



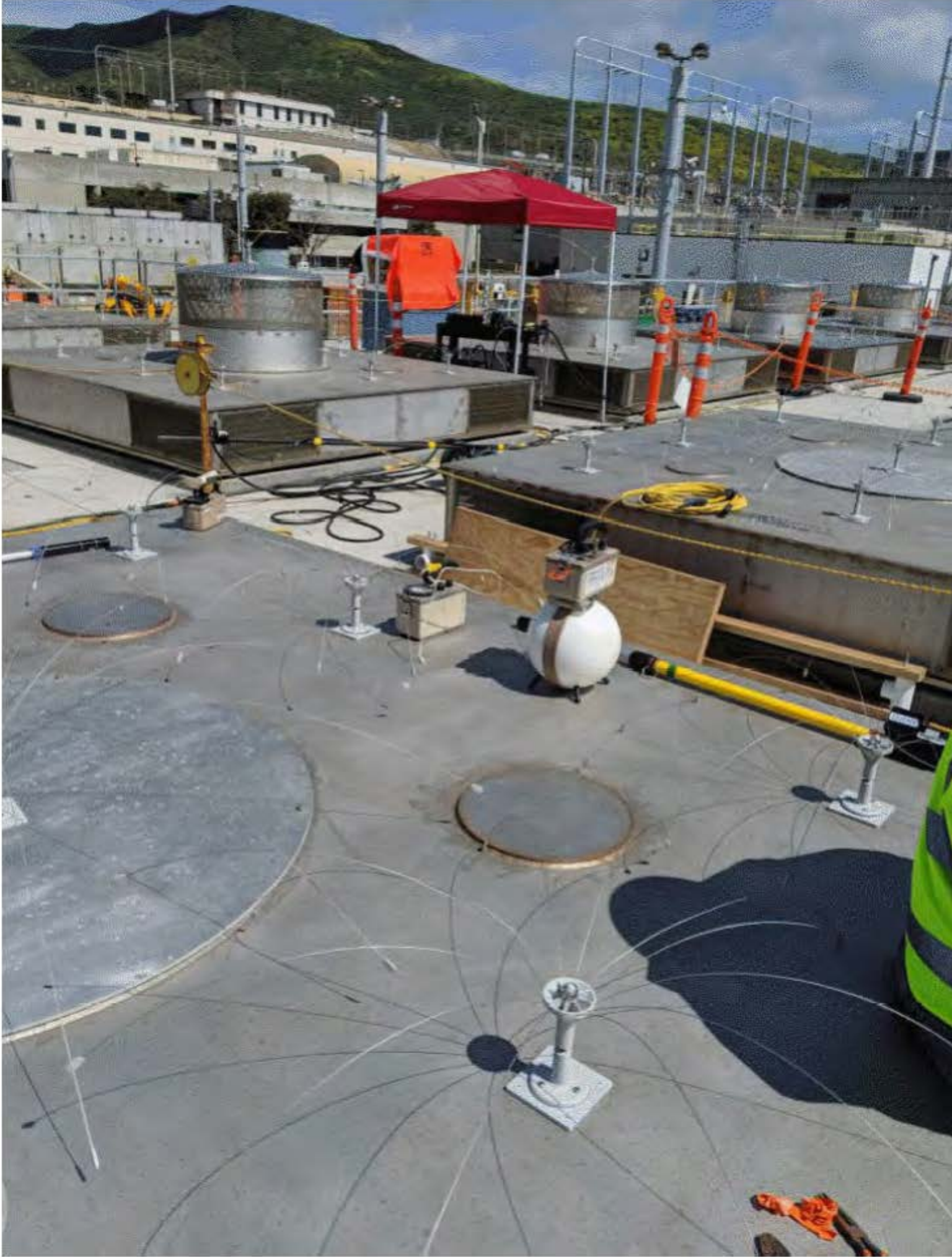
62

DS-0119
270















-90.0

Suf, Amb): 130, 116
RTD: 84
P(L,R): 178.2, 192.7











-90.7

T(Suf

+

Y3. N88
10/0712/2

Publicly Available at:
<https://digital.library.unt.edu/ark:/67531/metadc784373/>

NUREG-0712

According to NRC records in ADAMS, the NUREG is also available in the PDR (accession # 8105040580; microform address 6513:248-65313_317) and from the NTIS.

