity of changes in such core conditions as power, fuel and moderator temperature, moderator density, and boron concentration. These coefficients vary with fuel burnup and power level. The applicant has presented values of the coefficients in the FSAR and has evaluated the uncertainties of these values. The staff has reviewed the calculated values of reactivity coefficients and have concluded that they adequately represent the full range of expected values. The staff has reviewed the reactivity coefficients used in the transient and accident analyses and conclude that they conservatively bound the expected values, including uncertainties. Further, moderator and power Doppler coefficients along with boron worth are measured as part of the startup physics testing to ensure that actual values are within those used in these analyses.

(3) Control

To allow for changes in reactivity due to reactor heatup, load following, and fuel burnup with consequent fission product buildup, a significant amount of excess reactivity is built into the core. The excess reactivity is controlled by a combination of full length control rods and soluble boron. Soluble boron is used to control changes as a result of

- moderator density and temperature changes from ambient to operating temperatures

- equilibrium xenon and samarium buildup

- fuel depletion and fission product buildup (that portion not controlled by lumped burnable poison)

- transient xenon resulting from load following

Control rods are used to control reactivity changes as a result of

- moderator reactivity changes from hot zero to full power

- Fuel temperature changes (Doppler) reactivity changes

Burnable poison rods placed in some fuel assemblies are used for radial flux shaping and to control part of the reactivity change resulting from fuel depletion and fission product buildup.

The applicant has provided data to show that adequate control exists to satisfy the above requirements, with enough additional control rod worth to provide a hot shutdown effective multiplication factor less than the design basis value of 0.9825 (shutdown margin of 1.75% Δk) during initial equilibrium fuel cycles with the most reactive control rod stuck out the core. This shutdown margin is larger than the usual 1.6 or 1.3% Δk provided on other four-loop plants. In addition, the CVCS will be capable of shutting down the reactor by adding soluble boron and maintaining it shut down in the cold, xenon-free condition at any time in core life. These two systems satisfy GDC 26.

Comparisons have been made between calculated and measured control rod bank worth in operating reactors and in critical experiments. These comparisons lead to the conclusion that bank worths may be calculated to within approximately 10%. In addition bank worth measurements are performed as part of the startup test program to ensure that conservative values have been used in safety analyses. The South Texas control rod pattern design has 57 rods, rather than the more usual four-loop 53, to provide greater control. A 57-rod pattern was also used in the Seabrook design.

South Texas will use hafnium control rods rather than the more common Ag-In-Cd rods. The hafnium rod has been reviewed in connection with several other Westinghouse reactors (NUREG-0797, Supplement 1). The reviews concluded that the hafnium rods provide a completely acceptable replacement for Ag-In-Cd rods. They are, therefore, acceptable for South Texas.

On the basis of these comparisons, the staff concludes that the applicant has made suitably conservative assessments of reactivity control requirements and that adequate control rod worths have been provided to ensure shutdown capability.

(4) Control Rod Patterns and Reactivity Worths

The control rods are divided into two categories, shutdown rods and regulating rods. The shutdown rods are always completely out of the core when the reactor is at operating conditions. Core power changes are made with regulating rods that are nearly out of the core when it is operating at full power. Regulating rod insertion will be controlled by power-dependent insertion limits required in the Technical Specifications to ensure that

- There is sufficient negative reactivity available to permit rapid shutdown of the reactor with adequate margin.

- The worth of a control rod that might be ejected is not greater than that that has been shown to have acceptable consequences in the safety analyses.

The staff has reviewed the calculated rod worths and the uncertainties in these worths, and concludes that rapid shutdown capability exists at all times in

core life assuming the most reactive control rod assembly is stuck out of the core.

(5) Stability

The stability of the South Texas Units 1 and 2 cores to xenon-induced spatial oscillations is discussed in the FSAR. The overall negative reactivity (power) coefficient provides assurance that the reactor will be stable against total power oscillation. The applicant also concluded that sustained radial or azimuthal xenon oscillations are not possible. This conclusion is based on measurements on an operating reactor of the same radial dimensions that showed stability against these oscillations. The staff concurs with this conclusion.

This core is predicted to be unstable with respect to axial xenon oscillations after about 8000 MWd/t of exposure. This is somewhat sooner that for a 12-foot core (about 11,000 MWd/t), but the stability problem is not signficantly different. It can easily be controlled with the control rods at all times in life, and scram protection on axial power imbalance limits is always available. The applicant has acceptably shown that axial oscillations may be controlled by the regulating rods to prevent reaching any fuel damage limits.

(6) Criticality of Fuel Assemblies

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer and storage facilities. The FSAR includes information on calculational techniques and assumptions used to ensure that criticality is avoided. The staff has reviewed this information and the criteria that will be employed and finds them acceptable.

(7) Vessel Irradiation

Values are presented for the neutron flux in various energy ranges at mid-height of the pressure vessel inner boundary. Core flux shapes calculated by standard design methods are input to a transport theory calculation (S_n) that results in a neutron flux of 2.1×10^{10} neutrons per cm^2/sec per second having energy greater than 10^6 electron-volts at the inner vessel boundary. This

results in a fluence of 2.2×10^{19} neutrons per cm^2 for a 40-year vessel life with an 80% use factor. The methods used for these calculations are state of the art, and the staff conclude that acceptable analytical procedures have been used to calculate the vessel fluence.

4.3.3 Analytical Methods

The applicant has described the computer programs and calculational techniques used to obtain the nuclear characteristics of the reactor design. The calculations consist of three distinct types, which are performed in sequence: determination of effective fuel temperatures, generation of macroscopic few-group parameters, and space-dependent few-group diffusion calculations. The programs used (e.g., LASER, TWINKLE, LEOPARD, TURTLE and PANDA) have been applied as part of the applications for most earlier Westinghouse-designed nuclear plant facilities, and the predicted results have been compared with measured characteristics obtained during many startup tests for first-cycle and reload cores. These results have validated the ability of these methods to predict experimental results. Therefore, the staff concludes that these methods are acceptable for use in calculating the nuclear characteristics of South Texas Units 1 and 2.

4.3.4 Summary of Evaluation Findings

The South Texas 2 nuclear design was reviewed according to SRP Section 4.3 (NUREG-0800). All areas of review and review procedures from the SRP have been followed either for this reactor or for previous similar reactors (e.g., Callaway) or for Topical Report reviews.

The applicant has described the computer programs and calculational techniques used to predict the nuclear characteristics of the reactor design and has provided examples to demonstrate the ability of the analyses to predict reactivity and physics characteristics.

To allow for changes of reactivity as a result reactor heatup, changes in operating conditions, fuel burnup, and fission product buildup, a significant amount of excess reactivity is designed into the core. The applicant has

provided substantial information relating to core reactivity balances for the first cycle and has shown that means have been incorporated into the design to control excess reactivity at all times. The applicant has shown that sufficient control rod worth is available to make the reactor subcritical with an effective multiplication factor no greater than 0.9825 in the hot condition at any time during the cycle with the most reactive control rod stuck in the fully withdrawn position. On the basis of its review, the staff concludes (1) that the applicant's assessment of reactivity control requirements over the first-core cycle is suitably conservative, and (2) that adequate negative worth has been provided by the control system to ensure shutdown capability. Reactivity control requirements will be reviewed for additional cycles as this information becomes available. The staff also concludes that nuclear design bases, features, and limits have been established in conformance with GDC 10, 11, 12, 13, 20, 25, 26, 27, and 28.

The applicant has met GDC 11 with respect to prompt inherent nuclear feedback characteristics in the power operating range by calculating a negative Doppler coefficient of reactivity, and using calculational methods that have been found acceptable. The staff has reviewed the Doppler reactivity coefficients in this case and found this to be suitably conservative.

The applicant has met GDC 12 with respect to power oscillations that could result in conditions exceeding specified acceptable fuel design limits by showing that such power oscillations are not possible and/or can be easily detected and thereby remedied, and using calculational methods that have been found acceptable.

The applicant has met GDC 13 with the respect to provisions of instrumentation and controls to monitor variables and systems that can affect the fission process by providing instrumentation and systems to monitor the core power distribution, control rod positions and patterns, and other process variables such as temperature and pressure, and providing suitable alarms and/or control room indications for these monitored variables.

The applicant has met GDC 26 with respect to provision for two independent reactivity control systems of different design by (1) having a system that can reliable control anticipated operational occurrences, (2) having a system that

can hold the core subcritical under cold conditions, and (3) having a system that can control planned, normal power changes.

The applicant has met GDC 27 with respect to reactivity control systems that have a combined capability in conjunction with poison addition by the emergency core cooling system of reliable controlling reactivity changes under postulated accident conditions by providing a movable control rod system and a liquid poison system, and performing calculations to demonstrate that the core has sufficient shutdown margin with the highest-worth stuck rod.

The applicant has met GDC 28 with respect to postulated reactivity accidents by (reviewed under Section 15.4.8) (1) meeting the regulatory position in RG 1.77, (2) meeting the criteria on the capability to cool the core, and (3) using calculational methods that have been found acceptable for reactivity insertion accidents.

The applicant has met GDC 10, 20, and 25 with respect to specified acceptable fuel design limits by providing analyses demonstrating (1) that normal operation, including the effects of anticipated operational occurrences, have met fuel design criteria; (2) that the automatic initiation of the reactivity control system assures that fuel design criteria are not exceeded as a result of anticipated operational occurrences and assures the automatic operation of systems and components important to safety under accident conditions; and (3) that no single malfunction of the reactivity control system causes violation of the fuel design limits.

4.4 Thermal-Hydraulic Design

4.4.1 Design Bases

The principal thermal-hydraulic design basis for the South Texas plant is the avoidance of thermal-hydraulic-induced fuel damage during normal steady-state operation and anticipated operational transients. To satisfy the design basis, design analysis is performed and design limits are established based on the criteria discussed in the subsections which follow.

4.4.1.1 Departure From Nucleate Boiling

The margin to DNB at any point in the core is expressed in terms of the departure from nucleate boiling ratio (DNBR). The DNBR is defined as the ratio of the heat flux required to produce departure from nucleate boiling at the calculated local conditions to the actual local heat flux.

The thermal-hydraulic design basis for the DNB is given in FSAR Section 4.4.1.1.

4.4.1.2 Fuel Temperature

The fuel temperature design basis is given in FSAR Section 4.4.1.2.

4.4.1.3 Core Flow Design Basis

A minimum of 95.5% of the thermal flow passes through the fuel rod region of the core and is effective for fuel rod cooling. Coolant flow through the thimble tubes and the leakage from the core barrel-baffle region into the core are not considered effective for heat removal.

Core cooling evaluations are based on the thermal flow rate (minimum flow) entering the reactor vessel. A maximum of 4.5% of this value is allowed as bypass flow. This includes rod cluster control guide thimble cooling flow, head cooling flow, baffle leakage, and leakage to the vessel outlet nozzle.

4.4.1.4 Hydrodynamic Stability

The hydrodynamic stability design basis is given in FSAR Section 4.4.1.4.

4.4.2 Thermal-Hydraulic Design Methodology

4.4.2.1 Thermal-Hydraulic Comparison

The thermal-hydraulic design of South Texas is not identical to any operating units. It is very similar to the RESAR-414 design which has been previously reviewed and approved by the staff but not proposed for licensing of any actual

reactor units. FSAR Table 4.4-1 compares the design parameters of South Texas and McGuire, which is a similar operating reactor.

The fundamental difference in core geometry between South Texas and McGuire is an increase of 24 inches in the nominal active fuel length from 144 to 168 inches. (Note that the actual fuel rod is 176.69 inches long.)

This increase in the active fuel length allows the average and linear heat generation rate (kW/ft) and heat flux to remain approximately the same for the 168-inch core with 3800 MWt power rating as that of a 144-inch, 3411-MWt core, (see FSAR Table 4.4-1). A slightly higher peak linear heat generation rate and heat flux results from a higher design peaking factor, $F_Q = 2.5$. The grid design for both plants is identical with the 14-foot core using two more grids (10) than the 12-foot core (8).

4.4.2.2 Departure from Nucleate Boiling

DNBRs are calculated using the W-3 critical heat flux correlation. The coupled THINC-IV/THINC I computer code is used to determine the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The reactor is designed to a minimum DNBR ≧ 1.30 as well as to no fuel centerline melting during normal operation, operational transients and faults of moderate frequency. All DNBR analyses preformed for South Texas have included a DNBR multiplier of 0.88 (R factor) in accordance with the results of 17 x 17 geometry DNB tests.

4.4.3 Design Abnormalities

4.4.3.1 Fuel Rod Bowing

The phenomenon of fuel rod bowing, as described in WCAP-8691 (Revision 1), which has been reviewed and approved by the staff, must be accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from the evaluation of DNBR and/or margin obtained from measured plant operating parameters (such as

$F^N_{\Delta H}$ or core flow), which are less limiting than those required by the plant safety analysis, are used to offset the effect of rod bow.

The safety analysis for the South Texas reactors maintained sufficient margin (3.3%) to accommodate full-and low-flow DNBR penalties identified in WCAP-8691 (Revision 1) with the incorporation of the L^2/I scaling factor (I = fuel rod bending moment of inertia, L = span length) to account for 17x17 XL span lengths. A design limit DNBR of 1.30 versus 1.28, a grid spacing coefficient (K_S) of 0.059 versus 0.066, and a thermal diffusion coefficient (TDC) of 0.059 versus 0.061 are examples of conservatism utilized in the safety analysis.

The maximum rod bow penalties accounted for in the design safety analysis are based on a region average burnup of 33,000 MWd/MTU. At burnups greater than 33,000 MWd/MTU, credit is taken for the effect of $F^N_{\Delta H}$ burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory, and no additional rod bow penalty is required. The staff finds that rod bow penalties have been properly offset by the DNBR margins calculated by Westinghouse and are acceptable.

4.4.3.2 Crud Deposition and Flow Uncertainty

Crud deposition in the core and the associate change in core pressure drop is to be detected by flow measurement as described in the FSAR. Therefore, South Texas Technical Specifications should require that the RCS flow be monitored at least every 24 hours.

The thermal design flow for South Texas is defined as 91.8% of the best estimate flow. The procedure for verifying this value must be included in the plant Technical Specifications and tests of the primary system before initial criticality must be made to verify that a conservative primary system coolant flow rate has been used in the design and analyses of the plant.

4.4.3.3 Hydrodynamic Stability

In steady-state, two-phase, heated flow in parallel channels, the potential for hydrodynamic instability exists. The applicant provided information in FSAR

Section 4.4.4.6 to support the contention that the South Texas core is thermal-hydraulically stable. This information is further supported by Lahey and Moody, 1977,; Saha, Ishii and Zuber, 1976; and Kao, Morgan, and Parker, 1973.

The staff concludes that past operating experience, flow stability experiments, and the inherent thermal-hydraulic characteristics of Westinghouse PWRs provide a basis for accepting the South Texas stability evaluation.

4.4.4 Loose Parts Monitoring Systems

The applicant has provided documentation of the South Texas loose parts monitoring system. However, for the staff to complete its review the applicant must state that the installed system will conform to RG 1.133, Revision 1, "Loose-Part Detection Program for the Primary System of Light-Water Cooled Reactors."

4.4.5 NUREG-0737 Item II.F.2

The FSAR describes the inadequate core cooling (ICC) instrumentation, which utilizes the microprocessor based qualified display processing system (QDPS) for reactor coolant system subcooled margin monitoring, the generically approved Combustion Engineering HJTC system for measurement of the reactor coolant inventory in the upper head and plenum regions of the reactor vessel, and two redundant groups of thermo-couples to measure core exit temperature. To complete the review of this system, the staff requires the following:

(1) An item by item evaluation of the core exit thermocouple system against the requirements of Attachment 1 of Item II.F.2 of NUREG-0737.

(2) A delineation of any aspect of the ICC system that is not in conformance with NUREG-0737 Item II.F.2 and a justification for any deviations.

(3) The schedule for having the entire ICC system installed and ready for testing.

4.4.6 Conclusion and Summary

The thermal-hydraulic design of the reactor has been reviewed according to SRP Section 4.4 (NUREG-0800). The review has included the design basis and the steady-state analysis of the core thermal-hydraulic performance. The review concentrated on the difference between the proposed design and those designs that have been previously reviewed and found acceptable by the staff.

On the basis of its review, the staff concludes that the thermal-hydraulic design of the initial reactor core is acceptable, provided the applicant satisfactory resolves for the following items identified above.

(1) Loose Parts Monitoring Systems
(2) NUREG-0737 Item II.F.2, Inadequate Core Cooling Instrumentation

5 REACTOR COOLANT SYSTEM

5.1 Summary Description

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inspection and Testing

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

5.2.4.1 Compliance with the SRP

The review under SRP Section 5.2.4 is continuing because the applicant has not submitted the preservice inspection program (PSI) and has not completed the examinations. The review to date was conducted in accordance with Section 5.2.4 except as discussed below.

The review under Paragraph II.4, "Acceptance Criteria, Inspection Intervals," has not been done because this area applies only to inservice inspections (ISI). This subject will be addressed during review of the ISI program after licensing.

The review under Paragraph II.5, "Acceptance Criteria, Evaluation of Examination Results," was done. The applicant committed in the FSAR to incorporate ASME Code Article IWB-3000, "Acceptance Standards for Flaw Indications," into the PSI program. However, ongoing NRC generic activities and research projects indicate that the ASME Code procedures presently specified may not always detect the acceptable-size flaws specified in the IWB-3000 acceptance standards. For example, ASME Code procedures specified for volumetric examination of the reactor vessel, bolts and studs, and piping have not proven to be capable of detecting the acceptable-size flaws in all cases. The staff will continue to evaluate the development of new or improved procedures and will require that

these improved procedures be made a part of the inservice examination requirements. The applicant's repair procedures based on ASME Code Article IWB-4000, "Repair Procedures," have not been reviewed. Repairs are not generally necessary in the PSI program. This subject will be addressed during the staff review of the ISI program.

The review under Paragraph II.7, "Acceptance Criteria, Code Exemptions," has not been completed because the applicant has not submitted the PSI program. The SRP requires that the applicant list these exemptions, if any are used.

The review under Paragraph II.8, "Acceptance Criteria, Relief Requests," has not been completed because the applicant has not identified all limitations to examination. Specific areas where ASME Code examination requirements cannot be met will be identified as performance of the PSI progresses. The complete evaluation of the PSI program will be presented in a supplement to this SER after the applicant submits the required examination information, identifies all plant-specific areas where ASME Code Section XI requirements cannot be met, and provides a supporting technical justification.

5.2.4.2 Examination Requirements

GDC 32, "Inspection of Reactor Coolant Pressure Boundary," requires, in part, that components of the reactor coolant pressure boundary (RCPB) be designed to permit periodic examination and testing of important areas and features to assess their structural and leak-tight integrity. To ensure that no deleterious defects develop during service, selected welds and weld heat-affected-zones (HAZs) will be examined periodically.

The design of the ASME Code Class 1 and 2 components of the RCPB incorporates provisions for access for inservice examinations, as required by Subarticle IWA-1500 of Section XI of the ASME Code. 10 CFR 50.55a(g) defines the detailed requirements for the preservice and inservice inspection programs for light water-cooled nuclear power facility components. Based upon the construction permit date of December 22, 1975, components (including supports) that are classified as ASME Code Class 1 and 2 shall meet the preservice examination requirements set forth in editions of Section XI of the ASME Code and addenda

applied to the construction of the particular component. The components (including supports) may meet the requirements set forth in subsequent editions of this code and addenda that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. The initial ISI program must comply with the requirements of the latest edition and addenda of Section XI of the ASME Code in effect 12 months prior to the date of issuance of the operating license, subject to the limitations and modifications listed in 10 CFR 50.55a(b).

5.2.4.3 Evaluation of Compliance

The staff has reviewed the information presented in the FSAR through Amendment 46 and the applicant's letter dated April 4, 1985. The PSI program has not been submitted for staff review. However, the applicant has committed to submit preservice examination plans prior to the initiation of the associated examinations. The preservice examination plans will describe the PSI program for Unit 1 in terms of the Code and regulatory bases for the program, scope of systems and components subject to PSI, and technical positions and approaches to be incorporated in the program. The preservice examination plans will contain a detailed listing of the specific systems, welds, and examination areas to be examined; the examination methods and procedures applicable to each examination; and isometric drawings denoting the locations of welds and examination areas in Class 1, 2, and 3 systems subject to examination and testing.

The Unit 1 PSI will be conducted in accordance with the 1980 edition of ASME Code Section XI with addenda through the Winter 1981 addenda. In accordance with 10 CFR 50.55a(g), examination requirements of Subsection IWE of Section XI will not be included in the PSI program. The Unit 1 Class 1 components will be examined during the PSI in accordance with Subsection IWB of Section XI. Eddy current PSI examinations of steam generator tubing will be conducted at the site in accordance with the Technical Specifications and Section XI. Component supports for Unit 1 Class 1, 2, and 3 components will be examined and tested during the PSI in accordance with Subsection IWF of Section XI.

Preservice testing of snubbers as required by IWF-5000 of Section XI will be conducted in the shop of the snubber manufacturer. The additional preservice

examination and pre-operational testing requirements for snubbers specified in the staff October 17, 1980, letter to the applicant (ST-AE-HL-608) will be done at the site.

The applicant will comply with RG 1.150, "Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations," Revision 1, Appendix A as permitted by paragraph 8.0 of the regulatory guide. Examinations of the reactor pressure vessel (RPV) will be performed during PSI and ISI in accordance with Appendix A. In addition to the 0°, 45°, and 60° ultrasonic examinations required by Section XI, a full V, 45° shear wave examination will be conducted by gating the instrumentation. This will be done to ensure that the examination covers the near-surface volume of clad and base metal between the 1/4 T through-wall position and the examination surface. Additionally, a refracted longitudinal wave ultrasonic examination technique will be employed to detect flaws in the near-surface volume of clad and base metal of the core belt region of the vessel. This technique will be optimized for detection of under-clad cracking. The calibration sensitivity of this technique will be established on side-drilled holes installed in the RPV calibration blocks at the clad-base metal interface and within the base metal.

The applicant has stated that the ultrasonic examination procedure that will be used to examine welds in SA-351 Grade CF-8A (centrifugally cast stainless steel) piping during the Unit 1 PSI will meet the requirements of ASME Code Section XI. This refracted longitudinal wave ultrasonic examination procedure has been used at several other PWR plants. The applicant is aware that recent studies by research organizations indicate that the acoustic properties of SA-351, Grade CF-8A material may reduce the effectiveness of some ultrasonic examination procedures for flaw detection. Thus the applicant is currently evaluating potential methods for determining the effectiveness of the procedure that will be used. The applicant has committed to identify all plant-specific areas where the Code requirements cannot be met and to provide a supporting technical justification for requesting relief. The staff review will be completed after the applicant

(1) dockets a complete and acceptable PSI program

(2) submits all relief requests with a supporting technical justification

The ISI program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b) but before inservice inspection begins during the first refueling outage.

5.2.4.4 Conclusion

The conduct of periodic examinations and hydrostatic testing of RCPB pressure-retaining components in accordance with the ASME Code and 10 CFR 50 will provide reasonable assurance that structural degradation or loss of leak-tight integrity occurring during service will be detected in time to permit corrective action before the safety functions of a component are compromised. Compliance with the preservice and inservice examinations required by the Code and 10 CFR 50 constitutes an acceptable basis for satisfying the inspection requirements of GDC 32.

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

The staff has reviewed the fracture toughness of ferritic reactor vessel and RCPB materials, and the materials surveillance program for the reactor vessel beltline according to Paragraphs II.5, II.6, and II.7 (Appendices G and H, 10 CFR 50) of SRP Section 5.3.1 (NUREG-0800).

GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," requires, in part, that the RCPB be designed with sufficient margin to ensure that, when stressed under operating, maintenance, and test conditions, the boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. GDC 32, "Inspection of Reactor Coolant Pressure Boundary," requires, in part, that the RCPB be designed to permit an appropriate material surveillance program for the reactor pressure vessel.

The fracture toughness requirements for the ferritic materials of the reactor coolant pressure boundary are defined in 10 CFR 50 Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Requirements."

5.3.1.1 Compliance with 10 CFR 50.55(a)

10 CFR 50.55(a) specifies the edition and addenda of the ASME Code that are applicable to the design and fabrication of the reactor vessel and RCPB components. The Code edition and addenda required depend on the date the construction permit (CP) was issued. The South Texas Projects Units 1 and 2 construction permit was issued in December 1975. Based upon that CP date, 10 CFR 50.55(a) requires that ferritic materials used for the reactor vessels be designed and constructed to editions that are no earlier than the Summer 1972 Addenda to the 1971 ASME Code and that ferritic materials used in piping, pumps, and valves be constructed to editions that are no earlier than the Winter 1972 Addenda to the Code. The South Texas ferritic materials meet all the above requirements.

5.3.1.2 Compliance with Appendix G to 10 CFR 50

The staff evaluation of the FSAR to determine the degree of compliance with the fracture toughness requirements of Appendix G to 10 CFR 50, indicates that the applicant has met all the requirements of this Appendix.

5.3.1.3 Compliance with Appendix H to 10 CFR 50

The materials surveillance program will be used to monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from exposure to neutron irradiation and the thermal environment, as required by GDC 32. The surveillance program, which must be in compliance with Appendix H to 10 CFR 50 and ASTM E-185-82, "Standard Recommended Practices for Surveillance Tests for Nuclear Reactor Vessels," requires that fracture toughness data be obtained from material specimens that are representative of the limiting base, weld, and heat-affected zone materials in the beltline region. These data will permit the determination of the conditions under which the vessel can be operated with adequate margins of safety against fracture throughout its service life.

On the basis of its review of the applicant's submittal, the staff has determined that the reactor vessel surveillance program meets Appendix H to 10 CFR 50 and ASTM E-185-82.

5.3.1.4 Conclusions Regarding Compliance with Appendices G and H to 10 CFR 50

Appendix G, "Protection Against Non-Ductile Failures," to Section III of the ASME Code was used--together with the fracture toughness test results required by Appendices G and H to 10 CFR 50--to calculate the pressure-temperature limitations for the reactor vessels.

The fracture toughness tests required by the ASME Code and by Appendix G of 10 CFR 50 provide reasonable assurance that adequate safety margins against the possibility of nonductile behavior or rapidly propagating fracture can be established for all RCPB pressure-retaining components. The use of Appendix G to Section III of the ASME Code as a guide in establishing safe operating procedures and the use of the results of the fracture toughness tests performed in accordance with the ASME Code and NRC regulations will provide adequate safety margins during operating, testing, maintenance, and anticipated transient conditions. Compliance with these Code provisions and NRC regulations constitutes an acceptable basis for satisfying GDC 31.

The materials surveillance program, required by Appendix H to 10 CFR 50, will provide information on the effects of irradiation on material properties so that (1) changes in the fracture toughness of the material in the reactor vessels beltline can be properly assessed and (2) adequate safety margins against the possibility of vessel failure can be provided.

Compliance with Appendix H to 10 CFR 50 and ASTM E-185-82 ensures that the surveillance program will be capable of monitoring radiation-induced changes in the fracture toughness of the reactor vessel material and satisfies GDC 32.

There is reasonable assurance that the surveillance program will monitor the change in the beltline region material properties to the extent required for establishing pressure-temperature limits and to preserve the integrity of the vessel. The surveillance program will generate sufficient information to

permit the determination of conditions under which the reactor vessel will be operated with an adequate margin against rapidly propagating fracture throughout its service lifetime.

5.3.1.5 Reactor Vessel Fasteners

The reactor vessel head closure system used for securing the vessel head to the reactor pressure vessel is called Roto-lok. This closure system is made up of a stud, vessel insert, closure nut, and spherical washer. These parts are made of 4340 steel, as is the conventional closure system. Specific material properties are SA-540, Class 3 - GR B-24 (as modified by ASME Code Case 1605).

The use of Code Case 1605 does not constitute an issue between the NRC and Westinghouse, because use of this Code Case was approved in RG 1.85 (Revision 6, May 1976).

Westinghouse is in conformance with RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." Westinghouse has specified both 45 ft-lb and 25 mils lateral expansion for control of fracture toughness determined by Charpy V-notch testing, required by the ASME Code Section III, Summer 1973 Addenda, and Appendix G to 10 CFR 50, (July 17, 1973, Paragraph IV.A.4). These toughness requirements ensure optimization of the stud bolt material tempering operation with the accompanying reduction of the tensile strength level, when compared with previous ASME Code requirements. After publication of the Summer 1973 Addenda to the Code and Appendix G to 10 CFR 50, wherein the toughness requirements were modified to 45 ft-lb with 25 mils lateral expansion, all bolt material data reviewed on Westinghouse plants showed tensile strengths of less than 170 kpsi.

Additional protection against the possibility of incurring corrosion effects is ensured by the design of the reactor vessel studs, nuts, and washers, which allows them to be completely removed during each refueling. This permits visual and/or nondestructive inspection in parallel with refueling operations to assess protection against corrosion as part of the inservice inspection program.

The closure stud material meets the fracture toughness requirements of ASME Code Section III and Appendix G to 10 CFR 50. Nondestructive examinations are

performed in accordance with ASME Code Section III. Fracture toughness data for the closure stud bolting materials is presented in the FSAR. The stud holes in the reactor flange are sealed with bolting materials, and stud holes are never exposed to the borated refueling cavity water.

The Roto-lok closure stud uses a modified breech-lock design to secure the reactor vessel to the head. The interrupted lugs of the Roto-lok stud cut in the lower and upper ends are generated by cutting separate parallel grooves in the studs rather than a continuous helical groove, as is the case with standard breech-lock threads. This modification prevents any contact with the engaging lugs when the stud is rotated.

An insert is used in the stud hole of the reactor vessel flange. The Roto-lok lugs are machined on the inside diameter of the insert, and the outside diameter is machined with standard threads. The insert is threaded into the vessel flange and locked in place by pins so that the interrupted portions of the lugs assume the same position on all inserts relative to the vessel centerline.

The closure nut threads onto the stud at the reactor vessel head. The closure nut uses a modified four-pitch centralizing acme thread form.

The closure nut rests on a spherical washer that sits on top of the reactor closure head. This spherical washer alleviates bending of the Roto-lok stud.

A prototype Roto-lok closure system has been tested to verify this closure design. Static loads were imposed on the studs which simulated loads during operation. Results of tests performed on the Roto-lok closure system were presented in WCAP-8447.

On the basis of its review, the staff concludes that the reactor vessel fasteners are acceptable and meet the appropriate GDC.

The material used for construction of the reactor vessel bolting has been identified by specification and found to be in conformance with ASME Code Section III. Compliance with the above Code provisions for material specifications satisfies the quality standards requirements of GDC 1 and 30, and 10 CFR 50.55a.

Because the applicant has certified that the materials and fabrication requirements of ASME Code Section III have been complied with, the processes used are considered acceptable. Compliance with these Code provisions meets the quality standards requirements of GDC 1 and 30 and 10 CFR 50.55a.

5.3.2 Pressure Temperature Limits

Appendices G and H to 10 CFR 50 describe the conditions that require pressure-temperature limits and provide the general bases for these limits. These appendices specifically require that pressure-temperature limits provide safety margins at least as great as those recommended in the ASME Code Section III, Appendix G. Appendix G to 10 CFR 50 requires additional safety margins for the closure flange region materials and beltline materials whenever the reactor core is critical, except for low-level physics tests.

The following pressure-temperature limits imposed on the reactor coolant pressure boundary during operation and tests are reviewed to ensure that they provide adequate safety margins against nonductile behavior or rapidly propagating failure of ferritic components, as required by GDC 31:

(1) preservice hydrostatic tests
(2) inservice leak and hydrostatic tests
(3) heatup and cooldown operations
(4) core operation

Appendices G and H to 10 CFR 50 require the applicant to predict the amount of increase in reference temperature, RT_{NDT}, as a result of neutron irradiation. The shift in RT_{NDT} as a result of neutron irradiation is then added to the initial RT_{NDT} to establish the adjusted reference temperature.

The applicant, in letter dated January 25, 1985, provided pressure-temperature limits which they indicate are adequate for 32 effective full power years (EFPY) for Unit 1 and 16 EFPY for Unit 2. Using both Revisions 1 and 2 of RG 1.99, the staff has determined that the proposed pressure-temperature limits meet Appendix G to 10 CFR 50 for 32 EFPY for Unit 1 and 16 EFPY for Unit 2.

The pressure-temperature limits to be imposed on the reactor coolant system for all operating and testing conditions must have adequate safety margins against nonductile or rapidly propagating failure, and must be in conformance with established criteria, codes, and standards. The use of operating limits based on these criteria, as defined by applicable regulations, codes, and standards, will provide reasonable assurance that nonductile or rapidly propagating failure will not occur, and will constitute an acceptable basis for satisfying the applicable requirements of GDC 31.

5.3.3 Reactor Vessel Integrity

Although most areas are reviewed separately in accordance with other review plans, reactor vessel integrity is of such importance that a special summary review of all factors relating to reactor vessel integrity is warranted. In this section, the staff has reviewed the fracture toughness of ferritic reactor vessel and RCPB materials, the pressure-temperature limits for operation of the reactor vessel, and the materials surveillance program for the reactor vessel beltline, according to SRP Section 5.3.3 (NUREG-0800).

The staff has reviewed the information in each area to ensure that it is complete and that no inconsistencies exist that would reduce the certainty of vessel integrity. The areas reviewed and the sections of this report in which they are discussed are

(1) design (Section 5.3.1)
(2) materials of construction (Section 5.3.1)
(3) fabrication methods (Section 5.3.1)
(4) operating conditions (Section 5.3.2)

The staff has reviewed the above factors contributing to the structural integrity of the reactor vessel and concludes that the applicant has complied with Appendices G and H to 10 CFR 50 and there are no special considerations that make it necessary to consider potential reactor vessel failure.

5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pump Flywheel Integrity

The safety objective of this review is to ensure that the integrity of the primary reactor coolant pump flywheel is maintained to prevent failure at normal operating speeds and speeds that might be reached under accident conditions and thus preclude the generation of missiles.

The basis for review is outlined in SRP Section 5.4.1.1 and RG 1.14, "Reactor Coolant Pump Flywheel Integrity," which describes and recommends a method acceptable to the staff for implementing GDC 4, "Environmental and Missile Design Bases," with regard to minimizing the potential for failure of flywheels of the reactor coolant pump.

5.4.1.1 Materials and Fabrication

The flywheel consists of two thick plates bolted together. Each plate is fabricated from SA-533, Grade B, Class 1 steel. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties. The materials as well as finished flywheels are subjected to 100% volumetric ultrasonic inspection using procedures and acceptance standards specified in Section III of the ASME Code.

The nil-ductility transition temperature (NDTT) of the flywheel-material is no higher than 10°F. The Charpy V-notch energy level is at least 50 foot-pounds at 70°F in both the parallel and normal orientation with respect to the rolling direction of the flywheel material. Hence, the reference temperature RT_{NDT}, of 10°F can be assumed.

5.4.1.2 Design Basis

The calculated stresses at the operating speed that result from centrifugal forces and the interference fit on the shaft are within the RG 1.14 limit. The pump runs at about 1190 rpm and may operate briefly at overspeed up to 109% during the loss of outside load. The design speed is 125% of the

operating speed. The flywheels are also tested at 125% of the maximum synchronous speed of the motor. The combined stresses at the design overspeed that result from the interference fit and centrifugal forces are within the RG 1.14 limit.

The flywheels can be inspected by removing the cover; hence, any crack that developed can be noticed. The inservice inspection program follows requirements of Section XI of the ASME Code and the recommendations of RG 1.14.

5.4.1.3 Evaluation

On the basis of its review of the material, fabrication, design, and inspection aspects of the pump flywheels for compliance with RG 1.14, the staff has concluded that the structural integrity of the flywheels is adequate to withstand the forces imposed by overspeed transients without the loss of function. The flywheel will be inspected periodically to ensure that the integrity is maintained.

5.4.2 Steam Generators

5.4.2.1 Steam Generator Materials

5.4.2.2 Steam Generator Tube Inservice Inspection

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

5.4.2.2.1 Compliance with the SRP

The staff has reviewed the FSAR through Amendment 46 and the applicant's letter dated April 4, 1985, in accordance with SRP Section 5.4.2.2.

5.4.2.2.2 Evaluation of the Inspection Program

GDC 32 requires, in part, that RCPB components be designed to permit periodic examination and testing of important areas and features to assess their

structural and leak-tight integrity. The South Texas steam generators have been designed to meet the ASME Code requirements for Class 1 and 2 components. Provisions also have been made to permit inservice inspection of the Class 1 and 2 components, including individual steam generator tubes. The design aspects that provide access for examination and the proposed inspection program must comply with the requirements of Section XI of the ASME Code, and follow RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, and NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," with respect to the examination methods to be used, provisions for a baseline examination, selection and sampling of tubes, inspection intervals, and actions to be taken if defects are identified.

The applicant has committed to perform a preservice examination of the steam generator tubing at the site in accordance with RG 1.83, Revision 1, and the requirements of the Technical Specifications and Section XI of the ASME Code. NUREG-0452, Revision 4, requires a preservice examination of the full length of each tube in each steam generator using eddy-current techniques to establish the baseline condition of the tubing. The examination is to be performed prior to initial power operation using the equipment and techniques expected to be used during subsequent inservice examinations.

The staff considers the examination of the steam generators a confirmatory issue. The staff will complete the review and report the results in a supplement to the SER after the actual Technical Specifications are established.

5.4.3 Deleted*

5.4.4 Deleted*

5.4.5 Deleted*

5.4.6 Reactor Core Isolation Cooling

*This section deleted from the 1981 version of the SRP (NUREG-0800).

5.4.7 Residual Heat Removal System

5.4.8 Reactor Water Cleanup System

5.4.9 Deleted*

5.4.10 Deleted*

5.4.11 Pressurized Relief Tank

*This section deleted from the 1981 version of the SRP (NUREG-0800).

6 ENGINEERING SAFETY FEATURES

6.1 Materials

6.1.1 Engineered Safety Features Materials

This staff review of the post-accident emergency cooling water chemistry is related to the applicant's ability to provide and maintain the proper pH of the containment sump water and recirculated containment spray water following a design-basis accident to reduce the likelihood of stress corrosion cracking of austenitic stainless steel.

The applicant will use borated water with a concentration of 2500 to 2600 ppm boron (as boric acid) from the refueling water storage tank during the initial injection phase of containment spray. The borated water will be mixed with a 34% to 36% by weight sodium hydroxide solution from the chemical addition tank.

The resulting solution will have a pH greater than 7, and will drain to the containment sump. Mixing is achieved as the solution is continuously recirculated from the sump to the containment spray nozzles during the recirculation phase of containment spray.

The staff reviewed the post-accident emergency cooling water chemistry in accordance with SRP Section 6.1.1. The staff evaluated the pH of the water (mixture of refueling water storage tank and sodium hydroxide solution) in the containment sump. The staff verified, by independent calculations, that sufficient sodium hydroxide is available to raise the containment sump water pH above the minimum 7.0, as required by BTP MTEB 6-1 to reduce the probability of stress-corrosion cracking of austenitic stainless steel components. The effectiveness of the chemical additive in removing fission products in the containment is addressed in Section 6.5.2 below. The staff will include surveillance requirements in the plant Technical Specifications to verify that sufficient sodium hydroxide is maintained in the containment spray additive tanks.

On the basis of its review, the staff concludes that the post-accident emergency cooling water chemistry meets the minimum pH acceptance criterion of SRP Section 6.1.1, the positions of BTP MTEB 6-1, and GDC 14. It is, therefore, acceptable.

6.1.2 Organic Materials

The staff review is conducted to verify that protective coatings applied inside containment meet the testing requirements of American National Standards Institute (ANSI) Standard N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," 1972, and the quality assurance guidelines of RG 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants." Compliance with these requirements ensures that the protective coatings will not fail under design-basis accident (DBA) conditions and will not generate significant quantities of solid debris or combustible gas that could adversely affect the engineered safety features.

The applicant referenced the Westinghouse alternative to RG 1.54 for the protective coatings on NSSS equipment inside containment. This information was documented in NS-CE-1352 dated February 1, 1977, and was accepted by the NRC staff by letter dated April 27, 1977 from C. J. Heltemes to C. Eicheldinger.

For the balance of plant inside containment, the applicant has committed to use protective coatings systems that meet the testing requirements of ANSI N101.2 (1972) and conform to the quality assurance guidelines of RG 1.54. Organic materials under DBA conditions are addressed in Section 6.2.5 below.

The control of combustible gases that can potentially be generated from the organic materials and from qualified and unqualified paints also is addressed in Section 6.2.5. The consequences of solid debris that can potentially be formed from unqualified paints are addressed in Section 6.2.2.

On the basis of its evaluation, the staff concludes that the protective coating systems and their applications are acceptable and meet Appendix B to 10 CFR 50. This conclusion is based on the applicant's having met the quality assurance requirements of Appendix B to 10 CFR 50, because the coating systems and their

applications meet the positions of RG 1.54 and the quality assurance standards of ANSI N101.2. The containment coating systems have been evaluated as to their suitability to withstand a postulated DBA environment. The coating systems chosen by the applicant have been qualified under conditions that take into account the postulated DBA conditions. Therefore, the protective coatings are acceptable.

6.2 Containment Systems

6.2.7 Fracture Prevention of Containment Pressure Boundary

In its review, the staff assessed the ferritic materials in the containment systems that constitute the containment pressure boundary to determine if the material fracture toughness complies with GDC 51, "Fracture Prevention of Containment Pressure Boundary."

GDC 51 requires that under operating, maintenance, testing, and postulated accident conditions (1) the ferritic materials of the containment pressure boundary behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized.

The South Texas containments are reinforced concrete, with a thin steel liner that serves as a leaktight membrane on the inside surface. The ferritic materials of the containment pressure boundary considered in the staff assessment are those that have been applied in the fabrication of the equipment hatch, personnel locks, penetrations, and fluid system components, including the valves required to isolate the system. These components are the parts of the containment system that are not backed by concrete and must sustain loads during the performance of the containment function under the conditions cited by GDC 51.

The staff has determined that the fracture toughness requirements contained in ASME Code editions and addenda typical of those used in the design of the South Texas containments may not ensure compliance with GDC 51 for all areas of the containment pressure boundary. In its licensing reviews of ferritic containment pressure boundary materials, the staff has elected to apply the criteria for Class 2 components identified in the Summer 1977 addenda of Section III

of the ASME Code. Because the fracture toughness criteria that have been applied in construction typically differ in Code classification and Code edition and addenda, the staff has chosen the criteria in the Summer 1977 addenda of Section III of the Code to provide a uniform review, consistent with the safety function of the containment pressure boundary materials. Therefore, the staff reviewed the materials of the components of the containment pressure boundary according to the fracture toughness requirements of the Summer 1977 addenda of Section III for Class 2 components.

Considered in the review were components of the containment system that are load bearing and provide a pressure boundary in the performance of the containment function under operating, maintenance, testing, and postulated accident conditions, as addressed in GDC 51. These components are the equipment hatch, personnel airlocks, penetrations, and elements of specific containment penetrating systems.

The staff assessment of the fracture toughness of materials is based on the metallurgical characterization of these materials and fracture toughness data presented in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generator and Reactor Coolant Pump Supports," and ASME Code Section III, Summer 1977 addenda, Subsection NC.

The metallurgical characterization of these materials, with respect to their fracture toughness, was developed from a review of how these materials were fabricated and their thermal history during fabrication. The metallurgical characterization of these materials, correlated with the data in NUREG-0577 and the Summer 1977 addenda of ASME Code Section III, provided the technical basis for the staff evaluation of compliance with the Code requirements.

On the basis of its review of the available fracture toughness data and materials fabrication histories, and the use of correlations between metallurgical characteristics and material fracture toughness, the staff concludes that the ferritic materials of the components of the containment pressure boundary meet the fracture toughness requirements that are specified for Class 2 components by the 1977 addenda of Section III of the ASME Code. Compliance with these Code requirements provides reasonable assurance that the reactor containment pressure

boundary will behave in a nonbrittle manner, that the probability of rapidly propagating fracture will be minimized, and that GDC 51 is satisfied.

6.5 Engineered Safety Feature (ESF) Filter Systems

The staff has reviewed the applicant's design, design criteria, and design bases for the ESF filter systems according to SRP Section 6.5.1 (NUREG-0800). These acceptance criteria include the applicable GDC, ANSI N509-1980, "Nuclear Power Plant Air Cleaning Units and Components," and ANSI N510-1980, "Testing of Nuclear Air Cleaning Systems." Guidelines for implementation of the requirements of the acceptance criteria are provided in the ANSI standards, regulatory guides, and other documents identified in Section II of the SRP. Conformance to the acceptance criteria provides the bases for the staff's concluding that the ESF filter systems meet the requirements of 10 CFR 50.

Each South Texas Unit has two ESF filter systems, the main control room heating, ventilation, and air conditioning (HVAC) makeup and cleanup filtration unit and the fuel handling building exhaust system.

6.5.1 Main Control Room HVAC Makeup and Cleanup Filtration Unit

The function of the main control room HVAC makeup and cleanup filtration system is to supply nonradioactive air from the makeup system to the control room after a design-basis accident, to pressurize the control room, and to provide cleanup filtration by the recirculation filter system of the control room air. Both the air supply makeup system and the recirculation cleanup system consist of three 50% capacity fans and filtration units. When they are needed to operate, two units are started, with the third unit as a backup.

The makeup system supplies 2000 ft^3/min of filtered air to the inlet of the control room recirculation filtration system. This pressurizes the control room and provides additional filtration (via the recirculation filters) of the outside air before it enters the control room spaces. Each 50% capacity makeup filtration unit consists, in order, of a supply fan, an electric heater for humidity control, a prefilter, a high efficiency particulate air (HEPA) filter, a 4-inch charcoal filter, and a HEPA filter.

Each 50% capacity control room recirculation unit consists, in order, of a prefilter, a HEPA filter, 2-inch charcoal filter, a HEPA filter, and recirculation fan. For the charcoal filters, a water spray system is provided in the event of high temperature or fire in the carbon beds. The control room makeup air and recirculation system is Safety Class 3, seismic Category I, powered by a Class 1E power source, physically separated and located within a seismic Category I structure. The system will be automatically activated by an emergency signal and can also be activated manually from the control room.

From the system description in the FSAR, the staff determined that the control room air makeup and cleanup system is designed consistent with GDC 19, 61, and 64, as referenced in the SRP. In its evaluation of the system design efficiencies for removal of elemental iodine and organic iodine, the staff assigned the system decontamination iodine removal (elemental and organic) efficiencies of 99% for the control room makeup air filtration and 95% for control room recirculation filtration system. The staff also assigned a 99% removal efficiency for particulates for the HEPA filters in accordance with RG 1.52, "Design, Testing, and Maintenance Criteria for Postaccident Engineered-Safety-Feature Atmopshere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants." The staff determined that the provisions for instrumentation, readout, and alarm were consistent with SRP Table 6.5.1-1. Adequate indication and alarms are provided in the control room to ensure proper monitoring of systems performance, per RG 1.52.

On the basis of its evaluation, the staff concludes that the control room makeup air and recirculation cleanup systems are adequately designed to control the concentration of radioactive materials and pressure within the control room in accordance with applicable regulations following a postulated design-basis accident.

6.5.2 Fuel Handling Building Exhaust System

The function of the fuel handling building (FHB) exhaust system is to filter airborne radioactive iodine and particulates that may leak from spent fuel or

from a spent fuel drop accident, or from the emergency core cooling and containment spray systems during a design-basis accident. The exhaust flow is discharged through the plant main vent stock.

The FHB exhaust system maintains the FHB at a negative pressure. The exhaust system consists of two 100% capacity filtration systems and three 50% capacity filtration exhaust fan systems. Each exhaust system consists of three filtration units, and each filtration unit consists, in order, of an electric heater for humidity control, prefilter, HEPA filter, 2-inch charcoal filter, and a HEPA filter. Downstream of all the filter units are three 50% capacity exhaust booster fans. During normal operations, two out of three main FHB exhaust fans discharge the flow without filtration. However, should an accident occur or high activity be detected in the FHB exhaust, two out of three FHB exhaust booster fans start and the FHB exhaust is directed through one of the two filtration systems. All the charcoal filters are protected by a water spray system in case of overheating or fire.

6.5.3 Evaluation Findings

From the system description in the FSAR, the staff determined that the ESF atmosphere cleanup systems are designed consistent with GDC 41, 42, 43, 61, and 64, as referenced in the SRP. In the evaluation of the FHB system design efficiencies for removal of elemental iodine and organic iodines, the staff assigned the system decontamination efficiencies of 95% for elemental and organic iodines for the carbon adsorbers (2-inch-deep bed), in accordance with RG 1.52, and 99% for particulates for the HEPA filters. Provisions for instrumentation, readout, and alarm were determined to be consistent with SRP Table 6.5.1-1. Adequate indication and alarms are provided in the control room to ensure proper monitoring of system performance, as suggested by RG 1.52.

These filter efficiencies are allowed only if the applicant can provide adequate assurance that the water seals in the filter housing drain system (especially drain pipes submerged in a water-filled barrel) are always maintained. The applicant will be requested to address this issue.

The staff concludes that the design of the ESF atmosphere cleanup systems, including the equipment and instrumentation to control the release of radioactive materials in gaseous effluents following a postulated design-basis accident, is acceptable.

The applicant has met the requirements of GDC 42, 43, and 64 by providing for inspecting and testing of the ESF atmosphere cleanup systems and monitoring for radioactive materials in effluents from these systems. In meeting these regulations, the applicant has demonstrated that the design of the ESF atmosphere cleanup systems meets RG 1.52 and ANSI N509 and N510, as referenced in the SRP. The staff has reviewed the applicant's system descriptions and design criteria for the ESF atmosphere cleanup systems. On the basis of its evaluation, the staff finds the proposed ESF atmosphere cleanup systems acceptable. The filter efficiencies given in Table 2 of RG 1.52 are appropriate for use in accident analyses. The staff will be discussing with the applicant inspection of the water seals provided by drain traps to ensure the required water level.

6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

6.6.1 Compliance with the SRP

The staff review under SRP Section 6.6 is continuing because the applicant has not submitted the PSI program and has not completed the examinations. The staff review to date has been conducted in accordance with SRP Section 6.6 except as discussed below.

The review under Paragraph II.4, "Acceptance Criteria, Inspection Intervals," has not been done because this area applies only to inservice inspection (ISI) not to PSI. This subject will be addressed during review of the ISI program after licensing.

The review under Paragraph II.5, "Acceptance Criteria, Evaluation of Examination Results," has been done. The applicant committed in the FSAR to incorporate

ASME Code Article IWC-3000, "Acceptance Standards for Flaw Indications," into the PSI program. However, ongoing NRC generic activities and research projects indicate that the presently specified ASME Code procedures may not always be capable of detecting the acceptable-size flaws specified in these standards.

For example, ASME Code procedures specified for volumetric examination of vessels, bolts and studs, and piping have not proven to be capable of detecting acceptable-size flaws in all cases. The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made a part of the inservice examination requirements. The applicant's repair procedures based on ASME Code Articles IWC-4000 and IWD-4000, "Repair Procedures," have not been reviewed. Repairs are not generally necessary in the PSI program. This subject will be addressed during the review of the ISI program.

The review under Paragraph II.8, "Acceptance Criteria, Code Exemptions," has not been completed because the applicant has not submitted the PSI program. The SRP requires that the applicant list these exemptions, if used.

The review under Paragraph II.9, "Acceptance Criteria, Relief Requests," has not been completed because the applicant has not identified the limitations to examination. Specific areas where ASME Code examination requirements cannot be met will be identified as the PSI progresses. The complete evaluation of the PSI program will be presented in a supplement to the SER after the application submits the required examination information and identifies all plant-specific areas where ASME Code Section XI requirements cannot be met and provides a supporting technical justification.

6.6.2 Examination Requirements

GDC 36, 39, 42, and 45 require, in part, that the Class 2 and 3 components be designed to permit appropriate periodic inspection of important components to ensure system integrity and capability. 10 CFR 50.55a(g) defines the detailed requirements for the preservice and inservice inspection programs for light-water-cooled nuclear power facility components. Based upon the CP date of December 22, 1975, components (including supports) that are classified as ASME

Code Class 2 shall meet the preservice examination requirements set forth in editions of Section XI of the ASME Code and addenda applied to the construction of the particular component. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein. The initial ISI program must comply with the requirements of the latest edition and addenda of Section XI of the ASME Code in effect 12 months prior to the date of issuance of the operating license, subject to the limitations and modifications listed in 10 CFR 50.55a(b).

6.6.3 Evaluation of Compliance with 10 CFR 50.55a(g)

The staff review has been completed on the information presented in the FSAR through Amendment 46 and the applicant's letter dated April 4, 1985. The PSI program has not been submitted for staff review. However, the applicant has committed to submit preservice examination plans prior to the initiation of the associated examinations. The preservice examination plans will describe the PSI program for Unit 1 in terms of Code and regulatory bases for the program, scope of systems and components subject to PSI, and technical positions and approaches to be incorporated in the program. The preservice examination plans will contain a detailed listing of the specific systems, welds, and examination areas to be examined; the examination methods and procedures applicable to each examination; and isometric drawings denoting the locations of welds and examination areas in Class 1, 2, and 3 systems subject to examination and testing. The Unit 1 PSI will be conducted in accordance with the 1980 edition of ASME Code Section XI with addenda through the Winter 1981 addenda.

The applicant has committed to identify all plant-specific areas where the Code requirements cannot be met and provide a supporting technical justification for requesting relief. The staff review will be completed after the applicant

(1) dockets a complete and acceptable PSI program

(2) submits all relief requests with a supporting technical justification

The applicant has not submitted the initial ISI program. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b) but before inservice inspection commences during the first refueling outage.

6.6.4 Conclusions

Compliance with the preservice and inservice inspections required by the ASME Code and 10 CFR 50 constitutes an acceptable basis for satisfying applicable requirements of GDC 36, 39, 42, and 45.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

9.1.2 Spent Fuel Storage

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a sub-critical array during all credible storage conditions. In accordance with SRP Section 9.1.2, the staff has reviewed the compatibility and chemical stability of the materials (except the fuel assemblies) wetted by the pool water.

The pool liner, rack lattice structure and fuel storage tubes are stainless steel.

The pool contains oxygen-saturated demineralized water containing 2500 ppm boron as boric acid.

In this environment of oxygen-saturated borated water, the corrosive deterioration of the type 304 stainless steel should not exceed a depth of 6.00×10^{-5} inch in 100 years (Weeks, 1977), which is negligible relative to the initial thickness. Dissimilar metal contact corrosion (galvanic attack) between the stainless steel of the pool liner, rack lattice structure, fuel storage tubes, and the Inconel and the Zircaloy in the spent fuel assemblies will not be significant because all of these materials are protected by highly passivating oxide films and are therefore at similar potentials. Provisions are incorporated to allow for the periodic inspection of spent fuel pool components.

Therefore, the staff concludes that the environmental compatibility and stability of the materials used in the spent fuel storage pool is adequate, based on

test data and actual service experience in operating reactors. The staff also concludes that in selecting materials the applicant has met GDC 61 by having a capability to permit appropriate periodic inspection and testing of components and GDC 62 by preventing criticality by maintaining structural integrity of components. The materials are, therefore, acceptable.

9.1.3 Spent Fuel Pool Cleanup System

The spent fuel pool cleanup system is designed to maintain optical clarity of and to remove corrosion products, fission products, and impurities from the spent fuel pool water. The spent fuel pool water will be sampled weekly for chlorides, fluorides, pH, boron, calcium, magnesium, and radioactivity. The applicant has provided the chemical impurity limits to be maintained in the pool water in accordance with the chemistry criteria and specifications for Westinghouse pressurized water reactors (Westinghouse, 1977). A decontamination factor for the demineralizer will be measured to monitor its performance. Sampling and differential pressure measurements will be used to determine demineralizer resin and filter replacement. Area radiation monitors are provided.

The spent fuel pool cleanup system description, piping and instrumentation diagrams, and applicant responses to staff questions have been reviewed in accordance with SRP Section 9.1.3 (NUREG-0800).

The staff has determined that the spent fuel pool cleanup system (1) provides the capability and capacity of removing radioactive materials, corrosion products and impurities from the pool water, and thus meets GDC 61 as it relates to appropriate filtering systems for fuel storage; (2) is capable of reducing occupational exposure to radiation by removing radioactive products from the pool water, and thus meets 10 CFR 20.1(c) as it relates to maintaining radiation exposures as low as is reasonably achievable; (3) confines radioactive materials in the pool water into the demineralizer and filters, and thus meets Position C.2.f(2) of RG 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable," as it relates to reducing the spread of contaminants from the source; and (4) removes suspended impurities from the pool water by filters,

and thus meets Position C.2.f(3) of RG 8.8, as it relates to removing crud through physical actions.

On the basis of its review, the staff concludes that the spent fuel pool cleanup system meets GDC 61, 10 CFR 20.1(c), and the appropriate sections of RG 8.8. It is, therefore, acceptable.

9.1.4 Fuel-Load-Handling System

9.1.5 Overhead Heavy Load Handling Systems

Generic Task A-36, "Control of Heavy Loads Near Spent Fuel," led to the issuance of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." Following the issuance of NUREG-0612, a generic letter dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that they indicate their degree of compliance with the guidelines of NUREG-0612. They were also asked to commit to mutually agreeable changes and modifications that would be required to fully satisfy these guidelines. By letters dated December 19, 1983, and October 19, 1984, the applicant provided the responses to this request.

The staff and its consultant, the Idaho National Engineering Laboratory (INEL) have reviewed the applicant's submittals. As a result of its review, NRC has issued the Technical Evaluation Report (TER). On the basis of its review, which included the technical evaluation report ~~included~~ reproduced as Appendix F to this SER, the staff finds that the guidelines in NUREG-0612 have been satisfied. Thus, the staff concludes that Phase I of compliance with NUREG-0612 for South Texas Nuclear Power Plants Units 1 and 2 is acceptable.

9.2 Water Systems

9.3 Process Auxiliaries

9.3.1 Compressed Air System

9.3.2 Process Sampling Systems

The process sampling system is designed to provide representative liquid and gaseous samples drawn from the primary and secondary coolant systems, the associated auxiliary system process streams, and the spent fuel pool cleanup system. Provisions are made to ensure that representative samples are obtained from well-mixed streams or volumes of effluent by the selection of proper sampling equipment and location of samples points, as well as proper sampling procedures. In the event of an accident, all sample lines that pass through the containment are automatically isolated by fail-closed valves on either side of the containment.

The information provided by the applicant has been reviewed in accordance with SRP Section 9.3.2 (NUREG-0800).

The process sampling system includes piping and other components associated with the system from the point of sample withdrawal from a fluid system up to the analyzing station, sampling station, or local sampling point. The staff review included the provisions to sample all principal fluid process streams associated with plant operation and the applicant's design of these systems, including the location of sampling points, as shown on piping and instrumentation diagrams.

The staff determined that the process sampling system meets (1) GDC 13 to monitor variables that can affect the fission process for normal operation, anticipated operational occurrences, and accident conditions, by sampling the reactor coolant, the safety injection accumulators, the refueling water storage tank, the chemical and volume control system, and boron recycle system for boron concentration; (2) GDC 14 to ensure a low probability of abnormal leakage, rapidly propagating failure, and gross rupture, by sampling the reactor coolant

and the secondary coolant for chemical impurities that can affect the reactor coolant pressure boundary material integrity; (3) GDC 26 to control the rate of reactivity changes, by sampling the reactor coolant, the chemical and volume control system, reactor makup water storage tank, and the boron recovery system for boron concentration; and (4) GDC 63 and 64 to monitor for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents, by sampling the reactor coolant, the pressurizer, the steam generator blowdown, the secondary coolant condensate polisher waste, the sump inside containment, the containment atmosphere, the spent fuel pool, and the gaseous radwaste storage tank for radioactivity.

The staff further determined that the proposed process sampling system meets ANSI N13.1-1969 for obtaining airborne radioactive samples; 10 CFR 20.1(c) and Positions 2.d(2), 2.f(3), 2.f(8), and 2.i(6) of RG 8.8, Revision 3, for maintaining radiation exposures to as low as is reasonably achievable, by providing (1) ventilation systems and a gaseous radwaste treatment system to contain airborne radioactive materials; (2) a liquid radwaste treatment system to contain radioactive material in fluids; (3) a spent fuel pool cleanup system to remove radioactive contaminants in the spent fuel pool water; and (4) remotely operated containment isolation valves to limit reactor coolant loss in the event of rupture of a sampling line. The system also meets GDC 60 for controlling the release of radioactive materials to the environment because it has provided isolation valves that will fail in the closed position; and Positions C.1, C.2, and C.3 of RG 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," Revision 3, and Positions C.1, C.2, C.3, and C.4 of RG 1.29, "Seismic Design Classification," Revision 3, because it has the sampling lines and components of the process sampling system that conform to the classification of the system to which each sampling line and component is connected. Thus, the system meets the quality standards requirements of GDC 1 and the seismic requirements of GDC 2.

On the basis of the above evaluation, the staff concludes that the proposed process sampling system meets the relevant requirements of 10 CFR 20.1(c); GDC 1, 2, 13, 14, 26, 60, 63, and 64; and the appropriate Positions in RGs 8.8, 1.26, and 1.29. It is, therefore, acceptable.

NUREG-0737 Item II.B.3, Post-Accident Sampling System

After the accident at TMI-2, the staff recognized the need for an improved post-accident sampling system (PASS) to determine the extent of core degradation following a severe reactor accident. Criteria for an acceptable sampling and analysis system are specified in NUREG-0737, Item II.B.3. The system should have the capability to obtain and quantitatively analyze reactor coolant and containment atmosphere samples without radiation exposure to any individual exceeding 5 rems to the whole body or 75 rems to the extremities (GDC 19) during and following an accident in which there is core degradation. Materials to be analyzed and quantified include certain radionuclides that are indicators of severity of core damage (e.g, noble gases, isotopes of iodine and cesium, and nonvolatile isotopes), hydrogen in the containment atmosphere and total dissolved gases or hydrogen, boron, and chloride in reactor coolant samples.

To comply with NUREG-0737 Item II.B.3, the applicant should (1) review and modify the sampling, chemical analysis, and radionuclide determination capabilities as necessary and (2) provide the staff with information pertaining to system design, analytical capabilities, and procedures in sufficient detail to demonstrate that the criteria are met.

The applicant has not provided adequate information for the staff review. The staff will perform its review after the requested information is received.

9.3.3 Equipment and Floor Drainage System

9.3.4 Chemical and Volume Control System

The chemical and volume control system (CVCS) is designed to control and maintain reactor coolant inventory and to control the boron concentration in the reactor coolant through the process of charging (makeup) and letdown (drawing off). The system is also designed to provide seal-water injection flow to the reactor coolant pumps, and to control the reactor coolant water chemistry conditions and activity level by chemical addition and ion exchange, soluble chemical neutron absorber concentration, and makeup water. An essential portion of the system consists of the three charging pumps, one positive displacement and two

centrifugal. These pumps are used during normal operation. The centrifugal charging pumps are also used for high-pressure safety injection when the emergency core cooling system (ECCS) is required to function. (The ECCS is evaluated in Section 6.3.2.2).

The volume control tank serves as a surge for the reactor coolant letdown system, to provide for control of hydrogen concentration in the reactor coolant and to provide a reservoir of makeup for the charging pumps. The boric acid makeup system provides for boron addition to compensate for reactivity changes and to provide shutdown margin for maintenance and refueling operations or emergencies. The charging and letdown portions of the system are designed to seismic Category I requirements and contain redundant active components and an alternate flow path to meet the single failure criterion.

The volume control system description and piping and instrumentation diagrams have been reviewed in accordance with SRP Section 9.3.4 (NUREG-0800). The volume control system (including boron recovery system) includes components and piping associated with the system from the letdown line of the primary system to the charging lines that provide makeup to the primary system and the reactor coolant pump seal-water systems.

In its review, the staff has determined that the design of the CVCS system conforms with the following regulations and regulatory guides: (1) GDC 1 and RG 1.26, by assigning quality group classifications to system components in accordance with the importance of the safety function to be performed; (2) GDC 2 and RG 1.29, by having safety-related portions of the system designed to seismic Category I requirements; (3) GDC 14 by maintaining reactor coolant purity and material compatibility to reduce corrosion and thus reduce the probability of abnormal leakage, rapid propagating failure, or gross rupture of the RCPB; (4) GDC 29 as related to the reliability of the CVCS to provide negative reactivity to the reactor by supplying borated water to the reactor coolant system in the event of anticipated operational occurrences; (5) GDC 33 and 35 because the CVCS has the capability to supply reactor coolant makeup in the event of small breaks or leaks in the RCPB and to function as part to ECCS assuming a single failure coincident with loss of offsite power; and (6) GDC 60 and 61 with

respect to confining radioactivity by venting and collecting drainage from the CVCS components through closed systems.

On the basis of its review, the staff concludes that the design of the CVCS and supporting system meets GDC 1, 2, 14, 29, 33, 60, and 61, and is, therefore, acceptable.

9.4 Heating, Ventilation, and Air Conditioning Systems

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

The staff has reviewed the applicant's fire protection program as set forth in the Fire Hazards Analysis Report through Amendment 46 for conformation with the technical requirements of Appendix A to BTP APCSB 9.5-1 ("Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976") and Appendix R to 10 CFR 50.

As part of its review, the staff will visit the plant site to examine the relationship of safety-related components, systems, and structures in specific plant areas to both combustible materials and to associated fire detection and suppression systems. This site visit has not yet been made because the construction of the plant has not progressed to the level where such a visit would be meaningful.

The staff review included an evaluation of the automatic and manually operated water and gas fire suppression systems, the fire detection systems, fire barriers, fire doors and dampers, fire protection administrative controls, and the fire brigade size and training. The objective of the review is to ensure that in the event of a fire, personnel and plant equipment would be adequate to safely shut down the reactor, to maintain the plant in a safe shutdown condition, and to minimize the release of radioactive material to the environment.

Because Units 1 and 2 are of the same design except as noted, the comments made in this report apply to both units.

9.5.1.1 Fire Protection Program Requirements

Fire Protection Program

The fire protection program is described in the applicant's Fire Hazards Analysis Report. The program establishes policy for the protection of structures, systems, and components important to safety. The applicant's program conforms to the technical requirements in Appendix A to BTP APCSB 9.5-1, Section A and is, therefore, acceptable.

Fire Hazards Analysis

The applicant's fire hazard analysis specified the combustible materials present in fire areas, identified safety-related equipment, determined the consequences of a fire on safe shutdown capability, and summarized available fire protection. The staff evaluation of the identified fire hazards is in the paragraphs below. Alternative shutdown capability has been provided for the control room; this capability also is evaluated below.

GDC 3 requires that fire fighting systems be designed to ensure that rupture or inadvertent operation does not signficantly impair the safety capability of structures, systems, and components important to safety. The applicant has not indicated that components required for hot shutdown are so designed that rupture or inadvertent operation of fire suppression systems will not adversely affect the operability of these components. The staff is concerned whether the mechanisms by which fire and fire fighting systems may cause the simultaneous failure of redundant or diverse trains have been adequately considered in the design. The staff will require the applicant to identify the mechanisms that were considered in the fire hazards analysis and the measures taken to preclude the fire- or fire-suppressant-induced failure of redundant or diverse safety trains and to document the procedures.

9.5.1.2 Administrative Controls

The administrative controls for fire protection consist of the fire protection program and organization, the fire brigade training, the controls over combustibles and ignition sources, the prefire plans and procedures for fighting fires, and quality assurance. The applicant has not provided sufficient information to verify compliance with the staff guidelines. The staff will require that the applicant comply with the guidelines of Appendix A to BTP APCSB 9.5-1, Section B.

9.5.1.3 Fire Brigade and Fire Brigade Training

The applicant has not provided an adequate description of the plant fire brigade, including equipment and training. The staff will require that the applicant follow Appendix A to BTP APCSB 9.5.1, Section B in the establishment and training of the fire brigade.

9.5.1.4 General Plant Guidelines

Building Design

The walls that separate buildings and walls and floor ceiling assemblies used to separate fire areas containing safe shutdown systems are 3-hour-fire rated. The applicant has stated that all fire-rated assemblies are designed and constructed of reinforced concrete of a thickness of 8 inches or more, in accordance with the Uniform Building Code for a minimum 3-hour fire-resistance rating. On the basis of its review, the staff concludes that these fire-rated walls and floor/ceiling assemblies are provided in accordance with Appendix A to BTP APCSB 9.5-1, Section D.1 and are, therefore, acceptable.

Thermal insulating materials are noncombustible. Interior walls and structural components, radiation shielding materials, and sound-proofing and interior finishes are noncombustible, or are listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriters Laboratories (UL) for a flame spread rating of 50 or less in their use configuration. The staff finds

this is an acceptable deviation from Appendix A to BTP APCSB 9.5-1 Section D.1.d. The materials are, therefore, acceptable.

Metal deck roof construction is of noncombustible construction. Suspended ceiling and their supports are of noncombustible materials, and concealed spaces above the suspended ceilings are devoid of combustibles. The staff finds this in accordance with Appendix A to BTP APCSB 9.5-1, Sections D.1.e and f and, therefore, acceptable.

High-voltage/high-amperage transformers installed inside buildings are the dry type. All oil-filled transformers are installed outside buildings containing safety-related equipment. All building walls of buildings containing safety-related equipment located within 50 feet of any oil-filled transformer have a minimum fire resistance rating of 3 hours. Each oil-filled transformer is protected with a water spray extinguishing system that is automatically actuated by heat detectors. On the basis of its evaluation, the staff concludes that the installation of the transformers meets Appendix A to BTP APCSB 9.5-1, Sections D.1.g and h and is, therefore, acceptable.

The door openings in fire-rated barriers are provided with fire door assemblies that have ratings commensurate with the fire ratings of the walls in which they are installed; however, all doors will not be labeled fire doors assemblies. Doors installed in fire-rated assemblies required for missile protection and water-tight doors will not be labeled assemblies. Although these doors are constructed as fire doors, they are modified to perform another function. Suitability of fire doors is determined by test by nationally recognized testing laboratories, and doors not tested and not labeled cannot be relied on for effective protection. Therefore, the staff will require the applicant to test and label fire door assemblies in accordance with National Fire Protection Association (NFPA) Standard 252, "Fire Tests of Doors Assemblies."

The heating, ventilation, and air conditioning (HVAC) penetrations of fire-rated barriers have UL-labeled fire damper assemblies that have ratings commensurate with the fire ratings of the walls in which they are installed. The fire dampers are installed according to the manufacturer's directions. Three-hour fire dampers are provided in all 3-hour-fire-rated barriers. On the basis of

its evaluation, the staff concludes that the fire dampers are provided in accordance with the guidelines of Appendix A to BTP APCSB 9.5-1, Section D.1.j. They are, therefore, acceptable.

Control of Combustibles

Safety-related systems have been isolated or separated from combustible materials as much as possible. The storage of flammable liquids complies with NFPA 30, "Flammable and Combustible Liquids Code."

The fire protection for the reactor coolant pumps and the diesel generator fuel oil day tanks is discussed in Sections 9.5.1.6 below.

The turbine building does not contain any circuits or equipment of safe shutdown systems and is separated from such areas by 3-hour-rated fire walls.

On the basis of its evaluation, the staff concludes that combustibles have been separated from safety-related systems or provided with suppression in accordance with the guidelines of Appendix A to BTP APCSB 9.5-1, Section D.2.a. They are, therefore, acceptable.

No high-pressure gas storage containers are stored inside of buildings containing safety-related equipment. Bulk gas, including hydrogen, is stored out of doors. The hydrogen piping routed in areas containing safety-related systems is seismic Category II/I. Hydrogen piping is equipped with excess flow valves so that in case of a line break, the hydrogen concentration in the affected areas will not exceed 2%.

On the basis of its evaluation, the staff concludes that the hydrogen storage and piping meets Appendix A to BTP APCSB 9.5-1, Section D.2.b and is, therefore, acceptable.

Electrical Cable Construction, Cable Trays, and Cable Penetrations

All cable trays are of steel construction. Electrical cable construction passes the flame test of the Institute of Electrical and Electronics Engineers (IEEE)

383-1974. The cables are designed to allow wetting down with fire suppression water without electrical faulting.

Three-hour fire-rated penetration seals are provided for all penetrations of fire-rate walls of floors/ceiling tested in accordance with standard E-119 of the American Society for Testing and Materials (ASTM). On the basis of its review, the staff concludes that fire-barrier penetrations seals meet Appendix A to BTP APCSB 9.5-1, Section D.3.d, and are, therefore, acceptable.

The applicant has requested a deviation from the staff guidelines that require automatic water suppression systems in the heavily cabled areas of the plant outside of the cable spreading room. The applicant has not provided enough information for the staff to evaluate this deviation. The applicant's criteria for determining where such systems will be provided is not definitive. The staff will require the applicant to meet the guidelines of Appendix A to BTP APCSB 9.5-1, Section D.3.c for the protection of cable trays outside the cable spreading room or provide adequate justification for the deviation.

Ventilation

The electrical auxiliary building has a dedicated ventilation system designed specifically to exhaust smoke or other products of combustion. In other areas, normal plant ventilation systems will be used for this purpose. Portable smoke ejectors will be provided to assist in removal of the products of combustion should the normal ventilation systems be unavailable because of damper closures or other failures. The staff finds this acceptable.

Where total flooding gas extinguishing systems are used, air intake and exhaust ventilation dampers are provided with mechanisms that close them when gas flow starts. The staff finds this acceptable. Fire-barrier ventilation openings have fire dampers that close if a fire causes room temperature to exceed a set value.

Fresh air supply intakes to areas containing safety-related equipment or systems are remote from exhaust air outlets of other fire areas. Stairwells are designed to minimize smoke infiltration during a fire.

Charcoal filters have been provided with fire suppression systems in accordance with RG 1.52. The staff finds this acceptable.

On the basis of its evaluation, the staff finds that the ventilation system meets Appendix A to BTP APCSB 9.5-1, Section D.4 and is, therefore, acceptable.

Lighting and Communication

Emergency lighting will be installed in all areas of the plant that may have to be staffed for safe shutdown operations and along all access and egress routes. The emergency lighting consists of fixed lights powered by individual 8-hour batteries. The applicant has not determined the illumination level and location of emergency lights for all points on the floor, including angles and intersections of corridors, passageways, and stairways. To meet the guidelines of Appendix A to BTP APCSB 9.5-1, Section D.5, the staff will require the applicant to demonstrate that there is adequate illumination at all points where equipment operation is needed for safe shutdown, as well as along all access and egress routes thereto.

The applicant has provided, at pre-selected stations, a fixed emergency communication system that is independent of the normal plant communication system. A portable radio communications system has been provided for use by the fire brigade. This system uses hand-held portable radios, powered by rechargeable batteries. A pre-operational test will be conducted to ensure that the frequencies used for portable communications systems will not affect the actuation of protective relays.

Fixed repeaters will be required for portable radio communication. The applicant has not provided a description of the fire protection provided for the fixed repeaters. The staff will require the applicant to meet Appendix A to BTP APSCB 9.5-1, Section D.5.d for the protection of the fixed repeaters.

9.5.1.5 Fire Detection and Suppression

Fire Detection

The fire detection system consist of the detectors, associated electrical circuitry, and electrical power supplies. The types of detectors used are products of combustion, rate-of-rise, and fixed temperature detectors. The system provides distinctive audible and visual alarms locally and in the control room. Detection devices are installed in all areas containing or presenting fire exposure to safety-related equipment.

The applicant states that the fire detection system does not comply with the requirements of NFPA 72D, and the applicant has not provided justification for the deviations. The staff will require the applicant to follow the guidelines in NFPA 72D or provide adequate justification for the deviations.

Primary and secondary power supplies for the fire detection system satisfy the provisions of Section 2220 of NFPA 72D. The staff finds this acceptable.

The applicant's Fire Hazards Analysis Report does not indicate that fire detectors have been selected and installed in accordance with NFPA 72E. The staff will require the applicant to select and install early warning fire detectors in accordance with NFPA 72E.

Fire Protection Water Supply System

The water supply system consists of three fire pumps. Each pump is diesel engine driven, and each is separately connected to a buried 16-inch water main loop around the plant. Each fire pump has a rated capacity of 2500 gpm at 125 psig. The fire pumps and controllers are UL listed. The fire pump installation has been designed and installed and will be tested in accordance with NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps."

The fire pumps are located in the fire pump house. Each fire pump is separated from others with 3-hour-fire-rated barriers. Automatic sprinklers have been provided in the fire pump house.

The water supply for fire protection is taken from two 300,000-gallon water storage tanks. The suction piping to the three fire pumps is arranged to permit suction from either or both of the two fire water storage tanks. The greatest water demand for the fixed fire suppression system is 3000 gpm; coupled with 500 gpm for hose streams, this creates a total water demand of 3500 gpm. The staff finds that the water supply system can deliver the required water demand with one pump out of service.

Yard hydrants are provided at intervals of 250 feet along the fire protection water supply loop, approximately 100 feet from the buildings. The lateral to each yard hydrant is provided with an isolation valve to facilitate hydrant maintenance and repairs without shutting down any part of the fire water supply system. Standard hose houses are provided at each hydrant in accordance with NFPA codes. Sectional control valves are provided to isolate portions of the underground main for maintenance or repair without shutting off the supply to primary and backup fire suppression systems that serve areas containing or exposing safety-related systems.

The fire protection water supply system is kept pressurized at 125 psi by a fire service jockey pump. The fire pumps are automatically started when low pressure is sensed in the pump discharge header. All pumps are stopped manually at the fire pump house. Separate audible and visual alarms on supervised circuits are provided in the control room to monitor fire pump status, prime mover availability, power failure, and failure of the fire pumps to start.

? All valves in the fire protection water supply have been <u>supervised</u> in accordance with Appendix A to BTP APCSB 9.5-1, Section E.3.b.

On the basis of its review, the staff concludes that the fire protection water supply system meets Section E.3 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

Sprinkler and Standpipe Systems

The applicant states that NFPA 13 and 15 have been used as guidance in the design of wet pipe sprinkler system, deluge systems, and pre-action systems,

but has not indicated how these systems might vary from the applicable standards. The staff will require that the applicant meet NFPA 13 and 15 or identify and justify any deviations.

Each automatic sprinkler system and interior hose standpipe is supplied through separate connections from the yard main or from the internal cross connections through buildings to ensure that no single failure in the water supply system will impair both the primary and backup fire protection in building areas. Each sprinkler and standpipe system connection to the distribution system is equipped with an indicating valve so that groups of sprinkler systems and/or manual hose stations can be isolated without interrupting the supply to other sprinkler systems and manual hose stations connected to the same header.

Standpipes are 4 inches in diameter for multiple hose stations and 2½ inches in diameter for single stations. Manual hose stations are located throughout the plant in accordance with NFPA 14, "Standard for the Installation of Standpipe and Hose Systems." Hose stations are installed so that all areas of the plant can be reached with an effective hose stream with a maximum of 100 feet of hose. The standpipe installation meets Appendix A to BTP APCSB 9.5-1, Section E.3 and is, therefore, acceptable.

Halon Suppression Systems

Total flooding Halon 1301 systems are provided for the central control room, computer room and subfloor space, associated battery and changer room, relay room, and technical support center computer room and subfloor space. The systems are designed to provide a concentration of 5% to 7% by volume of Halon 1301 within 10 seconds of initiation. The Halon 1301 suppression systems are to be manually initiated upon receipt of fire alarms or automatically discharged upon operation of the heat detectors in the area.

On the basis of its review, the staff concludes that the Halon 1301 extinguishing systems meet Appendix A to BTP APCSB 9.5-1, Section E.4 and are, therefore, acceptable.

Portable Extinguishers

Portable fire extinguishers are provided to conform with NFPA 10. The staff finds this acceptable.

On the basis of its review, the staff concludes that the fire extinguishers meet Appendix A to BTP APCSB 9.5-1, Section D.6 and are, therefore, acceptable.

9.5.1.6 Fire Protection of Specific Areas

Containment

The containment building is separated from adjacent buildings by 3-hour-fire-rated barriers. The containment building fire protection features include hose stations, heat detectors, and portable fire extinguishers.

The applicant committed to provide oil collection systems for each reactor coolant pump with a collection tank for each pump size to contain the entire pump oil inventory, in accordance with Section III.O of Appendix R. The staff finds this acceptable.

On the basis of its review, the staff concludes that the fire protection for containment meets Appendix A to BTP APCSB 9.5-1, Section F.1 and is, therefore, acceptable.

Control Room

The control room complex is separated from all other areas of the plant by 3-hour-fire-rated assemblies. Smoke detectors have been installed in the control room and in the main control room console. All smoke detector alarms are anunciated in the control room panel. Portable fire extinguishers inside the control room and hose stations outside the control room are provided in accordance with Section F.2 of Appendix A to BTP APCSB 9.5-1.

The applicant has provided an alternate shutdown system for the control room. The alternate shutdown system is reviewed in Section 9.5.1.7 below.

The outside air intakes for the control room ventilation system are equipped with smoke detectors that alarm in the control room.

On the basis of its review, the staff concludes that the fire protection for the control room complex is in accordance with Appendix A to BTP APCSB 9.5-1, Section F.2 and is, therefore, acceptable.

Cable Spreading Room

Separate cable spreading rooms are provided for each of the three safe shutdown divisions. Each divisional cable is separated from its redundant division on the balance of the plant by 3-hour-fire-rated barriers.

Partial coverage automatic suppression systems have been provided where manual fire fighting would be difficult.

Manual fire suppression capability is provided by hose stations and portable extinguishers. Early warning fire detection is provided by smoke detectors that annunciate alarm and trouble conditions in the control room.

The applicant has requested a deviation from the staff guidelines that require full-coverage automatic fixed water suppression system in the cable spreading rooms. However, the applicant has not provided adequate justification for the deviation. The staff will require the applicant to provide automatic fixed water suppression systems in the cable spreading rooms to meet Appendix A to BTP APCSB 9.5-1, Section F.3.a.

Switchgear Rooms

The Division A, Division B, and Division C switchgear rooms are separated from each other by 3-hour-fire-rated floor/ceiling assemblies; however, the switchgear rooms are not separated from the remainder of the plant by 3-hour-fire-rated barriers. The staff will require the applicant to separate the Division A, B, and C switchgear rooms from the balance of the plant by 3-hour-fire-rated barriers, in accordance with Appendix A to BTP APCSB 9.5-1, Section F.5.

Automatic fire detection is provided by ionization smoke detectors. Manual protection is provided by standpipe hose stations and portable extinguishers.

Safety-Related Battery Rooms

The redundant divisional battery rooms are separated from each other by 3-hour-fire-rated barriers; however, they are not separated from the balance of the plant by 3-hour-fire-rated barriers. The staff will require the applicant to separate the safety-related battery rooms from the balance of the plant by 3-hour-fire-rated barriers, in accordance with Appendix A to BTP APCSB 9.5-1, Section F.7.

Smoke detection systems are provided in each battery room. Hose stations and portable fire extinguishers are available in the areas for fire manual suppression. The ventilation system is designed to maintain the hydrogen levels below 2%. Air flow monitors that alarm in the control room to monitor the loss of ventilation have been provided in each battery room.

Emergency Diesel Generator Rooms

The diesel generator rooms are separated by 3-hour-fire-rated barriers. There are no openings in the fire-rated barriers separting the diesel generator rooms.

Automatic preaction sprinkler systems have been provided for each diesel generator room. Manual fire suppression capability is provided by thermal detection systems that alarm in the control room, hose stations, and portable fire extinguishers.

On the basis of its review, the staff concludes that the fire protection for the diesel generator rooms meets the guidelines of Appendix A to BTP APCSB 9.5-1, Section F.9 and is, therefore, acceptable.

Diesel Fuel Oil Storage Areas

Three 70,000-gallon diesel fuel oil storage tanks are installed on the floor level above the diesel generators. Each fuel oil tank room is located directly

above the diesel generator served by the fuel oil tank in the room. The tanks are separated from each other and from other areas of the plant by 3-hour-fire-rated barriers.

The diesel generator building is located 5 feet from the electrical auxiliary building, the control room, and the cable spreading room. The first line of defense against a fire is the building foam-water fire protection system. The system is designed, installed, tested, and maintained in accordance with NFPA codes and standards. The tank rooms are provided with drain lines of sufficient capacity to remove the fire protection system water and foam at the same rate that it is released; they have additional margin for simultaneous removal of spilled oil. The heating, ventilation, and air conditioning system is designed to maintain the room ambient temperature safely below the minimum flash point of diesel fuel oil. The diesel fuel tank room will be locked closed except during per'odic inspections and maintenance. An analysis has been submitted that includes prediction of effluent rates and the concentration of inerts, carbon monoxide, and soot at the unaffected engines and control room air intakes in the event of the postulated fire.

Automatic fire detection is provided by thermal spot type detectors. Manual protection is provided by standpipe hose stations and portable fire extinguishers.

Appendix A to BTP APCSB 9.5-1, Section F.10, prohibits the storage of more than 1100 gallons of diesel fuel in diesel fuel oil tanks inside building containing safety-related equipment. However, the staff has reviewed the fire protection measures provided for the storage tank areas and concludes that adequate protection has been provided to ensure that a fire in any one of the storage tank rooms will not affect the redundant safe shutdown systems. Therefore, the staff finds that the installation of the diesel fuel oil storage tank in the diesel generator building is an acceptable deviation from Appendix A to BTP APCSB 9.5-1, Section F.10.

On the basis of its review and the approved deviation, the staff concludes that the fire protection for the diesel fuel oil storage area meets Appendix A to APCSB 9.5-1, Section F.10 and is, therefore, acceptable.

Remote Safety-Related Panels

The remote shutdown panels are separated from the remainder of the plant by walls and floor/ceiling assemblies, with fire ratings of 3-hours. Automatic fire detectors are located at various points in the area. Manual fire suppression capability is provided by portable fire extinguishers. The staff finds that the fire protection for this area is in accordance with the guidelines of Appendix A to BTP APCSB 9.5-1, Section F.6 and is, therefore, acceptable.

Other Plant Areas

The applicant's Fire Hazards Analysis Report addresses other plant areas not specifically discussed in this report.

The staff finds that the fire protection for these areas is in accordance with the guidelines of Appendix A to BTP 9.5-1 and is, therefore, acceptable.

9.5.1.7 Fire Protection of Safe Shutdown Capability

Safe Shutdown Capability

The applicant states that safe shutdown capability is provided by systems that "typically" consist of three redundant safety trains (A, B, and C) powered from independent Class 1E power supplies. The design objective is to provide two protected, redundant shutdown pathways wherever possible.

Thus, according to this design objective, the applicant deviates from the staff guidelines that require certain fire barriers and suppression systems, as stated in other sections of this report. In addition, FSAR Table 2.1 identifies 15 locations where the applicant has not met the design objective.

The applicant indicates that the redundant trains will be separated by one of the alternatives set forth in Section III of Appendix R. An alternate shutdown capability is provided for the control room.

The applicant states that the design is not complete and final assessment of safe shutdown is dependent on the final routing of cable. The applicant's Fire Hazards Analysis Report will be revised to reflect the final design.

The staff review of the applicant's safe shutdown capability and the associated deviations from the staff guidelines is ongoing and will be addressed in a supplement to this report after the final design is received.

Alternate Shutdown Capability

Alternative shutdown capability is provided for the control room by remote shutdown panels. The staff has not completed its review of the alternate shutdown capability and will address it in a supplement to this report.

9.5.1.8 Summary of Deviations from NRC Guidelines

The applicant had identified several deviations from the NRC guidelines in Appendix A to BTP APCSB 9.5-1 and in Sections III.G, III.J, and III.O of Appendix R to 10 CFR 50. These deviations are summarized in Table 9.1.

Eight of these deviations are normally accepted as being in compliance with the staff guidelines and are designated "normal" in Table 9.1. Two deviations have been evaluated and are designated "accepted." The remainder are "open" because the staff needs additional information to complete its review.

9.~~4~~5.1.9 Conclusions

The following fire protection items are open:

(1) potential systems interaction (Section 9.5.1.1)

(2) administrative controls (Section 9.5.1.2)

(3) fire brigade and fire brigade training (Section 9.5.1.3)

(4) qualification of fire doors (Section 9.5.1.4)

(5) protection of cable trays outside the cable spreading room (Section 9.5.1.4)

(6) emergency lighting (Section 9.5.1.4)

(7) fire protection for the fixed repeaters (Section 9.5.1.4)

(8) fire detection system compliance with NFPA 72D (Section 9.5.1.5)

(9) installation of fire detectors (Section 9.5.1.5)

(10) compliance of water suppression systems with NFPA 13 and 15 (Section 9.5.1.5)

(11) lack of full-coverage automatic water suppression systems in the cable spreading rooms (Section 9.5.1.5)

(12) separation of the switchgear rooms (Section 9.5.1.5)

(13) separation of the safety-related battery rooms (Section 9.5.1.5)

(14) safe shutdown capability (Section 9.5.1.7)

(15) alternate shutdown capability (Section 9.5.1.7)

The two deviations specifically evaluated in this report are flame spread rating of interior finish (Section 9.5.1.4) and fuel storage tanks above the diesel generators (Section 9.5.1.6).