Safety Evaluation Report

related to the operation of
San Onofre Nuclear Generating Station,
Units 2 and 3

Docket Nos. 50-361 and 50-362

Southern California Edison Company, et al.

**U.S. Nuclear Regulatory
Commission**

Office of Nuclear Reactor Regulation

February 1981



metadc784373

Available from

GPO Sales Program
Division of Technical Information and Document Control
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Printed copy price: \$12.00

and

National Technical Information Service
Springfield, Virginia 22161

Safety Evaluation Report

related to the operation of
**San Onofre Nuclear Generating Station,
Units 2 and 3**

Docket Nos. 50-361 and 50-362

Southern California Edison Company, et al.

**U.S. Nuclear Regulatory
Commission**

Office of Nuclear Reactor Regulation

February 1981



TABLE OF CONTENTS

	<u>PAGE</u>
1.0 INTRODUCTION AND GENERAL DISCUSSION.	1-1
1.1 Introduction.	1-1
1.2 General Plant Description	1-3
1.3 Comparison with Similar Facility Designs.	1-4
1.4 Identification of Agents and Contractors.	1-5
1.5 Summary of Principal Review Matters	1-5
1.6 Modifications to the Facility During the Course of Our Review . .	1-6
1.7 Summary of Outstanding Issues	1-6
1.8 Confirmatory Issues	1-12
1.9 License Conditions	1-12
1.10 Generic Issues	1-12
2.0 SITE CHARACTERISTICS	2-1
2.1 Geography and Demography	2-1
2.1.1 Site Description	2-1
2.1.2 Exclusion Area Control	2-1
2.1.3 Population and Population Distribution	2-5
2.1.4 Conclusions	2-8
2.2 Nearby Industrial, Transportation and Military Facilities	2-10
2.2.1 Locations, Routes, and Descriptions.	2-10
2.2.2 Evaluation of Potential Accidents.	2-13
2.3 Meteorology	2-15
2.3.1 Regional Climatology	2-15
2.3.2 Local Meteorology	2-16
2.3.3 Onsite Meteorological Measurements Program	2-18
2.3.4 Short-Term (Accident) Diffusion Conditions	2-23
2.3.5 Long-Term (Routine) Diffusion Estimates.	2-26
2.3.6 Conclusions.	2-26
2.4 Hydrology	2-26
2.4.1 Hydrologic Description	2-26
2.4.2 Flood Design Considerations.	2-28
2.4.3 Probable Maximum Surge, Seiche and Tsunami Flooding. . . .	2-29
2.4.4 Ice Effects.	2-31
2.4.5 Cooling Water Canals and Reservoirs.	2-31
2.4.6 Channel Diversion.	2-31
2.4.7 Flood Protection Requirements.	2-31
2.4.8 Low Water Considerations	2-32
2.4.9 Groundwater.	2-32
2.4.10 Ultimate Heat Sink Dependability	2-32
2.5 Geology, Seismology, and Geotechnical Engineering	2-33
2.5.1 Basic Geologic and Seismic Information	2-33
2.5.1.1 Introduction.	2-33
2.5.1.2 Conclusions Reached Prior to Construction	
Permit Issuance	2-34
2.5.1.3 Geologic Features Found During Excavation for	
Plant Foundations	2-35
2.5.1.4 Investigation of Trenching Across Cristianitos	
Fault	2-35
2.5.1.5 Stratigraphy and Mapping of the Site Area	2-37
2.5.1.6 Investigations of the Sea Cliff South of	
San Onofre 2 and 3.	2-37
2.5.1.7 Orange County Earthquakes of January, 1975.	2-38
2.5.1.8 Tectonics of Capistrano Embayment	2-39
2.5.1.9 Slip Rate Versus Magnitude and Its	
Application to the OZD.	2-40
2.5.1.10 Evaluation of Slip Rate and Magnitude Data	
Used in the WCC Report.	2-40
2.5.1.11 Determination of the OZD Rupture Length	2-42
2.5.1.12 Investigation of Offshore Extension of	
Cristianitos Fault.	2-45