Table 9.1 Deviations from NRC fire protection guidelines

Deviation	Applicable section of APCSB 9.5-1	Status
Water supply for reactor containment building from single pipe	A.4	normal
Separation of safety-related and shutdown systems	D.1.a	open
Combustibles in concealed spaces	D.1.f	normal
Some walls, floors, ceilings of fire areas not 3-hour-rated barriers: • Roofs • Outside walls that do not separate buildings • Fire zone boundaries	D.1.j	normal
Safety-related system not separated from combustibles by fire barriers	D.2.a	open
Storage of flammable liquids	D.2.d	accepted; see Section 9.5.8.6
Automatic sprinkler system in cable spreading room	D.3.c	open
Sealing inside conduit	D.3.d	normal
Some non-IEEE 383-Qualified Cable	D.3.f	normal
Stairwells with 1½-hour-rated doors	D.4.f	normal
Interconnection fire alarm panel to transmitter deviates from NFPA 72D	E.1.a	open
Partial suppression in cable spreading room (see D.3.c); walls not barriers	F.3	open
Switchgear not separated from remainder of plant by 3-hour-rated barrier	F.5	open
Battery room not separated from balance of plant	F.6	open

Table 9.1 (continued)

Deviation	Applicable section of APCSB 9.5-1	Status
Diesel fuel oil tank inside building larger than 1100-gallons	F.10	accepted; see Section 9.5.1.6
Radwaste handling area not separated by 3-hour-rated barriers	F.14	normal
Deviations identified in section 3 of the applicant's Fire Hazards Analysis Report	III.G*	open
Associated circuits evaluated per IEEE 384 and RG 1.75		open
No fixed suppression system in control room		normal

*From Section III.G of Appendix R to 10 CFR 50.

audit date and to select equipment for the audit. The staff review of this area will be completed after the applicant has demonstrated the adequacy of the South Texas qualification program through a satisfactory audit. The staff will report the results of its audit in a supplement to this report.

3.10.2 Pump and Valve Operability Assurance

The staff evaluation of the adequacy of the applicant's pump and valve operability assurance program consists of (1) a determination of the acceptability of the procedure used, standards followed, and the completeness of the program in general, and (2) an onsite audit of selected equipment items to develop the basis for the staff's judgement on the completeness and adequacy of the implementation of the entire pump and valve operability assurance program. The staff has reviewed the methodology and procedures of the pump and valve operability assurance program in FSAR Section 3.9. The staff has concluded that, except for the areas discussed below, the information in the FSAR meets the intent of SRP Section 3.10 (NUREG-0800). The SRP requires the applicant's qualification program to (1) meet IEEE 323-1974, RG 1.148, and the draft standards ANSI/ASME N551.1, N551.2, N551.4, and ANSI B.16.41 and N41.6 and (2) provide adequate assurance that such equipment will function properly under all imposed design and service loads including the loadings imposed by the safe shutdown earthquake, postulated accidents, and loss-of-coolant accidents.

The following information has not yet been provided in the FSAR for staff review:

(1) As of Amendment 38, Tables 3.10-1, 3.11-2, 3.11-5, and 3.11N-1 have not been added to the FSAR. The pump and valve operability review team (PVORT) is interested in examining these seismic and environmental qualification tables to evaluate the applicant's overall pump and valve operability assurance program.

(2) It is not clear that Table 3.9-1.2 (Amendment 44) is a complete list of active balance-of-plant (BOP) valves.

- BOP check valves have not been included in the table.

10 STEAM AND POWER CONVERSION SYSTEM

10.1 Summary Description

10.2 Turbine Generator

10.2.1 Deleted*

10.2.2 Deleted*

10.2.3 Turbine Disk Integrity

10.3 Main Steam Supply System

10.3.3 *
10.3.4 *

10.3.5 Secondary Water Chemistry

In late 1975, the staff incorporated provisions into the Standard Technical Specifications that required limiting conditions for operation and surveillance requirements for secondary water chemistry parameters. The Technical Specifications for all PWRs that were issued an operating license from 1974 until 1979 contain either these provisions or a requirement to establish these provisions after baseline chemistry conditions have been determined. The intent of the provisions was to provide added assurance that the operators of newly licensed plants would properly monitor and control secondary water chemistry to limit corrosion of steam generator components such as tubes and tube support plates.

In a number of instances, the plant Technical Specifications have significantly restricted the operational flexibility of the plant with little or no benefit with regard to limiting degradation of steam generator tube and the tube support plates. On the basis of this experience and the knowledge gained in recent

*Deleted from the July 1981 edition of the Standard Review Plan (NUREG-0800).

years, the staff has concluded that Technical Specification limits are not the most effective way to ensuring that steam generator degradation will be minimized.

Because of the complexity of the corrosion phenomena and the state of the art as it exists today, the staff considers that it is more effective to specify a Technical Specification that requires the implementation of a secondary water chemistry monitoring and control program containing appropriate procedures and administrative controls. This has been the approach used for control of secondary water programs since 1979.

The required program and procedures are to be developed by applicants, with input from their reactor vendor or other consultants, to account for site- and plant-specific factors that affect water chemistry conditions in the steam generators. It is the opinion of the staff that plant operation following such procedures would provide adequate assurance that licensees would devote proper attention to controlling secondary water chemistry, while also providing the needed flexibility to allow them to deal effectively with an off-normal condition that might arise.

Consequently, the staff asked the applicant to propose a secondary water chemistry program that would be referenced in a condition to the operating license and would replace any proposed Technical Specification on secondary water chemistry.

However, the applicant has not yet provided adequate information for the staff to perform an independent evaluation. The staff will perform its review after it receives the requested information.

10.4 Other Features

10.4.2 Main Condenser Evacuation System

The staff has reviewed the applicant's design, design criteria, and design bases for the main condenser air removal sytsem (MCARS) according to SRP Section 10.4.2. The acceptance criteria include the applicable GDC and the Heat Exchanger Institute Standard "Standards for Steam Surface Condensers." Guidelines for implementation of the requirements of the acceptance criteria are

provided in the regulatory guides referenced in Section II of the SRP. Conformance to the acceptance criteria of the SRP provides the bases for concluding that the MCARS meets the requirements of 10 CFR 50.

The main condenser evacuation system (MCES) is designed to (1) establish a vacuum on the condenser and (2) remove noncondensible gases from the main condenser and discharge them to the atmosphere. The major components are three water seal mechanical vacuum pumps each followed by a moisture separator and muffler.

The mechanical vacuum pumps are used to evacuate the main condenser and maintain a condenser pressure of 1 to 3.5 inches of mercury absolute above the water vapor pressure of the condenser circulating water. The vacuum pumps discharge the air and noncondensible gases into the turbine building. The exhaust is continuously sampled before it is released inside the turbine building for acceptable low concentration of activity by a noble gas radiation monitor. The monitor alarms in the control room on high activity. The turbine building air is exhausted to the environment without filtration or monitoring for radioactivity.

The MCES includes equipment and instruments to establish and maintain condenser vacuum and to prevent an uncontrolled release of gaseous radioactive material to the environment. The scope of the staff review included the system capability to monitor and control releases of radioactive materials in effluents. The staff has reviewed the applicant's system descriptions, piping and instrumentation diagrams, and design criteria for the components of the MCES in accordance with the SRP.

The staff concludes that the MCES design is acceptable in that the applicant has met the requirements of GDC 60 and 64 with respect to the control and monitoring of releases of radioactive materials to the environment. The applicant has met the criteria for applying appropriate industrial standard on the design of heat exchangers and air ejectors. Regarding the control of releases, the applicant will be requested to specify the action that will be taken if there is a high activity alarm from the mechanical vacuum pump discharge monitor. In addition, the dose contribution from this pathway should be reflected in the applicant's offsite dose calculation manual (ODCM).

10.4.3 Turbine Gland Sealing System

The staff has reviewed the applicant's design, design criteria, and design bases for the turbine gland sealing system (TGSS) in accordance with SRP Section 10.4.3 (NUREG-0800). The acceptance criteria are the applicable GDC as referenced in the SRP. Guidelines for implementation of the requirements of the acceptance criteria are provided in the regulatory guides identified in Section II of the SRP. Conformance to the acceptance criteria provides the bases for concluding that the TGSS meets the requirements of 10 CFR 50.

The TGSS is designed to provide a continuous supply of clean steam to the main turbine and the steam generator feed pump turbine shaft seals. In addition, the valve stem packing leakoff from various stop valves and control valves is directed into the gland steam condenser. This sealing steam is used to prevent air leaking into the turbine and prevent outleakage of steam into the turbine building.

The TGSS includes both main steam and auxiliary steam as the sources of sealing steam. Instruments and controls are provided to reduce the steam pressure and direct the sealing steam to the labyrinth seals of the turbines. A seal packing exhaust condenser receives the seal steam flow and the valve stem leakoffs where it is condensed and returned to the seal leakoff tank. Vent gases from the condenser are exhausted via redundant air exhausters to the turbine building atmosphere. No provisions for monitoring or controlling radioactive gases from the condenser exhaust is provided, as suggested by the SRP.

The staff notes that even though the TGSS design does not meet the effluent monitoring and sampling provision suggested in the SRP, any activity released to the environment by this path is insignificant compared to the much larger main condenser vacuum pump discharge. Because the main condenser vacuum pump discharge is continuously monitored for noble gases and has provisions for drawing grab samples for laboratory analysis, radioactive effluents from both the main condenser air removal system and steam gland sealing system can be determined during normal power operation. During those periods (such as startup and

shutdown) when turbine steam flow does not exist but sealing steam flow is operating, the condition for unmonitored effluent releases via the seal steam condenser exhaust does exist but it is considered not to pose a problem. This conclusion is based on the facts that (1) uncontaminated auxiliary steam is applied during the startup operations and (2) that there is expected to be only a short period when mainsteam could be applied to the gland sealing system without the simultaneous main turbine steam flow, when activity monitoring would be accomplished by the MCARS.

Based on these judgments, the staff concludes that no significant improvement in plant or public safety would be achieved by the installation of radiation monitors in the gland seal exhaust, and this installation is not justified on a cost basis.

The staff has reviewed the applicant's system descriptions and design criteria for the components of the TGSS and found them consistent with RG 1.26, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants."

On the basis of the above findings and considerations, the staff concludes that the TGSS design is acceptable. Activity release via this pathway is a small fraction of that released via the MCARS.

10.4.6 Condensate Polishing Demineralizer System

The condensate polishing demineralizer system (CPDS) removes dissolved and suspended impurities from the condensate. The CPDS is not required for safe shutdown or mitigation of postulated accidents, but is important in maintaining the secondary water quality.

The staff has reviewed the condensate cleanup in accordance with SRP Section 10.4.6 (NUREG-0800). The CPDS includes all components and equipment necessary for the removal of dissolved and suspended impurities that may be present in the condensate. The CPDS is capable of removing contaminants from the full condensate flow during normal operation and anticipated operational occurrences

to produce feedwater purity in accordance with BTP MTEB 5-3 (SRP Section 5.4.2.1 (NUREG-0800)).

The instrumentation and sampling equipment provided is adequate to monitor and control process parameters in accordance with BTP MTEB 5-3. The applicant has met the requirements of GDC 14 for maintaining acceptable chemistry control for PWR secondary coolant during normal operation and anticipated operational occurrences by reducing corrosion of PWR steam generator tubes and materials, thereby reducing the likelihood and magnitude of primary-to-secondary coolant leakage.

On the basis of its review of the applicant's proposed design criteria and design bases for the CPDS and the requirements for operation of the system, the staff concludes that the design of the CPDS and supporting systems is acceptable.

10.4.7 Condensate and Feedwater System

10.4.8 Steam Generator Blowdown System

The steam generator blowdown system (SGBS) is used in conjunction with the condensate demineralizer, chemical addition, and sampling systems to control the chemical composition of the steam generator shell side water within specified limits during all operating modes. The blowdown fluids are directed to the blowdown tank and then to the condenser.

The staff has reviewed the SGBS in accordance with SRP Section 10.4.8 (NUREG-0800). The SGBS controls the concentration of chemical impurities and radioactive materials in the secondary coolant. The review included piping and instrumentation diagrams, seismic and quality group classifications, design process parameters, and instrumentation and process controls.

The SGBS is monitored continuously for radiation in the secondary side of the steam generator. It has the capability of diverting the blowdown liquid (after isolation and substantial cooldown of the steam generator) to the radioactive liquid waste system in the event of a high radiation signal resulting from a steam generator tube leak.

The portion of the SGBS up to and including the containment isolation valves is seismic Category I. All other piping and equipment in the SGBS is not safety related and is designed and built to ANS B31.1 requirements. Thus, the SGBS meets the quality standards requirements of GDC 1 and the seismic requirements of GDC 2.

Instrumentation and automatic controls are provided to monitor and control the operation of the blowdown system, with provision for sampling of the blowdown, in conformance with BTP MTEB 5-3.

The secondary water chemistry monitoring and control program is evaluated in Section 10.3.5 above.

On the basis of its review, the staff concludes that the proposed SGBS meets its guidelines and is acceptable.

10.4.9 Auxiliary Feedwater System

11 RADIOACTIVE WASTE MANAGEMENT

The South Texas radioactive waste management system is designed to provide for the controlled handling and treatment of liquid, gaseous, and solid wastes. The liquid waste system processes wastes from equipment and floor drains, sample wastes, decontamination and laboratory wastes, and chemical wastes. The gaseous radioactive waste system provides holdup capacity to allow decay of short-lived noble gases from degassed primary coolant and treatment of ventilation exhausts through HEPA filters and carbon adsorbers as necessary to reduce releases of radioactive materials to "as low as is reasonably achievable" levels, in accordance with 10 CFR 20 and 10 CFR 50.34a. The solid waste management system collects and processes wet and dry waste generated by the plant and packages the material into a solid product for shipment to a permanent disposal site. The radioactive waste management review includes process and effluent radiological monitoring and sampling systems.

The staff has reviewed the applicant's design criteria and design bases for the radioactive waste management systems in accordance with SRP Sections 11.1, 11.2, 11.3, 11.4, and 11.5 (NUREG-0800). These acceptance criteria include the applicable GDC, 10 CFR 20.106, Appendix I to 10 CFR 50, and ANSI N13.1, "Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities." Guidelines for implementation of the acceptance criteria are in the ANSI standards, regulatory guides, and other documents identified in the SRP. Conformance to the acceptance criteria provides the bases for the staff's concluding that the radioactive waste management systems meet the requirements of 10 CFR 20 and 50.

11.1 Liquid and Gaseous Effluent Source Terms

The applicant calculated the estimated releases of radioactive materials in liquid and gaseous effluents using the PWR GALE Code described in NUREG-0017, Revision 0. The staff has reviewed these source terms and found them consistent with the guidelines of SRP Section 11.1. However, staff-calculated source terms

using Revision 1 of NUREG-0017 were used in the staff's evaluation. The principal parameters used in the staff's calculations are givcn in Table 11.1.

11.2 Liquid Radwaste Processing Systems

11.2.1 System Description

The liquid waste processing system for Unit 1 is identical to that for Unit 2. Each liquid radioactive waste processing system consists of process equipment and instrumentation necessary to collect, process, monitor, and recycle or dispose of radioactive liquid wastes. The liquid wastes from operation of Units 1 and 2 will be collected and processed in separate systems that consist of a high purity system, a low purity system, a condensate publishing regenerant system, and a laundry system. The high purity liquid radwaste system is designed to collect and process wastes from reactor coolant equipment drains, containment normal sump, and other noncontaminated sources of reactor coolant. The low purity liquid radwaste system is designed to collect and process floor drain waste from the mechanical auxiliary building, as well as other potentially contaminated waste. The condensate polishing regenerant and chemical radwaste subsystem receives high conductivity waste from the condensate demineralizer regeneration subsystem, chemical laboratory drains, boron recycle evaporator condensate, and component cooling water sump pump. The laundry waste subsystem processes wastes from the laundry and shower drains and fuel handling building sump.

The liquid radwaste processing systems are designed to store processed water with the capability for eventual reuse in the plant. However, the design-basis valve alignment releases the processed water under controlled conditions to the environment. A radiation monitor in the plant discharge line will automatically terminate liquid waste discharge if radiation measurements exceed a predetermined level.

The high purity drain subsystem processes the low conductivity, high purity wastes. Waste is first collected in a waste holdup tank and is later processed through a mixed bed demineralizer (or an evaporator followed by a demineralizer)

before being stored in two waste evaporator condensate tanks. From these tanks, the processed water is either stored in the reactor water makeup storage tank for reuse or a portion can be discharged to the environment. The applicant estimates that the high purity drain subsystem will receive waste input flow of approximately 530 gpd, which is consistent with SRP guidelines. Adequate initial tank storage (10,000 gallons) is provided to accommodate flexible operation and the process flow rate (limited to 30 gpm by evaporators) is sufficient to treat the daily inputs within an adequate time frame (less than 1 hour per day).

The equipment and floor drain subsystem processes higher conductivity, low purity wastes. Waste is initially collected in a 33,000-gallon tank, and later will be processed through a replaceable cartridge filter, an evaporator, a mixed bed demineralizer, in series, prior to being collected in a waste management tank for sampling. The applicant estimates the equipment and floor drain subsystem waste input to be approximately 6900 gpd. The design process capacity of the floor drain subsystem is approximately 30 gpm (limited by the evaporator). This flow rate is sufficient to process the daily inputs within an acceptable time (less than 4 hours per day).

The regenerant waste subsystem will process resin regenerant from the condensate demineralizers and high conductivity waste from other radwaste area drains. Regenerant waste (approximately 4500 gpd) is first collected in the condensate polishing regeneration waste collections tank. Then it is processed through a disposable filter, an evaporator package where water is separated out leaving a highly concentrated mixture of resin regenerant and solids in the evaporator bottoms. The concentrated waste in the evaporator is later sent to the solid waste processing system for solidification and disposal. The condensed water from the evaporator is then processed through a demineralizer, before it is temporarily stored in the waste evaporator condensate tank. This water can then be recycled or discharged from the plant via the open cooling water system.

The laundry and hot shower waste processing system first collects laundry waste and personnel decontamination drainage in a 10,000-gallon hold tank. Then this waste is processed by filtration, temporarily stored in a waste monitor tank, and discharged from the plant via the open cooling water system.

All plant discharges are controlled releases and are monitored for radioactivity before they are released.

In its evaluation of the liquid radioactive waste management system, the staff considered (1) the capability of the system for keeping the levels of radioactivity in effluents "as low as is reasonably achievable" based on expected radwaste inputs over the life of the plant; (2) the capability of the system to maintain releases below the limits in 10 CFR 20 and to limit radiological doses to less than that allowed by Appendix I to 10 CFR 50, during periods of fission product leakage at expected levels from the fuel; (3) the capability of the system to meet the processing demands of the station during anticipated operational occurrences; (4) the quality group and seismic design classification applied to the equipment and components and structures housing the system; and (5) the design features that are incorporated to control the releases of radioactive materials in accordance with GDC 60.

The estimated releases of radioactive materials in liquid effluents were calculated by the staff using the PWR GALE Code described in NUREG-0017 (Rev. 1). The principal parameters used in the staff calculations are given in Table 11.1.

11.2.2 Evaluation Findings

The liquid radwaste systems include the equipment necessary to control the releases of radioactive materials in liquid effluents in accordance with GDC 60 and 61 and 10 CFR 50.34a. The staff concludes that the design of the liquid waste management system is acceptable and meets 10 CFR 20.106; 10 CFR 50.34a; GDC 60 and 61; and 10 CFR 50, Appendix I, as referenced in the SRP.

The applicant has met the requirements of Section II.A of Appendix I of 10 CFR 50 with respect to dose limiting objectives by proposing a liquid radwaste treatment system that is capable of maintaining releases of radioactive materials in liquid effluents such that the calculated individual doses to an unrestricted area from all liquid pathways of exposure are less than 5 millirems per year to the total body and less than 15 millirems per year to any organ.

The staff has concluded that the applicant has met the requirements of the Commission's September 4, 1975 Annex to Appendix I of 10 CFR 50 with respect to meeting the site activity release limitations and "as low as is reasonably achievable" criterion, and is, therefore, exempt from the cost-benefit analysis required by Section II.D of Appendix I to 10 CFR 50.

The applicant has met the requirements of 10 CFR 20.106, because, on the basis of its evaluation of the potential consequences of reactor operation, the staff has determined that the concentrations of radioactive materials in liquid effluents in unrestricted areas will be a small fraction of the limits in 10 CFR 20, Appendix B, Table II, Column 2.

The applicant has met GDC 60 and 62 with respect to controlling releases of radioactive material to the environment, because, on the basis of its evaluation of the capabilities of the proposed liquid radwaste treatment system to meet the demands of the plant resulting from anticipated operational occurrences, the staff has concluded that the system capacity and design flexibility are adequate to meet the anticipated needs of the plant. The staff has reviewed the applicant's quality assurance provisions for the liquid radwaste systems, the quality group classifications used for system components, and the seismic design applied to structures housing these systems and concludes that they meet the criteria as set forth in RG 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants" (Revision 1). The staff has reviewed the provisions incorporated in the applicant's design to control the release of radioactive materials in liquids as a result of inadvertent tank overflows and concludes that the measures proposed by the applicant are consistent with the criteria, as set forth in RG 1.143 (Revision 1).

11.3 Gaseous Radwaste Processing System

11.3.1 System Description

The gaseous radioactive waste processing and plant ventilation systems are designed to collect, delay, process, monitor, and discharge potentially radioactive gaseous wastes that are generated during normal operation of the plant.

The systems consist of equipment and instrumentation necessary to reduce releases of radioactive gases and particulates to the environment. The principal sources of gaseous waste are the effluents from the gaseous waste processing system, condenser mechanical vacuum pumps, and ventilation exhausts from the reactor building, auxiliary building and fuel handling building.

The gaseous waste processing system (GWPS) is a charcoal delay system that receives vent gases from the volume control tank purge, boron recycle holdup tank, boron recycle evaporator, liquid waste evaporator, reactor coolant drain tank, and pressurizer relief tank. In addition, for rapid degassing of the reactor coolant before refueling, a vacuum degassing compressed storage tank system is utilized for radioactive gas holdup. This gas is later released through the charcoal delay system. The gas discharge from the charcoal delay system and gas decay tanks passes through a HEPA filter and is discharged to the environment through the mechanical auxiliary building vent.

The reactor building ventilation exhaust system discharges air (40,000 ft^3/min) from the reactor containment to the atmosphere without filtration during refueling. Before refueling, the containment atmosphere is recirculated for 16 hours through the containment cleanup system for airborne radioactivity removal. This system consists, in order, of a redundant roughing filter, a HEPA filter, a charcoal filter, and a HEPA filter, followed by two circulation fans. Gases released from liquid radwaste system equipment vents are directed through the plant vent header without filtration.

Exhaust flow from the refueling floor of the reactor building is normally unfiltered unless activity is detected in the refueling flow exhaust duct. If the latter is the case, then the refueling floor exhaust flow is diverted through redundant HEPA/charcoal filtration units before it is released to the atmosphere. These filtration units are dicussed in Section 6.5.4.2 of this SER.

The turbine building ventilation exhaust is unfiltered. The main condenser mechanical vacuum pump discharge is unfiltered.

The major source of gaseous radwaste during normal plant operation will be vent gases from the primary coolant and primary coolant leakage. The South Texas

gaseous waste processing system is essentially a charcoal delay system. Hydrogen vent gases from various primary coolant tanks and the volume control tank purge at a flow of 0.7 to 1.0 scfm pass through a water-removal skid where water is condensed out and the gas stream leaves at a 40°F dew point. The gas then proceeds through ambient temperature (85°F) charcoal delay tanks. In these tanks, the expected delay time for krypton is 3.65 days and for xenon it is 67.5 days. The gas leaves the charcoal delay tanks and passes through a HEPA filter before it is discharged to the atmosphere via the mechanical auxiliary exhaust ventilation system. The charcoal delay system is designed to withstand the effects of a hydrogen explosion.

Before refueling, when the reactor is in cold shutdown, the reactor coolant is rapidly degassed by the reactor coolant vacuum degassing system. Nitrogen gas is alowed to fill the space underneath the reactor vessel head. A water seal vacuum pump followed by a diaphram compressor removes most of the nitrogen that sweeps the released noble gases from underneath the vessel head into storage tanks. Two 600-ft^3 storage tanks receive and store these gases at a maximum operating pressure of 120 psig. The gases in these tanks will be released to the atmosphere before the next refueling, approximately 18 months later. These tanks can be discharged through the charcoal delay beds (or they can bypass the charcoal delay system) before they are released through a HEPA filter at the mechanical auxiliary exhaust ventilation system.

In its evaluation of the gaseous radwaste management system, the staff considered the following SRP criteria: (1) the capability of the system for keeping the levels of radioactivity in effluents "as low as is reasonably achievable" based on expected radwaste inputs over the life of the plant; (2) the capability of the system to maintain releases below the limits in 10 CFR 20 during periods of fission product leakage at expected levels from the fuel; (3) the capability of the system to meet the processing demands of the station during anticipated operational occurrences; (4) the seismic design classification applied to the equipment and components and structures housing the system; (5) the design features that are incorporated to control the releases of radioactive materials, in accordance with GDC 60; and (6) the potential for gaseous releases as a result of hydrogen explosions in the gaseous radwaste system.

The estimated releases of radioactive materials in gaseous effluents were calculated by the staff using the PW GALE Code described in NUREG-0017 (Revision 1). The principal parameters used in these calculations are given in Table 11.1.

The staff has reviewed the applicant's quality assurance provisions for the gaseous radwaste systems, the quality group classifications used for system components, the seismic design criteria applied to the design of the system, and of structures housing the radwaste systems. The design of the system and structures housing these systems meets RG 1.143 (Revision 1), as referenced in the SRP.

The staff has reviewed the provisions incorporated in the applicant's design to control releases resulting from hydrogen explosions in the gaseous radwaste system and concludes that the measures proposed by the applicant are adequate to prevent the occurrences of an explosion or to withstand the effects of a hydrogen detonation.

The staff has reviewed the provisions incorporated in the applicant's design to collect airborne radioactivity material in the normal ventilation exhaust systems during normal plant operation, including anticipated operational occurrences. The staff finds the design of air filtration and adsorption units consistent with RG 1.140, "Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" (Revision 1), as referenced in the SRP.

11.3.2 Evaluation Findings

The staff concludes that the design of the gaseous waste management system is acceptable and meets 10 CFR 20.106; 10 CFR 50.34a; GDC 3, 60 and 61; and 10 CFR 50, Appendix I, as referenced in the SRP.

The applicant has met GDC 60 and 64 with respect to controlling releases of radioactive material to the environment by ensuring that the design of the gaseous waste management system includes the equipment and instruments necessary to detect and to control the release of radioactive materials in gaseous

effluents. Capacities of principal components considered in the gaseous waste processing system evaluation are listed in Table 11.2.

The applicant has met the requirements of Appendix I of 10 CFR 50 by meeting the "as low as is reasonably achievable" criterion as follows:

(1) Regarding Section II.B and II.C of Appendix I, the staff has considered releases of radioactive material (noble gases, radioiodine, and particulates) in gaseous effluents for normal operation including anticipated operational occurrences based on expected radwaste inputs over the life of the plant. The staff has determined that the proposed gaseous waste management system is capable of limiting releases of radioactive materials in gaseous effluents such that the calculated individual doses in an unrestricted area from all pathways of exposure are less than 5 mrems to the total body or 15 mrems to the skin and less than 15 mrems to any organ from releases of radioiodine and radioactive material in particulate form.

(2) The applicant has met the Commission's September 4, 1975 Annex to Appendix I to 10 CFR 50 with respect to meeting the siting limits and "as low as is reasonably achievable" criterion, and is, therefore, exempt from the cost-benefit analysis required by Section II.D of Appendix I to 10 CFR 50.

The applicant has met 10 CFR 20 because, on the basis of its evaluation of the potential consequences of reactor operation with a fission product release rate associated with 1% failed fuel, the staff has determined that under these conditions, the concentrations of radioactive materials in gaseous effluents in urestricted areas will be a small fraction of the limits specified in 10 CFR 20, Appendix B, Table II, Column 1.

The staff has considered the capabilities of the proposed gaseous waste management system to meet the demands of the plant as a result of anticipated operational occurrences and has concluded that the system capacity and design flexibility are adequate to meet these demands.

The staff has reviewed the applicant's quality assurance provisions for the gaseous waste management system, the quality group classifications used for system

components, the seismic design applied to the design of the system, and of structures housing the radwaste system. The design of the system and of structures housing the system meet the criteria in RG 1.143 (Revision 1).

The staff has reviewed the provisions incorporated in the applicant's design to control releases resulting from hydrogen explosions in the gaseous waste management system and has concluded that the measures proposed by the applicant are adequate to prevent the occurrence of an explosion and to withstand the effects of a hydrogen detonation, in accordance with GDC 3.

11.4 Solid Waste Management System

11.4.1 System Description

The solid waste processing system (SWPS) is designed to package and solidify with Portland cement all types of liquid waste, spent resins, and expended liquid filter cartridges. Additional equipment is provided to compact dry radioactive waste. In brief, liquid waste from the evaporator concentrates storage tank or spent resin storage tank is transferred to a mixing tank where chemicals can be added to neutralize the waste material. This waste is then dewatered where excess water is returned to the spent resin storage tank in the liquid waste system, and the remaining slurry is sent under controlled flow to the waste mixers. In the waste mixer, a controlled amount of cement is mixed with the waste slurry and the cement-waste mixture is deposited into shipping containers (drums) for solidification.

The solidified waste will be stored on the site in the onsite staging facility. This facility is designed to store solid waste generated from operation of both Units 1 and 2 for 5 years.

11.4.2 Evaluation Findings

On the basis of its review, the staff concludes that the design of the solid waste management system meets 10 CFR 20.106; 10 CFR 50.34a; GDC 60, 63, and 64; and 10 CFR 71. The staff also concludes that the applicant has provided

sufficient solid waste storage capacity (for greater than 30 days at normal processing rates) to meet BTP ETSB 11-3. In addition, the proposed system design meets the quality assurance group classification and seismic criteria as recommended in RG 1.143 (Revision 1) for solid radwaste systems.

The applicant has not provided sufficient details on the solid waste process control program and the solid waste requirements of 10 CFR 61. Therefore, before processing solid waste, the applicant must obtain staff approval of the solid waste process control program, addressing 10 CFR 61 and BTP ETSB 11-3. Guidelines for this procedure will be sent to the applicant under separate letter.

The applicant also must provide a process and instrumentation diagram for the solid waste process system.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

11.5.1 System Description

The process and effluent radiological monitoring systems are designed to provide information concerning radioactivity levels in systems throughout the plant, indicate radioactive leakage between systems, monitor equipment performance, and monitor and control radioactivity levels in plant discharges to the environs.

Table 11.3 provides the proposed locations of continuous monitors. Monitors on certain effluent release lines will automatically terminate discharge if radiation levels exceed a predetermined value. Systems that are not amenable to continuous monitoring, or for which detailed isotopic analyses are required, will be periodically sampled, and the samples will be analyzed in the plant laboratory.

All normal airborne radioactive releases to the environs from each South Texas unit are from the plant main exhaust duct at the roof of the mechanical auxiliary building. These gaseous releases are considered ground level releases for establishing the dispersion coefficient.

Redundant radiation monitors are installed in the main exhaust vent. They sample effluent air downstream of the last point of mixing and provide continuous readout of noble gas and particulate activity. In addition, charcoal adsorbers are provided to sample the air stream for radioiodine. Sampling flow is through a regulated isokinetic probe.

In addition to the main plant vent discharge point monitors, ventilation radiation monitors are also provided in the exhaust streams of the reactor containment and fuel handling buildings. These monitors are used to identify sources of airborne activity before mixing and dilution in the main plant exhaust vent.

The principal radioactive liquid effluent release point for each South Texas unit is the discharge of the circulating water system. Potentially radioactive inputs to the circulating water system will be continuously monitored for radioactivity prior to and during release. Because the circulating water is a high flow rate system, the radioactive inputs to the system will be highly diluted. The liquid radwaste discharge process monitor provides alarm signals for termination of discharge of the liquid radwaste system in the event a predetermined Technical Specification limit is exceeded.

Process liquid radiation monitors are also used in the closed loop component cooling water system to detect any heat exchanger leakage at primary coolant.

11.5.2 Evaluation Findings

The staff review included the locations and types of effluent and process monitoring provided for each South Texas unit. On the basis of the plant design and the continuous monitgring and intermittent sampling locations, the staff has concluded that all normal and potential release pathways will be monitored. The applicant's description indicates that the process and effluent monitoring system design meets the guidelines in RG 4.15, "Quality Assurance for Radiological Monitoring Programs." The staff also determined that the sampling and monitoring provisions are adequate for detecting radioactive material leakage to normally uncontaminated systems and for monitoring plant processes that could affect radioactivity releases. On these bases, the staff considers that the

monitoring and sampling provisions meet GDC 60, 63, and 64 and RG 1.21, "Measuring, Evaluating and Reporting Radioactivity in Solid Waste and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants" (Revision 1). Therefore, they meet the acceptance criteria of the SRP. In addition, the applicant has provided appropriate effluent monitors for post-accident conditions in accordance with the guidelines of NUREG-0737 Items II.F.1.1 and II.F.1.2. These monitors are designed in accordance with RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident" (Revision 2).

Table 11.1 Parameters for evaluating liquid waste processing system

Parameter	Value
Reactor power	3,800 MWt
Mass of primary coolant	573,000 lb
Primary systems letdown flow	100 gpm
Letdown cation demineralizer flow	20 gpm
Number of steam generators	4
Total steam flow	26.96 $x20^6$ lb/hr
Mass of liquid in each steam generator	123,000 lb
Total mass of water in steam generator	492,000 lb
Steam generator blowdown rate	168,000 lb/hr
Primary to secondary leak rate	75 lb/day
Condensate demineralizer regeneration time	21.10 days
Fission product carryover fraction	0.005
Halogen carryover fraction	0.010
Fraction of feedwater through condensate demineralizer	0.54
Shim bleed rate to boron recycle system	2740 gpd
Decontamination factors (iodine, cesium, others)	$5x10^3$, $2x10^3$, $1x10^5$
BRS holding tank collection time	21.9 days
Process time	6.1 days
Discharge fraction	0.10
Primary coolant, drains (leakoff)	530 gpd
Decontamination factors (iodine, cesium, others)	$5x10^2$, $1x10^3$, $1x10^4$
Fraction of primary coolant activity	1.0
Collection time	7.6 days
Processing time	0.115 day
Fraction released	1.0
Equipment and floor drains	6,900 gal
Decontamination factors (iodine, cesium, others)	$5x10^2$, $1x10^3$, $1x10^4$
Fraction of primary coolant activity	0.11
Collection time	2.0 days
Processing time	0.6 day
Discharge fraction	1.0

Table 11.1 (Continued)

Parameter	Value
Condensate demineralizer regenerant	4,650 gpd
Decontamination factor (iodine, cesium, others)	5×10^2, 2×10^3, 1×10^4
Collection time	2 days
Processing time	0.2 day
Discharge fraction	1.0

Table 11.2 Parameters for evaluating airborne radioactive releases from plant vent

Parameter	Value
Primary coolant degassing	
Holdup time for xenon	67.5 days
Holdup time for krypton	3.65 days
Waste gas system particulate release fraction	0.01
Auxiliary building	
Iodine release fraction	1.0
Particulate release fraction	1.0
Containment volume	3.6×10^6 ft^3
Frequency of containment high volume purges/per year	2.0
Iodine release fraction	1.0
Particulate release fraction	1.0
Containment low volume purge rate	5,000 cfm
Iodine release fraction	1.0
Particulate release fraction	1.0
Steam leak to turbine building	1700.0 lb/hr
Fraction of iodine released from blowdown vent	0.0
Fraction of iodine removed from main condenser vacuum pump exhaust	0.0

Table 11.3 Process and effluent radiation monitoring system

Monitor	Service	Sample Location	Detector Number	Detector Type	Analysis Performed	Range (µCi/cc)	MDC (1) (µCi/cc)	Controlling Isotope	Alert Alarm (µCi/cc)	High Alarm (µCi/cc)	Control Function
RT-8011	Reactor Containment Building Atmosphere	Containment Atmosphere	RE-8011A Particulate (P)	(2)	Gross Beta	(8)	*	Cs-137	5.0 (-8)	1.0 (-7)	Sends Signal to SSPS for Containment Ventilation Isolation (Section 9.4.5)
			RE-8011B Iodine (I) R	(3)	Gross Gamma	(9)	*	I-131	9.0 (-8)	9.0 (-7)	
			RE-8011C Noble Gas (NG)	(2)	Gross Beta	(10)	*	Kr-85	1.0 (-4)	4.0 (-4)	
RT-8010A	Unit Vent Particulate and Iodine	Unit Vent Stack, MAB Roof	RE-8010A (P)	(2)	Gross Beta	(8)	*	Cs-137	5. (-8)	1.0 (-7)	NONE
			RE-8010B (I)	(3)	Gross Gamma	(9)	*	I-131	1.0 (-7)	4.0(-7)	
RT-8010B	Unit Vent Wide Range Gas	Unit Vent Stack, MAB Roof	RE-8010C (NG) Low Range	(2)	Gross Beta	1.4×10^{-7} to 1.4×10^{-1}	*	Kr-85	*	*	NONE
			RE-8010D (NG) Mid-Range	(5)		6.6×10^{-4} to 6.6×10^{2}	*	Kr-85	NA		
			RE-8010E (NG) High Range	(5)		1.7×10^{-1} to 1.7×10^{5}	*	Kr-85	NA		
RT-8033	Control Room/ Electrical Auxiliary Building (EAB) Air Intake	EAB Intake Air	RE-8033 (NG)	(2)	Gross Beta	(11)	5.3 (-8)	Kr-85	7.5 (-4)	1.5 (-3)	Initiates Control Room/EAB Emergency Ventilation (Section 9.4.1)
RT-8034	Control Room/ Electrical Auxiliary Building (EAB) Air Intake	EAB Intake Air	RE-8034 (NG)	(2)	Gross Beta	(11)	5.3 (-8)	Kr-85	7.5 (-4)	1.5 (-3)	Initiates Control Room/EAB Emergency Ventilation (Section 9.4.1)
RT-8027	Condenser Vacuum Pump (CVP)	CVP Exhaust Pipe, TGB	RE-8027A (NG) Low Range	(2)	Gross Beta	1.4×10^{-7} to 1.4×10^{-1}	*	Kr-85	*	*	NONE
			RE-8027B (NG) Mid-Range	(5)		6.6×10^{-4} to 6.6×10^{2}	*	Kr-85	N/A		
			RE-8027C (NG) High Range	(5)		1.7×10^{-1} to 1.7×10^{5}	*	Kr-85	N/A		

* Later
See notes at end of table

Table 11.3 (Continued)

Monitor	Service	Sample Location	Detector Number	Detector Type	Analysis Performed	Range (μCi/cc)	MDC (1) (μCi/cc)	Controlling Isotope	Alert Alarm (μCi/cc)	High Alarm (μCi/cc)	Control Function
RT-8035	Spent Fuel Pool Exhaust	Fuel Handling Building Ventilation Exhaust	RE-8035 (NG)	(2)	Gross Beta	(11)	1.1 (-7)	Kr-85	*	*	Initiates Fuel Handling Building Exhaust Filtration (Section 9.4.2)
RT-8036	Spent Fuel Pool Exhaust	Fuel Handling Building Ventilation Exhaust	RE-8036 (NG)	(2)	Gross Beta	(11)	1.1 (-7)	Kr-85	4.0 (-2)	8.1 (-2)	Initiates Fuel Handling Building Exhaust Filtration (Section 9.4.2)
RT-8012	Reactor Containment Building (RCB) Purge Isolation	RCB Normal Purge System Exhaust	RE-8012 (NG)	(2)	Gross Beta	(11)	5.3 (-8)	Kr-85	7.5 (-3)	7.5 (-2)	Sends Signal to SSPS for Containment Ventilation Isolation (Section 9.4.5)
RT-8013	RCB Purge Isolation	RCB Normal Purge System Exhaust	RE-8013 (NG)	(2)	Gross Beta	(11)	5.3 (-8)	Kr-85	7.5 (-3)	7.5 (-2)	Sends Signals to SSPS for Containment Ventilation Isolation (Section 9.4.5)
RT-8043	Steam Generator Blowdown (SGBD) Liquid	SGBD Flash Tank Outlet Demineralizer Outlet	RE-8043 Liquid (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	Closes SGBD Discharge to Neutralization Basin Isolation Valve, FV-5019
RT-8038	Liquid Waste Processing System (LWPS)	Upstream of LWPS Diversion Valve FV-4077	RE-8038 (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	Positions Diversion Valve FV-4077 to Divert Effluent Back to Waste Monitor Tanks (Section 11.2)
RT-8045	Liquid Waste Processing System (LWPS)	Upstream of LWPS Diversion Valve FV-5050	RE-8045 (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	NONE

Table 11.3 (Continued)

Monitor	Service	Sample Location	Detector Number	Detector Type	Analysis Performed	Range (μCi/cc)	MDC (1) (μCi/cc)	Controlling Isotope	Alert Alarm (μCi/cc)	High Alarm (μCi/cc)	Control Function
RT-8040	Component Cooling Water (CCW)	Discharge of CCW Pumps	RE-8040 (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	NONE
RT-8037	Boron Recycle System (BRS)	BRS Evaporator Condensate Line	RE-8037 (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	Positions Diversion Valve RCV-4202 to Divert Fluid Back to BRS Evaporator Feed Demineralizers (Section 9.3.4.2)
RT-8041	Turbine Generator Building Drain	Discharge Sump Pumps Sump No. 1	RE-8041 (L)	(4)	Gross Gamma	(11)	3.9 (-8)	Cs-137	*	*	Stops TBG Sump No. 1 Sump Pump (Section 9.3.3)
RT-8039	Failed Fuel	Chemical and Volume Control System Letdown Line	RE-8039 (L)	(4)	Gross Gamma	(11)	7.9 (-8)	Cs-137	*	*	NONE
RT-8042	Condensate Polishing System (CPS)	Discharge of CPS to Neutralization Basin	RE-8042 (L)	(4)	Gross Gamma	(11)	3.6 (-8)	Cs-137	*	*	Closes FV-5804, CPS Discharge to Neutralization Basin Valve (Section 10.4.6)
RT-8031	Gaseous Waste Processing System (GWPS) Inlet	Adjacent to Inlet Line to GWPS	RE-8031 Adjacent-to-line (ATL)	(3)	Gross Gamma	*	5.6 (-7)	Kr-85	1.0 (0)	2.5 (0) mR/hr	NONE
RT-8032	Gaseous Waste Processing System (GWPS) Discharge	Adjacent to Discharge Line, Upstream of GWPS Discharge Valve	RE-8032 (ATL)	(3)	Gross Gamma	*	5.6 (-7)	Kr-85	6.0 (0)	1.2 (1) mR/hr	Closes FV-4671, GWPS Discharge Valve (Section 11.3)

Table 11.3 (Continued)

Monitor	Service	Sample Location	Detector Number	Detector Type	Analysis Performed	Range (μCi/cc)	MDC (1) (μCi/cc)	Controlling Isotope	Alert Alarm (μCi/cc)	High Alarm (μCi/cc)	Control Function
RT-8046	Main Steam Line 'A'	IVC, Adjacent to Main Steam Line	RE-8046A (ATL) RE-8046B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	*	*	NONE
RT-8047	Main Steam Line 'B'	IVC, Adjacent to Main Steam Line	RE-8047A (ATL) RE-8047B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	*	*	NONE
RT-8048	Main Steam Line 'C'	IVC, Adjacent to Main Steam Line	RE-8048A (ATL) RE-8048B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	*	*	NONE
RT-8049	Main Steam Line 'D'	IVC, Adjacent to Main Steam Line	RE-8049A (ATL) RE-8049B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	*	*	NONE
RT-8022	SGBD Steam Generator 'A'	IVC, Adjacent to SGBD Line	RE-8022A (ATL) RE-8022B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	5.0	10.0 mR/hr	NONE
RT-8023	SGBD Steam Generator 'B'	IVC, Adjacent to SGBD Line	RE-8023A (ATL) RE-8023B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	1.0	2.0 mR/hr	NONE
RT-8024	SGBD Steam Generator 'C'	IVC, Adjacent to SGBD Line	RE-8024A (ATL) RE-8024B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	1.0	2.0 mR/hr	NONE
RT-8025	SGBD Steam Generator 'D'	IVC, Adjacent to SGBD Line	RE-8025A (ATL) RE-8025B (ATL)	(6) (7)	Gross Gamma	(12) (13)	*	Xe-133	1.0	2.0 mR/hr	NONE

Notes:

1. Minimum Detectable Concentration
2. Beta Scintillation Detector
3. Gamma Scintillation Detector
4. NaI(Tl) Gamma Scintillatin Detector
5. CdTe, Chlorine-doped, Solid State Sensor
6. GM Tube
7. Ion Chamber
8. 3.3×10^{-11} to 3.3×10^{-6} Ci/cc
9. 7.7×10^{-12} to 3.8×10^{-6} Ci/cc
10. 2.8×10^{-7} to 2.8×10^{-1} Ci/cc
11. 1×10^{-6} to 1×10^{-1} Ci/cc
12. 10^{-1} to 10^{4} mR/hr
13. 10^{2} to 10^{7} mR/h

12 RADIATION PROTECTION

The staff has evaluated the applicant's radiation protection program as described in FSAR Chapter 12 against SRP Section 12. The radiation protection measures incorporated at South Texas are intended to ensure that internal and external occupational radiation exposure to plant operating personnel, contractors, administrators, visitors, and the general population as a result of station conditions, including anticipated operational occurrences, will be within the applicable limits of 10 CFR 20 and will be as low as is reasonably achievable (ALARA).

The basis of the staff's acceptance of the material reviewed is that doses to personnel will be maintained within the limits of 10 CFR 20, "Standards for Protection Against Radiation." The applicant's radiation protection design and program features must also be consistent with the guidelines of RG 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable," Revision 3.

12.1 Ensuring that Occupational Radiation Exposures Are As Low As Is Reasonably Achievable

The basis for acceptability of the material reviewed in this section is that the applicant's policy, design, and operational considerations ensure that occupational radiation exposures will be ALARA and meet SRP Section 12.1.

12.1.1 Policy Considerations

The applicant has provided a management commitment to ensure that South Texas will be designed, constructed, and operated in a manner consistent with the guidance of RGs 8.8; 8.10, "Operating Philosophy for Maintaining Occupational Radiation Exposures As Low As Is Reasonably Achievable" (Revision 1-R); and 1.8, "Personnel Selection and Training" (Revision 1-R). The staff's position is that the applicant must base the radiation protection practices on the latest

revision of RG 8.8 (Revision 3) instead of Revision 1, as referenced in the FSAR. This is an open item.

The applicant's Radiological Services Division, under the Radiological Services Manager, has the responsibility for ensuring that an effective ALARA program is implemented at South Texas. During the initial design of the plant, the ALARA philosophy was implemented through internal design reviews and documentation. During the startup and operational phases, the Radiological Protection Supervisor has the responsibility for implementing the station operational ALARA program and procedures. The applicant's ALARA policy is implemented at South Texas by the radiation protection staff under the direction of the Radiological Services Supervisor.

12.1.2 Design Considerations

The plant is designed to provide overall radiation protection by (1) minimizing the need for personnel access into high-radiation areas and (2) reducing the duration of personnel exposure. The applicant intends to maintain occupational radiation exposure ALARA at South Texas by meeting these objectives.

During construction of the South Texas plant, the applicant continually reviewed and studied published accounts of operating experience and results of tests and studies performed by the NSSS vendor to determine design features that could be incorporated into the South Texas plant to prevent recurrence of problems. Some of the equipment and facility design considerations incorporated at South Texas to satisfy the plant radiation protection design objectives are discussed in the paragraph below.

Every effort is made to route radioactive piping within pipe chases that have been denoted as radioactive pipe chases and to locate multiple radiation sources in individually shielded cubicles. The applicant has provided adequate space so maintenance and other operations can be performed easily, thus minimizing the time plant personnel spend in radiation zones. The materials used to fabricate components of the reactor coolant system were selected to minimize corrosion and maintenance requirements. The steam generator tubes have been bright-annealed to reduce the corrosion tendency and minimize the crud retention

properties of the tubes. Corrosion-and maintenance-free, long-wearing materials are specified for systems handling radioactive fluids. Systems that may accumulate crud deposits are designed with provisions for draining, flushing, or decontaminating to reduce radiation levels. The applicant will use remote viewing devices such as shielding windows to minimize the need to enter radiation areas. Radiation sources are separated and/or shielded from normally accessible low radiation areas. Space for temporary control points is allocated in low radiation areas near potential work areas in radiation zones. Valves in radioactive systems can be operated remotely so the operator can remain in a low dose area during valve manipulation. These design considerations conform with RG 8.8 and are acceptable.

The applicant should describe in the FSAR how ALARA principles have been incorporated into the design of lighting fixtures located in high radiation areas at South Texas (for example, by using multi-bulbed, easily servicable fixtures, or using long-life bulbs). This is an open item.

12.1.3 Operational Considerations

The radiation exposure of plant personnel will be kept ALARA by means of a health physics program that follows RG 8.2, "Guide For Administrative Practices in Radiation Monitoring" (Revision 0). All procedures for routine radiation-related operations will be reviewed by Radiological Services Division personnel to ascertain that ALARA concepts have been included. Procedures will be reviewed and revised to incorporate experience gained during operation and information learned from other utilities.

The South Texas design incorporates many design features intended to reduce radiation exposures associated with operation and maintenance of systems processing and conveying contaminated fluids as a result of corrosion product buildups. These design features include (1) the use of prefilters in the chemical volume and control system (CVCS) upstream of the demineralizers to trap and remove suspended corrosion products, (2) maintenance of dissolved oxygen concentration and pH limits in the reactor coolant system (RCS) to reduce corrosion rates, and (3) the use of permanent or temporary shielding around radioactive components to reduce worker exposure.

The applicant has incorporated ALARA techniques into such major operations as steam generator repairs, inservice inspections, and reactor head removal and installation (where use of the rapid refueling system will significantly reduce personnel exposure). Many of these techniques have been used with success at other commercial and military nuclear power plants. In addition to maintaining occupational exposures ALARA during plant operation, a majority of the features included in the South Texas design for maintaining operational radiation exposures ALARA also will assist in maintaining exposures ALARA during decommissioning operations. These features include crud control, isolation and decontamination, access and space requirements, and provisions for inplace decontamination. The ALARA practices are in accordance with RGs 8.8 and 8.10 and are acceptable.

With the exception of the <u>open items</u> described, the staff finds that the applicant's policy, design, and operational considerations meet SRP Section 12.1 and are acceptable.

12.2 Radiation Sources

FSAR Section 12.2 describes the sources of contained and airborne radioactivity used as inputs for the dose assessment and for the shielding and ventilation designs. Also included are the assumptions made by the applicant in arriving at quantitative values for the contained and airborne source terms. The basis for acceptance in the staff review of this section is that all sources of radiation that necessitate designed shielding, special ventilation designs, or access control considerations are described to the degree needed for the shielding codes used in the design process. The information presented in the FSAR must meet the criteria of SRP Section 12.2.

12.2.1 Contained Sources

The shielding design source terms at South Texas are based on the three general plant conditions: normal full-power operation, shutdown, and design-basis events. The principal source of radiation inside the containment during reactor operation is the reactor core. Radiation sources include nitrogen-16, noble gases, and neutrons. The radiation sources in the main steam system piping include activation gases, principally nitrogen-16, and the activated corrosion

products and fission products carried over to the steam system. The largest radiation sources after reactor shutdown are decaying fission products in the fuel. The radiation source terms for a design-basis event are described in RG 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors" (Revision 2). FSAR Section 12.1 includes listings of all major source terms at South Texas by gamma energy group.

12.2.2 Airborne Radioactive Material Sources

The principal sources of airborne radioactivity at South Texas are leakage from the primary system, secondary system, spent fuel pool, and the refueling pool. The contribution to airborne activity as a result of reactor vessel head removal is considered negligible because the RCS vacuum degassing system will remove the activity before the head is removed. In the FSAR, the applicant has provided tabulations of the expected airborne isotopic concentrations in typical accessible regions of the South Texas plant during normal operations.

The ventilation system will route air from areas of low potential contamination to areas of increasing potential airborne contamination. The applicant will use area radiation monitors and airborne radiological monitoring systems to continuously monitor levels of airborne radioactivity. The estimated airborne radioactivity concentrations in frequently occupied areas will be below the 10 CFR 20.103 limits and are, therefore, acceptable.

12.3 Radiation Protection Design Features

This section describes the applicant's radiation design features relating to the following four areas: (1) facility design features, (2) shielding, (3) ventilation, and (4) area radiation and airborne radioactivity monitoring instrumentation. The staff ensured that the applicant had either committed to follow the criteria of the regulatory guides referenced in SRP Section 12.3 or provided acceptable alternatives. The basis of acceptability for each of these areas is described below.

12.3.1 Facility Design Features

The acceptability of the facility design features at South Texas is based on the applicant's application of RG 8.8. The radiation protection design features at South Texas are intended to help maintain occupational radiation exposures ALARA. The design features are based on the applicant's ALARA design considerations described in FSAR Section 12.1.

Liquid filters are designed to be changed remotely. Canned pumps or pumps equipped with very high quality shaft seals are used in systems that contain radioactive liquids to minimize leakage. The reactor pressure vessel (RPV) and the RPV thermal insulation are designed to minimize personnel exposures during inservice inspection of the RPV welds. The solid radwaste system is designed to solidify and drum liquids and spent resin by remote control. The mechanical auxiliary building is designed with a centrally located radioactive pipe chase that allows radioactive piping between cubicles in this building to be run in shielded pipe chases.

In addition to having plant equipment and components designed to comply with ALARA guidelines, the applicant has designed the facility layout to reduce personnel exposures. Wherever practicable, pipes carrying radioactive materials are separated from nonradioactive piping and are located in shielded pipe chases. Penetrations are designed to minimize radiation streaming. Major components in radioactive systems are isolated in individual shielded compartments. These cubicles are large enough to allow motion for maintenance and inspection. There are local instrument readouts outside shielding walls. In many areas permanent platforms, with ladders or stairs, facilitate maintenance and inservice inspection and help keep occupational exposures ALARA. These features conform with RG 8.8 and are acceptable.

The applicant is in the process of revising the radiation zone layout drawings in FSAR Chapter 12. These revised layout figures will reflect the use of proper source terms for radioactive pipe chases. When the staff receives these revised figures, the staff will review them. The applicant should indicate on these

figures the typical traffic patterns used by plant personnel during their daily activities. The applicant also should state how the shielding design considers potential locations for temporary shielding. These are <u>open items</u>.

South Texas has several features to reduce radiation sources where operations will be performed. The production of activation products in the RCS is minimized by using corrosion-resistant materials and by controlling the oxygen and pH in the reactor coolant. The CVCS continuously purifies the reactor coolant letdown stream. The spread of contamination is reduced by providing each component with an adequate drainage system and by routing drains to sumps for disposal. Cubicle walls are painted for ease of decontamination. However, the applicant must state to what height these cubicles walls are painted. This is an <u>open item</u>.

Plant areas are divided into five radiation zones for normal operations and nine zones for post-accident conditions. The dose rate criterion for each of these zones is based on the expected occupancy and access restrictions for each zone; the staff finds the applicant's criteria acceptable. The maximum design dose rates for each of these zones are then used as input for shielding of the respective zones. Plant layout drawings in FSAR Section 12.3 depict the specific zoning for each plant area during normal operations, cold shutdown, and post-accident operations. These plant areas are zoned so that exposures are below the limits of 10 CFR 20 and will be ALARA. The zoning system and access control features will also meet the posting entry requirements of 10 CFR 20.203 and are consistent with RG 8.8.

The design features incorporated by the applicant for maintaining occupational radiation doses ALARA during plant operation and maintenance will also serve to maintain radiation doses ALARA during decommissioning operations. They are, therefore, acceptable.

12.3.2 Shielding

The applicant's shielding design is acceptable if the methods used are comparable to commonly accepted shielding calculations and assumptions and if the shielding serves to minimize personnel exposures.

The primary design objective of the plant radiation shielding is to protect plant personnel and the public against radiation exposure from the various sources of ionizing radiation in the plant during normal operation, anticipated operational occurrences, postulated accident conditions, and maintenance. Radioactive components and piping are located in separate, shielded cubicles to minimize exposure during maintenance and inspection activities. Labyrinth entryway shields are used to reduce radiation streaming through access openings in shielded cubicles. Where applicable, pumps and other support equipment for components that contain radioactive material are located outside the component cubicle in separate, shielded cubicles. Penetrations in shield walls are located to reduce direct radiation streaming from major components containing radioactive material. Piping that normally contains radioactive material is separated from nonradioactive piping and is routed through radioactive pipe chases. To minimize crud traps, piping is designed to minimize low points, dead legs, and horizontal runs. The plant's radioactive systems and shielding designs are constantly reviewed, updated, and modified as necessary during design and construction. These shielding techniques are designed to maintain personnel radiation exposures ALARA and are acceptable.

The applicant's shielding design bases for normal operations are 4100 MWt and 1% failed fuel. Some of the plant structures built during the early stages of construction were designed based on 0.25% failed fuel. The applicant used well-known computer codes--including ANISN, MORSE-CG, and QAD-CG--for the shielding designs. The radiation shielding design incorporates the guidance of RG 1.69, "Concrete Radiation Shields for Nuclear Power Plants" (Revision 0). Most bulk shielding was analyzed via the methods in the Reactor Shielding Design Manual. The applicant's shielding design follows RG 8.8 and satisfies the facility's design objectives. Therefore, the staff finds the applicant's shielding design acceptable.

In accordance with NUREG-0737 Item II.B.2, the applicant has performed a design review of station shielding to ensure the accessibility of vital areas after an accident.

In performing this review, the applicant used a three-region core model (300, 600, 900 effective full-power days (EFPD)), with the core release fractions

specified by NUREG-0737. As specified in NUREG-0737, the applicant prepared a set of post-accident radiation zone maps depicting the radiation levels in various areas of the plant following a design-basis accident.

The control room evelope and the Technical Support Center are areas that will be occupied continuously after an accident; they are considered vital areas. The integrated dose to these areas for the duration of the accident will be less than 5 rems, whole body, as specified in GDC 19. Other vital areas accessible on an infrequent basis following an accident are the post-accident sampling system (PASS), the auxiliary shutdown panel, and the counting room.

Before the staff can fully evaluate the applicant's response to NUREG-0737 Item II.B.2, the FSAR must be amended to include a summary of the integrated doses (whole body, skin, and thyroid) to personnel in each of the vital areas requiring either continuous occupancy during normal operation or infrequent access for the duration of the accident (these doses should include exposure received while in transit between vital areas) and a listing of the dose rates in these areas 1 hour, 1 day, 1 week, and 1 month following an accident. This is an open item.

12.3.3 Ventilation

A ventilation system is considered acceptable if it maintains airborne concentrations of radioactive material in normally occupied areas within the limits in 10 CFR 20 and if the applicant has followed RG 8.8 or suitable alternatives.

The ventilation system is designed to maintain inplant airborne activity levels within the limits of 10 CFR 20 in personnel access areas, prevent the spread of airborne radioactivity during normal plant operation and anticipated abnormal occurrences, and provide a suitable environment for personnel and equipment during normal and anticipated abnormal plant occurrences. The applicant intends to maintain personnel exposure ALARA by (1) maintaining airflows from areas of potentially low airborne contamination to areas of progressively higher potential airborne contamination; (2) exhausting a greater volumetric flow from potentially contaminated compartments than is supplied; and (3) providing the means to isolate and pressurize the control room envelope to minimize inleakage

of contaminated air to the operator. These design criteria are in accordance with RG 8.8 and are acceptable.

The engineered safety feature filtration systems at South Texas are designed in accordance with the criteria for reducing occupational exposure outlined in RG 1.52, "Design, Testing, and Maintenance Criteria for Post-accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" (Revision 2), except for the minor deviations delineated in the FSAR. Because the current design meets Appendix I to 10 CFR 50, only the air from the radiochemistry laboratory and sample room in the mechanical auxiliary building is filtered during normal operations. Air from the fuel handling building will be filtered when radioactive contamination is indicated. Work space is provided around each air supply unit for anticipated maintenance, testing, and inspection. Ventilation equipment rooms for outside air supply and building exhaust system components are generally located in radiation zone 2 and are accessible to the operators. Local heating, ventilation, and air-conditioning (HVAC) equipment is located in areas of low contamination. The staff concludes that the applicant's ventilation system is designed to maintain personnel exposures within the limits of 10 CFR 20 and is, therefore, acceptable.

12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

12.3.4.1 Area Radiation Monitoring Instrumentation

The applicant's area radiation monitoring system provides the capability to accurately determine the radiation levels within the plant and protects plant personnel from unknowingly entering areas with excessive airborne radioactivity or background radiation. The applicant plans to use 47 fixed area monitors per unit. These will be located (1) in areas where personnel may be present and where there is a potential for personnel to receive radiation doses in excess to 10 CFR 20 limits in a short period and (2) in areas where exposure rate is affected by equipment or process system operation. These area monitors are located to best measure the representative exposure rates within a specific area. They are designed for changing detectors for maintenance and are located in open, uncluttered areas for easy access for calibration and field alignment.

All area monitors will have two local audible and visual alarms as well as remote radiation level displays in the control room. Area monitors will have a five-decade range, with the upper range selected so that the maximum zone dose rate at the monitor location can be detected. The applicant will calibrate all area monitors at least once every 18 months, or during each refueling, or whenever maintenance work is done on the detectors.

To meet NUREG-0737 Item II.F.1.3, the applicant has committed to install two physically separated, gamma-sensitive radiation monitors at the operating deck level (elevation 68 feet) of the containment building. These monitors will be separated from each other by 180 degrees. In accordance with the criteria of NUREG-0737 Item II.F.1.3, these monitors will have a maximum range of 1 to 10^8 rems per hour and will have continuous radiation readout on the main control room control/display panel. Before the staff can fully evaluate the applicant's response to Item II.F.1.3, the applicant must verify that these high-range radiation monitors are easily accessible for calibration and repair and are placed so that they will be exposed to a representative volume of the containment atmosphere. This is an open item.

12.3.4.2 Airborne Radioactivity Monitoring Instrumentation

The applicant's airborne radioactivity monitoring system is designed to provide a continuous surveillance of the airborne radioactivity level within selected plant areas to warn if airborne activity exceeds 10 times the MPC-hours*, as set forth in 10 CFR 20, Appendix B, for iodine and particulate radiation. The areas monitored were selected on the basis of the potential airborne radioactivity sources in the area and how often the area may be occupied by people.

The applicant will have three mobile continuous air monitors (CAMs) capable of monitoring particulate, iodine, and gaseous airborne concentrations in the plant. The applicant will use these monitors to collect representative samples of airborne radioactive concentrations and to determine the exact source of airborne radioactivity when the fixed monitors have reached an alarm condition. In

*Maximum permissible concentration.

addition to using the CAMs, the applicant can use high-volume grab-type air samplers for rapid determinations of airborne radioactivity concentrations.

With the exception of the open item described, the objectives and location of the area and airborne radiation monitoring systems are in conformance with 10 CFR 20 and 50 and RGs 8.8 and 8.2.

FSAR Section 12.3 pertaining to facility design features, shielding, ventilation, and area and airborne radioactivity monitoring instrumentation (except as noted) meets SRP Section 12.3 and is acceptable.

12.4 Dose Assessment

The acceptability of the South Texas dose assessment is based on how thoroughly the applicant has provided occupancy factors, dose rates, and numbers of personnel required to perform job functions in various areas of the plant and on compliance with SRP Section 12.4.

The applicant has assessed the estimated radiation exposures that plant personnel will receive from operation of the facility. RG 8.19, "Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants--Design Stage Man-Rem Estimates" (Revision 1), recommends assessing annual dose estimates using a function-by-function analysis. The applicant's dose assessment involved estimating annual doses for each personnel type and then grouping these into the categories of administrative, operating, technical, and maintenance personnel. The applicant also itemized annual dose estimates for the following work categories: refueling, special maintenance, inservice inspection, and selected systems checks. For each dose assessment, the applicant estimated expected occupancy time in each of the five radiation zones and the annual person-rem exposure. The exposure times are based on estimates of the average times required to perform the designated tasks. The applicant based the radiation protection personnel exposure estimates on 1976 occupational exposure reports submitted to the NRC by the licensees of PWR power plants. The applicant should update these exposure estimates by using more recent exposure data. For example, NUREG-0713, Vol. 5, "Occupational Radiation Exposure at Commercial Nuclear Power

Reactors-1983," contains exposure data through 1983. The applicant should then revise the overall annual plant dose estimates if necessary. This is an open item.

The applicant estimated the annual person-rem dose to station staff and contractor personnel to be 396 person-rems per unit. This dose estimate does not include doses from unexpected maintenance and emergency operations. The current average annual operating dose for PWRs (based on data from 1974 through 1983) is 510 person-rems, with particular plants experiencing average lifetime annual doses as high as 1310 person-rems. The applicant's total dose estimate is based on the incorporation of many ALARA techniques intended to reduce overall personnel doses. These techniques include flushing and draining tanks, pumps, and fluid lines; installing temporary shielding; and using remote handling equipment. Although the applicant's person-rem estimate was not made using the exact format suggested in RG 8.19, the staff concludes that the applicant's dose assessment is acceptable because the assessment itself meets the intent of the regulatory guide.

The applicant has estimated the annual dose to construction workers employed building Unit 2 while Unit 1 is in operation (estimated to be 29 months). The total direct gamma exposure to all construction workers during the construction period for Unit 2 is estimated to be 140 person-rems.

The plant ventilation design features help to ensure that the airborne radioactivity concentrations in all normally accessible areas will be well below the limits specified in 10 CFR 20. FSAR Section 12.4 includes compilations of the estimated annual occupancy times and the estimated annual whole body and thyroid exposures to airborne radioactivity for all plant personnel at South Texas. The assumptions and models on which the applicant's dose estimates for occupational exposures are based meet SRP Section 12.4 and are acceptable.

12.5 Operational Radiation Protection Program

Acceptability of the applicant's health physics program is based on the applicant's adherence to 10 CFR 20 and SRP Section 12.5, and the applicant's intent to follow RGs 8.2, 8.8, 8.10, and 1.8.

12.5.1 Organization

The Radiological Services Manager is the radiation protection manager (RPM) at South Texas. The Radiological Services Manager is responsible for managing the plant radiological controls (health physics) program and radiological environmental surveillance program to ensure that environmental and radiation control is maintained to protect employees, visitors, the general public, and surrounding communities. The Radiological Services Manager reports directly to the Plant Manager-South Texas Project. The Plant Manager is ultimately responsible for all station activities, including radiation safety. The Radiological Services Manager reports at the same level as the Reactor Operations Superintendent. He is also a member of the Plant Operations Review Committee (PORC) and, therefore, is able to interact with the general manager, who is also a member of the PORC, and with other plant supervisory personnel.

The items discussed above are in agreement with NUREG-0731, "Guidelines for Utility Management Structure and Technical Resources," and RG 8.8 (Revision 3) and are acceptable. The applicant has stated that the Radiological Services Manager will meet RG 1.8, "Personnel Selection and Training" (Revision 1), for the RPM. The applicant must provide a copy of the Radiological Services Manager's résumé in the FSAR for the review staff. This is an open item.

Reporting to the Radiological Services Manager are the radiological support staff, the Radiological Laboratory Supervisor, and the Radiological Protection Supervisor. The Radiological Protection Supervisor is responsible for implementing the plant (site) health physics program. The applicant has designated the Radiological Protection Supervisor as the backup for the Radiological Services Manager. The draft of Standard 3.1 of the American National Standards Institute (ANSI 3.1) recommends that individuals temporarily filling the RPM position have a B.S. degree in science or engineering and 2 years of experience in radiation protection, 1 year of which should be nuclear plant experience and 6 months of which should be on site. The applicant should include the Radiological Protection Supervisor's résumé in the FSAR and verify that he meets the qualifications as backup for the RPM. This is an open item.

When the résumés of the Radiological Services Manager and the Radiological Protection Supervisor are received, the staff will review them against the qualifications of RPM and backup RPM, respectively, as indicated above.

Reporting to the plant Radiological Supervisor are the Lead Radiation Protection Technicians and the radiation protection technicians. The applicant has committed to having at least one radiation protection technician for each unit on the backshift at all times whenever there is fuel in the reactor. ANSI 18.1 (Section 4.5.2) states that technicians in responsible positions shall have a minimum of 2 years of experience in their speciality. The applicant should verify that all radiation protection technicians serving in sole capacity on backshifts meet this criterion. This is an open item.

With the exception of the open items discussed above, the health physics organization at the South Texas plant meets NUREG-0731 and RG 8.8 (Revision 3) for an acceptable radiation protection organization.

12.5.2 Radiation Protection Facilities, Equipment, and Instrumentation

The radiation protection facilities, equipment, and instrumentation at South Texas were designed to meet RG 8.8 (Revision 3). The applicant must indicate whether RGs 8.4, "Direct-Reading and Indirect-Reading Pocket Dosimeters"; 8.9 "Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program"; 8.12, "Criticality Accident Alarm Systems"; 8.15, "Acceptable Program for Respiratory Protection"; and 8.28, "Audible Alarm Dosimeters," have been followed in the design and acquisition of the radiation protection facilities, equipment, and instrumentation. This is an open item.

The access control complex consists of radiation protection offices and work areas, controlled area entrance and exit corridors, clothing and equipment storage rooms, separate personnel decontamination facilities, and separate men's and women's locker rooms, showers, and toilet facilities. RG 8.8 recommends that change rooms be equipped with enough lockers to accommodate permanent and contract workers who may be required during major outages. The applicant should verify that the change and locker room facilities have this capability. This is an open item.

Other health physics facilities include equipment decontamination facilities, laundry facilities, a shielded sampling area and radiochemistry laboratory, a radiochemistry counting room, and a radiation protection instrument calibration room. With the exception of the open item described above, these facilities are consistent with the provisions of RG 8.8 (Revision 3).

Equipment to be used for radiation protection includes fixed radiation protection instrumentation, portable radiation survey instruments, personnel monitoring instruments, fixed and portable area and airborne radioactivity monitors, air samplers, respiratory equipment, and protective clothing. The counting equiment in each unit will be used to perform the following types of analysis: (1) isotopic identification and analysis on air and water samples, (2) alpha and beta determination on air and water samples and smears, (3) low-energy beta analysis, and (4) gross beta counting for smears and air samples. The applicant must list in the FSAR the fixed radiation-counting instrumentation used at South Texas. This is an open item.

Radiation and contamination survey instrumentation at South Texas includes various alpha, beta, gamma, and neutron survey meters and instruments for obtaining samples of surface and airborne contamination. The applicant must list in the FSAR the quantity, type of radiation detected, and sensitivity range for each type of survey instrument. This list should include portable survey instruments capable of detecting photons in the 10^{-3} to 10^{4} rems-per-hour range and beta radiation and low-energy photons in the 10^{-3} to 10^{4} rads-per-hour range for post-accident use. This is an open item.

The applicant plans to use high-volume variable-flow air samplers, constant flow low-volume air samplers, and CAMs to monitor airborne concentrations at specific work locations. The applicant must state how this plan complies with NUREG-0737 Item III.D.3.3, which states that each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident. The staff will review this material when it is submitted. This is an open item.

The applicant will use thermoluminescent dosimeters (TLDs) or direct-reading pocket dosimeters for personnel monitoring. TLDs normally will be used as the dosimeter of record. All persons assigned TLDs are also required to wear self-reading dosimeters. The readings from these dosimeters will be used to keep a running total of an individual's exposure before TLD processing. Personnel working in neutron exposure areas will be assigned a calculated neutron dose equivalent based on measurements with portable monitoring instruments and known occupancy times. The applicant must list in the FSAR the quantity, sensitivity, and range of each type of TLD and self-reading dosimeter that will be used at South Texas. This is an open item.

All members of the permanent plant organization who work in the restricted area will undergo annual whole-body counts.

12.5.3 Procedures

The applicant will ensure that personnel radiation exposures are maintained ALARA and are within the limits of 10 CFR 20 by adhering strictly to the plant's radiation protection procedures. The applicant must indicate whether these procedures incorporate the guidance of the latest revisions of RGs 8.7, "Occupation of Radiation Exposure Records Systems"; 8.9; 8.13, "Instruction Concerning Potential Radiation Exposure"; 8.20, "Application of Bioassay for I-125 and I-131"; 8.26, "Applications of Bioassay for Fission and Activation Products"; 8.27, "Radiation on Protection Training for Personnel at Light-Water Cooled Nuclear Power Plants"; and 8.29, "Instruction Concerning Risks from Occupational Radiation Exposures," or suitable alternatives. This is an open item.

Radiation protection personnel routinely will survey selected areas throughout the plant to assess radiation levels, radioactive contamination, and airborne radioactivity concentrations. Areas subject to variations in radiation levels and occupancy times may be surveyed more frequently.

The applicant has procedures to minimize doses during refueling, inservice inspection, radwaste handling, and spent fuel handling. All work in high-radiation areas where whole-body doses are expected to exceed 100 mrems or removable contamination levels are expected to exceed 10^5 dpm/100 cm^2 will be

preplanned. Dry runs and mockups will be used on complex jobs with exceptionally high radiation exposure potential. Entry and exit points will be set up in areas so personnel are exposed to as low a level of radiation as practicable. Radiation levels in work areas will be posted at the entrance to the area and/or in the work area so hot spots are clearly identifiable. The applicant will use auxiliary ventilation, where feasible, for jobs that significantly increase airborne activity.

The applicant will issue a radiation work permit (RWP) for work performed in areas where the radiation dose rates, airborne concentrations, or surface contamination levels exceed station administrative limits. RWPs are used to limit access to and time spent in radiation areas. Completed RWPs can be used to determine the effectiveness of ALARA efforts.

Each member of the permanent operating organization whose duties entail entering controlled areas or directing the activities of others who enter controlled areas must receive general employee indoctrination. Personnel who want unescorted access to radiologically controlled areas must also receive radiation worker training. Retraining is administered annually.

With the exception of the open items described, the applicant's health physics program, as described in FSAR Section 12.5, meets the criteria in SRP Section 12.5 and is acceptable.

12.5.4 Conclusions

On the basis of the information presented in the FSAR and the applicant's responses to staff questions, and subject to the resolution of the open items, the staff concludes that the applicant intends to implement a radiation protection program that will maintain inplant exposures within the applicable limits and will maintain radiation exposures ALARA.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.1 Management and Technical Support Organization

13.1.1.1 General

The staff has reviewed the proposed organization for the operation of the South Texas project from the level of the senior corporate officer responsible for nuclear matters down to and including the proposed operating staff at the plant. The review was based on the applicant's Final Safety Analysis Report, as amended (through Amendment 45).

The South Texas project is a joint project of Houston Lighting & Power Company (HL&P) and three other Texas-based organizations (Central Power & Light Company, the City Public Service Board of San Antonio, and the City of Austin). HL&P is the project manager and is responsible for the design, engineering, construction, licensing, startup, and operation of South Texas Units 1 and 2. Bechtel Energy Corporation provides design, engineering, procurement, and construction management services. Ebasco Services, Inc., provides construction services. Westinghouse Electric Corporation supplies the nuclear steam supply system (NSSS) and the fuel assemblies.

13.1.1.2 Organizational Arrangements

The current corporate organizational structure for HL&P and the HL&P nuclear group is shown in Figures 13.1 and 13.2. The senior corporate officer in charge of nuclear matters is the Group Vice President--Nuclear. The incumbent officer has approximately 30 years of nuclear experience, including a period as a Vice President for Stone & Webster Corporation, where he was involved with the construction, maintenance, and refueling of a number of nuclear plants. He is responsible for all HL&P nuclear activities related to design, procurement,

construction, testing, quality assurance, and operation. He reports directly to the Chairman of the Board and Chief Executive Officer of HL&P. Fossil plant construction and operation and matters related to the distribution of electric power are the responsibility of other officers in the HL&P corporate organization.

Project support for purchasing, material control, contract administration, and environmental protection comes through the President and Chief Operating Officer, rather than through the Group Vice President--Nuclear (Figure 13.1). The Manager--Nuclear Plant Purchasing reports to the Vice President--Purchasing and Services and provides personnel to the South Texas project for purchasing, material control, and contract administration. The Manager--Environmental Protection reports to the General Manager--Fossil Plant Engineering and is responsible for environmental licensing (exclusive of NRC licensing), air and water quality, ecology, water resources, nonradiological waste handling, preparation of the Environmental Report, and preparation of environmentally related parts of the FSAR.

Reporting directly to the Group Vice President--Nuclear are the Vice President--Nuclear Plant Operations, the Manager--Quality Assurance, the Manager--South Texas Project, the General Manager--Nuclear Engineering, the Manager--Nuclear Licensing, the Manager--Safeteam, and the Manager--Engineering Assurance. Brief descriptions of these positions are presented below.

(1) Vice President--Nuclear Operations

The Vice President--Nuclear Operations is responsible for activities related to operations, maintenance, and training at Units 1 and 2. The incumbent has approximately 17 years of nuclear experience, including a period as Assistant Director of Nuclear Operations for the Tennessee Valley Authority (TVA). Reporting directly to the Vice President--Nuclear Plant Operations are the Plant Manager--South Texas Project, the Training Manager--Nuclear Training, and the operations support staff. The Nuclear Plant Operations organization is shown in Figure 13.3; additional detail on the Nuclear Plant Operations Department is in Section 13.1.2 below.

(2) Manager--Quality Assurance

The Manager--Quality Assurance is responsible for the overall direction and administration of HL&P quality assurance plans related to the construction and operation of Units 1 and 2. The incumbent has approximately 8 years of nuclear experience, including a period as a quality assurance (QA) supervisor for Bechtel Power Corporation. Reporting directly to the Manager--Quality Assurance are the Project QA Manager--South Texas Project, the Operations QA Manager, and the Support QA Manager. The Quality Assurance organization is shown in Figure 13.4; additional detail on the HL&P Quality Assurance Program is in Chapter 17 of this report.

(3) Manager--South Texas Project

The Manager--South Texas Project is responsible for the management, coordination, scheduling, cost control, engineering, construction, and startup of the South Texas project. The incumbent has approximately 26 years of nuclear experience, including approximately 10 years of project engineering experience with Commonwealth Edison Company. Reporting directly to the Manager--South Texas Project are the Manager--Support Services, the Deputy Project Manager, and the Manager--Engineering. The South Texas project organization is shown in Figure 13.2.

The Startup Manager reports to the Manager--South Texas Project through the Deputy Project Manager. The startup organization is responsible for prerequisite testing (component tests and system flushes) and preoperational testing (system and subsystem functional tests) up to the time of fuel loading. The onsite Nuclear Plant Operations Department is responsible for supporting the prerequisite and preoperational testing and for conducting the fuel loading and initial startup testing. Administrative control of the initial test program is discussed in more detail in Section 13.5.1 below.

(4) General Manager--Nuclear Engineering

The General Manager--Nuclear Engineering is responsible for nuclear services (safety analyses and waste disposal) and nuclear fuel (economics, procurement and analysis). The incumbent has approximately 19 years of nuclear experience,

including supervisory experience in nuclear analysis for Stone & Webster Engineering Corporation. Reporting directly to the General Manager--Nuclear Engineering are the Manager--Nuclear Services and the Manager--Nuclear Fuel. The Nuclear Engineering Organization is shown in Figure 13.2.

(5) Manager--Nuclear Licensing

The Manager--Nuclear Licensing is responsible for developing and coordinating HL&P nuclear licensing policy and for coordinating the flow of licensing information among the various nuclear groups. The incumbent has approximately 21 years of nuclear experience, including several years of supervisory experience in licensing for TVA. Various supervisors and staff report to the Manager--Nuclear Licensing. The Nuclear Licensing Organization is shown in Figure 13.2.

(6) Manager--Engineering Assurance

The Manager--Engineering Assurance is responsible for reviewing the technical adequacy of project design and engineering. The incumbent has approximately 13 years of nuclear experience, including several years of management experience in the HL&P QA organization.

(7) Manager--Safeteam

The Manager--Safeteam is responsible for the investigation of employee concerns. The incumbent has approximately 22 years of nuclear experience, including several years of management experience in the HL&P quality assurance organization.

13.1.1.3 Summary and Conclusions

The applicant meets SRP Section 13.1.1 (NUREG-0800) except for the following open items:

(1) current and projected size of offsite staff segments

(2) procedures for how the offsite support organization interfaces with the onsite plant organization

(3) corporate responsibility for fire protection, and compliance with Branch Technical Position CMEB 9.5.1

(4) commitment to conform to ANSI N18.1-1971 (or more recent standard on the qualification of nuclear power plant personnel), plus résumés or other information (beyond what is now in the FSAR) showing conformance

13.1.2 Operating Organization

13.1.2.1 Plant Organization

The plant staff organization is shown in Figure 13.3. The Plant Manager is responsible for power production and support activities to ensure the safe and efficient operation, maintenance, technical support, and refueling of the South Texas units. He reports to the Vice President--Nuclear Plant Operations, who has overall responsibility for operations, maintenance, and training at HL&P nuclear facilities.

The plant organization is subdivided into seven main disciplines: reactor operations, chemical operations, technical support, maintenance, management services, radiological services, and nuclear training.

The Management Services General Supervisor and the Radiological Services General Supervisor report directly to the Plant Manager. The Reactor Operations Superintendent, the Chemical Operations and Analysis Superintendent, the Technical Support Superintendent, and the Maintenance Superintendent report to the Plant Manager through the Plant Superintendent. The training organization reports directly to the Vice President--Nuclear Plant Operations. A brief description of each of the main plant disciplines is as follows:

(1) <u>Reactor Operations Division</u>

The Reactor Operations Superintendent is responsible for the safe and efficient operation of the plant in accordance with the Operating Licenses and Technical Specifications. An Operations Supervisor, who reports to the Reactor Operations Superintendent, is responsible for the safe and efficient operation of each unit.

The Reactor Operations Superintendent and the Operations Supervisor will hold senior reactor operator (SRO) licenses.

FSAR Figure 13.1-2B implies that the applicant plans to operate the units with six shift crews. Each shift crew will be under the overall direction of a Shift Supervisor (who will have an SRO license), who reports to the Operations Supervisor for the unit. Specific control room activities are directed by a Unit Supervisor (who will have an SRO license), who reports to the Shift Supervisor. The remainder of each shift crew is comprised of Reactor Operators (with reactor operator (RO) licenses), Reactor Auxiliary Operators, and Administrative Aides. Shift staffing should satisfy, at a minimum, the requirement of 10 CFR 50.54(m)(2)(i) for licensed operators and NUREG-0737, Item I.A.1.3, for unlicensed auxiliary operators.

The applicant does not plan to have shift technical advisors. Engineering expertise on shift will be provided by upgrading the training and qualifications of the Shift Supervisor. This is an <u>open item</u> pending Commission action to finalize a policy statement on engineering expertise on shift.

The NRC began a dialogue with the industry late in 1983 to find a way of ensuring that each operating shift at a newly licensed plant had at least a certain amount of previous hot operating experience. On February 24, 1984, an Industry Working Group representing utilities with nuclear power plants under construction or ready for operation presented a proposal to the Commission on the amount of previous operating experience considered to be the minimum desirable on each shift and how that experience could be obtained. On June 14, 1984, the Commission accepted the industry proposal with certain clarifications. Information regarding the Commission action was forwarded to the industry as Generic Letter 84-16, dated June 27, 1984. The applicant should apply the guidelines of Generic Letter 84-16 to ensure that each operating shift crew has sufficient hot operating experience.

(2) <u>Chemical Operations and Analysis Division</u>

The Chemical Operations and Analysis Division is responsible for primary, secondary, and auxiliary chemistry control, which includes chemistry and

radiochemistry sampling/analysis and the operation of water and waste treatment systems (makeup water, radwaste, condensate, steam generator blowdown, and chemical waste). Plant programs are developed to meet plant needs and regulatory requirements for chemical control and environmental discharges. The Chemical Operations and Analysis Superintendent reports to the Plant Superintendent.

(3) Technical Support Division

The Technical Support Division provides technical support to plant operations and maintenance personnel for management of various plant programs (Technical Specification surveillance testing, pump and valve testing, leak rate testing, snubber testing, filter testing, and vibration testing), and for monitoring plant performance. The Technical Support Superintendent reports to the Plant Superintendent.

(4) Maintenance Division

The Maintenance Division is comprised of the Mechanical Group, the Electrical Group, the Instrument and Control Group, and the Maintenance Support Group. It is responsible for preventive and corrective maintenance for Units 1 and 2 and their common support facilities. The Maintenance Superintendent reports to the Plant Superintendent.

(5) Management Services Division

The Management Services Division is responsible for various administrative support functions, such as data processing, scheduling, budgeting, cost control, payroll, drawing control, and document control. The Management Services General Supervisor reports to the Plant Manager.

(6) Radiological Services Division

The Radiological Services Division is responsible for the plant health physics program and the radiological environmental surveillance program. The Radiological Services General Supervisor position corresponds to the "Radiation Protection

Manager" position in RG 1.8. The Radiological Services General Supervisor reports to the Plant Manager.

(7) Nuclear Training Department

The Nuclear Training Department is responsible for the overall management and administration of the HL&P nuclear training program, which is described in SER Section 13.2. The Training Manager--Nuclear Training reports directly to the Vice President--Nuclear Plant Operations.

13.1.2.2 Summary and Conclusions

The applicant meets SRP Section 13.1.2 except (NUREG-0800) for the following open items:

(1) final acceptability of the applicant's plans regarding engineering expertise on shift

(2) compliance with shift crew operating experience guidelines of Generic Letter 84-16

(3) current and projected size of onsite staff groups

(4) résumé for Plant Superintendent (position currently vacant)

(5) operator license requirement for the Plant Manager and/or Plant Superintendent

(6) commitment to conform to ANSI N18.1-1971 (or more recent standard on qualifications of nuclear power plant personnel), plus résumés or other information (beyond what is now in the FSAR) supporting conformance

(7) résumé for Radiation Protection General Supervisor showing compliance with RG 1.8, Revision 1-R

(8) onsite responsibility for fire protection and compliance with Branch Technical Position CMEB 9.5.1

13.2 Training

nud

The applicant submitted the South Texas Project Electric Generating Station Nuclear Training Program by letter dated April 17, 1985. HL&P is drafting an amendment that will incorporate this program description into FSAR Section 13.2. Additional training material was submitted by letters dated April 23 and April 29, 1985.

The applicant's training program was reviewed according to SRP Section 13.2. The acceptance criteria included applicable portions of 10 CFR 19, 50, and 55; NUREG-1021 (Revision 1); RGs 1.8 (Revision 1-R) and 1.149; and NUREG-0737, including the H.R. Denton letter of March 28, 1980, to all power reactor applicants and licensees.

nud GL

The South Texas training program is designed using a systematic approach to training (SAT). The applicant provided the Training Administrative Manual, which describes the elements of SAT and the methods for implementing the program. In addition, the applicant provided LP-8.1, the Interdepartmental Procedure concerning Technical Advisory councils. Each council provides a formal interface mechanism between the Nuclear Training Department and the Nuclear Plant Operations Department. This interface requirement is called for by the SAT. The program provides the required training based on individual employee experience, the intended position, and previous training/education. The objective of the program is to provide the necessary numbers of fully trained and qualified operating, maintenance, professional, and technical support personnel in time for fuel loading. Where practical, the concept of team training is used. Personnel will receive on-the-job training during the pre-operational testing program by performing their job-associated tasks.

13.2.1 Licensed Operator Training Programs

13.2.1.1 Training Program for SRO and RO Candidates

The training program for SRO and RO candidates is designed to prepare these employees for NRC license examinations and, subsequently, station operations.

13.2.1.1.1 Training Program Phases

The program is divided into five discrete phases as follows:

(1) Phase I--Nuclear Power Plant Fundamentals (11 weeks)

This training will be conducted at the Westinghouse Nuclear Training Center and will combine onsite classroom instruction and offsite research reactor training. Topics included are

- nuclear reactor theory (2 weeks)
- large PWR core physics (2 weeks)
- health physics, instrumentation, and chemistry (2 weeks)
- power plant systems and engineering concepts (2 weeks)
- reactor loading, reactor operations, and experiments (3 weeks)

(2) Phase II--Operating PWR Training (10 weeks)

This training will consist of both systems lectures and plant observations at Commonwealth Edison's Zion Station or another plant similar to South Texas. These observations will cover the specific systems observations and hardware discussed in the lectures.