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
2.5.2 Seismology	2-50
2.5.2.1 Background and Summary.	2-50
2.5.2.2 Seismicity.	2-51
2.5.2.3 Magnitude of the Maximum Earthquake on the OZD.	2-52
2.5.2.4 Vibratory Ground Motion	2-58
2.5.2.5 Summary	2-68
2.5.2.6 Operating Basis Earthquake.	2-68
2.5.3 Stability of Subsurface Materials and Foundations	2-69
2.5.3.1 Introduction.	2-69
2.5.3.2 Subsurface Explorations	2-69
2.5.3.3 Site Preparation.	2-70
2.5.3.4 Foundation Excavation	2-70
2.5.3.5 Groundwater	2-70
2.5.3.6 Bearing Capacity and Settlement	2-70
2.5.3.7 Liquefaction Potential.	2-71
2.5.3.8 Slope Stability	2-71
2.5.4 Dewatering Well Cavities	2-71
3.0 DESIGN CRITERIA-STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS.	3-1
3.1 Conformance with General Design Criteria.	3-1
3.1.1 Conformance with Industry Codes and Standards.	3-1
3.2 Classification of Structures, Components, and Systems	3-1
3.2.1 Seismic Classification	3-1
3.2.2 System Quality Group Classificaton.	3-2
3.3 Wind and Tornado Loadings	3-3
3.3.1 Wind Design Criteria	3-3
3.3.2 Tornado Design Criteria.	3-4
3.4 Water Level (Flood) Design.	3-5
3.5 Missile Protection.	3-6
3.5.1 Missile Selection and Description.	3-6
3.5.1.1 Internally Generated Missiles (Outside Containment).	3-6
3.5.1.2 Internally Generated Missiles (Inside Containment).	3-7
3.5.1.3 Turbine Missiles.	3-8
3.5.1.4 Tornado Missiles.	3-8
3.5.2 Barrier Design Procedures	3-9
3.6 Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping.	3-10
3.6.1 Postulated Piping Failures in Fluid Systems Outside of Containment	3-10
3.6.2 Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping	3-11
3.7 Seismic Design.	3-12
3.7.1 Seismic Input.	3-12
3.7.2 Seismic System and Subsystem Analysis.	3-13
3.7.3 Seismic Instrumentation Program.	3-14
3.8 Design of Category I Structures	3-14
3.8.1 Concrete Containment	3-15
3.8.2 Steel Containment.	3-17
3.8.3 Concrete and Structural Steel Internal Structures.	3-17
3.8.4 Other Category I Structures.	3-18
3.8.5 Foundations.	3-21
3.8.6 System Interaction	3-22
3.9 Mechanical Systems and Components	3-22
3.9.1 Special Topics for Mechanical Components	3-22