(3) Phase III--Simulator Training (9 weeks)

License candidates will receive simulator training at the Westinghouse Nuclear Training Center. The course provides training in plant operations and transient situations including startup, shutdown, and operation under normal, off-normal, and emergency conditions. At the conclusion of the course, RO- and SRO-level written, oral, reactor startup, and simulator crew operating examinations will be given to the candidates. Upon successful completion of simulator training, the candidates receive RO or SRO certification from Westinghouse. This course may also be conducted on a simulator that is similar to the South Texas unit; the training will be conducted on the South Texas simulator when it becomes available.

(4) Phase IV--Onsite Training

This phase of the training program consists of classroom training that meets all the requirements of NUREG-0737, Item I.A.2.1 and the letter from H.R. Denton to All Power Reactor Applicants and Licensees, dated March 28, 1980. The training consists of classroom training (24 weeks); procedure training on actual or simulated control boards and on the South Texas simulator when it becomes operational (4 weeks); on-the-job training, including system checkouts, administered by training instructors or designated systems experts (12 months); and required reading assignments and/or classroom training in all phases of procedures and facility changes.

(5) Phase V--Pre-License Review and Audit (3 to 4 weeks)

This phase of the program consists of a 3- to 4-week review of subjects covered in Phase IV and an audit examination given in the same manner as the NRC licensing examination.

13.2.1.1.2 Candidate Categories

Candidates with no prior nuclear experience will participate in all five phases of the training. Those candidates with nuclear navy experience as defined in ES-109, 3b of NUREG-1021 will, as a minimum, receive Phase III of the program (modified to suit the candidates' previous nuclear training), in addition to all of Phase IV and V. The audit examination in Phase V will validate the candidates' prior nuclear experience. Candidates who have been licensed previously at a comparable facility will receive, as a minimum, all the training in Phases IV and V. The courses for these candidates will be taught at the SRO level. These courses are augmented with training in various supervisory skills.

13.2.1.1.3 Conclusions

The applicant has committed to a license training program that conforms to 10 CFR 55, to Item I.A.2.1 of NUREG-0737, and to Enclosures 1 and 2 of the Letter from H.R. Denton to All Power Reactor Applicants and Licensees, dated March 28, 1980. In addition, the program includes operations experience training on power plant simulators. The applicant has provided the content of

the simulator program, the length of the course, and the identity of the simulator. At present, the South Texas simulator is not operational. However, the applicant should make clear that the South Texas simulator will meet RG 1.149 when it does become operational. The applicant has provided all the appropriate information with respect to the onsite training program, including course description, duration of course, and distinction between classroom training and on-the-job training.

The applicant has included a chart that shows the schedule of each part of the training program with respect to pre-operational testing and expected time for examinations for licensed operators prior to criticality. However, the chart does not indicate the time for examinations for licensed operators after criticality or the number of licensed operators for whom training is planned prior to criticality. In a telephone conversation with the staff, the applicant indicated that a schedule relevant to these items was sent to the NRC regional office. The applicant will supply this information as soon as possible. The applicant also has contingency plans for additional training if fuel loading is delayed.

On the basis of its review, the staff concludes that the applicant's license training program is acceptable.

13.2.1.2 Requalification Training For Licensed Operating Personnel

The applicant has provided the Nuclear Training Department Procedure for the Licensed Operator Requalification Training Program for review. The program consists of the following segments.

(1) <u>Classroom Training (5 weeks)</u>

Classroom training consists of lectures and required reading. Lecture topics cover all the material required by Appendix A of 10 CFR 55 and H.R. Denton's March 28, 1980 letter. The required reading portion of this program segment may include, but is not limited to, plant procedures, procedure changes or new procedures, plant design or license changes, operating experience reports, and Technical Specification review.

(2) <u>On-the-Job Training</u>

All licensed and certified personnel must participate in on-the-job training. This segment of the program consists of required reading, watchstanding, and control manipulations, as listed below. (The starred items will be performed annually; all other items will be performed on a 2-year cycle.)

*• plant or reactor startups, to include range that reactivity feedback from nuclear heat addition is noticeable and heatup rate is established

• plant shutdown

*• manual control of steam generators and/or feedwater during startup and shutdown

• boration or dilution or both during power operation

*• any significant (10%) power changes with rod control

*• losses of coolant including

  (1) significant steam generator tube leak
  (2) inside and outside primary containment
  (3) large and small, including leakrate determination
  (4) saturated reactor coolant response

• loss of instrument air (if simulated, plant specific)

• loss of electrical power (or degraded power sources, or both)

*• loss of core coolant flow/natural circulation

• loss of condenser vacuum

• loss of essential cooling water

- loss of shutdown cooling
- loss of component cooling system or cooling to an individual component
- loss of normal feedwater or normal feedwater system failure
- *loss of all feedwater (normal and emergency)
- loss of protective system channel
- mispositioned control rod or rods (or rod drops)
- inability to drive control rods
- conditions requiring use of emergency boration
- fuel cladding failure or high activity in reactor coolant or offgas
- turbine or generator trip
- malfunction of automatic control system(s) which affect reactivity
- malfunction of reactor coolant pressure/volume control system
- reactor trip
- main steam line break (inside or outside containment)
- nuclear instrumentation failure(s)

(3) Simulator Training

The applicant states that all licensed and certified personnel will be assigned to a 5-day simulator training course. The applicant has committed to this requirement, as specified in Enclosure 1 of H.R. Denton letter of March 28, 1980, which requires all licensed operators to participate in a simulator training program as part of the requalification program.

(4) Trainee Evaluation

- Classroom Training

A written examination will be given at the end of each week of classroom lecture. A score of less than 80% requires a self-study remedial program. If the operator scores less than 80% on a second examination in this same subject area, a plan of action is submitted for the Plant Manager's approval. The plan may entail removal from licensed duties and accelerated requalification training and re-examination or other appropriate action.

- Simulator Training

An instructor or supervisor from Reactor Operations or Operations Training will observe the operations performed on the simulator and will submit an evaluation of the operator's performance and competency. The evaluation will include actions taken during abnormal and emergency conditions, demonstrated understanding of equipment operations, and demonstrated knowledge of operating procedures. Exhibiting deficiencies in any of these areas results in the operator's being removed from licensed duties. Appropriate retraining will be conducted as proposed by the person who conducted the evaluation and jointly approved by the Reactor Operations Superintendent and the Manager--Operations Training Division. The operator will be re-evaluated after this retraining and be returned to licensed duties after the individual demonstrates competence in the areas in which the individual was deficient.

- Annual Examinations & Accelerated Requalification

Operators who score less than 70% on any section of the annual written examination or less than 80% overall, or who fail the oral examination, will be removed from all license duties and placed in the accelerated requalification program. Upon completion of this program, the operator will re-take the failed section or the entire examination, as appropriate. A score of 80% is required to pass. If this standard is not met, the individual cannot perform license duties until remediation is successfully completed.

The applicant's criteria for passing the annual requalification examination and participation in the accelerated requalification program meet the requirements of Appendix A of 10 CFR 55 and Enclosure 1 of the March 28, 1980 Denton letter.

13.2.1.3 TMI-Related Requirements

I.A.2.1 Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications

The initial training program is designed to prepare RO and SRO candidates for NRC license examinations and station operations.

South Texas is an operating license applicant and, therefore, is not subject to the 1-year experience requirement for cold license SRO candidates. However, after 1 year of station operation, individuals applying for an SRO license will be required to comply with the 1-year experience criterion for hot-license SRO applicants, unless they are previously experienced in an equivalent position at another nuclear plant or at a military propulsion reactor. The experience of license applicants in the latter category will be documented by the applicant on an individual basis. This documentation must be in sufficient detail for the staff to determine equivalency. SRO license applicants with a degree in engineering or applicable science are considered to meet the 1 year experience requirement as an RO provided they (1) satisfy the requirements set forth in Section A.1.a and A.2 of Enclosure 1 to the letter from H.R. Denton to All Power Reactor Applicants and Licensees, dated March 28, 1980, and (2) have participated in a training program equivalent to that of a cold license SRO senior reactor operator applicant.

The requirements for 3 months of training on shift as an extra person in the control room for RO candidates and 3 months as an extra person on shift for SRO candidates do not apply to cold license candidates. However, the applicant will be required to meet this requirement after 3 months of operation.

The applicant's training program provides training in heat transfer, fluid flow, thermodynamics, mitigating core damage, and reactor and plant transients.

All license candidates will participate in simulator training programs. The applicant has also committed to a requalification program that includes performance of the control manipulations called for in Enclosure 4 of the Denton letter of March 28, 1980. These manipulations will be performed or participated in by all licensed operators.

The staff concludes that the applicant's training program meets the requirements of Item I.A.2.1.

I.A.2.3 Administration of Training Programs

The organization and lines of responsibility for the training department are outlined in detail in the applicant's training administrative manual. Instructors who teach safety systems, integrated plant response, and transient and simulator training will be certified through an NRC Senior Operator Instructor Examination. The applicant states that, initially, the qualifications of instructors will be maintained through their participation in the conduct of the Phase IV training program. This phase of the program is a comprehensive onsite program that encompasses all the requirements of the requalification program as called for in 10 CFR 55, Appendix A. Instructors will also be enrolled in appropriate requalification programs.

The staff finds that applicant has satisfied Item I.A.2.3.

II.B.4 Training for Mitigating Core Damage

The applicant has provided a description of the program for training for mitigating core damage that includes all the subjects in Enclosure 3 of the March 28, 1980 Denton letter. The applicant states that STAs and all operating personnel--including licensed operators, appropriate managers, instrumentation and control technicians, health physics technicians, and chemistry technicians--shall receive this training commensurate with their responsibilities.

The staff concludes that the applicant has met the requirements of Item II.B.4.

13.2.1.4 Conclusions

The staff concludes that the applicant's operator requalification training program meets the requirements of Appendix A of 10 CFR 55 and the letter from H.R. Denton to All Power Reactor Applicants and Licensees, dated March 28, 1980. Therefore, the staff finds the applicant's requalification program acceptable.

13.2.2 Training For Nonlicensed Plant Staff

The applicant has described the training programs for nonlicensed personnel. These programs include general employee training; training for maintenance supervisors, electricians, mechanics, instrumentation and control personnel, supervisory and technician level personnel of the Health and Safety Division and the Chemical Operations and Analysis Division; and training for technical support personnel.

The applicant's fire protection training program is conducted in accordance with the SRP; 10 CFR 50, Appendix R; and Branch Technical Position (BTP) CMEB 9.5-1. The training includes classroom instruction, hands-on fire extinguishing, and drills. In addition to the training for the fire brigade, training is conducted for station employees, contract personnel, offsite fire departments, and construction personnel. On the basis of its review, the staff concludes that the applicant's fire protection training program is acceptable.

The staff has reviewed the procedure for the shift technical advisor (STA) training program and finds it comparable in scope and depth to the program outlined in Appendix C of NUREG-0737. Therefore, the staff finds the applicant's STA Training Program is acceptable.

On the basis of its review, the staff concludes that the applicant's training programs for non-licensed personnel are acceptable.

13.4 Operational Review

The applicant has established a review and audit program designed to meet the requirements of Section 4 of ANSI/ANS-3.2-1982. Onsite review activities,

independent review activities, and audit program activities are discussed below.

13.4.1 Onsite Review

Onsite review activities are performed by the Plant Operations Review Committee (PORC), which began meeting on a monthly basis in July 1978. The basic function of the PORC is to review matters that affect nuclear safety to keep management aware of general plant conditions and to verify that day-to-day activities are conducted safely.

The PORC is composed of the Plant Superintendent (Chairman); the Reactor Operations Superintendent; the Chemical Operations and Analysis Superintendent; the Technical Support Superintendent; the Maintenance Superintendent; the Radiological Services General Supervisor; and the Operations QA Manager. Formal meetings require a quorum, which consists of the Chairman, the Operations QA Manager, and four of the remaining five members. All PORC members have designated alternates; however, a maximum of two alternates may participate as voting members at any one time. The responsibilities and conduct of the PORC are generally the same as those given in Section 6.5.1 of the Standard Technical Specifications for Westinghouse Pressurized Water Reactors (NUREG-0452, Revision 4).

13.4.2 Independent Review

The independent review function is performed by two groups: the Nuclear Safety Review Board (NSRB) and the Independent Safety Engineering Group (ISEG).

13.4.2.1 Nuclear Safety Review Board

The NSRB is a corporate review group located off the site at HL&P headquarters. The basic function of the NSRB is to identify operational problem areas, monitor corrective actions, and, in some cases, make recommendations to appropriate management of possible solutions to problems.

The NSRB is composed of the Group Vice President--Nuclear (Chairman), the General Manager--Nuclear Engineering, the managers from five corporate

departments (Engineering Assurance, Nuclear Services, Nuclear Licensing, Nuclear Fuel, and Quality Assurance), and additional members as appointed by the Chairman. Formal meetings require a quorum, which consists of the Chairman and at least three members. All NSRB members have designated alternates. The responsibilities and conduct of the NSRB are generally the same as those given in Section 6.5.2 of NUREG-0452, Revision 4.

13.4.2.2 Independent Safety Engineering Group

The ISEG is a group of site-based engineers who report to offsite management up to the Group Vice President--Nuclear. The basic function of the ISEG is to systematically assess plant activities so it can advise management on the overall quality of operations and, if possible, identify areas for improving plant safety.

The applicant has committed to supply information on the ISEG in a future FSAR amendment.

13.4.3 Audit Program

Audits of the nuclear program are scheduled in accordance with a written plan to ensure that all safety-related functions are audited within a 2-year period. The audit program is conducted as part of the corporate quality assurance program described in Chapter 17 of the FSAR. The Nuclear Safety Review Board, which is cognizant of QA audit activities, provides a means for management review of the quality assurance program.

13.4.4 Summary and Conclusions

The staff has reviewed the HL&P organizations that perform review and audit functions for the South Texas project and finds them in conformance with RG 1.33, Revision 2 ("Quality Assurance Program Requirements"), ANSI/ANS-3.2-1982, and NUREG-0737. The staff concludes that the applicant meets SRP Section 13.4 except for the following open item:

(1) plans for an ISEG

13.5 Plant Procedures

13.5.1 Administrative Procedures

The staff has reviewed plant administrative procedures and determined that safety-related activities will be conducted in accordance with detailed written procedures that have been reviewed by the PORC and approved by the Plant Manager. RG 1.33, Revision 2, will be used as a guide to prepare plant administrative policies and procedures.

The staff has reviewed the applicant's plans regarding the responsibilities of the shift supervisor, control room access, working hours, shift relief/turnover requirements, operating experience feedback, verification of correct performance of operating activities, crane operations, and the conduct of the initial test program. Each of these items is discussed below.

13.5.1.1 Shift Supervisor Responsibilities

Each operating shift will have a designated Shift Supervisor who is a licensed senior operator. Each Shift Supervisor has the responsibility of directing the licensed activities of licensed operators on the supervisor's shift, pursuant to 10 CFR 50.54(1). It is the staff's position that a management directive to this effect, signed by the Vice President--Nuclear Plant Operations, must be reissued to all station personnel on an annual basis.

The applicant's procedures will define the authority and responsibility of each member of the operating shift crew, pursuant to Section 5.2 of ANSI/ANS-3.2-1982. Each shift will have Administrative Aides to relieve the Shift Supervisor of routine administrative duties and to process and route various records, logs, and correspondence. The applicant's plans for the organization and conduct of the operating shift crews meet the pertinent requirements of 10 CFR 50.54 and NUREG-0694, Item I.C.3.

13.5.1.2 Control Room Access

The applicant will have a procedure to limit normal access to the control room to individuals responsible for direct operation of the plant, technical advisors, and specified NRC personnel. The procedure must establish a clear line of authority, responsibility, and succession in the control room. The Shift Supervisor is responsible for controlling access to the control room and may approve special access for good cause. In the absence of the Shift Supervisor, the Unit Supervisor (an SRO) should control access to the control room. The applicant has committed to limit access to the control room to meet the requirements of NUREG-0694, Item I.C.4.

13.5.1.3 Limits on Working Hour

The applicant will establish a policy governing the working hours of plant personnel who perform safety-related functions. The policy should apply to SROs, ROs, health physicists, auxiliary operators, and key maintenance personnel. The purpose of the policy is to preclude the routine use of overtime; however, overtime beyond the set limits is allowed on a case-by-case basis, if authorized by the Plant Manager, the manager's deputy, or higher levels of management. The applicant has committed to limit working hours to meet the requirements of NUREG-0737 Item I.A.1.3, as clarified by Generic Letter 82-12.

13.5.1.4 Shift Relief/Turnover Requirements

The applicant will prepare and implement a procedure for use during shift relief or shift turnover. The procedure must prescribe the use of checklists and logs to ensure that the operating staff, including auxiliary operators and maintenance personnel, is aware of critical plant parameters and the status of plant systems. The applicant has committed to meet the shift relief and turnover requirements of NUREG-0694, Item I.C.2.

13.5.1.5 Operating Experience Feedback

An organizational unit must be assigned to screen operating information from both inside and outside the South Texas project organization. Information that

is applicable and important to the plant should be forwarded to the ISEG, which has the lead responsibility for the operating experience and feedback function. The ISEG should then forward selected information, which may include recommendations for action, to the appropriate group within HL&P. The applicant has committed to meet the feedback requirements of Item I.C.5 of NUREGs-0694 and -0737.

13.5.1.6 Verification of Correct Performance of Operating Activities

The applicant will have a procedure for verifying the correct performance of operating activities. The Shift Supervisor, or, in the absence of the Unit Supervisor (an SRO) should be responsible for releasing equipment for testing, maintenance, or modification. Following such activities, a qualified person from the shift crew (who does not have to be a licensed operator) should be assigned to independently verify the proper positioning of valves, circuit breakers, and control switches of systems that are important to safety. The applicant has committed to verifying the correct performance of operating activities to meet the requirements of Item I.C.6 of NUREG-0737.

13.5.1.7 Crane Operations

The applicant will have a procedure governing crane operations, including a requirement that those who operate cranes over fuel pools be qualified and conduct themselves pursuant to the guidelines of ANSI B30.2-1976 (Chapters 2 and 3), "Overhead and Gantry Cranes."

13.5.1.8 Conduct of the Initial Test Program

FSAR Section 14.2 describes the applicant's program for developing initial test procedures, conducting the test programs, and reviewing and evaluating test results in accordance with 10 CFR 50.34, Appendix B of 10 CFR 50, and RG 1.68, Revision 2.

The initial test program has three phases: prerequisite testing, preoperational testing, and initial startup testing. They are defined as follows:

- <u>prerequisite testing</u> begins after installation/construction of a given structure, system, or component is complete. It consists of calibration,

electrical checks, vibration checks, cleaning, flushing, functional testing, etc., to verify integrity and readiness for preoperational testing.

- preoperational testing is hot functional testing to verify that safety-related systems and equipment meet design and safety requirements before fuel load.

- Initial startup testing is physics testing to verify nuclear and thermal-hydraulic parameters and power ascension testing to verify the ability of the plant to operate safely at various power levels up to rated capacity. This phase of the initial test program begins at fuel load and continues through the full-power acceptance run.

Prerequisite and preoperational test procedures are prepared in accordance with the Plant Procedures Manual. Procedures are prepared using standard formats (different categories of procedures may use different standard formats), and they contain appropriate sign-off provisions to control test performance and the sequence of testing.

Test results are reviewed by appropriate management/supervisory personnel to ensure that tests are performed in accordance with an approved procedure, that documentation requirements are met, and that acceptance criteria are satisfied. If acceptance criteria are not met, a Nonconformance Report is prepared for disposition by designated organizations. Test results for each phase of the initial test program are normally verified as complete before the next phase is begun. Testing left incomplete must be technically justified. HL&P has overall responsibility for the initial test program. The primary organizational entities involved with initial test activities are the South Texas project startup organization, the Nuclear Plant Operations Department, the Joint Test Group, and the Plant Operations Review Committee. They are discussed below.

- Startup Organization

The startup organization is under the direction of the Startup Manager, who reports through the Deputy Project Manager to the Manager--South Texas Project (Figure 13.2). The startup organization, which may be augmented by contractor

and vendor personnel, is responsible for developing, scheduling, and conducting prerequisite and preoperational tests. The qualifications of personnel participating in prerequisite and preoperational testing will conform to the guidance in RG 1.58.

- Nuclear Plant Operations Department

The operating organization (the Nuclear Plant Operations Department) supports the startup organization during prerequisite and preoperational testing, but takes the lead responsibility for initial startup testing at the time of fuel load. The operating organization is under the direction of the Plant Manager, who reports to the Vice President--Nuclear Plant Operations (Figure 13.3).

- Joint Test Group

The Joint Test Group (JTG) reviews preoperational test procedures, revisions to preoperational test procedures, and results of preoperational tests. The JTG is chaired by the Startup Manager and includes representatives from the operating organization, the offsite nuclear support organization, the quality assurance organization, the construction manager (Bechtel), and the NSSS vendor (Westinghouse).

- Plant Operations Review Committee

The Plant Operations Review Committee (PORC) reviews safety-related procedures, including those associated with the initial test program. The PORC is chaired by the Plant Superintendent and includes representatives from major segments of the onsite operating organization, as prescribed in the Technical Specifications.

Under current practices for new licensees, it is the staff's position that individuals responsible for preoperational and startup testing activities for safety-related systems shall be qualified in accordance with Section 4.4.6 of ANSI/ANS-3.1-1981. (In the case of South Texas, this does not include prerequisite testing.) These individuals include personnel from the groups listed above who are responsible for developing preoperational and startup test procedures, for reviewing and approving preoperational and startup test procedures,

for briefing personnel responsible for operating the plant during tests, for ensuring that tests are performed in accordance with procedures, for generating preoperational and startup test reports, and for reviewing and approving preoperational and startup test results.

13.5.1.9 Summary and Conclusions

The applicant has described the program and procedures that provide administrative controls over activities important to safety, including the control of the initial test program. The applicant meets SRP Section 13.5.1 (NUREG-0800) except for the following open items:

(1) The staff will verify the applicant's compliance with commitments to have administrative procedures to control shift supervisor responsibilities, control room access, working hours, shift relief and turnover, feedback of operating experience, verification of operating activities, and crane operations.

(2) The applicant should provide a position regarding the applicability of ANSI/ANS-3.1-1981 qualification requirements to preoperational and initial startup test personnel.

13.5.2 Operating and Maintenance Procedures

13.5.2.1 General

The staff has reviewed the applicant's plan for development and implementation of operating and maintenance procedures according to SRP Section 13.5.2. The review was conducted to determine the adequacy of the applicant's program for ensuring that routine operating, offnormal, and emergency activities will be conducted in a safe manner. The review was based on information in the FSAR and correspondence from the applicant.

The staff review included evaluation of (1) the applicant's classification system for procedures that are performed by licensed operators in the control room, and for other operating and maintenance procedures; (2) the applicant's plan for

completion of operating and maintenance procedures before fuel loading; (3) the applicant's program for compliance with RG 1.33, Revision 2, "Quality Assurance Program Requirements," regarding the minimum procedural requirements for safety-related operations; (4) conformance with ANSI N18.7-1975/ANS 3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"; and (5) the applicant's program for compliance with the requirements of Supplement 1 to NUREG-0737.

13.5.2.2 Operating and Maintenance Procedures

In the FSAR, the applicant committed to a program in which activities important to safety are to be conducted in accordance with detailed written and approved procedures meeting RG 1.33. However, the applicant did not specify that the latest revision of RG 1.33, Revision 2, would be used.

As described in the FSAR, the applicant will use the following procedure categories for those operations performed by the plant operating staff:

- system operating
- general operating
- offnormal operating
- emergency operating
- annunicator response
- temporary operating
- radiation protection
- emergency preparedness
- chemical analysis

- radioactive waste management
- maintenance
- plant security
- fire protection

The staff requires additional information to determine that the applicant's program for use of operating and maintenance procedures meets the relevant requirements of 10 CFR 50.34, and is consistent with RG 1.33, Revision 2, and ANSI/ANS 3.2-1978.

In a submittal dated April 14, 1983, the applicant committed to develop emergency operating procedures (EOPs), as required by Supplement 1 to NUREG-0737. In this submittal, the applicant submitted the procedures generation package (PGP) to the staff in June 1985. The applicant also stated that operator training on the procedures will begin in October 1985 with the implementation of EOPs scheduled for December 1986.

13.5.2.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures

read

In letters of September 13 and 27, October 10 and 30, and November 9, 1979, the staff required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to (1) perform analyses of transients and accidents, (2) prepare EOP guidelines, (3) upgrade EOPs, and (4) conduct operator retraining (see also NUREG-0737 Item I.A.2.1). EOPs must be consistent with the actions necessary to cope with the transients and accidents analyzed. Clarification of the scope of the task and appropriate schedule revisions were included in NUREG-0737 Item I.C.1 and Supplement 1 to NUREG-0737, which require development and submittal of PGPs to the staff. The PGP will describe how the South Texas EOPs will be written using the generic emergency response guidelines (ERGs) developed by the Westinghouse Owners Group (WOG).

The NRC staff reviewed the proposed WOG ERGs as described in Westinghouse Owners Group letters OG-64, OG-76, OG-83, OG-111, and OG-123; and in the material

accompanying those letters. The staff determined that the guidelines are based on reanalysis of transients and accidents and concluded that the guidelines are acceptable for implementation.

In accordance with NUREG-0737 Item I.C.7, NSSS vendor review of low power testing, power ascension, and EOPs was necessary to further verify adequacy of the procedures. Because the applicant has committed to implement procedures based on the NRC-approved Westinghouse ERGs, the staff does not consider an additional NSSS vendor review of the EOPs necessary.

Since the incident at TMI-2, applicants have been required to meet NUREG-0737 Item I.C.8, "Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants." This pilot monitoring program was used on an interim basis for evaluation of applicant's EOPs prior to staff approval of generic technical guidelines and staff development of the long-term program for upgrade of EOPs. This is no longer necessary because the NRC has approved the Westinghouse ERGs and the applicant has committed to develop EOPs based on the ERGs. Therefore, the staff considers NUREG-0737 Item I.C.8 resolved.

The staff has published guidelines for long-term upgrading of EOPs (NUREG-0899) in accordance with TMI Action Plan Item I.C.9. These guidelines should be used in the preparation of the South Texas EOPs.

The applicant has not yet submitted a PGP in accordance with the requirements of Supplement 1 to NUREG-0737. Each licensee and applicant for an operating license must submit to the NRC a PGP that includes:

(1) plant-specific technical guidelines

(2) a writer's guide

(3) a description of the program to be used for the validation of EOPs

(4) a description of the training program for the use of upgraded EOPs

The applicant submitted the PGP in June 1985, and the staff review of the applicant's response will be included in the final SER.

13.6 Industrial Security

The applicant has submitted documents entitled "South Texas Project Electrical Generating Station Security Plan," "South Texas Electrical Generating Station Security Personnel Training and Qualification Plan," and "South Texas Project Electrical Generating Station Safeguards Contingency Plan" for protection against radiological sabotage. The plans were reviewed in accordance with Section 13.6.

On the basis of its review, the staff has identified certain portions of these plans as requiring additional information and upgrading to satisfy the requirements of 10 CFR 73.55 and Appendices B and C of 10 CFR 73. Accordingly, security of the South Texas plant remains an open item.

The applicant's security plans are being protected from unauthorized disclosure in accordance with 10 CFR 73.21.

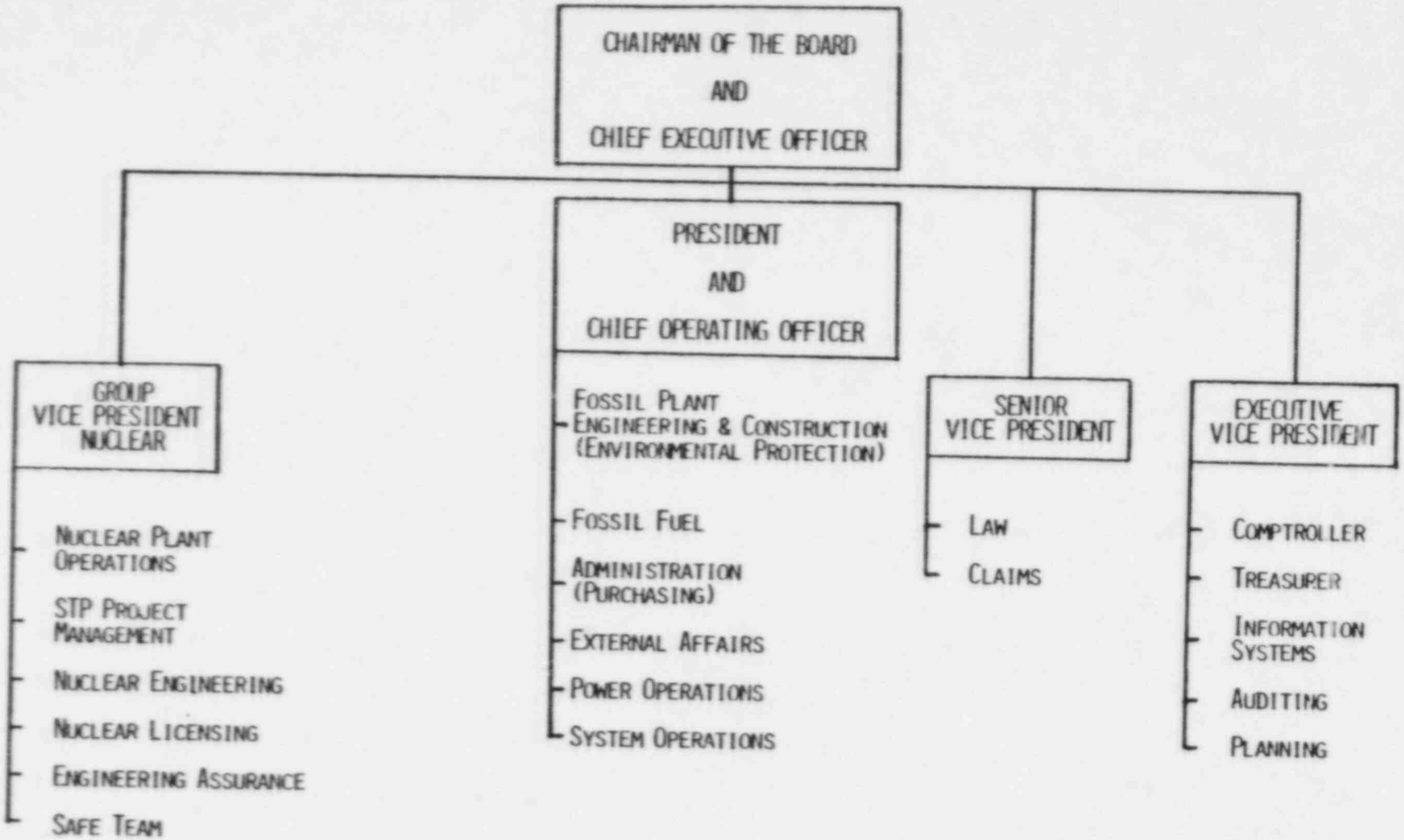

Figure 13.1 HL&P corporate organization

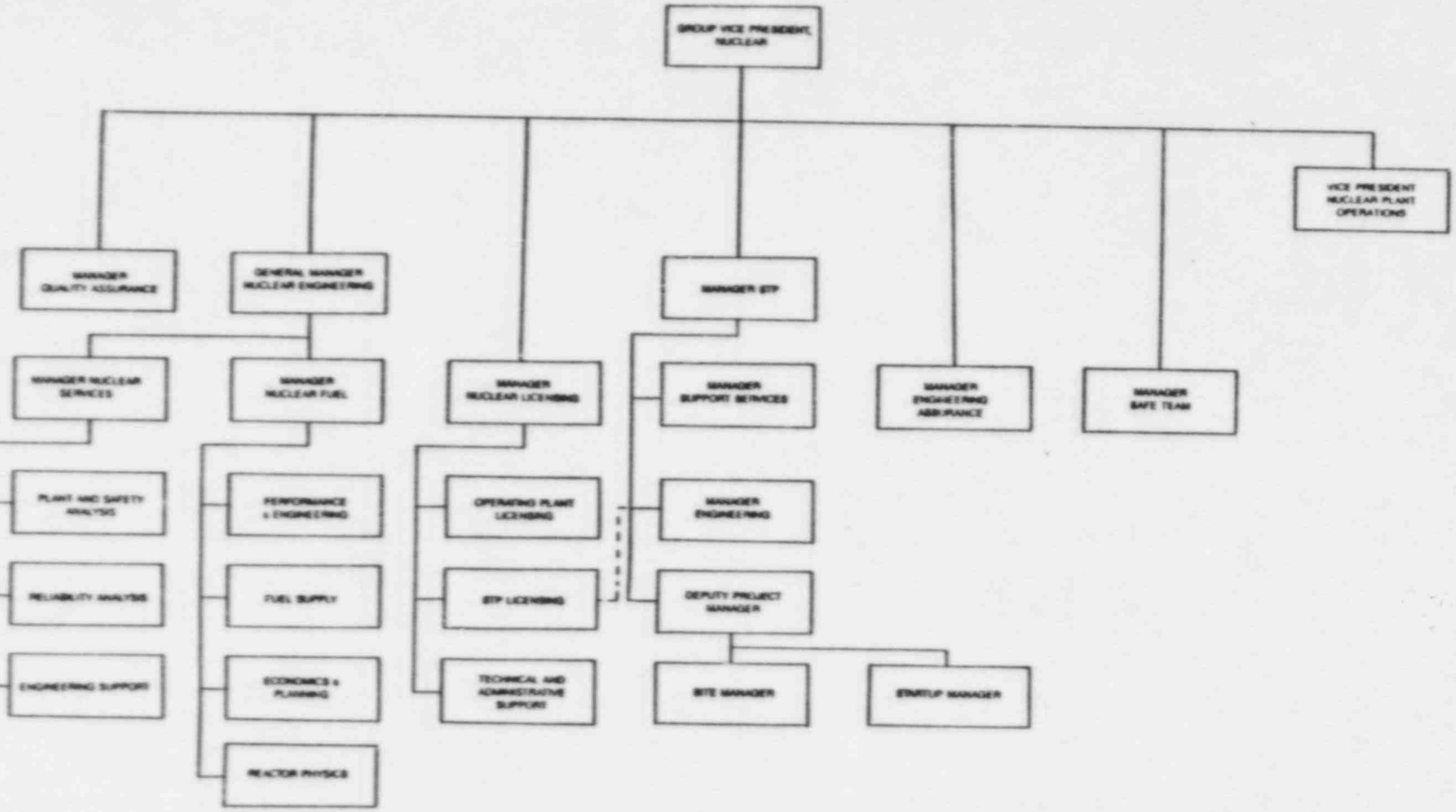

Figure 13.2 HL&P nuclear group

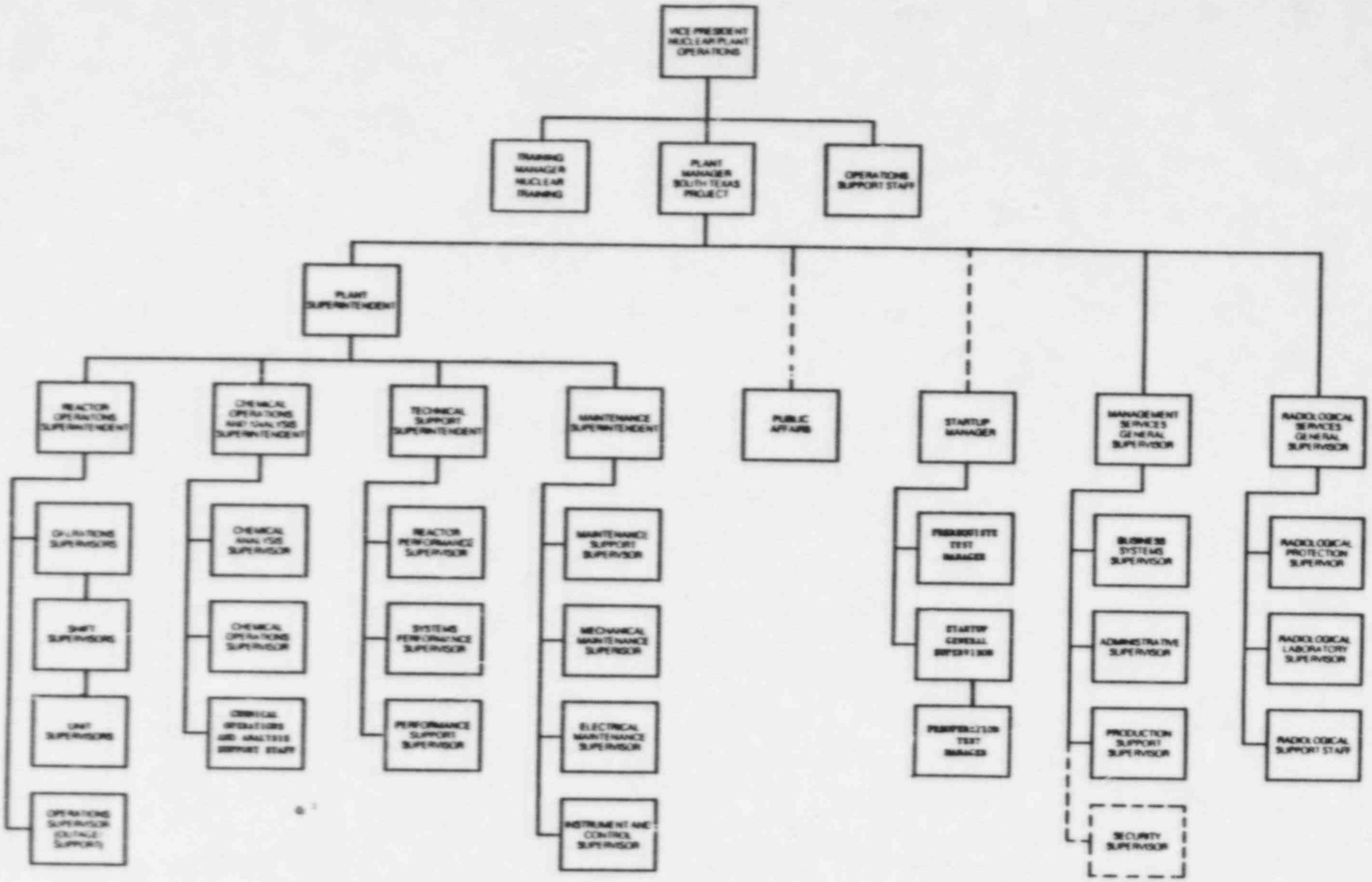

Figure 13.3 Nuclear plant operations department

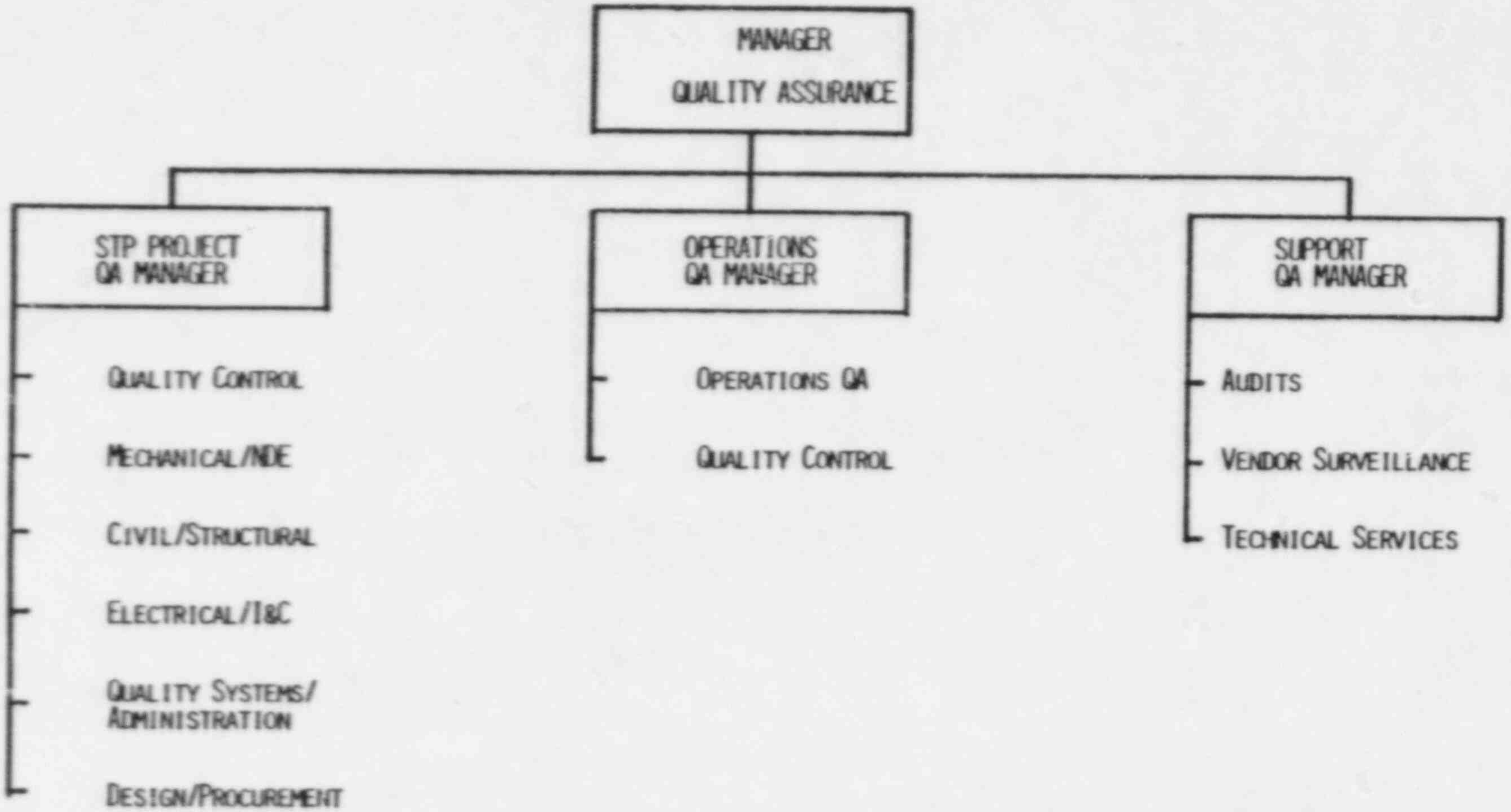

Figure 13.4 Quality assurance department

14 INITIAL TEST PROGRAM

The initial test program encompasses the scope of events that begins with completion of system construction and ends with completion of power ascension testing. The initial test program consists of the preoperational and the startup test programs. At the conclusion of these test programs, a unit is ready for routine power operation.

The preoperational test program begins with system/component turnover from the construction organization to the operations organization, and ends with the beginning of fuel loading. These tests demonstrate, to the extent practicable, the capability of structures, systems, and components to meet performance requirements and to satisfy design requirements. To the extent practicable, the objectives of the preoperational test program are

(1) to document the performance and operability of equipment and systems

(2) to provide baseline test and operating data on equipment and systems

(3) to operate new equipment for a sufficient time to identify and correct design, manufacturing, and installation defects

(4) to ensure integrated systems operation

(5) to familiarize plant operating, technical, and maintenance personnel with facility operation

(6) to confirm the adequacy of normal operating and emergency operating procedures

The startup test program begins with fuel loading, is followed by zero power and low power testing, and ends with the completion of power ascension testing. These tests confirm the design bases and demonstrate to the extent practicable that the plant operates and responds to transients as designed.

Startup testing is sequenced to ensure that the safety of the plant is not dependent on the performance of untested structures, systems, or components. The objectives of the startup test program are

(1) to accomplish a controlled, orderly, and safe initial core loading

(2) to accomplish a controlled, orderly, and safe initial criticality

(3) to conduct low power testing sufficient to ensure that design parameters are satisfied and that safety analysis assumptions are correct or conservative

(4) to perform a controlled, orderly, and safe power ascension with requisite testing, terminating at plant rated conditions

(5) to confirm codes and analytical models used in the reactor design

The staff review of FSAR Chapter 14, done according to the SRP, concentrated on the administration of the test program and the completeness of the preoperational and startup tests. The review included SER-CP; the FSAR; Licensee Event Report summaries for operating reactors of similar design; the Standard Technical Specifications; operation; NUREGS-0660, NUREG-0694, and NUREG-0737; and startup test reports for other similar-type plants.

The staff reviewed the initial test program to determine that the applicant will

(1) develop test procedures using input from the NSSS vendor, the architect-engineer, its engineering staff, and equipment suppliers and contractors. Operating experiences at similar plants must be factored into the development of the test procedures.

(2) conduct tests using approved test procedures. Administrative controls must cover the completion of test prerequisites, the completion of necessary data sheets and other documentation, and the review and approval of modifications to test procedures. Administrative procedures must also

cover implementation of modifications or repairs identified as being required by the tests and any necessary retesting.

(3) will review the results of each test for technical adequacy and completeness by review groups including the NSSS vendor and architect-engineer, as appropriate. Preoperational test results must be reviewed before fuel loading, and the startup test results from each test condition or power level must be reviewed before the applicant proceeds to the next test condition or power level.

(4) use normal operating procedures and emergency operating procedures to the extent practicable in performing the initial test program, thereby verifying the correctness of the procedures.

(5) schedule the initial test program to allow adequate time for all preoperational and startup tests. Preoperational test procedures must be available for review by NRC regional personnel at least 60 days before scheduled implementation. Startup test procedures must be available for review not less than 60 days before the scheduled fuel loading date.

(6) include an abstract of each test in FSAR Chapter 14. The staff must verify that there are test abstracts for those structures, systems, components, and design features that (a) will be used for shutdown and cooldown of the reactor under normal, transient, and accident conditions and for maintaining the reactor in a safe shutdown condition for an extended period of time; (b) will be used for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications; (c) are classified as engineered safety features or will be relied on to support or ensure the operations of engineered safety features within design limits; (d) are assumed to function or for which credit is taken in the accident analysis for the facility, as described in the FSAR; or (e) will be used to process, store, control, or limit the release of radioactive materials.

(7) include enough detail in the test objectives, prerequisites, test methods, and acceptance criteria for each test abstract to verify that each test

will properly demonstrate the functional adequacy of the structures, systems, components, and design features.

(8) identify and adequately justify exceptions to RG 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," Revision 2.

The staff was unable to verify all of the above; the open items are listed in Table 14.1.

On the basis of its review, the staff has concluded that when the open items identified in Table 14.1 are satisfactorily resolved, the initial test program described in the FSAR will meet the acceptance criteria of SRP Section 14.2 and the regulatory requirements of

(1) 10 CFR 50.34(b)(6)(iii), which requires inclusion of plans for preoperational testing and initial operations in the FSAR

(2) 10 CFR 50, Appendix B, Section XI, which requires a test program 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 which incorporate the requirements and acceptance limits contained in applicable design documents

(3) NUREG-0737 Item I.G.1, which requires additional testing and training during the initial test program

This review and evaluation was performed with the assistance of Battelle Pacific Northwest Laboratories personnel.

Table 14.1 Initial test program open items

Item	Description
1	As a result of the latest amendment to FSAR Section 14.2, the following responses must be revised or commitments therein reinstated: 423.22-1.k(2) 423.22-5.u 423.22-5.v 423.22-5.aa 423.22-5.bb 423.22-5.cc 423.22-5.ii 423.23(d) 423.23(1)
2	FSAR Section 14.2.12.3, test description 15 (nuclear instrumentation calibration test), must provide acceptance criteria regarding overlap of source, intermediate, and power range instrumentation.
3	FSAR Section 14.2.12.3, test description 27 (static RCCA drop and RCCA below-bank position measurements test), acceptance criteria must state that misalignment within the limits of the rod position indicators will not cause a power maldistribution outside the Technical Specification limits.
4	FSAR Section 14.2.11.5 (test procedure preparation schedule as related to system testing) must describe the availability of acceptance and initial startup test procedures for staff review.
5	FSAR Section 14.2.12.2, test description 37 (annunciator system), must be reinstated or appropriate test abstracts should be referenced that demonstrate the proper operation of the annunciators for reactor control and engineered safety features.
6	FSAR Section 14.2.12.2, test description 31 (containment HVAC isolation valve cubicle subsystem) or Section 14.2.12.2, test description 85 (auxiliary feedwater system), must be modified to remove ac power sources from any ventilation systems serving the steam-driven pump area during auxiliary feedwater pump operability testing to adequately test the operation of the pump.
7	FSAR Table 3.12-1 (regulatory guide matrix); Section 14.2.12.2, test description 71 (instrument air system); and the response to Items 423.17 (2) and 423.23 (z) must be modified, as appropriate, to demonstrate conformance with RG 1.68.3, "Preoperational Testing of Instrument and Control Air Systems."

Table 14.1 (Continued)

Item	Description
8	FSAR Section 14.2.12.2, test description 76 (safety injection system train A, B, and C) and FSAR Table 3.12-1 must be modified to demonstrate that containment sump recirculation performance is in accordance with RG 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," Position 1.b(2).
9	Existing preoperational and startup test abstracts must be modified to indicate the source of acceptance criteria to be used in determining test adequacy.
10	FSAR Section 14.2.12.2, test description 88 (essential cooling water system), must be modified to verify that the essential cooling pond is tested to verify adequate NPSH and the absence of vortexing over the range of pond level from maximum to the minimum calculated 30 days following a LOCA.
11	FSAR Section 14.2.12.2, test description 21 (125-V dc battery and bus channels I, II, III, and IV), should be modified to verify that dc loads as installed will function as necessary to ensure plant safety with the battery terminal voltage at the allowable minimum for the discharge load test.
12	The testing described in FSAR Section 14.2.12.2, test description 2 (unit standby transformer), must be modified so it will test the capability of this transformer to accept transfer of the other units ESF loads while supplying its own unit's normal loads.
13	Testing or analysis should be provided to demonstrate that the maximum capacity of any single steam generator PORV is less than the value assumed in FSAR Section 15.1.4 (inadvertent opening of a steam generator or safety valve causing a depressurization of the main steam system).
14	FSAR Appendix 7A (post-TMI requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements"), Section I.G.1 (Training Requirements), should include or reference the information contained in response to Item 640.21N.
15	The FSAR Section 14.2.12.2 test abstracts listed below are either not classified or are classified as acceptance tests. These abstracts must be classified as preoperational tests (as defined by FSAR Section 14.2.1.2) or specific technical justification for any other classification must be provided. (1) No. 2, Unit Standby Transformer (2) No. 3, 13.8 kV Auxiliary and Standby Buses

Table 14.1 (Continued)

Item	Description
	(3) No. 16, 13.8 kV Emergency Transformer
	(4) No. 17, 13.8 kV Emergency Bus
	(5) No. 46, Incore Monitoring Instrumentation System
	(6) No. 47, Control Rod Drive System
	(7) No. 49, Digital Rod Position Indication System
	(8) No. 65, Main Feedwater System
	(9) No. 73, RCS Hydrostatic
	(10) No. 74, Incore Thermocouple and RTD Cross-Calibration
	(11) No. 93, Containment Integrated Leak Rate Test and Structural Integrity
	(12) No. 102, Seismic Monitoring System

15 TRANSIENT AND ACCIDENT ANALYSIS

The postulated design-basis accidents analyzed by the applicant to determine the offsite radiological consequences are the same as those analyzed for previously licensed PWRs. To evaluate the effectiveness of the engineered safety features (ESF) proposed for South Texas and to ensure that the radiological consequences of these accidents meet the applicable dose criteria, the staff has analyzed a steamline break accident, a control rod ejection accident, a fuel-handling accident, and small-line failures. The calculated doses for these accidents are shown in Table 15.1. Analysis of the loss-of-coolant accident is under review; the staff is waiting for additional information on the containment spray system, an ESF that significantly affects the radiological consequences of a LOCA. As noted below, the staff will complete its analysis of a steam generator tube rupture (SGTR) accident after it receives additional information. This issue may be resolved on a generic basis because the applicant is a member of a subgroup formed within the Westinghouse Owners Group to address SGTR licensing issues.

15.1 Increase in Heat Removal by the Secondary System

15.1.1 Decreases in Feedwater Temperature

15.1.2 Increase in Feedwater Flow

15.1.3 Increase in Steam Flow

15.1.4 Inadvertent Opening of a Steam Generator Relief Valve or Safety Valve

15.1.5 Main Steamline Failure Outside Containment

The staff has reviewed the applicant's analysis of the radiological consequences of a postulated steamline break outside containment upstream of the main steam isolation valve. In the postulated accident, the increased steam flow through

the ruptured pipe will cause increased energy removal from the reactor coolant system, a reduction of coolant temperature and pressure, and introduction of positive reactivity due to the negative moderator temperature coefficient. If the plant is at power, the reactor is automatically tripped and the main steam and feedwater line isolation valves are automatically closed. Upon reactor trip, offsite power is assumed to be lost, and, consequently, the condenser is assumed to be unavailable for steam dump. The affected steam generator blows down completely, and decay heat is removed, as necessary, through the unaffected steam generators by venting steam from the secondary system safety and relief valves, with makeup water supplied by the auxiliary feedwater system.

The staff independently calculated the thyroid and whole-body doses resulting from the main steamline break (MSLB) accident using the assumptions of RG 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors," except for the atmospheric dispersion factors that are discussed in Section 2 of this report. The staff used the applicant's FSAR estimates of steam releases to the environment, and all releases were assumed to terminate within 8 hours of the accident when the residual heat removal system starts operation to cool down the plant. Three cases were analyzed for the reactor coolant iodine concentration corresponding to (1) a pre-accident iodine spike with primary coolant specific activity at maximum 60 microcuries per gram, dose equivalent I-131; (2) the maximum equilibrium iodine concentration for continued full power operation in combination with an assumed accident-initiated iodine spike; and (3) additional coolant iodine activity as a result of potential fuel failures from an MSLB.

Although the applicant's FSAR analysis showed no departure from nucleate boiling occurring as a result of an MSLB, assuming the most reactive control rod assembly stuck in its fully withdrawn position, the applicant and staff have conservatively assumed failure of 5% of the fuel rods in the core. Equilibrium primary and secondary coolant activity concentrations were assumed to be those allowed in the proposed South Texas Technical Specifications. The maximum primary-to-secondary leakage of 1 gpm allowed in the Technical Specifications was assumed to occur in the affected steam generator. During periods of steam generator dry-out, all iodine transported to the secondary side by primary coolant leakage was assumed to be released to the atmosphere. The assumptions used

in calculating the radiological consequences are presented in Table 15.2, and the resultant estimated doses are given in Table 15.1. Results are not presented for the case with an assumed pre-accident spike, because its coolant activity levels are bounded by the fuel failure case.

The staff concludes that the distances to the exclusion area boundary (EAB) and to the low population zone (LPZ) outer boundary for the South Texas site, in conjunction with operation within the limits of the proposed Technical Specifications, are sufficient to provide reasonable assurance that the calculated radiological consequences of a postulated main steamline failure outside the containment do not exceed (1) the exposure guidelines in 10 CFR 100 for an MSLB with an assumed pre-accident iodine spike or for an MSLB with the highest worth control rod stuck out of the core, and (2) 10% of these exposure guidelines for an MSLB with an equilibrium iodine concentration in combination with an assumed accident-generated iodine spike.

The staff's conclusion is based on (1) review of the applicant's analysis of the radiological consequences, (2) an independent dose calculation using conservative assumptions, including atmospheric dispersion factors as discussed in Section 2 of this report, and (3) the proposed Technical Specifications for the iodine concentrations in the primary and secondary coolant systems, and for the primary-to-secondary leakage in the steam generators.

15.2 Decrease in Heat Removal by the Secondary System

15.2.1 Loss of External Heal Loads

15.2.2 Turbine Trip

15.2.3 Loss of Condenser Vacuum

15.2.4 Inadvertent Closure of Main Steam Isolation Valves

This review under this SRP section applies to boiling water reactors only. South Texas is a pressurized water reactor.

15.2.5 Steam Pressure Regulator Failure

15.2.6 Loss of Nonemergency Power to the Station Auxiliaries

15.2.7 Loss of Normal Feedwater Flow

15.2.8 Feedwater system Pipe Break

15.3 Decrease in Reactor Coolant Flow Rate

15.4 Reactivity and Power Distribution Anomalies

15.4.1 Uncontrolled Rod Cluster Control Assembly (Rod) Bank Withdrawal from Zero Power Conditions

The staff has reviewed the applicant's analysis of the consequences of an uncontrolled rod cluster control assembly bank withdrawal at zero power according to SRP Section 15.4.1. Such a transient can be caused by a failure of the reactor control rod control systems. The analysis assumed a conservatively small (in absolute magnitude) negative Doppler coefficient and a conservative moderator coefficient. Further, hot zero power initial conditions with the reactor just critical are chosen because they are known to maximize the calculated consequences. The reactivity insertion rate is assumed to be equivalent to the simultaneous withdrawal of the two highest worth banks at maximum speed (45 inches per minute).

The analysis also assumed that two reactor coolant pumps are in operation. The staff has been reviewing this aspect of the assumptions because Technical Specifications have not been requiring two pumps to be in operation in Modes 3 and 4. Several Technical Specifications have required that two pumps be in operation in Mode 3 or that the control rods not be operational. The same problem for Mode 4 is under generic review, but may require the same specifications. The Technical Specifications will be examined later with this problem in mind.

Reactor trip is assumed to occur on the low setting of the power range neutron flux channel at 35% of full power (a 10% uncertainty has been added to the set

point value). The maximum heat flux is much less than the full-power value, and average fuel temperature increases to a value lower than the nominal full-power value. The minimum DNBR at all times remains above the limiting value of 1.30. The staff has reviewed the possibilities for single failures of the reactor control system that could result in uncontrolled withdrawal of control rods during low power startup conditions. The review has included investigations of initial conditions and control rod reactivity worths, the course of the resulting transients or steady-state conditions, and the instrument response to the transient or power maldistribution. The staff has examined the methods used to determine the peak fuel rod response and the inputs into the analysis, such as power distributions and reactivity feedback effects due to moderator and fuel temperature changes.

On the basis of its review, the staff concludes that the applicant has met GDC 10, 20, and 25.

The applicant has met the requirement of GDC 10 that the specified acceptable fuel design limits are not exceeded, of GDC 20 that the reactivity control systems are automatically initiated so that specified acceptable fuel design limits are not exceeded, and of GDC 25 that single malfunctions in the reactivity control system will not cause the specified acceptable fuel design limits to be exceeded. The applicant has met these requirements by comparing the resulting extreme operating conditions and response for the fuel with the acceptance criteria for fuel damage (e.g., critical heat flux, fuel temperatures, and clad strain limits should not be exceeded) to ensure that fuel rod failure will be precluded for this event. The basis for acceptance in the staff review is that the applicant's analyses of the maximum transients for single error control rod withdrawal from a subcritical or low-power condition have been confirmed, that the analytical methods and input data are reasonably conservative, and that specified acceptable fuel design limits will not be exceeded.

15.4.2 Uncontrolled Rod Cluster Control Assembly (Rod) Bank Withdrawal at Power

The staff has reviewed the applicant's analysis of the consequences of uncontrolled withdrawal of a rod bank in the power operating range. The effect of

such an event is an increase in coolant temperature (as a result of the core-turbine power mismatch) that must be terminated before fuel design limits are exceeded.

The analysis is performed as a function of reactivity insertion rates, reactivity feedback coefficients, and core power level. Protection is provided by the high neutron flux trip, the overtemperature ΔT and overpower ΔT trips, and pressurizer pressure and pressurizer water level trips. In no case does the departure from nucleate boiling ratio fall below 1.30. Adequate fuel cooling is therefore maintained. The maximum heat flux reached including uncertainties does not exceed 118% of full power, thus precluding fuel centerline melting.

The staff has reviewed the possibilities for single failures of the reactor control system that could result in uncontrolled withdrawal of control rods beyond normal limits under power operation conditions. The review has included investigations of possible initial conditions and the range of reactivity insertions, the course of the resulting transients and the instrumentation response to the transient. The staff has examined the methods used to determine the peak fuel rod response, and the inputs into the analysis, such as power distributions, rod reactivities, and reactivity feedback effects of moderator and fuel temperature changes.

The staff concludes that the applicant has met GDC 10, 20, and 25.

The applicant has met the requirements of GDC 10 that the specified acceptable fuel design limits are not exceeded, of GDC 20 that the reactivity control systems are automatically initiated so that specified acceptable fuel design limits are not exceeded, and of GDC 25 that single malfunctions in the reactivity control system will not cause the specified acceptable fuel design limits to be exceeded. The applicant has met these requirements by comparing the resulting extreme operating conditions and response for the fuel with the acceptance criteria for fuel damage (e.g., critical heat flux, fuel temperatures, and clad strain limits should not be exceeded) to ensure that fuel rod failure will be precluded for this event. The basis for acceptance in the staff review is that the applicant's analysis of maximum transients for single error control rod malfunctions has been confirmed, that the analytical methods and input data are

reasonably conservative, and that specified acceptable fuel design limits will not be exceeded.

15.4.3 Rod Cluster Control Assembly Malfunctions

The staff has reviewed the applicant's analysis of rod cluster control assembly misalignment incidents including a dropped full length assembly, a dropped full length bank, a misaligned full length assembly, and the withdrawal of a single assembly while operating at power. Misaligned rods are detectable (1) by asymmetric power distributions sensed by excore nuclear instrumentation or core exit thermocouples; (2) by rod deviation alarm; and (3) by rod position indicators. A deviation of a rod from its bank by about 15 inches or twice the resolution for the rod position indicator will not cause the power distribution to exceed design limits. Additional surveillance will be required to ensure rod alignment if one or more rod position channels are out of service.

In the case of a dropped assembly or group of assemblies, the reactor will typically scram on a neutron flux negative rate trip, and analysis indicates that thermal limits will not be exceeded for the event. If the rod locations are such that the reactor does not scram, however, the automatic controller may return the reactor to full power and the control could result in a power overshoot. An analysis methodology for this event has been developed by Westinghouse and reported in WCAP-10297-P (Westinghouse, 1982). This methodology has been reviewed and approved by the staff (Rubenstein, March 2, 1983). Generally, detailed analyses for most reactors, for most cycles, show that if this event occurs thermal limits will not be exceeded. However, the analysis is reactor and cycle specific, and the analyses for South Texas Units 1 and 2 for Cycle 1 have not been completed as yet. The staff has also accepted an interim position for operating reactors that consists of a restriction on operations above 90% power so that either the reactor is in manual control or rods must be out more than 215 steps. This restriction will be applied to South Texas Units 1 and 2 if calculations for Cycle 1 operation are not completed in time for initial operations. With this restriction, thermal limits will not be exceeded. When the analysis specific to South Texas Units 1 and 2 for Cycle 1 is approved, the restriction will be removed. A similar analysis will be needed for each subsequent reload cycle.

The applicant's analysis indicates that for cases where a group is inserted to its insertion limit with a single rod in the group stuck in the fully withdrawn position, departure from nucleate boiling will not occur. The staff has reviewed the calculated estimates of the expected reactivity and power distribution changes that accompany postulated misalignments of representative assemblies. The staff has concluded that the values used in this analysis conservatively bound the expected values including calculational uncertainties.

The inadvertent withdrawal of a single assembly requires multiple failures in the control system, multiple operator errors, or deliberate operator actions combined with a single failure of the control system. As a result, the single assembly withdrawal is classified as an infrequent occurrence. The resulting transient is similar to that resulting from a bank withdrawal, but the increased peaking factor may cause departure from nucleate boiling to occur in the region surrounding the withdrawn assembly. Less than 5% of the rods in the core experience departure from nucleate boiling for such a transient.

The staff has reviewed the possibilities for single failures of the reactor control system that could result in a movement or malposition of control rods beyond normal limits. The review has included investigations of possible rod malposition configurations, the course of the resulting transients or steady-state conditions, and the instrumentation response to the transient or power maldistribution. The staff also has examined the methods used to determine the peak fuel rod response, and the inputs to that analysis, such as power distribution changes, rod reactivities, and reactivity feedback effects resulting from moderator and fuel temperature changes.

The staff concludes that the applicant has met GDC 10, 20, and 25.

The applicant has met the requirements of GDC 10 that the specified acceptable fuel design limits are not exceeded, of GDC 20 that the reactivity control systems are automatically initiated so that specified acceptable fuel design limits are not exceeded, and of GDC 25 that single malfunctions in the reactivity control system will not cause the specified acceptable fuel design limits to be exceeded. These requirements have been met by comparing the resulting extreme operating conditions and response of the fuel with the acceptance

criteria for fuel damage (e.g., critical heat flux, fuel temperatures and clad strain limits should not be exceeded) to ensure that the fuel rod failure will be precluded for this event. The basis for acceptance in the staff review is that maximum configurations and transients for single error control rod malfunctions have been analyzed, that the analysis methods and input data are reasonably conservative, and that specified acceptable fuel design limits will not be exceeded.

15.4.4/15.4.5 Startup of An Inactive Loop or Recirculation Loop at an Incorrect Temperature

15.4.6 Inadvertent Boron Dilution

15.4.7 Inadvertent Loading of a Fuel Assembly into Improper Position

Strict administrative controls in the form of previously approved established procedures and startup testing are followed during fuel loadings to prevent operation with a fuel assembly in an improper location or a misloaded burnable poison assembly. Nevertheless, the applicant has performed an analysis of the consequences of a loading error.

The applicant has compared power distributions calculated for the nominal fuel loading pattern and those calculated for five loadings with misplaced fuel assemblies or burnable poison assemblies. The selected nonnormal loadings represent the spectrum of potential inadvertent fuel misplacement. Calculations included, in particular, the power in assemblies that contain provisions for monitoring with incore detectors.

As part of the required startup testing, the incore detector system is used to detect misloaded fuel before the plant operates at power. The analysis described above shows that all but one of the above misloading events would be detected by this test. In the excepted case--an interchange of Region 1 and 2 assemblies near the center of the core--the increase in the power peaking is approximately equal to the uncertainty in the measurement of this quantity (5%). The analyses allow for this uncertainty so that this misloading event does not result in unacceptable consequences.

The staff has evaluated the consequences of a spectrum of postulated fuel loading errors. The staff has concluded that the analyses provided by the applicant show for each core considered that either the error is detectable by the available instrumentation (and hence remediable) or the error is undetectable but the offsite consequences of any fuel rod failures are a small fraction of 10 CFR 100 guidelines. The applicant affirms that the available incore instrumentation will be used before the start of significant power operation to search for fuel loading errors.

The staff concludes that the applicant has met GDC 13 and 10 CFR 100.

The applicant has met of GDC 13 with respect to providing adequate provisions to minimize the potential of a misloaded fuel assembly going undetected and has met 10 CFR 100 with respect to mitigating the consequences of reactor operations with a misloaded fuel assembly. The applicant has met these requirements by providing acceptable procedures and design features that will minimize the likelihood of loading fuel in a location other that its designated place.

15.4.8 Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

The mechanical failure of a control rod mechanism pressure housing would result in the ejection of a rod cluster control assembly. For assemblies initially inserted, the consequences would be a rapid reactivity insertion, together with an adverse core power distribution, possibly leading to localized fuel rod damage. Although mechanical provisions make this accident extremely unlikely, the applicant has analyzed the consequences of such an event.

Methods used in the analysis are reported in WCAP-7588, Revision 2, "An Evaluation of the Rod Ejection Accident in Westinghouse Reactors Using Spatial Kinetics Methods," which has been reviewed and accepted by the staff. This report demonstrated that the model used in the accident analysis is conservative relative to a three-dimensional kinetics calculation.

The applicant's criteria for gross damage of fuel are a maximum clad temperature of 2700°F and an energy deposition of 200 or 225 calories per gram in the

hottest pellet. These criteria are more conservative* than those proposed in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." Therefore, they are acceptable.

Four cases were analyzed: beginning-of cycle at 102% and zero power and end-of-cycle at 102% and zero power. The highest clad temperatures, 2422°F, and the highest fuel enthalpy, 179 calories per gram, were reached in the end-of-cycle zero power and beginning-of-cycle full-power cases, respectively. The analysis also shows that less than 10% of the fuel experiences departure from nucleate boiling and less than 10% of the hot pellet melts. Analyses have been performed to show that the pressure surge produced by the rod ejection is mild and will not approach the reactor coolant system emergency limits. Further analyses have shown that a cascade effect (the ejection of a further rod due to the ejection of the first one) is not credible.

The staff concludes that the analysis of the rod ejection accident is acceptable and meets GDC 28.

The applicant met GDC 28 with respect to preventing postulated reactivity accidents that could result in damage to the reactor coolant pressure boundary greater than limited local yielding, or cause sufficient damage that would significantly impair the capability to cool the core. The applicant has met the requirements by demonstrating compliance with RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for PWRs." The staff has evaluated the applicant's analysis of the assumed control rod ejection accident and finds the assumptions, calculation techniques, and consequences acceptable. Because the calculations resulted in peak fuel enthalpies less than 280 calories per gram, prompt fuel rupture with consequent rapid heat transfer to the coolant from finely dispersed molten uranium dioxide was assumed not to occur. The pressure surge was, therefore, calculated on the basis of conventional heat transfer from the fuel and resulted in a pressure increase below "Service Limit C" (as defined in ASME Code Section III) for the maximum control rod worths

---

*RG 1.77 has an acceptance criterion of 280 calories per gram energy deposition and no criterion for clad temperature other than that implicit in requirements for fuel and pressure vessel damage.

assumed. The staff believes that the calculations contain sufficient conservatism, both in the initial assumptions and in the analytical models, to ensure that primary system integrity will be maintained.

The staff has reviewed the applicant's analysis of the radiological consequences of a control rod ejection accident. Independent calculations of whole-body and thyroid doses at the exclusion area boundary and low population zone outer boundary resulted in values that were well within the exposure guideline values specified in 10 CFR 100.

In a postulated control rod ejection accident, a mechanical failure of a control rod mechanism housing is assumed which results in the ejection of a rod cluster control assembly and drive shaft. This postulated failure of the control rod system creates a high rate of reactivity insertion. The applicant has conservatively assumed that 10% of the fuel elements in the core will experience departure from nucleate boiling, and 0.25% of the fuel rods will experience fuel melting as a result of a control rod ejection accident.

Two fission product release paths to the environment are considered independently for this accident. The first pathway is via containment leakage of fission products released from the primary system to the containment. The second pathway is via leakage from the secondary system, outside containment, following primary-to-secondary leakage (as limited in the Technical Specification) in the steam generators. The primary reactor containment is assumed to leak at the Technical Specification design leak rate (0.3% per day) for the first 24 hours and at 50% of the design rate for the remainder of the accident. The release of fission products from the secondary system is evaluated with the assumption of a coincident loss of offsite power. The actual doses for the postulated accident would be a composite of the doses computed for the independent releases via the containment building and through the secondary system.

The staff has reviewed the applicant's analysis of the control rod ejection accident and has performed an independent calculation of the radiological consequences following the accident. The assumptions used in calculating the radiological consequences are presented in Table 15.3, and the resultant doses for each pathway are given in Table 15.1.

The staff concludes that the distances to the exclusion area and to the low population zone boundaries for the site, in conjunction with the proposed operation of the South Texas plant within the limits of the Technical Specifications assumed in the above analysis, are sufficient to provide reasonable assurance that the calculated radiological consequences are well within the exposure guidelines as set forth in 10 CFR 100.11.

The staff's conclusion is based on (1) review of the applicant's analysis of the radiological consequences, (2) independent dose calculations using the recommendations of Appendix B of RG 1.77 and the atmospheric dispersion factors as discussed in Section 2 of this report, and (3) the proposed South Texas Technical Specifications for the primary-to-secondary leakage in the steam generators.

15.4.9 Spectrum of Rod Drop Accidents

This section applies to BWRs only; the South Texas units are PWRS.

15.5 Increases in Reactor Coolant System Inventory

15.6 Decreases in Reactor Coolant Inventory

15.6.1 Inadvertent Opening of a Pressurizer Pressure Relief Valve

15.6.2 Failure of Small Lines Carrying Primary Coolant Outside Containment

The staff has reviewed the applicant's analysis of the radiological consequences of failures outside the containment of small lines connected to the primary coolant pressure boundary. No instrument lines carry primary coolant outside the containment. Analyses were performed for failures of (1) the pressurizer liquid sample line, which results in the greatest release of primary coolant activity of all sample line failures; and (2) the letdown line of the chemical and volume control system outside containment. In both cases, the rate of coolant loss from the ruptured line is within the capability of the reactor coolant makeup system.

The initial fission product concentrations in the primary coolant are assumed to be the maximum equilibrium values allowed in the proposed technical specifications. In addition, the analysis assumed an accident-initiated iodine spike in the primary system. The fraction of the iodine postulated to become airborne and available for release to the atmosphere, without credit for plateout, was assumed to equal the fraction of the coolant flashing into steam upon discharging from the ruptured line. The assumptions used in calculating the radiological consequences are listed in Table 15.4. The resultant thyroid and whole-body doses are shown in Table 15.1.

The staff concludes that the distances to the exclusion area and to the low population zone outer boundaries for the South Texas site are sufficient to provide reasonable assurance that the calculated radiological consequences of a postulated small line failure outside containment, assuming the primary coolant equilibrium iodine concentrations are at the maximum permitted in the proposed Technical Specifications, in combination with an accident-generated iodine spike, do not exceed a small fraction (10%) of the exposure guidelines as set forth in 10 CFR 100.

The staff's conclusion is based on (1) the staff review of the applicant's analysis of radiological consequences, (2) the independent dose calculation by the staff using Position C.1.b. of Regulatory Guide 1.11 and conservative atmospheric dispersion factors discussed in Section 2 of this report, and (3) the proposed technical specifications for the equilibrium iodine concentrations in the primary coolant system.

15.6.3 Steam Generator Tube Rupture Accident

A review of the applicant's analysis of the radiological consequences of a postulated SGTR accident has identified a number of areas where additional information is required. Major areas of concern about this accident are the possibility and resulting consequences of overfilling the affected steam generator, the operator action time required to bring primary system pressure to below that of the secondary system safety valve setpoints, the qualification of the equipment which is assumed to be used in recovering from the tube rupture accident, and evaluation of the most limiting single failures in the analyses. The

applicant has not responded to the staff's request for additional information regarding the FSAR analysis for the SGTR accident.

The applicant is a member of a subgroup that was formed within the Westinghouse Owner's Group to address the licensing issues associated with a steam generator tube rupture event on a generic basis. The staff has received the initial report of the subgroup, WCAP-10698, and is currently waiting for supplements that will transmit evaluations of the evolution and transport of radioactivity and offsite radiation doses, and the consequences of steam generator overfill, before completing its review of the SGTR licensing issues on a generic basis. Plant-specific analyses also will be required.

Upon receipt of this additional information, the staff will complete its review of the radiological consequences of an SGTR event.

15.6.4 Radiological Consequences of Main Steamline Failure Outside Containment

This SRP review section applies to BWRs only.

15.6.5 Radiological Consequences of a Design-Basis LOCA

15.7 Radioactive Releases from a Subsystem or Component

15.7.1 Deleted*

15.7.2 Deleted*

15.7.3 Liquid Tank Failures

According to the SRP, the radioactivity in liquid tanks outside containment should be limited so that a tank rupture will not result in radioactivity concentrations at the nearest drinking water source in excess of the limits in 10 CFR 20, Appendix B, Table II, Column 2.

1/2 *This section was deleted from the July 1981 revision of the Standard Review Plan.

The staff is presently performing an independent analysis for liquid tank rupture and associated consequences. This analysis will be available by September 1985.

15.7.4 Fuel Handling Accidents

The staff has reviewed the applicant's analysis of the radiological consequences of a postulated fuel handling accident. The staff independently calculated the whole-body and thyroid doses at the exclusion area boundary and low population zone outer boundary following SRP Section 15.7.4 and RG 1.25, with the exception of atmospheric dispersion factors, which are discussed in Section 2 of the report.

A fuel handling accident during refueling operations could release a fraction of the fission product inventory in the damaged fuel assemblies to the environment. The postulated accident sequence consists of the dropping of the fuel assembly with the peak inventory in the reactor core assuming maximum full-power operation at the end of core life, breaching of the cladding for all rods in the fuel assembly, release of the portion of fission products present in the fuel-clad gap and plenums, absorption of water-soluble gases in and transport of soluble and insoluble gases through the water in the spent fuel pool or refueling cavity, air filtration of a portion of the release prior to release into the environment, and dispersion of the released fission products into the atmosphere.

Two cases were considered in the analysis for the South Texas facility. First, for a postulated fuel handling accident in the fuel building, the radioactive release escaping the spent fuel pool is initially exhausted directly to the environment until the flow is automatically diverted on detection of high radiation through the exhaust air subsystem's ESF filter trains. Credit was taken for dilution of the release due to forced convection in the spent fuel pool area of the fuel building. The applicant used a dilution volume of 50,000 ft^3, which was reviewed and found acceptable by the staff. Second, for an accident inside containment, the normal containment purge subsystem is operating during refueling operations; thus, the activity escaping the water in the refueling

cavity would be exhausted to the environment until automatic containment isolation is achieved upon detection of high radiation. A dilution volume of 3% of the containment free volume was used by the applicant, based on an estimate of the extent of dilution of the release in containment from natural and forced convection. The staff has reviewed the applicant's analysis of the fuel handling accident and has performed an independent calculation of the radiological consequences following the accident. The assumptions used in calculating the radiological consequences are presented in Table 15.5, and the resultant doses for each case are given in Table 15.1.

The staff finds that the applicant has provided an adequate system to mitigate the radiological consequences of a postulated fuel handling accident inside the containment and in the fuel building. The staff concludes that the fuel handling system meets the relevant requirements of GDC 61. The staff further concludes that the distances to the exclusion area and to the low population zone outer boundaries for the South Texas site, in conjunction with the operation of dose mitigating engineered safety features, are sufficient to provide reasonable assurance that the calculated offsite radiological consequences of a postulated fuel handling accident are well within the 10 CFR 100 exposure guidelines.

The staff's conclusion is based on (1) the staff's determination that the design features and plant procedures meet GDC 61 with respect to radioactivity control; (2) the staff review of the applicant's assumptions and analyses of the radiological consequences from the fuel handling accident; and (3) the staff's independent analyses using the assumptions in RG 1.25, Positions C.1.a through C.1.i.

With regard to a postulated spent fuel cask drop accident, the applicant states in the FSAR that the building arrangement and lifting rig design prevent the cask handling crane from lifting spent fuel casks higher than 30 feet above the floor. Because spent fuel casks are designed to withstand falls of 30 feet or less with no significant radioactive releases, the staff has concluded that an analysis of the radiological consequences of this accident is not necessary.

Table 15.2 Assumptions used to evaluate the radiological consequences following a postulated MSLB outside containment

Parameter	Value
Power, MWt	4,100
Iodine concentration (DEI-131) in primary coolant, pre-accident spike case, μCi/gm	60
Iodine concentration (DEI-131) in primary coolant, accident initiated spike case, μCi/gm	1.0
Iodine spiking release rate factor	500
Fraction of rods experiencing failure, fuel failure case	0.05
Fraction of noble gases (except Kr-85) and iodine inventory in gap of failed rods	0.1
Above fraction for Kr-85	0.3
Iodine concentration (DEI-131) in secondary coolant, μCi/gm	0.1
Primary-to-secondary leak rate, gpm	1.0
Fraction of iodine entering affected steam generator secondary side released to environment	1.0
Initial steam release of secondary coolant from affected steam generator (0 to 30 minutes), lb_m	210,000
Long-term coolant release from affected steam generator (0 to 8 hours), lb_m	1,390
Steam release from unaffected steam generators, lb_m	
0 to 2 hours	484,000
2 to 8 hours	1,106,000

Table 15.3 Assumptions used for estimating the radiological consequences following a postulated control rod ejection accident

Parameter	Value
Power, MWt	4100
Technical Specification primary-to-secondary leak rate, gpm	1.0
Fraction of the fuel rods experiencing cladding failure	0.1
Fraction of noble gas and iodine inventory in gap of failed rods	0.1
Peaking factor	1.65
Fraction of the fuel rods experiencing fuel melting	0.0025
Fraction of iodine inventory released from rods experiencing melting	0.5
Fraction of noble gas inventory released from rods experiencing melting	1.0
Fraction of iodine entering secondary side released to environment	0.1
Time of primary and secondary system pressure equilibration, seconds	1250
Fraction of iodine plated out in containment	0.5
Technical specification design leak rate of containment, % per day	0.3

Table 15.4 Assumptions used for estimating the radiological consequences following postulated accidents involving small line breaks outside containment

Parameter	Value
Iodine concentration (DEI-131) in the primary coolant, μCi/gm	1.0
Iodine spiking factor	500
Letdown line failure	
Isolation valve closure time, minutes	30
Primary coolant released, lb_m	74,300
Pressurizer sample line failure	
Isolation valve closure time, minutes	30
Primary coolant released, lb_m	16,100

Table 15.5 Assumptions used for estimating the radiological consequences following a postulated fuel handling accident

Parameter	Value
Design power level, MWt	4100
Number of fuel rods damaged	264
Total number of fuel rods in core	50,952
Radial peaking factor	1.65
Shutdown time, hours	20
Fraction of noble gas (except Kr-85) and iodine inventory in gap of damaged rods	0.1
Fraction of Kr-85 in gap of damaged rods	0.3
Pool decontamination factors	
Iodine	100
Noble gases	1
Iodine species above fuel pool, %	
Inorganic iodine	75
Organic iodine	25
Filter efficiencies in fuel building, %	
Inorganic iodine	95
Organic iodine	95
Fuel handling building (FHB) exhaust isolation damper closure time, sec	20
FHB dilution volume, ft^3	50,000
Design airflow of FHB exhaust air subsystem, ft^3/min	37,000
Reactor containment building normal purge isolation valve closure time, seconds	60
Reactor containment building dilution volume (% of containment free volume)	3
Design airflow in normal containment purge subsystem, ft^3/min	40,000

16 TECHNICAL SPECIFICATIONS

The Technical Specifications in a license define certain features, characteristics, and conditions governing operation of a facility that cannot be changed without prior approval of the staff. The finally approved Technical Specifications will be made a part of the operating license. Included will be sections covering definitions, safety limits, limiting safety system settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls.

The Technical Specifications for the South Texas project Units 1 and 2 will be based on the revision of "Standard Technical Specifications for Westinghouse Pressurized Water Reactors" (NUREG-0452). The applicant submitted a set of proposed Technical Specifications for South Texas project on June 17, 1985. The staff will review the submittal with the recognition that the South Texas design incorporates various unique features compared with most Westinghouse PWRs.

17 QUALITY ASSURANCE

17.1 Quality Assurance During the Design and Construction Phase

17.2 Quality Assurance During the Operations Phase

17.2.1 General

FSAR Chapter 17 describes the QA program for the operations phase of Units 1 and 2 of the South Texas project. The staff reviewed the applicant's QA program for the operations phase to determine if it complies with 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and with the applicable QA-related regulatory guides and ANSI standards listed in Table 17.1. The basis of the review was Section 17.2 of NUREG-75/087.

17.2.2 Organization

The structure of the organization responsible for the operation of the South Texas project and for the establishment and execution of the operations phase QA program is shown in Figure 17.1. The Manager--Nuclear Assurance has overall responsibility for developing the QA program for the applicant's nuclear generating stations during the operations phase. The Manager--Nuclear Assurance reports directly to the Group Vice President--Nuclear, who has overall responsibility for QA at the South Texas project. The authority and responsibility of the Manager--Nuclear Assurance to direct and administer the quality assurance program have been granted in writing by the President of HL&P.

Reporting to the Manager--Nuclear Assurance is the Operations Quality Assurance Manager, who is responsible for ensuring that an adequate QA program is developed and implemented for safety-related structures, systems, components, and activities. Reporting to the Operations Quality Assurance Manager are the Operations Quality Assurance General Supervisor and the Operations Quality Control

General Supervisor. The Operations Quality Assurance General Supervisor is responsible for verifying compliance with all quality-related manuals and procedures through planned and systematic audits and surveillances. The Operations Quality Control General Supervisor is responsible for coordinating inspection of selected fabrication, construction, modification, maintenance, testing, material receiving activities; nonconformance identification; and inspection personnel certification.

The Technical Services General Supervisor, who reports to the Manager--Nuclear Assurance, performs vendor surveillance, vendor audits, and related activities, as requested by the Operations Quality Assurance Manager.

The applicant's QA organization is responsible for (1) establishing QA indoctrination and training programs for personnel performing quality-affecting activities; (2) reviewing and approving QA procedures and instructions; (3) ensuring that personnel qualifications are current and applicable to the work being performed; (4) ensuring that design and procurement documents include applicable QA requirements; (5) performing pre-award evaluation of suppliers and surveillance and inspection at the suppliers' facilities; (6) reviewing and verifying satisfactory completion of corrective actions; (7) performing final acceptance inspections of maintenance, modification, and operations activities; and (8) conducting internal audits of these activities and external audits of suppliers. These QA personnel have the authority to (1) identify quality-related problems that may involve a "stop work" decision; (2) initiate, recommend, or provide solutions; and (3) verify implementation of solutions.

The Plant Manager (who reports to the Vice President--Nuclear Plant Operations as shown in Figure 17.1) is responsible for the operation and maintenance of Units 1 and 2. The Plant Manager is assigned the specific responsibility for overall facility management including operation, maintenance, and technical supervision. His staff includes an Operations Section responsible for the safe operation of the plant; a Maintenance Section responsible for mechanical, electrical, and instrumentation and control maintenance at the plant; a Technical Section responsible for technical support in the areas of engineering; and a Nuclear Training Section. The Plant Manager and Vice President--Nuclear Plant

Operations are directly accountable to the Group Vice President--Nuclear for ensuring that all QA problems identified by the independent quality assurance organization are fully resolved.

17.2.3 QA Program

The applicant has structured the QA program for the operations phase to satisfy Appendix B to 10 CFR 50 and the regulatory guides shown in Table 17.1. This QA program for the operation is implemented by written policies, procedures, and instructions. These documents control quality-related activities involving safety-related items in accordance with the requirements of Appendix B to 10 CFR 50 and with other applicable regulations, codes, and standards. The QA organization is responsible for ensuring that procedures and instructions provide for complete and adequate QA requirements. In addition, QA personnel conduct reviews, inspections, and audits to verify the effective implementation of the entire QA program.

The applicant's QA program requires that implementing documents encompass detailed controls for (1) translating codes, standards, regulatory requirements, Technical Specifications, engineering requirements, and process requirements into drawings, specifications, procedures, and instructions; (2) developing, reviewing, and approving procurement documents and changes thereto; (3) prescribing all quality-related activities by documented instructions, procedures, drawings, and specifications; (4) issuing and distributing approved documents; (5) purchasing items and services; (6) identifying materials, parts, and components; (7) performing special processes; (8) inspecting and/or testing materials, equipment, processes, and services; (9) calibrating and maintaining measuring and test equipment; (10) handling, storing, and shipping items; (11) identifying the inspection, test, and operating status of items; (12) identifying and dispositioning nonconforming items; (13) correcting conditions adverse to quality; (14) preparing and maintaining QA records; and (15) auditing activities that affect quality.

The applicant's indoctrination and training program ensures that personnel performing activities affecting quality are knowledgeable in QA requirements, implementing procedures, and instructions; that they have competence and skill

in the performance of their quality-related activities; and that this competence is maintained through periodic retraining.

Quality is verified through checking, reviewing, surveilling, inspecting, testing, and auditing quality-related activities. The QA program requires that quality be verified by the QA organization. Inspections are performed by qualified QA personnel in accordance with procedures, instructions, and checklists that are reviewed by the quality assurance organization and approved by the Plant Operating Review Committee.

The QA organization is responsible for establishing and implementing the audit program. Audits are performed in accordance with pre-established written checklists by qualified QA personnel not having direct responsibilities in the areas being audited. Periodic audits will be performed by the QA organization to evaluate all aspects of the QA program, including the effectiveness of the QA program implementation.

The QA program requires the review of audit results by the person having responsibility in the area audited to determine and take corrective action where necessary. Continued deficiencies, or failure to implement corrective action, will be reported in writing by the QA organization to the appropriate executives within the applicant's organization.

QA personnel perform follow-up audits to determine that nonconformances and deficiencies are effectively corrected and that the corrective action precludes repetitive occurrences. Audit reviews, which indicate performance trends and the effectiveness of the QA program, are conducted by the QA organization and reported to responsible management for review and assessment.

17.2.4 Conclusions

On the basis of its review the staff concludes that

(1) The organizations and persons performing QA functions have the required independence and authority to effectively carry out the QA program without undue influence from those directly responsible for cost and schedule.

(2) The QA program describes requirements, procedures, and controls that, when properly implemented, comply with Appendix B to 10 CFR 50 and with SRP Section 17.2 (NUREG-75/087, Revision 0).

17.3 Review Against NUREG-0800

NUREG-75/087 was revised (Revision 1, February 1979) and reissued as NUREG-0800 (Revision 2, July 1981).