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
3.9.2 Dynamic Testing and Analysis	3-22
3.9.2.1 Preoperational Vibration and Dynamic Effects Piping Testing.	3-22
3.9.2.2 Snubber Operability Program	3-23
3.9.2.3 Reactor Internals	3-23
3.9.3 ASME Code Class 1, 2 and 3 Components, Component Supports and Core Support Structures.	3-24
3.9.3.1 Loading Combinations and Stress Limits.	3-24
3.9.3.2 Pump and Valve Operability Assurance.	3-25
3.9.3.3 Design and Pressure Relief Valve Mounting	3-26
3.9.3.4 Asymmetric Blowdown Loads on RCS.	3-26
3.9.4 Control Rod Drive Systems.	3-26
3.9.5 Reactor Pressure Vessel Internals.	3-27
3.9.6 Inservice Testing of Pumps and Valves.	3-27
3.10 Seismic Qualification of Seismic Category I Mechanical and Electrical Equipment.	3-28
3.11 Environmental Design of Mechanical and Electrical Equipment . . .	3-29
3.11.1 Environmental Conditions	3-29
3.11.2 Environmental Qualification.	3-29
4.0 REACTOR.	4-1
4.1 Introduction.	4-1
4.2 Fuel System Design.	4-1
4.2.1 Description.	4-2
4.2.2 Design Evaluation.	4-2
4.2.2.1 Fuel Densification.	4-2
4.2.2.2 Fission Gas Release at High Burnups	4-2
4.2.2.3 Cladding Collapse	4-3
4.2.2.4 Flow-Induced Vibration.	4-4
4.2.2.5 CEA Guide Tube Wear	4-4
4.2.2.6 Fuel Rod Waterlogging	4-6
4.2.2.7 Pellet/Cladding Interaction	4-6
4.2.2.8 Poison Rod Primary Hydriding.	4-6
4.2.2.9 Poison and Fuel Rod Bowing.	4-7
4.2.2.10 Combined LOCA and Seismic Loads	4-7
4.2.2.11 Zircaloy Growth	4-7
4.2.2.12 Fuel Assembly Inspection Program.	4-8
4.2.2.13 ECCS Analysis Using NUREG-0630 Model.	4-8
4.2.3 Testing, Inspection, and Surveillance Plans.	4-9
4.2.3.1 Fuel Surveillance Program	4-9
4.2.3.2 CEA Surveillance Program.	4-10
4.2.4 Fuel Design Conclusions.	4-10
4.3 Nuclear Design.	4-11
4.3.1 Design Bases	4-11
4.3.2 Power Distribution Control	4-11
4.3.3 Core Operating Limit Supervisory System.	4-12
4.3.4 Reactivity Coefficients.	4-13
4.3.5 Control.	4-13
4.3.6 Stability.	4-14
4.3.7 Vessel Irradiation	4-14
4.3.8 Criticality of Fuel Assemblies	4-15
4.3.9 Analytical Methods	4-15
4.3.10 Nuclear Design Conclusions	4-15
4.4 Thermal and Hydraulic Design.	4-16
4.4.1 DNBR Considerations.	4-16
4.4.2 Fuel Rod Bowing.	4-20
4.4.3 Crud Deposition.	4-20
4.4.4 Hydrodynamic Stability	4-21
4.4.5 Loose Parts Monitoring System.	4-21

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
4.4.6 Core Protection Calculator Algorithm	4-21
4.4.7 Conclusions.	4-21
4.5 Reactor Materials	4-21
4.5.1 Reactor Internals Materials.	4-21
4.5.2 Control Rod System Structural Materials.	4-22
4.6 Functional Design of Reactivity Control System.	4-23
5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS	5-1
5.1 Summary Description	5-1
5.2 Integrity of Reactor Coolant Pressure Boundary.	5-2
5.2.1 Compliance with Codes and Regulations.	5-2
5.2.1.1 Compliance with 10 CFR 50.55a	5-2
5.2.1.2 Applicable Code Cases	5-2
5.2.2 Overpressurization Protection.	5-2
5.2.2.1 High Temperature Overpressure Protection.	5-3
5.2.2.2 Low Temperature Overpressure Protection	5-3
5.2.3 Reactor Coolant Pressure Boundary Materials.	5-5
5.2.3.1 Material Specifications and Compatibility with Reactor Coolant	5-5
5.2.3.2 Fabrication and Processing of Ferritic Materials	5-5
5.2.3.3 Fabrication and Processing of Austenitic Stainless Steel	5-6
5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing.	5-7
5.2.5 Reactor Coolant Pressure Boundary Leakage Detection System	5-8
5.3 Reactor Vessel.	5-10
5.3.1 Reactor Vessel Materials	5-10
5.3.1.1 Compliance with Appendix G to 10 CFR 50	5-10
5.3.1.2 Compliance with Appendix H to 10 CFR 50	5-11
5.3.1.3 Conclusions	5-12
5.3.2 Pressure-Temperature Limits.	5-13
5.3.3 Reactor Vessel Integrity	5-14
5.3.4 Reactor Vessel Installation, Unit 2	5-15
5.4 Component and Subsystem Design.	5-16
5.4.1 Reactor Coolant Pumps.	5-16
5.4.1.1 Pump Flywheel Integrity	5-16
5.4.2 Steam Generators	5-17
5.4.2.1 Steam Generator Materials	5-17
5.4.2.2 Steam Generator Inservice Inspection.	5-18
5.4.2.3 Secondary Water Chemistry	5-19
5.4.3 Shutdown Cooling System (Residual Heat Removal System) . .	5-22
6.0 ENGINEERED SAFETY FEATURES	6-1
6.1 Engineered Safety Feature Materials	6-1
6.1.1 Metallic Materials	6-1
6.1.2 Organic Materials.	6-1
6.1.3 Post-Accident Chemistry.	6-2
6.2 Containment Systems	6-2
6.2.1 Containment Functional Design.	6-2
6.2.1.1 Containment Pressure Analysis	6-2
6.2.1.2 Containment Subcompartment Analysis	6-5
6.2.1.3 ECCS Containment Pressure Evaluation.	6-7
6.2.1.4 Containment Pressure Boundary Fracture Toughness. .	6-8
6.2.1.5 Conclusions, Containment Functional Design.	6-9
6.2.2 Containment Heat Removal Systems	6-9
6.2.3 Secondary Containment Functional Design.	6-10

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
6.2.4 Containment Isolation System	6-12
6.2.4.1 Containment Emergency Sump Recirculation.	6-12
6.2.4.2 ECCS Safety Injection Lines	6-12
6.2.4.3 Charging Line to Regenerative Heat Exchanger.	6-13
6.2.4.4 Diversity of Parameters for Initiation of Isolation	6-13
6.2.4.5 Containment Purge System.	6-13
6.2.4.6 Conclusions, Containment Isolation System	6-14
6.2.5 Combustible Gas Control System	6-14
6.2.6 Containment Leak Testing Program	6-15
6.3 Emergency Core Cooling System	6-17
6.3.1 System Design.	6-17
6.3.2 Evaluation	6-19
6.3.3 Testing.	6-24
6.3.3.1 Preoperational Tests.	6-24
6.3.3.2 Sump Tests.	6-25
6.3.4 Conclusions, Emergency Core Cooling System	6-25
6.4 Control Room Habitability Systems	6-26
6.4.1 Radiological Protection.	6-26
6.4.2 Toxic Gas Protection	6-26
6.5 Engineered Safety Feature Atmosphere Cleaning System.	6-27
6.5.1 Summary Description.	6-27
6.5.2 System Description and Evaluation.	6-27
6.5.2.1 Fuel Handling Building Post-Accident Cleanup Filter System	6-27
6.5.2.2 Containment Air Cleanup System.	6-27
6.5.2.3 Main Control Room Habitability System	6-28
6.6 Inservice Inspection of Class 2 and 3 Components.	6-28
7.0 INSTRUMENTATION AND CONTROLS	7-1
7.1 Introduction.	7-1
7.2 Reactor Protection System	7-1
7.2.1 "Loss of Load" Trip Input.	7-2
7.2.2 Computer Based Portion of Reactor Protection System- Core Protection Calculator	7-3
7.2.3 Plant Protection System Power Supply Independence.	7-4
7.2.4 Bypass of a Plant Protection System Trip Channel	7-4
7.3 Engineered Safety Features Actuation System	7-7
7.3.1 General.	7-7
7.3.2 Engineered Safety Features Input and Basic Logic	7-7
7.3.3 Inadvertent Actuation of Engineered Safety Features Equipment.	7-8
7.3.4 Main Steam Isolation System.	7-10
7.4 Systems Required for Safe Shutdown.	7-10
7.4.1 Atmospheric Steam Dump System.	7-10
7.4.2 Shutdown Outside the Control Room.	7-11
7.5 Safety-Related Display Instrumentation.	7-11
7.5.1 Post-Accident Monitoring Instrumentation	7-11
7.5.2 Inoperable Status Indication	7-11
7.6 Other Instrumentation Required for Safety	7-12
7.6.1 Shutdown Cooling System Low Pressure to High Pressure Isolation	7-12