An additional review of the South Texas QA Program shows that the program complies with NUREG-0800 except for the controls listed below. It should be noted that there is no NRC requirement that the applicant address these controls in the FSAR description of the QA program for the operations phase of the South Texas project.

The QA program description does not specify

(1) that controls, procedures, and lines of communication among participating design organizations and across technical disciplines are established to ensure geometric and functional compatibility with processes and environment during the operations phase (SRP Section 17.1, item 17.1.3, 3D)

(2) that procedures are established and documented by requiring a documented check to verify the dimensional accuracy and completeness (SRP Section 17.1, Item 17.1.3, 3E1)

These QA controls generally provide for increased emphasis on the need for procedures, documentation, and requirements for quality-related activities. As such, the staff believes that adequate QA controls in these areas are already included in the QA program for South Texas, and that the applicant need not be required at this time to describe how the above listed items described in NUREG-0800 are covered in the South Texas QA program.

17.4 Independent Design Verification Program

17.4.1 Background

On September 14, 1983, the applicant met with the staff to discuss the South Texas engineering assurance program (EAP). The EAP was described as an ongoing independent review of the South Texas design to confirm the adequacy of the engineering work performed. In response to a staff request, by letter dated November 29, 1983, the applicant provided documentation describing the EAP reports generated by the program. On March 1, 1984, the applicant gave the staff the details of the South Texas EAP. As a result of this meeting, and additional information provided by the applicant in a March 29, 1984 letter, the staff determined that the EAP could provide the additional assurances of design adequacy normally provided by an independent design verification program (IDVP). Formal acceptance of the EAP as a substitute for an IDVP was provided via an August 20, 1984 letter to the applicant, in which the staff committed to periodically inspect the implementation and progress of the applicant's EAP.

To date, the applicant has designated the following review topics to be included in the EAP:

Number	Topic title
83-1	Soil-structure interaction analysis and seismic design
83-2	Design process review of the residual heat removal/safety injection (RHR/SI) system
83-3	Pipe stress analysis of the RHR/SI system
84-1	Containment analysis
84-2	Equipment qualification program
84-3	Pipe support design of the RHR/SI system
84-4	Separation and fire protection
85-1	Control room HVAC system
85-2	Component cooling water system
85-3	Offsite and medium voltage ac power systems
85-4	High-energy line break analysis
85-5	Class 1 piping

The staff does not anticipate any further additions to the review topic list before fuel load. The applicant's level of effort associated with each review is between 3000 and 4000 hours. The applicant has hired Stone and Webster Engineering Corporation to provide an independent technical assessment for each review topic. To further ensure that the EAP is conducted properly, the applicant has formed a three-member Oversite Review Committee, composed of Dr. Joseph M. Hendrie, Dr. Herbert H. Woodson, and Mr. Robert V. Laney, who annually monitor the EAP program.

17.4.2 Results of the EAP

The EAP is an ongoing program that involves a topical assessment by Stone and Webster and subsequent issuance of an associated report, the evaluation of the report by the engineering assurance (EA) organization, and the iterative process of resolving action items from the report with Bechtel, EA, and Stone and Webster. To date six reports have been issued by Stone and Webster (on topics 83-1, 83-2, 83-3, 84-1, 84-2, and 84-3). Only the report for 83-2 had all its action items closed; the action items on the other five reports are being resolved. The remaining reports are scheduled to be issued by Stone and Webster prior to January 1986. The applicant is evaluating the feasibility of preparing a document that summarizes the conclusions of the EAP. To date, no overview of EAP results has been published; only the resolution of the individual action items is available.

17.4.3 Staff Assessment

Since accepting the EAP as a substitute for an IDVP, the staff has held the following meetings and/or inspections with the applicant and the applicant's contractors:

- December 11 to 13, 1984, the staff met with the applicant in Houston, Texas to review the progress of the EAP. This meeting resulted in three observations by the staff which were documented in a letter from G. Knighton to J. Goldberg, dated March 13, 1985. The applicant adequately responded to these observations in a letter to G. Knighton dated April 17, 1985.

- At a March 27, 1985, meeting between the staff and the applicant in Houston, the staff gathered information to support its forthcoming implementation inspection at Stone and Webster. Meeting minutes were documented by the applicant in a memorandum to file dated April 4, 1985.

- The staff conducted an implementation inspection of the EAP from April 23 through 26, 1985, at the Boston office of Stone and Webster, the EA contractor. The NRC Inspection Team evaluated the depth of review being performed by Stone and Webster for EAP assessments 85-1, 85-2, and 85-3. The results of this inspection are documented in Inspection Report No. 50-498/85-09.

Because the EAP is an ongoing program, the staff has decided to monitor the effectiveness of the program in three phases: (1) implementation of the program plan including depth of review evaluation; (2) review and evaluation of action items resulting from EAP reports; and (3) verification of corrective actions resulting from resolution of action items. The staff is actively involved in phase (1) for 85-1, 85-2, and 85-3, with another implementation inspection of Stone and Webster scheduled for mid-July 1985 for these review topics. Concurrently, the staff is reviewing the first six review topic reports (83-1, 83-2, 83-3, 84-1, 84-2, and 84-3) as part of the phase (2) review. Comments are to be forwarded to the applicant by July 1985. All 12 review topics will be reviewed as part of phases (2) and (3) of the staff's review.

17.4.4 Conclusion

The staff is reviewing the EAP. The staff review process is dependent upon the EAP schedule established by the applicant, which estimates a completion date in the summer of 1986.

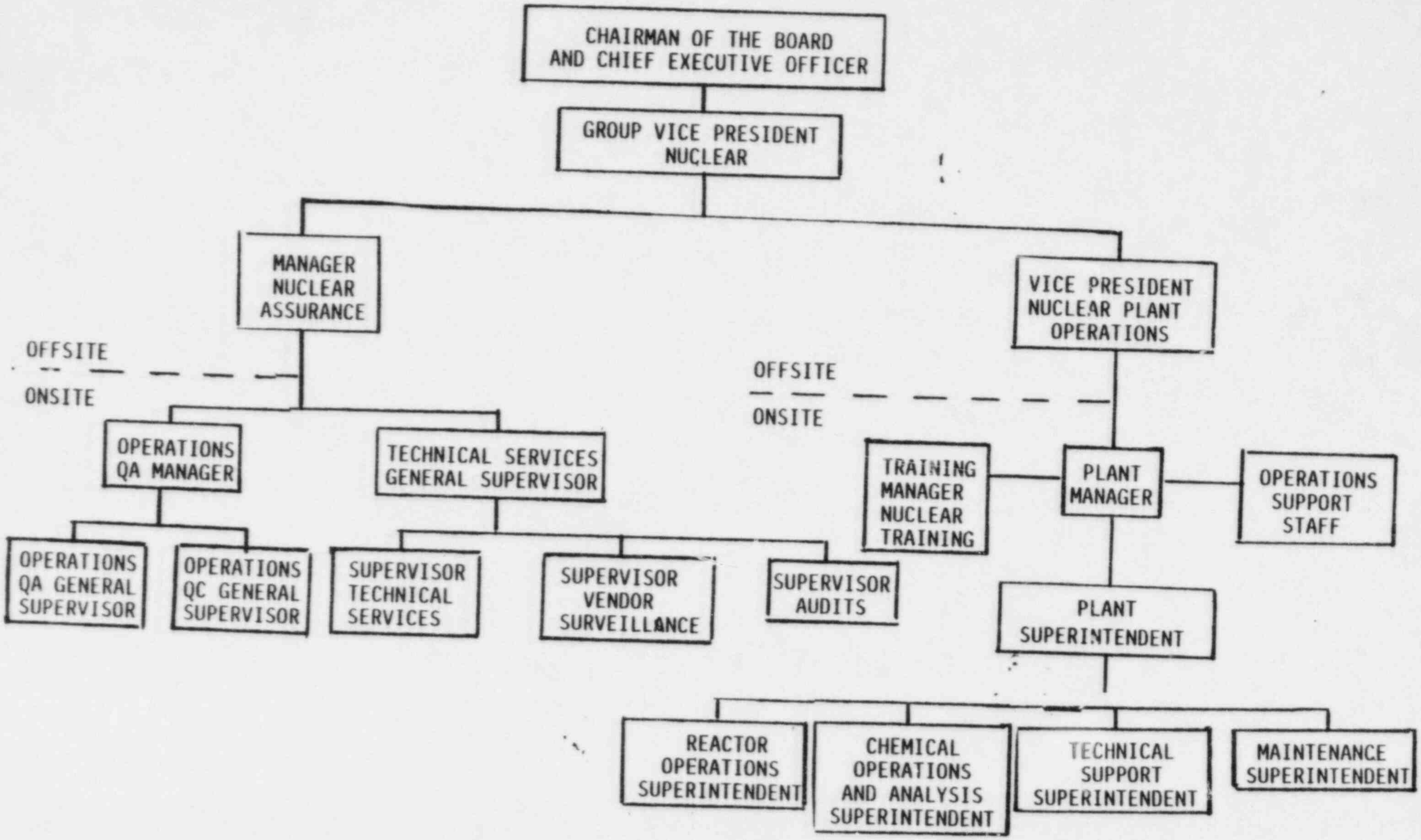

Figure 17.1 HL&P organization for operations

Table 17.1 QA-related regulatory guides and ANSI standards

Regulatory Guide	Title	Date	ANSI Standard Endorsed
1.8, Rev. 1-R	Personnel Selection and Training	5/77	N18.1
1.29, Rev. 3	Seismic Design Classification	9/78	
1.30, Rev.0	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	8/72	N45.2.4
1.33, Rev. 2	Quality Assurance Program Requirements (Operation)	2/78	N18.7
1.37, Rev. 0	Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants	3/73	N45.2.1
1.38, Rev. 2	Quality Assurance Requirements for Packaging Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants	5/77	N45.2.2
1.39, Rev. 2	Housekeeping Requirements for Water-Cooled Nuclear Power Plants	9/77	N45.2.3
1.58, Rev. 1	Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel	9/80	N45.1.6
1.64, Rev. 2	Quality Assurance Requirements for the Design of Nuclear Power Plants	6/76	N45.2.11

Table 17.1 (continued)

Regulatory Guide	Title	Date	ANSI Standard Endorsed
1.74, Rev. 0	Quality Assurance Terms and Definitions	2/74	N45.2.10
1.88, Rev. 2	Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records	10/76	N45.2.9
1.94, Rev. 1	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants	4/76	N45.2.5
1.116, Rev. 0-R	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems	5/77	N45.2.8
1.123, Rev. 1	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants	7/77	N45.2.13
1.144, Rev. 1	Auditing of Quality Assurance Programs for Nuclear Power Plants	9/80	N45.2.12
1.146, Rev. 0	Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants	8/80	N45.2.23

18 HUMAN FACTORS ENGINEERING

NRC requires licensees and applicants for operating licenses to conduct a detailed control room design review (DCRDR). The objective of this review is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (NUREG-0660, Item I.D). The need to conduct a DCRDR was confirmed in NUREG-0737 and Supplement 1 to NUREG-0737, and Supplement 1 to NUREG-0737 directed each applicant or licensee to conduct a DCRDR on a schedule negotiated with the staff.

NUREG-0700 describes four phases of the DCRDR and provides applicants and licensees with guidelines for its conduct: planning, review, assessment and implementation, and reporting. The criteria for evaluating each phase are in NUREG-0801.

To comply with these criteria, an applicant submits a program plan within 2 months of the start of the DCRDR. Supplement 1 to NUREG-0737 states that the program plan shall describe how the following elements of the DCRDR will be accomplished:

(1) establishment of a qualified multidisciplinary review team

(2) function and task analyses to identify control room operator tasks and information and control requirements during emergency operations

(3) a comparison of display and control requirements with a control room inventory.

(4) a control room survey to identify deviations from accepted human factors principles

(5) assessment of human engineering discrepancies (HEDs) to determine which HEDs are significant and should be corrected

(6) selection of design improvements

(7) verification that selected design improvements will provide the necessary correction

(8) verification that improvements will not introduce new HEDs

(9) coordination of control room improvements with changes from other programs such as the safety parameter display system (SPDS), operator training, RG 1.97 instrumentation, and upgraded emergency operating procedures

Then at the end of the DCRDR, an applicant submits a summary report. As a minimum, this summary report must

(1) outline proposed control room changes

(2) outline proposed schedules for implementation

(3) provide summary justification for HEDs with safety significance to be left uncorrected or partially corrected

The staff then evaluates the organization, process, and results of the DCRDR. This evaluation includes a review of required documentation (program plan and summary report) and may also include review of additional documentation, briefings, discussions, and onsite audits. In-progress audits may be conducted after the program plan is submitted but before the summary report is submitted. Preimplementation audits may be conducted after the summary report is submitted. The staff evaluation will be in accordance with the requirements of Supplement 1 to NUREG-0737, which states that significant HEDs shall be corrected. Improvements that can be done with an enhancement program may be done promptly. Additional guidance for the evaluation is in NUREGs-0700 and -0801.

To the extent practical, without delaying completion of the DCRDR, the staff recommends that the DCRDR address any control room modifications and any additions (such as controls and displays for inadequate core cooling and reactor system vents) made or planned as a result of other post-TMI actions, as well as the lessons learned from operating reactor events such as the Salem ATWS events. Implications of the Salem ATWS events are discussed in NUREG-1000, and the required actions are described in Section 1.2, "Post Trip Review - Date and Information Capability," of the enclosure to Generic Letter 83-28.

Licensing of South Texas Unit 1 is scheduled for December 1986. The DCRDR was initiated in September 1982, and a program plan was submitted October 20, 1982. Exceptions to the originally planned organization and process of the DCRDR were documented in a March 31, 1983 revision to the program plan. Staff comments based solely on the program plan were not prepared.

In November 1982, the applicant put a hold on DCRDR activities and decided to completely redesign the layout of six panels and upgrade the four remaining main control panels. The layout was redesigned to meet RG 1.97 and comply with the human factors engineering principles of NUREG-0700.

The mock-up of the control room was revised, and the redesign of the main control panels was completed in April 1983. At the request of the applicant, the staff conducted an in-progress audit May 2 through 6, 1983. The staff's report detailing the findings of the in-progress audit was transmitted to the applicant October 31, 1983; it discussed, as appropriate, issues normally addressed in the staff's program plan comments. The summary report for the DCRDR submitted by the applicant on April 12, 1984, consisted of 15 separate reports. It

(1) provided results of the DCRDR to date

(2) addressed staff recommendations and information needs listed in the memorandum to G. Knighton from V. Moore, "Results of In-progress Audit of STP," dated October 24, 1983.

(3) identified work that was in progress or that could not be completed until the control room and/or the simulator is operational

On January 22, 1985, the NRC sent the applicant a request for additional information regarding the DCRDR, which the applicant answered by letters dated February 26 and April 15, 1985. The April 15 letter included an addendum to the Executive Summary (Summary Report) and the Control Room Design Review HED Resolution Report. The staff has reviewed these reports.

In these letters, the applicant showed a commitment to comply with the requirements of Supplement 1 to NUREG-0737. To complete the DCRDR activities, before licensing, the applicant must satisfactorily resolve the following items:

(1) provide the results of the verification and validation program for the final emergency operating procedures (EOPs) to confirm that the instrumentation and control needs have been adequately identified and satisfied

(2) provide the results of the investigation of the green Roto-tellite indicating lights in the control room under actual operating conditions

(3) resolve Category D HEDs relative to providing dual filament indicating light bulbs, or double bulbs, or bulb-testing capabilities

(4) provide the results of the surveys of the lighting, sound, meter, and communication system when planned work in the control room is completed

19 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The application for operating licenses for the South Texas facility is being reviewed by the Advisory Committee on Reactor Safeguards. The NRC staff will issue a supplement to the Safety Evaluation Report after the Committee report to the Commission is available. The supplement will include a copy of the Committee's report, will address comments made by the Committee, and will describe steps taken by the NRC staff to resolve any issues raised as a result of the Committee's review.

21 FINANCIAL QUALIFICATIONS

On March 31, 1982, the NRC published in the Federal Register (47 FR 13750) amendments to its regulations that entirely eliminate the review relating to the financial qualifications of applicants for construction permits and operating licenses. Because these amendments were effective immediately, there will be no further review of the financial qualifications of the applicant.

22 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

22.1 General

Pursuant to the financial protection and indemnification provisions of the Atomic Energy Act of 1954, as amended (Section 170 and related sections), the Commission has issued regulations in 10 CFR 140. These regulations set forth the Commission's requirements with regard to proof of financial protection by, and indemnification of, licenses for facilities such as power reactors under 10 CFR 50.

22.2 Preoperational Storage of Nuclear Fuel

The Commission's regulations in 10 CFR 140 require that each holder of a construction permit under 10 CFR 50 who is also the holder of a license under 10 CFR 70 authorizing the ownership and possession for storage only of special nuclear material at the reactor construction site for future use as fuel in the reactor (after an operating license is issued under 10 CFR 50) shall, during the interim storage period before licensed operation, have and maintain financial protection in the amount of $1,000,000 and execute an indemnity agreement with the Commission. Proof of financial protection is to be furnished prior to, and the indemnity agreement executed as of, the effective date of the 10 CFR 70 license. Payment of an annual indemnity fee is required.

The applicant will furnish the Commission proof of financial protection in the amount of $1,000,000 in the form of a Nuclear Energy Liability Insurance Association Policy (Nuclear Energy Liability Policy, facility form NF-256). Further, the applicant will execute an Indemnity Agreement with the Commission effective as of the date of its preoperational fuel storage license. The applicant will pay the annual indemnity fee applicable to preoperational fuel storage.

22.3 Operating Licenses

Under the Commission's regulations in 10 CFR 140, a license authorizing the operation of a reactor may not be issued until proof of financial protection in the amount required for such operation has been furnished and an indemnity agreement covering such operation (as distinguished from preoperational fuel storage only) has been executed. The amount of financial protection that must be maintained for the South Texas plants (which has a rated capacity in excess of 100,000 electrical kilowatts), is the maximum amount available from private sources (that is, the combined capacity of the two nuclear liability insurance pools; this amount is currently $160 million).

Accordingly, licenses authorizing operation of the South Texas nuclear plant will not be issued until proof of financial protection in the requisite amount has been received and the requisite indemnity agreement executed.

The staff expects that, in accordance with the usual procedure, the nuclear liability insurance pools will provide, in advance of anticipated issuance of the operating license documents, evidence in writing, on behalf of the applicant, that the present coverage has been appropriately amended so that the policy limits have been increased, to meet the requirements of the Commission's regulations for reactor operation. Similarly, operating licenses will not be issued until an appropriate amendment to the present indemnity agreement has been executed. The applicant will be required to pay an annual fee for operating license indemnity as provided in NRC regulations.

On the basis of the above considerations, the staff concludes that the presently applicable requirements of 10 CFR 140 have been satisfied and that, before an operating license is issued, the applicant will be required to comply with the provisions of 10 CFR 140 applicable to operating licenses, including those as to proof of financial protection in the requisite amount and as to execution of an appropriate indemnity agreement with the Commission.

23 CONCLUSIONS

Based on its evaluation of the application as set forth above, the staff has determined that, upon favorable resolution of the outstanding matters described herein, it will be able to conclude that

(1) The application for operating licenses filed by the applicant complies with the requirements of the Atomic Energy Act of 1954, as amended (Act), and the Commission's regulations set forth in 10 CFR Chapter I, except as duly exempted therefrom.

(2) The facility will operate in conformity with the application as amended, the provisions of the Act, and the rules and regulations of the Commission.

(3) There is reasonable assurance (a) that the activities authorized by the operating licenses can be conducted without endangering the health and safety of the public and (b) that such activities will be conducted in compliance with regulations of the Commission set forth in 10 CFR Chapter I.

(4) The applicant is technically and financially qualified to engage in the activities authorized by the licenses, in accordance with the regulations of the Commission set forth in 10 CFR Chapter I.

(5) The issuance of these licenses will not be inimical to the common defense and security or to the health and safety of the public.

Before operating licenses are issued, the units must be completed in conformity with the Construction Permits, the application, the Act, and the rules and regulations of the Commission. Such completeness of construction as is required for safe operation at the authorized power levels must be verified by the NRC before the licenses are issued.

Before operating licenses are issued, the applicant will be required to satisfy the applicable provisions of 10 CFR 140.

APPENDIX B

BIBLIOGRAPHY

APPENDIX B

BIBLIOGRAPHY

American Society of Civil Engineers, "Wind Forces on Structures," Final Report of the Task Committee on Wind Forces of the Committee on Load Stresses of the Structural Division, Transactions of the American Society of Civil Engineers, New York, Paper No. 3269, Vol 126, Part II 1961, p. 1124-1198.

Amirikian, A. "Design of Protective Structures," Bureau of Yards and Docks, Publication No. NAVDOCKS P-51, Department of the Navy, Washington, DC, August 1950.

Anderson, T. M., Westinghouse, letter to J. R. Miller, NRC, "Responses to Request Number 3 for Additional information on WCAP-9500, NRC letter from J. R. Miller to T. M. Anderson, August 15, 1980, "January 12, 1981.

---, letter to J. R. Miller, NRC, "Responses to Questions on WCAP-9500, Section 4.2, Resulting from NRC/Westinghouse Meeting on March 18, 1981," April 21, 1981.

Appleby, W. K., et al., "Fluence and Temperature Dependence of Void Formation in Highly Irradiated Stainless Steels," in Radiation-Induced Voids in Metals, USAEC Proceedings of the 1977 International Conference held at Albany, New York, June 9-11, 1971, April 1972.

Barstow, H. L., et al., "An Approach to Seismic Zonation for Siting Nuclear Electric Power Generating Facilities in the Eastern United States," NUREG/CR-1577, 1981.

Bloom, E. E., "Nucleation and Growth of Voids in Stainless Steels During Fast-Neutron Irradiation," in Radiation-Induced Voids in Metals, USAEC Proceedings of the 1977 International Conference held at Albany, New York, June 9-11, 1971, April 1972.

Burns, J. J. Jr., "Reliability of Nuclear Power Plant Steam Turbine Overspeed Control Systems," 1977 ASME Failure Prevention and Reliability Conference, Chicago, Illinois, September 1977.

Campbell, K. W., "The Effects of Site Characteristics on Near-Source Recordings of Strong Ground Motion," LLNL-UCRL-86248, July 1983.

Carlson, S. M., "Investigations of Recent and Historical Seismicity in East Texas," University of Texas at Austin, M.S. Thesis, May 1984.

Clark, R. A., NRC, letter to J. M. Griffin, Arkansas Power and Light Co., "ANO-2 Fuel Inspection Results," July 24, 1983.

Clark, W. G. Jr., B. B. Seth, and D. H. Shaffer, "Procedures for Estimating the Probability of Steam Turbine Disc Rupture from Stress Corrosion Cracking," ASME/IEEE Power Generation Conference October 4-8, 1981, St. Louis, Missouri.

Clayton, H. B., NRC, memorandum to Dennis Ziemann, "Meeting Summary-Task Analysis Requirements of Supplement I to NUREG-0737--March 29, 1984, Meeting with Westinghouse Owners' Group Procedures Subcommittee and Other Interested Persons," April 5, 1984.

Coffman, J. L. and C. A. Von Hake, "Earthquake History of the United States," U.S. Department of Commerce Publication 41-1, 1973.

Devine, J. F., U.S. Geological Survey, letter to R. E. Jackson, NRC, November 18, 1982.

Dewey, J. W. and D. W. Gordon, U.S. Geological Survey (USGS) Miscellaneous Field Studies Map MR-1699, a map showing recomputed Hypocenters of Earthquakes in the Eastern and Central United States and adjacent Canada, 1925-1980, USGS, 1984.

Docekal, J., "Earthquakes of the Stable Interior with Emphasis on the Midcontinent," University of Nebraska, Ph.D. Thesis, 1970.

need more

Eggleston, F.T., "Safety-Related Research and Development for Westinghouse Pressurized Water Reactors, Program Summary,"

Foster, J. P., and R. V. Strain, "Empirical Swelling Equations for Solution-Annealed Type 304 Stainless Steel," in Nuclear Technology, Vol 24, p. 93, October 1974.

Froelich, C., "Seismicity of the Central Gulf of Mexico," in Geology, Vol 10, 1982.

Fukishiro, T., et al., "The Influence of Coolant Flow on Fuel Behavior Under Reactivity Initiated Accident Conditions," JAERI Report JAERI-M-9104, October 1980.

Gupta, I. N. and O. W. Nuttli, "Spatial Attenuation of Intensities for Central U.S. Earthquakes," in Bulletin of the Seismological Society of America, Vol 68, No. 3, 1976.

Hoshi, T., et al., "Fuel Failure Behavior of PCI-Remedy Fuels Under Reactivity Initiated Accident Conditions," JAERI Report JAERI-M-8836, May 1980.

Houston Lighting & Power (HL&P), letter to G. Knighton, NRC, April 17, 1985.

---, memorandum to file, April 4, 1985 (re March 27 1985 meeting with staff on EAP implementation inspection).

Hulman, L. G., NRC, memorandum to C. H. Berlinger, "Reload Reviews in DSI," December 20, 1982.

Jackson, M. P. A., "Fault Tectonics of the East Texas Basin," Texas Bureau of Economic Geology, Geological Circular No. 82-4, Austin, 1982.

Japanese Atomic Energy Research Institute (JAERI), "Semiannual Program Report on the NSRR Experiments - July to December 1979," JAERI Report JAERI-M-9011, September 1980.

Kalderon, D. "Steam Turbine Failure at Hinkley Point A," Proc. Instn. Mech. Engrs., 186, 31/72, 1972, p. 341.

King, P. B., "The Tectonics of North America," a discussion to accompany the tectonic map of North America, Scale 1:5,000,000, U.S. Geological Survey Professional Paper 628, 1969.

Knighton, G., NRC, letter to J. Goldberg, HL&P, March 13, 1985.

Kuffer, K., and H. R. Lutz, "Experience of Commercial Power Plant Operation in Switzerland," presented at the Fifth Foratom Conference, Florence, Italy, 1973.

Lahey, R. T. and F. J. Moody, "The Thermal Hydraulics of a Boiling Water Reactor," American Nuclear Society, 1977.

Leasburg, R. H., VEPCO, letter to H. R. Denton, NRC, "Fuel Assembly Guide Thimble Tube Wear Examination Report," March 1, 1982.

Miller, J., NRC, letter to E. Rahe, Westinghouse, "Acceptance for Referencing the 1981 version of the Westinghouse Large-Break ECCS Evaluation Model," December 1, 1981.

Nerses, V., NRC, letter to Florida Power and Light Co., "Summary of Meeting Held in Bethesda, MD, with FP&L on March 3, 1983, Regarding Axial Growth and High Burnup Fission Gas Release," April 28, 1983.

Northern States Utilities, "Preliminary Notification of Event or Unusual Occurrence--PNO-III-81-104: Circle in the hub of the 11th stage wheel in the main turbine at Monticello Nuclear Power Station November 24, 1981."

Nuttli, O. W., "Magnitude Recurrence Relation for the Central Mississippi Valley Earthquakes," Bulletin of the Seismological Society of America, Vol 64, No. 4, August 1974.

Nuttli, O. W., G. A. Bollinger, and D. W. Griffiths, "On the Relation Between Modified Mercalli Intensity and Body-Wave Magnitude," in Bulletin of the Seismological Society of America,Vol 69, 1979.

Nuttli, O. W. and K. G. Brill, "An Approach to Seismic Zonation for Siting Nuclear Electric Power Generating Facilities in the Eastern U.S.," NUREG/CR-1577, Part 2, 1981.

Nuttli, O. W. and R. B. Herrmann, "Consequences of Earthquakes in the Mississippi Valley," American Society of Civil Engineers, reprint 81-519, 1981.

---, "State of the Art for Assessing Earthquake Hazards in the United States," U.S. Army Corps of Engineers WES Report 12, 1978.

---, "Ground Motion of Mississippi Valley Earthquakes," Journal of Technical Topics in Civil Engineering, Vol 110, May 1984.

Nuttli, O. W. and J. A. Zollweg, "The Relation between Felt Area and Magnitude for Central United States Earthquakes," Bulletin of the Seismological Society of America, Vol 64, No. 1 February 1974.

Petrick N., SNUPPS, letter to H. Denton, NRC, August 31, 1981.

---, letter to H. Denton, NRC, September 9, 1981.

Rochester Gas and Electric Corporation, "Final Safety Analysis Report of Robert Emmett Ginna Nuclear Power Plant Unit 1," Docket Number 50-244, 103, 1972.

Rockwell, T., Reactor Shielding Design Manual, D. Van Nostrand Co., New York, 1956.

Rubenstein, L. S., NRC, memorandum to R. L. Tedesco, "Review of Westinghouse Optimized Fuel Assembly Topical Report (TAR-5254," August 8, 1980.

---, memorandum to R. L. Tedesco, "Review of Topical Report WCAP-8278," March 19, 1981.

---, memorandum to R. L. Tedesco, "Review of Topical Report WCAP-9401," April 23, 1981.

---, memorandum to R. L. Tedesco, "Safety Evaluation Report on WCAP-9500," May 15, 1981.

---, memorandum to T. Novak, "Resolution of the Westinghouse Guide Thimble Tube Wear Issue," April 19, 1982.

---, memorandum to R. L. Tedesco, "Safety Evaluation of WCAP-8720 Addendum 1," dated June 30, 1982.

---, memorandum to T. Novak, "SERs for Westinghouse, Combustion Engineering, Babcock & Wilcox, and Exxon Fuel Rod Bowing Topical Reports," October 25, 1982.

---, memorandum to F. J. Miraglia, "SER on Supplemental Information to WCAP-9179, Revision 1," June 6, 1983.

---, memorandum to F. J. Miraglia, "Review of Westinghouse Report 'Droppped Rod Methodology for Negative Flux Rate Trip Plant'," March 2, 1983.

---, memorandum to G. C. Lainas, "ANO-2 Fuel Inspection Results," June 17, 1983.

Saha, P., M. Ishii, and N. Zube, "An Experimental Investigation of the Thermally Induced Flow Oscillations in Two-Phase Systems," in Journal of Heat Transfer, November 1976.

Skaritka, J., see WCAP-8691, Revision 1.

Salvatori, R., Westinghouse, letter to D. Knuth, NRC, "Core Coolant and Rod Surface Temperature," January 4, 1973.

Schenk, H., "Experience from Fuel Performance at KWO," International Atomic Energy Agency Report Number SM-178-15, October 1973.

Shiozawa, S., et al., "Evaluation on Oxidation of Zircaloy-4 Cladding During Rapid Transients in NSRR Experiments," JAERI Report JAERI-M-8187, March 1979.

Southern California Edison and San Diego Gas and Electric Co., "Licensee Event Report No. 82-132, Docket 50-361: Failure of turbine stop valve 2UV-2200E to close fully at San Onofre Nuclear Generating Station, Unit 2, November 19, 1982."

Stello, V., NRC, memorandum to R. DeYoung, NRC, "Evaluation of Westinghouse Report WCAP-8377, Revised Clad Flattening Model," January 14, 1975.

Stolz, J. F., NRC, letter to T. M. Anderson, Westinghouse, "Safety Evaluation of WCAP-8963," May 19, 1978.

Stover, C. et al., USGS miscellaneous field studies map MF-1388, seismicity map of the State of Texas, USGS, 1982.

Tedesco, R. L., NRC, letter to T. M. Anderson, Westinghouse, "Acceptance for Referencing of Licensing Topical Report WCAP-9500," May 22, 1981.

Tokar, M., NRC, "Report to ACRS Concerning NRR Efforts on Pellet/Cladding Interaction," NRC, November 14, 1979.

Trifunac, M. D. and A. G. Brady, "On the Correlation of Seismic Intensity Scales with the Peaks of Recorded Strong Ground Motion," in Bulletin of the Seismological Society of America, Vol 65, No. 1, 1975.

U.S. National Weather Service (NWS), "Probable Maximum Precipitation Estimates, United States East of the 105th Meridian," Hydrometeorological Report 51, June 1978.

U.S. Nuclear Regulatory Commission, Generic-Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983.

---, NUREG-75/075, "Safety Evaluation on the South Texas Project, Unit 1 and 2," August 1975.

---, Generic-Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events, July 8, 1983.

---, NUREG-0011, "Safety Evaluation Report related to the operation of Sequoyah Nuclear Plant Units 1 and 2," 1979.

---, NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Pressurized Water Reactors (PWR-Gale Code)," April 1976.

---, NUREG-0390, "Topical Report Review Status," Vol 7, No. 1, 1983.

---, NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," Revision 4.

---, NUREG-0460, "Anticipated Transients Without Scram," Vol 3, December 1978.

date-rev

---, NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."

---, NUREG-0612, Control of Heavy Loads at Nuclear Power Plants--Resolution of Generic Technical Activity A-36," July 1980.

---, NUREG-0630, D. A. Powers and R. O. Meyer, "Cladding Swelling and Rupture Models for LOCA Analysis," April 1980.

---, NUREG-0660, "NRC Action Plan Developed as a Result of The TMI-2 Accident," May 1980; Revision 1, August 1980.

---, NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

---, NUREG-0731 "Guidelines for Utility Management Structures and Technical Resources," September 1980.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980; Supplement 1 (Generic Letter 82-33), January 1983.

---, NUREG-0787, "Safety Evaluation Report Related to the Operation of Waterford Steam Electric Station, Unit 3," 1981.

---, NUREG-0797, "Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station Units 1 and 2," 1981.

---, NUREG-0800, "Standard Review Plan," July 1981.

---, NUREG-0801, "Detailed Criteria for Control Room Design Review," October 1981 (draft for comment).

---, NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures; Resolution of Comments on NUREG-0799," August 1982.

---, NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," April 1983.

---, NUREG-1021, "Operating Licensing Examiner Standards," Revision 1, October 1984.

---, NUREG/CR-2919, J. Sagendorf, et al., "χOQDOQ: Computer Program for the Meteorological Evaluation of Routine Effluent Releases at Nuclear Power Stations," Pacific Northwest Laboratory, September 1982.

Van Houten, R., NRC, memorandum to M. Tokar, "Demonstrated Survivability of Zircaloy Cladding After Brief Exposure to Temperatures of 1775°K and Above," February 23, 1981.

Vassallo, D. B., NRC, letter to C. Eicheldinger, Westinghouse, May 30, 1975.

Weeks, J. R., "Corrosion of Materials in Spent Fuel Storage Pools," Brookhaven National Laboratory, BNL-NUREG-23021, July 1977

Westinghouse Electric Corp., "Standard Information Package," Section 1, Revision 2, 1977.

ned ---, WCAP-7588, "An Evaluation of the Rod Ejection Accident in Westinghouse Reactors Using Spatial Kinetics Methods," Revision 2, DATE.

---, WCAP-7838; J. Shefcheck, "Application of the THINC Program to PWR Design," January 1972; also WCAP-7359-L (proprietary), August 1969.

---, WCAP-8183; J. A. Iorii and J. Skaritka, "Operational Experience with Westinghouse Cores," (revised annually).

---, WCAP-8236 (proprietary) and WCAP-8288 (nonproprietary), L. Gesinski and D. Chiang, "Safety Analysis of the 17x17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident," 1973.

---, WCAP-8278 (proprietary) and WCAP-8279 (nonproprietary), E. E. Demario, "Hydraulic Flow Test of the 17x17 Fuel Assembly," February 1974.

---, WCAP-8377 (proprietary) and WCAP-8381 (nonproprietary), R. A. George, Y. C. Lee, and G. H. Eng, "Revised Clad Flattening Model," 1974.

---, WCAP-8385, T. Morita, et al., "Power Distribution Control and Load Follow Procedure," September 1974.

ned ---, WCAP-8447

---, WCAP-8691 (proprietary) and WCAP-8962 (nonproprietary), J. R. Reavis, et al., "Fuel Rod Bowing," 1975; Revision 1 (proprietary and nonproprietary), J. Skaritka, et al., "Fuel Rod Bow Evaluation," 1979.

---, WCAP-8720 (proprietary) and WCAP-8785 (nonproprietary). J. V. Miller, ed., "Improved Analytical Models Used in Westinghouse Fuel Rod Design Computations," 1976.

---, WCAP-8963 (proprietary) and WCAP-8964 (nonproprietary). D. H. Risher, et al., "Safety Analysis for the Revised Fuel Rod Internal Pressure Design Basis," 1976 and 1977, respectively.

---, WCAP-9179, Revision 1 (proprietary) and WCAP-9224 (nonproprietary). M. D. Beaumont et al., "Properties of Fuel and Core Component Materials," 1978.

---, WCAP-9220-P-A (proprietary) and WCAP-9221-A (nonproprietary), Revision 1. C. Eicheldinger, "Westinghouse ECCS Evaluation Model," 1981.

---, WCAP-9401-P-A (proprietary) and WCAP-9402-A (nonproprietary) M. D. Beaumont, et al., "Verification Testing and Analysis of the 17x17 Optimized Fuel Assembly," 1981.

---, WCAP-9500, "Reference Core Report 17x17 Optimized Fuel Assembly," 1979.

---, WCAP-10297-P, "Dropped Rod Methodology for Negative Fuel Rate Trip Plants," January 1982.

Willamson, R. A., and R. R. Alvy, Impact Effect of Fragments Striking Structural Elements, Holmes and Narver, Revised Edition, 1973.

APPENDIX D

ACRONYMS AND INITIALISMS

ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
AEC	Atomic Energy Commission
AEOD	Office of Analysis and Evaluation of Operational Data
AFST	auxiliary feedwater storage tank
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AISC	American Institute of Steel Construction
ALARA	as low as reasonable achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
ASCE	American Society of Civil Engineers
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transients without scram
BEA	Bureau of Economic Analysis
BOL	beginning of life
BOP	balance of plant
B&O	Bulletins and Orders
BRS	boron recycle system
BTP	Branch Technical Position
BWR	boiling water reactor
CAM	continuous air monitors
CAOC	constant axial control mode

CCW	component cooling water
CCWS	component cooling water system
CFR	Code of Federal Regulations
CHRS	containment heat removal system
CIS	containment isolation system
COA	City of Austin
COE	Corps of Engineers (U.S. Army)
CP	construction permit
CPDS	condensate polishing demineralizer system
CPL	Central Power and Light Company
CPS	City Public Service Board of San Antonio
CSS	containment spray system
CVCS	chemical and volume control system
DBA	design-basis accident
DCRDR	detailed control room design review
DES	Draft Environmental Statement
DG	diesel generator
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOE	Department of Energy
EA	engineering assurance
EAB	exclusion area boundary
EAP	engineering assurance program
ECC	emergency core cooling
ECCS	emergency core cooling system
ECP	essential cooling pond
ECWS	essential cooling water system
EFPD	effective full-power day
EFPY	effective full-power year
EHR	elastic half space
EOC	emergency operations center
EOF	emergency operations facility
EOP	emergency operationg procedure
EPRI	Electrical Power Research Institute
EPZ	emergency planning zone

EQ	equipment qualification
ER	environmental report
ERFDADS	emergency response facility data acquisition and display system
ERG	emergency response guidelines
ESF	engineered safety feature
FEM	finite element model
FEMA	Federal Emergency Management Agency
FES	Final Environmental Statement
FHB	fuel handling building
FM	Farm-to-Market Road
FSAR	Final Safety Analysis Report
GDC	General Design Criterion(a)
GWPS	gaseous waste processing building
HAZ	heat-affected zone
HED	human engineering discrepancy
HEPA	high efficiency particulate air
HJTC	
HL&P	Houston Lighting and Power Company
HVAC	heating, ventilation, and air conditioning
HVDC	high-voltage direct current
HX	heat exchanger
ICC	inadequate core cooling
IDVP	independent design verification program
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
INEL	Idaho National Engineering Laboratories
INPO	Institute of Nuclear Power Operations
ISEG	Independent Safety Engineering Group
ISI	inservice inspection
JTG	Joint Test Group

LOCA	loss-of-coolant accident
LNG	liquified natural gas
LPG	liquefied petroleum gas
LPZ	low population zone
MCARS	main condenser air removal system
MCC	motor control center
MCES	main condenser evacuation system
MCR	main cooling reservoir
MM	Modified Mercalli
MMI	Modified Mercalli intensity
MPC	
MS	main steam
MSIS	main steam isolation signal
MSIV	main steam isolation valve
msl	mean sea level
MSLB	main steamline break
MWt	megawatts thermal
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NOAA	National Oceanic and Atmospheric Administration
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSRB	Nuclear Safety Review Board
NSSS	nuclear steam supply system
OBE	opearating basis earthquake
ODCM	offsite dose calculation manual
OFA	optimized fuel assembly
OL	operating license
OSC	operational support center
PAD	performance analysis and design
PASS	post-accident sampling system

PCI	pellet cladding interaction
PCT	peak cladding temperature
PGP	procedures generation package
P&ID	piping and instrumentation diagram
PNSC	Plant Nuclear Safety Committee
PORC	Plant Operations Review Committee
PORV	power-operated relief valve
PSAR	Preliminary Safety Analysis Report
PSI	preservice inspection
PVORT	Pump and Valve Operability Review Team
PWR	pressurized-water reactor
QA	quality assurance
QDPS	qualified display processing system
RCCA	rod cluster control assembly
RCFC	reactor containment fan cooler
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	Regulatory Guide
RHR(S)	residual heat removal (system)
RMWS	reactor makeup water system
RO	reactor operator
RPM	radiation protection manager
RPV	reactor pressure vessel
RTS	reactor trip system
RWP	radiation work permit
RWST	refueling water storage tank
SAFDL	specified acceptable fuel design limits
SAT	systematic approach to training
SER	Safety Evaluation Report
SFA	standard fuel assembly
SFTA	systems fuction and task analysis
SG	steam generator

SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SMT	secondary makeup tank
SPDS	safety parameter display system
SQRT	seismic qualification review team
SRO	senior reactor operator
SRP	Standard Review Plan
SSE	safe shutdown earthquake
SSI	soil-structure interaction
SWPS	solid waste processing system
STA	shift technical advisor
TG	turbine generator
TLD	thermoluminescent dosimeter
TMI-2	Three Mile Island Unit 2
TSC	technical support center
TVA	Tennessee Valley Authority
UL	Underwriters Laboratory
USGS	U.S. Geological Survey
USI	unresolved safety issue
UTM	universal transverse mercator
W	Westinghouse
WOG	Westinghouse Owners Group
ZPA	zero period acceleration

Appendix E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This Draft Safety Evaluation Report is the product of the NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report.

Name	Branch
G. Suh	Accident Evaluation
F. Witt	Chemical Engineering
J. Stang	Chemical Engineering
G. Schwenk	Core Performance
M. Dunenfeld	Core Performance
H. Richings	Core Performance
A. Masciantonio	Equipment Qualification
J. Lombardo	Equipment Qualification
N. Romney	Equipment Qualification
H. Lefevre	Geosciences
G. Giese-Koch	Geosciences
S. Saba	Human Factors Engineering
D. Morrisseau	Licensee Qualifications
M. Schoppman	Licensee Qualifications
I. Schoenfeld	Licensee Qualifications
B. Elliott	Materials Engineering
J. Tsao	Materials Engineering
D. Sellers	Materials Engineering
M. Hum	Materials Engineering
J. Halapatz	Materials Engineering
R. Li	Mechanical Engineering
R. Pichumani	Mechanical Engineering
J. Fairobent	Meteorology and Effluent Treatment

Name	Branch
R. Fell	Meteorology and Effluent Treatment
W. Belke	Quality Assurance
C. Hinson	Radiological Assessment
A. Brauner	Site Analysis
N. Chokshi	Structural and Geotechnical Engineering

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
SOUTH TEXAS PROJECT UNITS 1 AND 2
(PHASE I)
Docket No. [50/498]
[50/499]

Author
C. R. Shaber

Principal Technical Investigator
T. H. Stickley

Published
December 1984

EG&G Idaho, Inc.
Idaho Falls, Idaho 83415

Prepared for the
U.S. Nuclear Regulatory Commission
Under DOE Contract No. DE-AC07-76ID01570

FIN No. A6457

ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants, either operating or under construction, submit a response of compliancy with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This report contains EG&G's evaluation for South Texas Project Units 1 and 2.

EXECUTIVE SUMMARY

Houston Lighting and Power has presented information and made commitments which show that South Texas Project Units 1 and 2 are consistent with NUREG-0612 Article 5.1.1, "Guidelines for Control of Heavy Loads at Nuclear Power Plants."

CONTENTS

TABLES

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
SOUTH TEXAS PROJECT UNITS 1 AND 2
(PHASE I)

1. INTRODUCTION

1.1 Purpose of Review

This technical evaluation report documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at South Texas Project Units 1 and 2 (STP). This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" [1], Section 5.1.1.