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
7.7 Control Systems Not Required for Safety	7-12
7.8 Separation of Wiring Within the Main Control Board and Instrumentation Cabinets.	7-13
8.0 ELECTRIC POWER SYSTEMS	8-1
8.1 General Considerations.	8-1
8.2 Offsite Power	8-1
8.3 Onsite Power.	8-5
8.3.1 Alternating Current Systems.	8-5
8.3.2 Direct Current Systems	8-12
8.3.3 Testability of Onsite Power Systems.	8-14
8.3.4 Separation and Identification of Safety-Related Power Equipment and Systems.	8-14
9.0 AUXILIARY SYSTEMS.	9-1
9.1 Fuel Storage and Handling	9-1
9.1.1 New Fuel Storage	9-1
9.1.2 Spent Fuel Storage	9-2
9.1.3 Spent Fuel Pool Cooling and Cleanup System	9-3
9.1.4 Fuel Handling System	9-4
9.2 Water Systems	9-5
9.2.1 Saltwater Cooling System	9-5
9.2.2 Component Cooling Water System	9-5
9.2.3 Ultimate Heat Sink	9-8
9.2.4 Condensate Storage and Transfer System	9-8
9.2.4.1 Introduction.	9-9
9.2.4.2 Structural Evaluation and Analytical Model.	9-9
9.2.4.3 Determination of Crack Widths	9-10
9.2.4.4 Analysis of Leakage	9-11
9.2.4.5 Results of the Analysis	9-12
9.2.4.6 Effects of Tornado on Condensate Tank	9-12
9.2.4.7 Conclusions	9-13
9.3 Process Auxiliaries	9-13
9.3.1 Compressed Air System.	9-13
9.3.2 Sump and Drain Systems	9-14
9.3.3 Chemical and Volume Control System	9-14
9.4 Air Conditioning, Heating, Cooling, and Ventilation Systems . . .	9-15
9.4.1 Auxiliary Building Ventilation Systems	9-15
9.4.2 Support Building Ventilation Systems	9-16
9.5 Other Auxiliary Systems	9-18
9.5.1 Fire Protection System	9-18
9.5.1.1 Introduction.	9-18
9.5.1.2 Fire Protection Systems Description and Evaluation.	9-19
9.5.1.3 Other Items Related to Fire Protection Program. . .	9-23
9.5.1.4 Seismically Induced Fires	9-24
9.5.1.5 Alternate Shutdown.	9-24
9.5.1.6 Plant Areas Containing Redundant Divisions.	9-25
9.5.1.7 Emergency Lighting.	9-26
9.5.1.8 Fire Protection for Specific Areas.	9-26
9.5.1.9 Administrative Controls and Fire Brigade.	9-28
9.5.1.10 Technical Specifications.	9-28
9.5.1.11 Appendix R Statement.	9-28
9.5.1.12 Conclusions	9-29
9.5.2 Communication Systems.	9-29
9.5.3 Lighting Systems	9-31

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System	9-32
9.5.5 Emergency Diesel Engine Cooling Water System	9-33
9.5.6 Emergency Diesel Engine Starting System	9-34
9.5.7 Emergency Diesel Engine Lubrication System	9-35
9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System	9-36
10.0 STEAM AND POWER CONVERSION SYSTEM	10-1
10.1 Summary Description	10-1
10.2 Turbine Generator	10-1
10.2.1 Overspeed Protection	10-1
10.2.2 Turbine Disc Integrity	10-3
10.3 Main Steam Supply System	10-4
10.3.1 System Design	10-4
10.3.2 Steam and Feedwater System Materials	10-5
10.4 Other Features of Steam and Power Conversion System	10-5
10.4.1 Main Condenser	10-6
10.4.2 Main Condenser Evacuation System	10-7
10.4.3 Turbine Gland Sealing System	10-7
10.4.4 Turbine Bypass System	10-7
10.4.5 Circulating Water System	10-9
10.4.6 Auxiliary Feedwater System	10-9
11.0 RADIOACTIVE WASTE SYSTEM	11-1
11.1 Summary Description	11-1
11.2 System Description and Evaluation	11-9
11.2.1 Liquid Waste Processing System	11-9
11.2.1.1 Chemical and Volume Control System	11-9
11.2.1.2 Coolant Radwaste System	11-10
11.2.1.3 Coolant and Boric Acid Recycle System	11-10
11.2.1.4 Miscellaneous Liquid Waste System	11-10
11.2.1.5 Laundry and Hot Shower Wastes	11-11
11.2.1.6 Turbine Area Drain	11-11
11.2.1.7 Steam Generator Blowdown System	11-12
11.2.1.8 Conformance with NRC Regulations and Positions	11-12
11.2.2 Gaseous Waste Processing System	11-14
11.2.2.1 Gaseous Radioactive Waste Processing System	11-15
11.2.2.2 Vent Gas Collection System	11-15
11.2.2.3 Containment Ventilation System	11-15
11.2.2.4 Ventilation Releases from Other Buildings	11-16
11.2.2.5 Main Condenser Air Ejector Exhaust	11-16
11.2.2.6 Conformance with NRC Regulations and Positions	11-16
11.2.3 Solid Radioactive Waste Treatment System	11-18
11.2.3.1 Wet Solids Wastes	11-18
11.2.3.2 Dry Solid Wastes	11-19
11.2.3.3 Conformance with Federal Regulations and NRC Positions	11-19
11.3 Process and Effluent Radiological Monitoring Systems	11-20
11.4 Conclusions	11-20
12.0 RADIATION PROTECTION	12-1
12.1 Assuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable	12-1
12.2 Radiation Sources	12-3

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
12.3 Radiation Protection Design Features.	12-4
12.4 Dose Assessment	12-7
12.5 Health Physics Program.	12-8
13.0 CONDUCT OF OPERATIONS.	13-1
13.1 Organizational Structure and Qualifications	13-1
13.2 Training Program.	13-1
13.3 Emergency Preparedness Evaluation	13-2
13.3.1 Introduction	13-2
13.3.2 Evaluation of Applicants' Emergency Plan.	13-2
13.3.3 Evaluation of State and Local Plans	13-14
13.3.4 Conclusions	13-14
13.4 Review and Audit.	13-14
13.5 Station Procedures.	13-15
13.6 Industrial Security	13-15
14.0 INITIAL TEST PROGRAM	14-1
15.0 ACCIDENT ANALYSIS.	15-1
15.1 General Discussion.	15-1
15.1.1 Introduction.	15-1
15.1.2 Analytical Techniques	15-4
15.2 Normal Operation and Anticipated Operational Occurrences.	15-6
15.2.1 Increase in Heat Removal by Secondary System.	15-6
15.2.2 Decrease in Heat Removal by Secondary System.	15-7
15.2.3 Decrease in Reactor Coolant Flow Rate	15-8
15.2.4 Reactivity and Power Distribution Anomalies	15-9
15.2.4.1 Uncontrolled CEA Withdrawal at Low Power	15-9
15.2.4.2 Uncontrolled CEA Withdrawal at Power	15-9
15.2.4.3 CEA Misoperation	15-10
15.2.4.4 Inadvertent Boron Dilution	15-11
15.2.4.5 Inadvertent Fuel Loading Errors.	15-11
15.2.4.6 CEA Ejection	15-12
15.2.5 Increase in Reactor Coolant System Inventory.	15-12
15.2.6 Conclusions	15-13
15.3 Limiting Accidents.	15-13
15.3.1 Steam Line Breaks	15-13
15.3.2 Feedwater System Pipe Breaks.	15-15
15.3.3 Single Reactor Coolant Pump Shaft Seizure	15-15
15.3.4 Reactor Coolant Pump Shaft Break.	15-16
15.3.5 Loss-of-Coolant Accident (LOCA)	15-17
15.3.6 Inadvertent Opening of a Pressurizer Safety Valve	15-18
15.3.7 Anticipated Transients Without Scram.	15-19
15.3.8 Conclusions	15-20
15.4 Radiological Consequences of Accidents.	15-20
15.4.1 Loss-of-Coolant Accident, Containment Direct Leakage.	15-22
15.4.2 Engineered Safety Features Post-LOCA Leakage.	15-22
15.4.3 Fuel Handling Accident in Containment	15-24
15.4.4 Fuel Handling Accident in the Fuel Building	15-26
15.4.5 Spent Fuel Cask Drop Accident	15-29
15.4.6 Gas Decay Tank Failure.	15-29
15.4.7 Main Steam Line Failure Outside Containment	15-29
15.4.8 Steam Generator Tube Failure.	15-29

TABLE OF CONTENTS (continued)