1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff applicant criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978 [2], to all power reactor applicants, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective, achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.5, is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane) or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter [3] to Houston Lighting and Power (HL&P), the applicant for STP requesting that the applicant review provisions for handling and control of heavy loads at STP, evaluate these provisions with respect-to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. On December 19, 1983, HL&P provided the initial response [4] to this request. On October 19, 1984 an additional response [5] was provided.

2. EVALUATION AND RECOMMENDATIONS

2.1 Overview

The following sections summarize HL&P's review of heavy load handling at STP accompanied by EG&G's evaluation, conclusions, and recommendations to the applicant for bringing the facilities more completely into compliance with the intent of NUREG-0612. HL&P's review of the facilities does not differentiate between the two units so it is assumed that both units are of identical design. The applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 2300 pounds.

2.2 Heavy Load Overhead Handling Systems

This section reviews the applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the above mentioned list.

2.2.1 Scope

"Report the results of your review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal."

A. Summary of Applicant's Statements

The applicant's review of overhead handling systems identified 59 cranes and hoists as those which handle heavy

loads in the vicinity of irradiated fuel or safe shutdown equipment. These units handled 161 loads and introduced risk to 53 targets. HL&P made a detailed review to determine units that could be eliminated for valid reasons, such as separation, redundancy, etc.

The review indicated that 18 crane/hoist units and 99 loads could be eliminated. The remaining 41 crane/hoist units are shown in Table 2.1

Separately from the above tabulation an additional 110 crane/hoist units were evaluated and excluded because they do not satisfy the criteria of the general guidelines of NUREG 0612.

B. EG&G Evaluation

The information as presented, generally shows consistent, valid response to this guideline. The crane/hoist data presented in Table form with suitable footnotes provides information that is consistent with the identification requirements.

C. EG&G Conclusions and Recommendations

Based on the information provided, EG&G concludes that the adjusted list, Table 2.1 includes all applicable hoists and cranes as those handling systems which must comply with the requirements of the general guidelines of NUREG-0612.

TABLE 2.1 NONEXEMPT HEAVY LOAD HANDLING SYSTEMS

Identification	Load Rating (tons)
Reactor Containment Building	
(RCB) Polar Crane Unit 1 Main Hoist	417
RCB Polar Crane Unit 1 Auxiliary Hoist	15
RCB Polar Crane Unit 2 Main Hoist	500
RCB Polar Crane Unit 2 Auxiliary Hoist	15
Mechanical Electrical Auxiliary Building	
(MEAB) Monorail 9M101NCM 103A	7.5
MEAB Monorail 9M102NCM 203A	7.5
MEAB Monorail 9M101NCM 104A	7.5
MEAB Monorail 9M102NCM 204A	7.5
MEAB Monorail 9M101NCM 105A	7.5
MEAB Monorail 9M102NCM 205A	7.5
MEAB Monorail 9M101NCM 106A	3
MEAB Monorail 9M102NCM 206A	3
MEAB Monorail 9M101NCM 107A	3
MEAB Monorail 9M102NCM 207A	3
Fuel Handling Building	
7F101NCB 103A	
Overhead Crane Main Hoist	15
Overhead Crane Auxiliary Hoist	2
7F102NCB 203A	
Overhead Crane Main Hoist	15
Overhead Crane Auxiliary Hoist	2
FHB Monorail 9F101NCM 104A	5
FHB Monorail 9F102NCM 204A	5
FHB Monorail 9F101NCM 104B	5
FHB Monorail 9F102NCM 204B	5
FHB Monorail 9F101NCM 104C	5
FHB Monorail 9F102NCM 204C	5
FHB Monorail 9F101NCM 104D	5
FHB Monorail 9F102NCM 204D	5

TABLE 2.1. (continued)

Identification	Load Rating (tons)
FHB Monorail 9F101NCM 104E	5
FHB Monorail 9F102NCM 204E	5
FHB Monorail 9F101NCM 104F	5
FHB Monorail 9F102NCM 204F	5
FHB Monorail 9F101NCM 104G	5
FHB Monorail 9F102NCM 204G	5
FHB Monorail 9F101NCM 104H	5
FHB Monorail 9F102NCM 204H	5
FHB Monorail 9F101NCM 104I	5
FHB Monorail 9F102NCM 204I	5
Essential Cooling Water (ECW) Intake Gantry 7P200NCG 001C	20
Diesel Generator Building (DGB) Overhead Crane 8D101NCB 101A	3
DGB Overhead Crane 8D102NCB 201A	3
DGB Overhead Crane 8D101NCB 101B	3
DGB Overhead Crane 8D102NCB 201B	3
DGB Overhead Crane 8D101NCB 101C	3
DGB Overhead Crane 8D102NCB 201C	3

1. Nine hoists each for STP Unit 1 and 2 were identified initially among the hoists from which a load drop may result in damage to a system required for plant shutdown or decay heat removal. These 18 hoists were subsequently eliminated by categories such as: adequate separation, redundancy, interlocks, site specific, or they were not required for safe shutdown, decay heat removal or spent fuel cooling.

2. A separate tabulation listed 110 hoist units exempt from the considerations of NUREG 0612.

2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612, Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- Guideline 1--Safe Load Paths
- Guideline 2--Load-Handling Procedures
- Guideline 3—Crane Operator Training
- Guideline 4—Special Lifting Devices
- Guideline 5—Lifting Devices (not specially designed)
- Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- Guideline 7—Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

"Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee."

A. Summary of Applicant's Statements

The submittal contains an attachment, titled "Safe Load Paths" which gives a brief description of each safe load path for the loads identified for handling by the cranes/hoists listed in Table 2.1.

The safe load paths follow, where practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand impact. Safe load paths will be explicitly defined in procedures. These will specify the requirements to move heavy loads over the safe load paths. Deviations from established load paths will require written alternatives which have been approved by the plant Safety Review Committee. Should changes to safe load paths become necessary through design evaluation or operating constraints, revised safe load paths will be established and incorporated into plant procedures in accordance with the guidelines used to establish the initial safe load paths.

It is not practical to permanently mark the safe load paths in the load handling areas. Administrative controls will be used to ensure safe load paths are followed. The administrative controls will include items such as temporary markings (ropes, cones, etc.), a signalman to lead the load along the safe load path, etc.

Loads handled by the Single Failure Proof FHB overhead crane have a path description given, although the single failure proof design provides adequate assurance that a load drop will not occur. The location of safe load paths, spent fuel and safety related equipment of concern for the cranes are identified. Figures 1 through 15 present Safe Load Paths, Figures 16 through 38 show safety related equipment and spent fuel. These are shown in the report on "Control of Heavy Loads" in lieu of including them on plant equipment layout drawings.

B. EG&G Evaluation

The NUREG 0612 guideline on safe load paths requires commitment on five components. The information submitted on these show:

- o A commitment is made to have safe load paths follow structural floor members, beams etc.
- o A commitment is made to define safe load paths in procedures.
- o Safe load paths are illustrated in Figures 1 through 15 of the submittal. This information is illustrated in the figures supporting the "Control of Heavy Loads" report, because plant layout drawings are primarily for construction and design at STP.
- o Floor markings to identify safe load paths in the plant area where the load is to be handled, has been discussed. The alternative of marking safe load paths on the floor of the load handling area, as presented, meets the intent of the guideline, e.g., temporary markings such as ropes, cones, and a signalman to lead the load along the safe load

path is consistent with the NRC "Synopsis of Issues Associated with NUREG-0612.

- o A commitment is given to follow a system for control of deviations and their approval procedure.

C. EG&G Conclusions and Recommendations

The HL&P actions and commitments for the five components of Guideline 1 on safe load paths are consistent with requirements.

2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

"Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load; the steps and proper sequence to be followed in handling the load; defining the safe path; and other special precautions."

A. Summary of Applicant's Statements

Procedure will be prepared to cover the requirements to move heavy loads over safe load paths. Load paths will be explicitly defined in the procedures. Deviations from established load paths will require written alternatives which have been approved by the plant safety review committee.

B. EG&G Evaluation

The commitment to prepare procedures that detail safe load paths and their use, will upon completion bring STP into consistency with the guideline.

C. EG&G Conclusions and Recommendations

The applicants commitment on procedure preparation will be consistent with NUREG-0612.

2.3.3 Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]

"Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, 'Overhead and Gantry Cranes' [6]."

A. Summary of Applicant's Statements

HL&P takes no exceptions to ANSI B30.2-1976, Chapter 2-3, "Qualifications for Operators."

B. EG&G Evaluation

Since the ANSI sections indicate all of the requirements in the sense of "shall be" and HP&L takes no exceptions, the EG&G evaluation is that they are agreeing to comply with all of the provisions. Therefore, when the actions have been taken they will be consistent with the guideline.

C. EG&G Conclusions and Recommendations

Crane operator training, qualification, and conduct during load handling operations at STP is indicated to be consistent with NUREG-0612, Guideline 3.

2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

"Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, 'Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials' [7]. This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress-design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) or the load and of the intervening components of the special handling device."

A. Summary of Applicant's Statements

Four special lifting devices are identified. They are:

- Reactor Vessel Head Lift Rig Assembly, including

  Lift Rig
  Missile Shield
  Lift Rods
  Upper Internals Lift Rod Assembly

- Reactor Vessel Internals Lift Rig
- Load Cell and Load Cell Linkage
- Reactor Coolant Pump Lifting Device (three loads).

A brief description of the function and use of these special lifting devices is given and a summary of results.

The reactor vessel head lift rig assembly, internals lift rig, load cell and load cell linkage generally meet the intent of the ANSI N14.6-1978 requirements for design and manufacture. The assembly and detailed manufacturing drawings and purchase order documents contain requirements equivalent to design specifications. The multi-functional items of the head lift rig assembly (a Class 1 support) have a design specification. Some exceptions are taken to the ANSI N14.6 requirements for acceptance testing, maintenance, and verification of continuing compliance.

The reactor coolant pump special lift device will be built to ANSI N14.6 requirements.

A stress report has been prepared for these devices, excluding the RCP lifting device, and a summary of the applicable results is included in Attachment B. The ANSI N14.6 criteria for stress limits associated with certain stress design factors for tensile and shear stresses are satisfied.

These devices were manufactured under Westinghouse (and in some instances, ASME Code) surveillance with identified hold points, procedure review, and personnel qualification which meet the related ANSI requirements. A 125 percent load test was performed on the head lift rig assembly, the upper internals lift rods, the internals lift rig, load cell and load cell linkage. The load test was performed at a fabricators shop and was followed by the appropriate nondestructive testing.

Exceptions to ANSI N14.6 and the justification of present design acceptability are presented.

B. EG&G Evaluation

The information presented on STP is well organized and effectively documents compliance in the submittal. Included are, identification, general discussions, a table tabulating exceptions to ANSI N14.6 with justifications of acceptability of STP design, and tables summarizing the result of component stress calculations. Overall, EG&G believes the presentation shows acceptable consistency with the guideline 4 requirements.

Three segments of the presentation justify specific comment.

- In the exceptions there is disagreement between the 150% proof test loading and the 125% industry standard actually used. Also the call for an annual 150% load test within the containment vessel. In the initial item EG&G concurs with HL&P that no beneficial result can be gained by subjecting the special lifting device to an additional 150% overload proof testing. In the latter item EG&G also concurs that the 100% load test prior to refueling, with visual examinations, supplemented by the load cell used with the head and internals lift rig, provides acceptable continuing safety.

- The rod housing of the reactor vessel internals lift rig does not meet the ANSI N14.6 criteria of 3W when analyzed for tensile stresses. This stress (32,400 psi) exceeds the minimum allowable yield stress (30,000 psi). However, since the actual mechanical properties for this item list the yield strength as 41,500 psi and the ultimate strength criterion of 5W is met, this item is considered acceptable.

- The guide sleeve of the reactor vessel internals lift rig does not meet the ANSI N14.6 criteria of 3W when analyzed for tensile stresses. This stress (31,800 psi) exceeds the allowable yield stress (30,000 psi). However, since the actual properties for this item list the yield strength as 35,000 psi and the ultimate strength criteria of 5W is met, this item is considered acceptable.

The above two comments are quoted verbatim from the STP submittal. They are self explanatory and EG&G concurs with their acceptable evaluation.

C. EG&G Conclusions and Recommendations

Although there are some exceptions and minor deviations from total literal compliance with the guideline, valid justification for the differences has been provided. EG&G believes STP is consistent with the intent of Guideline 4.

2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

"Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, 'Slings' [8]. However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the 'static load' which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used."

A. Summary of Applicant's Statements

Slings may be used throughout the plant to lift equipment. All slings will be procured to the requirements of

ANSI B30.9-1971 as modified by NUREG 0612. The rating identified on the sling will be in terms of the "static load" which produces the maximum static and dynamic loads. Where this restricts sling use to certain cranes, the slings will be clearly marked as to the cranes with which they may be used.

B. EG&G Evaluation

The procurement commitment and plans for marking given in the applicants statement will, upon completion be consistent with Guideline 5 requirements.

C. EG&G Conclusions and Recommendations

The planned procurement action is consistent with Guideline 5.

2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

"The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency (e.g., the polar crane inside a PWR containment may only be used every 12 to 18 months during refueling operations, and is generally not accessible during power operation. ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use)."

A. Summary of Applicant's Statements

A procedure has been approved which covers the inspection and testing of all plant cranes. This procedure is based on the requirements of ANSI B30.2-1976, Chapter 2-2, ANSI N45.2.2-1972, OSHA 2206 (29CFR1910), and the Manufacturers Instruction Manuals.

All preventive and corrective maintenance will be performed using procedures which invoke ANSI B30.2-1976, Chapter 2-2.

B. EG&G Evaluation

Compliance with the procedure and follow-up maintenance as indicated in the applicants statement is consistent with Guideline 6 requirements.

C. EG&G Conclusions and Recommendations

Inspection, testing, and maintenance according to procedure specified for STP are consistent with NUREG-0612 Guideline 6.

2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

"The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' and of CMAA-70, 'Specifications for Electric Overhead Traveling Cranes' [9]. An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

A. Summary of Applicant's Statements

The design of the Polar Cranes, the FHB 15/2 overhead cranes and the ECW gantry cranes comply with the guidelines of CMAA-70 and Chapter 2.1 of ANSI B30.2-1976.

The criteria in CMAA-70 is not directly applicable to the DGB crane because it is a top running single girder overhead crane. The design of this system was compared to the guidelines of CMAA-74 "Specification for Top Running and Under Running Single Grider Electric Overhead Traveling Cranes." The crane meets the requirements of CMAA-74 and Chapter 2.1 of ANSI B30.2-1976.

Because the criteria in CMAA-70 and ANSI B30.2 are not directly applicable to monorails and their hoists, the design of these handling systems was compared to the guidelines of ANSI B30.11-1973 "Monorail Systems and Underhung Cranes" and ANSI B30.16-1973 "Overhead Hoists." All of the monorails identified in Table 1 were designed to meet these guidelines.

B. EG&G Evaluation

The information presented indicates there is consistency with the guideline. The use of CMAA-74, ANSI B30.11 and B30.16 where they are the appropriate guide is acceptable for this guideline.

C. EG&G Conclusions and Recommendations

The design and fabrication of the overhead handling systems required to meet NUREG-0612 at STP are consistent with Guideline 7.

2.4 Interim Protection Measures

The NRC staff has established (NUREG-0612, Article 5.3) for interim measures of operating plants. Since STP is in the construction phase the Interim Protective Measures do not apply and therefore are not addressed.

3. CONCLUDING SUMMARY

3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the applicant as being subject to the provisions of NUREG-0612 is apparently complete (see Section 2.2.1).

3.2 Guideline Recommendations

Compliance with the seven NRC guidelines for heavy load handling (Section 2.3) are satisfied at STP. This conclusion is represented in tabular form as Table 3.1. Specific evaluations on commitments and compliance with the intent of these guidelines are provided as follows:

Guideline	Recommendation
1. Section 2.3.1 Safe Load Paths	a. The five components for showing consistency with Safe Load Paths are appropriately addressed. The paths are illustrated in Figures 1-15 and safety related equipment and spent fuel risks in Figures 16-38. These are in the documents on "Control of Heavy Loads" and are explained in detail in procedures.

TABLE 1.1 SOUTH TEXAS PROJECT UNITS 1 AND 2 NUREG 0612 COMPLIANCE MATRIX

Identification	Load Rating (Tons)	Safe Loads Paths	Load Handling Procedures	Crane Operator Training	Special Lifting Devices	Lifting Devices Not Special Design	Crane Inspection Test and Maintenance	Crane Design
Reactor Containment Building								
(RCB) Polar Crane Unit 1 Main Hoist	417	C	C	C	C	C	C	C
RCB Polar Crane Unit 1 Auxiliary Hoist	15	C	C	C	C	C	C	C
RCB Polar Crane Unit 2 Main Hoist	500	C	C	C	C	C	C	C
RCB Polar Crane Unit 2 Auxiliary Hoist	15	C	C	C	C	C	C	C
Mechanical Electrical Auxiliary Building								
(MEAB) Monorail 9M101NCM 103A	7.5	C	C	C		C	C	C
MEAB Monorail 9M102NCM 203A	7.5	C	C	C		C	C	C
(MEAB) Monorail 9M101NCM 104A	7.5	C	C	C		C	C	C
MEAB Monorail 9M102NCM 204A	7.5	C	C	C		C	C	C
MEAB Monorail 9M101NCM 105A	7.5	C	C	C		C	C	C
MEAB Monorail 9M102NCM 205A	7.5	C	C	C		C	C	C
MEAB Monorail 9M101NCM 106A	3	C	C	C		C	C	C
MEAB Monorail 9M102NCM 206A	3	C	C	C		C	C	C
MEAB Monorail 9M101NCM 107A	3	C	C	C		C	C	C
MEAB Monorail 9M102NCM 207A	3	C	C	C		C	C	C
Fuel Handling Building								
(FHB) Overhead Crane Main Hoist	15	C	C	C		C	C	C
FHB Overhead Crane Auxiliary Hoist	2	C	C	C		C	C	C
FHB Monorail 9F101NCM 104A	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204A	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104B	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204B	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104C	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204C	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104D	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204D	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104E	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204E	5	C	C	C		C	C	C

TABLE 3.1 (continued)

Identification	Load Rating (Tons)	Safe Loads Paths	Load Handling Procedures	Crane Operator Training	Special Lifting Devices	Lifting Devices Not Special Design	Crane Inspection Test Maintenance	Crane Design
FHB Monorail 9F101NCM 104F	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204F	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104G	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204G	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104H	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204H	5	C	C	C		C	C	C
FHB Monorail 9F101NCM 104C	5	C	C	C		C	C	C
FHB Monorail 9F102NCM 204C	5	C	C	C		C	C	C
Essential Cooling Water (ECW) Intake Gantry 7P200 NCG 001C	20	C	C	C		C	C	C
Diesel Generator Building (DGB) Overhead Crane 8D101NCB 101A	3	C	C	C		C	C	C
DGB Overhead Crane 8D102NCB 201A	3	C	C	C		C	C	C
DGB Overhead Crane 8D101NCB 101B	3	C	C	C		C	C	C
DGB Overhead Crane 8D102NCB 201B	3	C	C	C		C	C	C
DGB Overhead Crane 8D101NCB 101C	3	C	C	C		C	C	C
DGB Overhead Crane 8D102NCB 201C	3	C	C	C		C	C	C

C = Applicant action complies with NUREG 0612 Guideline.

NC = Applicant action does not comply with NUREG 0612 Guideline.

R = Applicant has proposed revision/modifications designed to comply with NUREG 0612 Guidelines.

I = Insufficient information provided by the applicant.

Guideline		Recommendation	
2.	Section 2.3.2 Load Handling Procedures	a.	Procedures prepared according to the STP commitment will be consistent with NUREG 0612 Guideline 2.
3.	Section 2.3.3 Operator Training	a.	Completing operator training, qualifications and conduct to ANSI B30.2 1976 requirements will be consistent with NUREG 0612, Guideline 3.
4.	Section 2.3.4 Special Lifting Devices	a.	Some exceptions have been identified and a justification provided for them. Actions are consistent with the intent of NUREG 0612, Guideline 4.
5.	Section 2.3.5 Lifting Devices Not Specially Designed	a.	Planned procurement actions are consistent with the Guideline 5.
6.	Section 2.3.6 Cranes Inspection, Test and Maintenance	a.	Reported procedures and plans indicate consistency with NUREG 0612, Guideline 6.
7.	Section 2.3.7 Crane Design	a	Information provided indicates consistency with NUREG 0612, Guideline 7.

3.3 Interim Protection

EG&G's evaluation of information provided by the applicant indicates that the interim protection is not required for the STP's which are under construction.

3.4 Summary

The report of actions taken and pending for compliance with NUREG 0612 Article 5.1.1 guidelines has been presented and a careful evaluation made. The commitments and actions upon completion will show that STP is consistent with the guidelines for "Control of Heavy Loads".

4. REFERENCES

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, NRC.

2. V. Stello, Jr. (NRC), Letter to all applicants. Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 17 May 1978.

3. US, NRC, Letter to Houston Lighting and Power. Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 22 December 1980.

4. H. J. Golberg, Houston Lighting and Power Co. to Mr. D. G. Eisenhut, US, NRC Washington, D.C. Subject: South Texas Project Units 1 and 2, Schedule for Submittal of response to generic letter 81-07, Control of Heavy Loads, December 19, 1983.

5. J. H. Goldberg, Houston Lighting and Power Co. to Mr. D. G. Eisenhut, US, NRC Washington, D.C. Subject, South Texas Project Units 1 and 2, Submittal of Revised Response to Generic Letter 81-07 Control of Heavy Loads, October 19, 1984.

6. ANSI B30.2-1976, "Overhead and Gantry Cranes."

7. ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or more for Nuclear Materials."

8. ANSI B30.9-1971, "Slings."

9. CMAA-70, "Specifications for Electric Overhead Traveling Cranes."

APPENDIX G

SAFETY EVALUATION FOR THE ELIMINATION OF ARBITRARY INTERMEDIATE PIPE BREAKS

I. INTRODUCTION

In the "Background" to Branch Technical Position (BTP) MEB 3-1 as presented in Standard Review Plan (SRP) Section 3.6.2 (Ref.1), the staff position on pipe break postulation acknowledged that pipe rupture is a rare event which may only occur under unanticipated conditions such as those which might be caused by possible design, construction, or operation errors, unanticipated loads or unanticipated corrosive environments. The BTP MEB 3-1 pipe break criteria were intended to utilize a technically practical approach to ensure that an adequate level of protection had been provided to satisfy the requirements of 10 CFR Part 50 Appendix A, General Design Criterion (GDC) 4. Specific guidelines were developed in MEB 3-1 to define explicitly how the requirements of GDC 4 were to be implemented. The SRP guidelines in BTP MEB 3-1 were not intended to be absolute requirements but rather represent viable approaches considered to be acceptable by the staff.

The SRP provides a well-defined basis for performing safety reviews of light water reactors. The uniform implementation of design guidelines in MEB 3-1 assures that a consistent level of safety will be maintained during the licensing process. Alternative criteria and deviations from the SRP are acceptable provided an equivalent level of safety can be demonstrated. Acceptable reasons for deviations from SRP guidelines include changes in emphasis of specific guidelines as a result of new developments from operating experience or plant-unique design features not considered when the SRP guidelines were developed.

The SRP presents the most definitive basis available for specifying NRC's design criteria and design guidelines for an acceptable level of safety for light water

reactor facility reviews. The SRP guidelines resulted from many years of experience gained by the staff in establishing and using regulatory requirements in the safety evaluation of nuclear facilities. The SRP is part of a continuing regulatory standards development activity that not only documents current methods of review, but also provides a basis for an orderly modification of the review process when the need arises to clarify the content, correct any errors, or modify the guidelines as a result of technical advancements or an accumulation of operating experience. Proposals to modify the guidelines in the SRP are considered for their impact on matters of major safety significance.

The staff has recently received a request from the applicant for South Texas Project (STP) Units 1 and 2 to consider an alternate approach to the existing guidelines in SRP 3.6.2, MEB 3-1 regarding the postulation of intermediate pipe breaks (Refs. 2 and 3). For high energy piping systems identified in Reference 2, the applicant proposes to eliminate from design considerations those breaks generally referred to as "arbitrary intermediate breaks" (AIBs) which are defined as those break locations which, based on piping stress analysis results, are below the stress and fatigue limits specified in BTP MEB 3-1, but are selected to provide a minimum of two postulated breaks between the terminal ends of a piping system. The applicant has documented the cost savings and reduced radiation exposure benefits resulting from the elimination of the structures associated with the protection against the effects of pipe rupture. The applicant has further stated that all dynamic effects associated with previously postulated arbitrary intermediate pipe breaks will be excluded from the plant design basis and that pipe whip restraints and jet shields associated with previously postulated arbitrary intermediate breaks will be eliminated. However, the applicant has stated that the elimination of AIBs will not affect the environmental qualification of equipment. The break postulation for environmental effects is performed independently of break postulation for pipe whip and jet impingement.

In the early 1970's when the pipe break criteria in MEB 3-1 were first drafted, the advantages of maintaining low stress and usage factor limits were clearly recognized, but it was also believed that equipment in close proximity to the piping throughout its run might not be adequately designed for the environmental consequences of a postulated pipe break if the break postulation proceeded on a

purely mechanistic basis using only high stress and terminal end breaks. As the pipe break criteria were implemented by the industry, the impact of the pipe break criteria became apparent on plant reliability and costs as well as on plant safety. Although the overall criteria in MEB 3-1 have resulted in a viable method which assures that adequate protection has been provided to satisfy the requirements of GDC 4, it has become apparent that the particular criterion requiring the postulation of arbitrary intermediate pipe breaks can be overly restrictive and may result in an excessive number of pipe rupture protection devices which do not provide a compensating level of safety.

At the time the MEB 3-1 criteria were first drafted, high energy leakage cracks were not being postulated. In Revision 1 to the SRP (July 1981), the concept of using high energy leakage cracks to mechanistically achieve the environment desired for equipment qualification was introduced to cover areas which are below the high stress/fatigue limit break criteria and which would otherwise not be enveloped by a postulated break in a high energy line. In the proposed elimination of arbitrary intermediate breaks, the staff believes that the essential design requirement of equipment qualification is not only being retained but is being improved since all safety-related equipment is to be qualified environmentally, and furthermore certain elements of construction which may lead to reduced reliability are being eliminated.

In addition, some requirements which have developed over the years as part of the licensing process have resulted in additional safety margins which overlap the safety margin provided in the pipe break criteria. For example, the criteria in MEB 3-1 include margins to account for the possibility of flaws which might remain undetected in construction and to account for unanticipated piping steady-state vibratory loadings not readily determined in the design process. However, inservice inspection requirements for the life of the plant to detect flaws before they become critical, and staff positions on the vibration monitoring of safety-related and high energy piping systems during preoperational testing, further reduce the potential for pipe failures occurring from these causes.

Because of the recent interest expressed by the industry to eliminate the arbitrary intermediate break criteria and, particularly, in response to the detailed

submittals provided by several utilities including HL&P, the staff has reviewed the MEB 3-1 pipe break criteria to determine where such changes may be made.

II BASES FOR THE ELIMINATION OF ARBITRARY INTERMEDIATE PIPE BREAKS

The applicant's submittals (Refs. 2 and 3) suggest a general consensus in the nuclear industry that current knowledge and experience support the conclusion that designing for the arbitrary intermediate pipe breaks is not justified. The bases for this conclusion are discussed in the following paragraphs.

1) Operating Experience Does Not Support Need for Criteria

The combined operating history of commercial nuclear plants (extensive operating experience in over 80 operating U.S. plants and a number of similar plants overseas) has not shown the need to provide protection from the dynamic effects of arbitrary intermediate breaks.

2) Piping Stresses Well Below ASME Code Allowables

Currently, AIBs are postulated to provide a minimum of two pipe breaks at the two highest stress locations between piping terminal ends. Consequently, arbitrary intermediate breaks are postulated at locations in the piping system where pipe stresses and/or cumulative usage factors are well below ASME Code allowables. Such postulation necessitates the installation and maintenance of complicated mitigating devices to afford protection from dynamic effects such as pipe whip and/or jet impingement. When these selected break locations have stress levels only slightly greater than the rest of the system, installation of mitigating devices not only lends little to enhance overall plant safety, but also provides the potential for inadvertent restraints of piping during thermal growth and seismic motion.

3) Arbitrary Intermediate Breaks Complicate the Design Process

The design of piping systems is an iterative process and, therefore, the location of the highest stress points usually change several times during design. Although SRP Section 3.6.2 (Ref. 1) provides criteria intended to reduce the

need to relocate the intermediate break locations when high stress points shift due to piping reanalysis, in practice, these criteria provide little relief from moving arbitrary break locations since the revised break locations must still be evaluated as to their effects on essential equipment and structures.

4) Substantial Cost Savings

The cost benefits to be realized from the elimination of the arbitrary intermediate break locations center primarily on the elimination of the associated pipe whip restraints and jet shields. While a substantial reduction ($5 million) in capital and engineering costs for these restraints and structures can be realized in the design and construction stages of the plant, there are also significant operational benefits to be realized over the 40 year life of the plant, as reduced manhours for inservice inspection and maintenance will result.

5) Improved Inservice Inspection

Pipe whip restraints are normally located adjacent to or surrounding the welds at changes in pipe direction. Access during plant operation for inservice inspection activities can be improved due to the elimination of congestion created by these pipe rupture protection devices and the supporting structural framing associated with arbitrary pipe breaks.

6) Reduction in Radiation Exposure

In the event of a radioactive release or spill inside the plant, decontamination operations could be more effective if the pipe whip restraints and jet shields associated with AIBs and the large structural frameworks supporting the restraints were eliminated. Recovery from unusual plant conditions would also be improved by reducing the congestion in the plant. A significant reduction in man-rem exposure can be realized through fewer man hours spent in radiation areas.

The applicant, as part of its justification for the elimination of arbitrary intermediate breaks, has estimated that the reduction in operational radiation

exposure due to elimination of arbitrary intermediate pipe breaks and the resulting decrease in pipe whip restraints and jet deflectors over the 40 year life of the plant will be in excess of 100 person-rem for both units. (Ref. 2).

7) Improved Operational Efficiency

The elimination of pipe whip restraints associated with arbitrary breaks will preclude the requirement for cutback insulation or special insulating assemblies near the close fitting restraints. This will reduce the heat loss to the surrounding environment, especially inside containment.

III EVALUATION OF THE BASES FOR THE ELIMINATION OF ARBITRARY BREAKS

The technical bases for the elimination of the arbitrary intermediate break criteria as discussed in the preceding section of this report provided many arguments supporting the applicant's conclusion that the current SRP guidelines on this subject should be changed. However, it is not apparent that a unilateral position by the utility concluding an unconditional deletion of the arbitrary intermediate break criteria can be justified without a clear understanding of the safety implications that may result for the various classes of high energy piping systems involved. In this section, we will discuss the bases behind the current arbitrary intermediate break criteria from an ASME Code design standpoint and put into perspective the uncertainty factors on which the need to postulate arbitrary intermediate breaks should be evaluated. We further evaluate the acceptability of the applicant's proposed deviation from SRP Section 3.6.2

ASME Code Class 1 Piping Systems

In accordance with BTP MEB 3-1 (paragraph B.1.c.(1)) breaks in ASME Code Class 1 piping should be postulated at the following locations in each piping and branch run:

(a) at terminal ends;

(b) at intermediate locations where the maximum stress range as calculated by Eq. (10) and either Eq. (12) or (13) of ASME Code NB-3650 exceeds 2.4 Sm;

(c) at intermediate locations where the cumulative usage factor exceeds 0.1.

(d) If two intermediate locations cannot be determined by (b) and (c) above, two highest stress locations based on Eq. (10) should be selected.

The arbitrary intermediate break criteria are stated in (d) above. It should be noted that the request for alternative criteria does not propose to deviate from the criteria in (a), (b), and (c) above. Pipe breaks will continue to be postulated at terminal ends irrespective of the piping stresses. Pipe breaks are to be postulated at intermediate locations where the maximum stress range as calculated by Eq. (10) and either (12) or (13) exceeds 2.4 Sm. The stress evaluation in Eq. (10) represents a check of the primary plus secondary stress intensity range due to ranges of pressure, moments, thermal gradients and combinations thereof. Equation (12) is intended to prevent formation of plastic hinges in the piping system caused only by moments due to thermal expansion and thermal anchor movements. Equation (13) represents a limitation for primary plus secondary membrane plus bending stress intensity excluding thermal bending and thermal expansion stresses; this limitation is intended to assure that the K_e - factor (strain concentration factor) is conservative. The K_e - factor was developed to compensate for absence of elastic shakedown when primary plus secondary stresses exceed 3 Sm.

With respect to piping stresses, the pipe break criteria were not intended to imply that breaks will occur when the piping stress exceeded 2.4 Sm (80% of the primary plus secondary stress limit). It is the staff's belief, however, that if a pipe break were to occur (in one of those rare occasions), it is more likely to occur at a piping location where there is the least margin to the ultimate tensile strength.

Similarly, from a fatigue strength standpoint, the staff believes that a pipe break is more likely to occur where the piping is expected to experience large cyclic loadings. Although the staff concurs with the industry belief that a cumulative usage factor of 0.1 is a relatively low limit, the uncertainties involved in the design considerations with respect to the actual cyclic loadings experienced by the piping tend to be greater than the uncertainties involved in the design considerations used for the evaluation of primary and secondary stresses in piping systems. The staff finds that the conservative fatigue considerations in the current SRP guidelines provide an appropriate margin of safety against uncertainties for those locations where fatigue failures are likely to occur (e.g. at local welded attachments).

In its presentation to the ACRS on June 9, 1983 and in an October 5, 1983 meeting between a group of PWR near-term operating license utilities and the NRC staff, the staff indicated that the elimination of arbitrary intermediate breaks was not to apply to piping systems in which stress corrosion cracking, large unanticipated dynamic loads such as steam- or water-hammer, or thermal fatigue in fluid mixing situations could be expected to occur. In addition, the elimination of arbitrary intermediate breaks was to have no effect on the requirement to environmentally qualify safety-related equipment and in fact this requirement was to be clarified to assure positive qualification requirements.

For Class 1 piping, a considerable amount of quality assurance in design, analyses, fabrication, installation, examination, testing, and documentation is provided which ensures that the safety concerns associated with the uncertainties discussed above are significantly reduced. Based on the staff evaluation of the design considerations given to Class 1 piping, the stress and fatigue limits provided in the MEB 3-1 break criteria, and the relatively small degree of uncertainty in unanticipated loadings, the staff finds that dispensing with arbitrary intermediate pipe breaks is justified for ASME Code Class 1 piping in which large unanticipated dynamic loads, stress corrosion cracking, and thermal fatigue such as in mixing situations are not expected to occur. This finding is based in part on two actions: 1) the piping designers have complied with the current SRP guidelines (Ref. 1) that provide an appropriate margin of safety against uncertainties for those locations where fatigue failures are likely to occur (e.g., at local welded attachments) and 2) all safety-related

equipment in the vicinity of Class 1 piping systems have been environmentally qualified for the non-dynamic effects of a non-mechanistic pipe break with the greatest consequences on the equipment. In addition, systems may actually perform more reliably for the life of the plant if the SRP criterion to postulate arbitrary intermediate breaks for ASME Code Class 1 piping is eliminated. The staff has concluded that the above described requirements are present for those ASME Code Class 1 piping systems identified in the applicant's submittal of August 20, 1984 (Reference 2). Since the applicant has committed to implement the above design considerations (Refs. 2 and 3), the requested deviation from the SRP for Class 1 piping is acceptable.

ASME Code Class 2 and 3 Piping Systems

In accordance with MEB 3-1 [paragraph B.1.c.(2)] breaks in ASME Code Class 2 and 3 piping should be postulated at the following locations:

(a) at terminal ends

(b) at intermediate locations selected by one of the following criteria:

(i) at each pipe fitting, welded attachment, and valve
(ii) at each location where the stresses exceed 0.8 ($1.2\ S_h + S_A$) but at not less than two separated locations chosen on the basis of highest stress.

In its proposal the applicant has not proposed changing criterion (a) above. Postulation of pipe breaks at terminal ends will not be eliminated in the proposed SRP deviation for Class 2 and 3 piping systems. Breaks are required to be postulated at terminal ends irrespective of piping stresses.

The "arbitrary intermediate break criteria" is stated in (b)(ii) above where breaks are to be postulated at intermediate locations where the stresses exceed 0.8 ($1.2\ S_h + S_A$) but "at not less than two separated locations chosen on the basis of highest stress." The stress limit provided in the above pipe break criterion represents the stress associated with 80% of the combined primary and secondary stress limit. Thus, a break is required to be postulated where the

maximum stress range as calculated by the sum of Equation (9) and (10) of NC/ND-3652 of the ASME Code, Section III, exceeds 80% of the combined primary and secondary stress limit, when we consider those loads and conditions for which level A and level B stress levels have been specified in the system's design specification (i.e. sustained loads, occasional loads, and thermal expansion) including an operating basis earthquake (OBE) event. However, the Class 2 and 3 pipe break criteria do not have a provision for the postulation of pipe breaks based on a fatigue limit since an explicit fatigue evaluation is not required in the ASME Code for these classes of construction because of favorable service experience and lower levels of operating cyclic stresses.

For those Class 2 and 3 piping systems which experience a large number of stress cycles (e.g., main steam and feedwater systems), the ASME Code has provisions which are intended to address these types of loads. The rules governing considerations for welded attachments in ASME Class 2 and 3 piping which do preclude fatigue failure are partially given in paragraph NC/ND-3645 of the ASME Code. The Code states:

> "External and internal attachments to piping shall be designed so as not to cause flattening of the pipe, excessive localized bending stresses, or harmful thermal gradients in the pipe wall. It is important that such attachments be designed to minimize stress concentrations in applications where the number of stress cycles, due either to pressure or thermal effect, is relatively large for the expected life of the equipment."

Code rules governing the fatigue effects associated with general bending stresses caused by thermal expansion are addressed in NC/ND-3611.2(e) and are generally incorporated into the piping stress analyses in the form of an allowable stress reduction factor.

Thus, it can be concluded that when the piping designers have appropriately considered the fatigue effects for Class 2 and 3 piping systems in accordance with NC/ND-3645, the likelihood of a fatigue failure in Class 2 and 3 piping caused by unanticipated cyclic loadings can be significantly reduced. The applicant has stated in Attachment D to its August 20, 1984 submittal that for Class 2 and 3 piping systems fatigue is considered in the ASME Code allowable stress range check for thermal expansion stresses, and that these stresses are included in the total stress value used to determine postulated break locations.

If the number of thermal cycles is expected to be greater than 7000, then the allowable stresses are further reduced by an amount dependent on the number of cycles (Ref. 2). The staff concludes that this commitment is acceptable.

Because of the susceptibility of feedwater (FW) systems to water hammer, the applicant has incorporated several water hammer prevention/minimization features into the design of the STP feedwater system (Ref. 3). Westinghouse has conducted extensive investigations into potential sources of water hammer in preheat steam generators as used at STP. Initiation of main feed water is controlled by procedure and system interlocks to minimize the potential for water hammer in the main FW system (Ref. 2). The FW piping employs feedwater injection in the feed preheater section of each of the 4 Westinghouse (W) Model E2 steam generators (SGs) instead of a feedring type design. The W criteria for piping layout to minimize or eliminate water hammer are complied with by the provision of loop seals and the shortest possible horizontal length of piping immediately upstream of the SGs.

Westinghouse studies have shown that pressure transients (water hammer) due to steam void collapse can occur in the SGs if FW below 250° is introduced to the SG main feedwater nozzle concurrent with low SG water level or low SG pressure. The applicant has incorporated the Westinghouse "Main Feedwater Temperature Pegging System" (deaerator pegging) in the design and operation of the FW system to ensure that the FW temperature is always above 250°F. The details of this system are described in Reference 3. A review of the additional information regarding the anti-water hammer features described in the Attachment 1 to Reference 3 indicates that the potential for SG feedwater preheater and upstream piping water hammer is minimized.

The applicant has stated that, although Westinghouse plants with preheat SGs have never experienced a bubble collapse type water hammer event in the main FW system, the SGs and the FW piping are designed for these water hammer events (Ref. 2).

The Attachment 3 to Reference 3 gives the details of the auxiliary feedwater (AFW) system design features that reduce the potential for condensation-induced water hammer. A separate AFW line and nozzle has been provided to each SG to

supply feedwater when the main feedwater is unavailable or is below a specified minimum temperature. The arrangement of the AFW discharge pipe inside the SG is such that AFW piping will not drain following a drop in SG water level and therefore the nozzle and the upstream piping will not fill with steam. Also the horizontal piping immediately upstream of the SG nozzle is short with a down turned elbow located near the SG. Backleakage is prevented or minimized in the AFW system piping by means of properly located check valves. Based on a review of these provisions and comparing them with the causes and evaluation of water hammer occurrences discussed in NUREG-0927 Revision 1, as stated in Reference 3, the staff concurs with the applicant's conclusion that the design features and operating procedures described above will minimize the potential for water hammer occurrence in the FW piping systems.

Based on the staff evaluation of the design considerations given to Class 2 and 3 piping, the stress limits provided in the SRP break criterion, and the relatively small degree of uncertainty in unanticipated loadings the staff finds that dispensing with arbitrary intermediate pipe breaks is justified for Class 2 and 3 piping in which stress corrosion cracking, large unanticipated dynamic loads, or thermal fatigue in fluid mixing situations are not expected to occur. This finding is based in part on two actions: 1) the piping designers have appropriately considered the effects of local welded attachments per NC/ND-3645, and 2) all safety-related equipment in the vicinity of Class 2 and 3 piping systems have been environmentally qualified for the non-dynamic effects of a non-mechanistic pipe break with the greatest consequences on the equipment. Based on References 2 and 3, the staff has concluded that the applicant has committed to implement the above design provisions. Therefore, the requested deviation from the SRP (Ref. 1) for Class 2 and 3 piping is acceptable.

Piping Systems Not Included in Proposal

For those piping systems, or portions thereof, which are not included in the applicant's submittals (Reference 2), the staff requires that the existing guidelines in BTP MEB 3-1 of the SRP (NUREG-0800) Revision 1 be met. However, should other piping lines which are not specifically identified in the applicant's submittal (Reference 2) subsequently qualify for the conditions described

above, the implementation of the proposed elimination of the arbitrary intermediate break criteria may be used provided those additional piping lines are appropriately identified to the staff.

Conclusion

The applicant has proposed a deviation from the current guidelines of the SRP by requesting relief from postulating arbitrary intermediate pipe breaks in high energy piping systems which are not susceptible to intergranular stress corrosion cracking, steam or water hammer effects and thermal fatigue in fluid mixing. The SRP guideline which requires that two intermediate breaks be postulated even when the piping stress is low resulted from the need to assure that equipment qualified for the environmental consequences of a postulated pipe break was provided over a greater portion of the high energy piping run. This proposal is based, in part, on the condition that all equipment in the spaces traversed by the fluid system lines, for which arbitrary intermediate breaks are being eliminated, is qualified for the environmental (non-dynamic) conditions that would result from a non-mechanistic break with the greatest consequences on surrounding equipment. In addition, the applicant has committed to perform preoperational testing of all the systems identified in Reference 2 and also monitor those systems for vibration during preoperational and startup testing, in its responses to MEB questions 210.41 and 210.42. The staff has evaluated the technical bases for the proposed deviation with respect to satisfying the requirements of GDC 4. Furthermore, the staff has considered the potential problems identified in NUREG/CR-2136 (Ref. 4) which could impact overall plant reliability when excessive pipe whip restraints are installed. Based on its review, the staff finds that when those piping system conditions as stated above are met, there is a sufficient basis for concluding that an adequate level of safety exists to accept the proposed deviation.

Thus, based on the piping systems having satisfied the above conditions, the staff concludes that the pipe rupture postulation and the associated effects are adequately considered in the design of the South Texas Project Units 1 and 2 and, therefore, the deviation from the Standard Review Plan is acceptable.

IV REFERENCES

1) "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", NUREG-0800 (Revision 1) dated July 1981.

2) Letter from J. H. Goldberg, HL&P, to H. Denton, NRC, subject, "South Texas Project Units 1 and 2, Elimination of Arbitrary Intermediate Pipe Breaks," dated August 20, 1984.

3) Letter from M. R. Wisenburg, HL&P, to G. W. Knighton, NRC, subject, "South Texas Project Units 1 and 2, NRC Request for Additional Information," dated March 8, 1985.

4) "Effect of Postulated Event Devices on Normal Operation of Piping Systems in Nuclear Power Plants", NUREG/CR-2136 dated May 1981.