	<u>PAGE</u>
15.4.9 Control Element Assembly Ejection Accident.	15-30
15.4.10 Reactor Coolant Pump Shaft Break.	15-30
15.4.11 Letdown Line Break	15-30
15.4.12 Postulated Radioactive Release Due to Liquid Tank Failures.	15-35
16.0 TECHNICAL SPECIFICATIONS	16-1
17.0 QUALITY ASSURANCE.	17-1
17.1 General	17-1
17.2 Organization.	17-1
17.3 Quality Assurance Program	17-4
17.4 Conclusions	17-5
18.0 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS	18-1
19.0 COMMON DEFENSE AND SECURITY.	19-1
20.0 FINANCIAL QUALIFICATIONS	20-1
21.0 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS.	21-1
21.1 General	21-1
21.2 Preoperational Storage of Nuclear Fuel.	21-1
21.3 Operating Licenses.	21-1
22.0 TMI-2 REQUIREMENTS	22-1
22.1 Introduction.	22-1
22.2 Discussion of Requirements.	22-2
23.0 CONCLUSIONS.	23-1
<u>APPENDICES</u>	<u>PAGE</u>
A. CHRONOLOGY OF RADIOLOGICAL REVIEW.	A-1
B. BIBLIOGRAPHY.	B-1
C. ACRS GENERIC CONCERNS.	C-1
D. EVALUATION OF ONSHORE ATMOSPHERIC DISPERSION AT THE SAN ONOFRE NUCLEAR GENERATING STATION	D-1
E. LETTER FROM DAVID B. SLEMMONS, CONSULTANT, TO ROBERT E. JACKSON, NRC, DATED NOVEMBER 5, 1980.	E-1
F. LETTER FROM ROBERT H. MORRIS, USGS, TO ROBERT JACKSON, NRC, DATED AUGUST 13, 1980.	F-1
G. LETTER FROM H. WILLIAM MENARD, USGS, TO HAROLD R. DENTON, NRC, DATED NOVEMBER 26, 1980.	G-1
H. PRESERVICE INSPECTION REQUIREMENTS OF 10 CFR §0.55a(g)(2).	H-1

TABLE OF CONTENTS (continued)

LIST OF TABLES

	<u>PAGE</u>
2.1 San Onofre Population Distribution	2-7
2.2 Design Basis Tornado Characteristics	2-17
2.3 Wind Direction with Greatest Frequency of Occurrence by Time of Day	2-19
2.4 Onsite Meteorological Instrumentation.	2-22
2.5 Short-Term Relative Concentrations by Downwind Direction	2-24
2.6 Short-Term Relative Concentration Values Used for Accident Analysis	2-25
2.7 Summary of Relative Concentration and Relative Deposition Values for Selected Locations	2-27
2.8 Components of Design Basis Flood	2-30
4.1 Reactor Design Comparison	4-17
6.1 Subcompartment Pressure Analysis	6-6
6.2 Comparison of Containment Emergency Sump Design with Regulatory Guide 1.82	6-11
6.3 Emergency Core Cooling System Equipment.	6-18
6.4 Parameters Used to Assess the Effectiveness of the Containment Spray as an Iodine Removal Mechanism	6-29
11.1 Principal Parameters and Conditions Used in Calculating Release of Radioactive Material in Liquid and Gaseous Effluents	11-3
11.2 Calculated Releases of Radioactive Materials in Liquid Effluents . . .	11-5
11.3 Calculated Releases of Radioactive Materials in Gaseous Effluents.	11-6
11.4 Calculated Doses to a Maximum Individual and the 50-Mile Population	11-7
11.5 Principal Parameters Used in the Cost-Benefit Analysis	11-8
11.6 Design Parameters of Principal Components Considered in the Evaluation of Liquid and Gaseous Radioactive Waste Treatment Systems	11-13
11.7 Process and Effluent Monitors.	11-21
15.1 Chapter 15 General Initial Conditions.	15-2
15.2 Topical Reports for Codes Used in Safety Analyses.	15-5
15.3 Radiological Consequences (REM) of Design Basis Accidents.	15-21
15.4 Input Parameters and Assumptions to Determine Radiological Consequences Due to Postulated Loss-of-Coolant Accident.	15-23
15.5 Assumptions for Evaluation of LOCA Doses Due to ESF Leakage Outside Containment.	15-25

TABLE OF CONTENTS (continued)

LIST OF TABLES (continued)

	<u>PAGE</u>
15.6 Assumptions Used in Analysis of a Fuel Handling Accident in Fuel Building.	15-28
15.7 Assumptions Used in Analysis of: MSL Failure Outside Containment, SG Tube Failure, CEA Ejection Accident, Letdown Line Break Accident	15-31
15.8 Main Steam Line Break Accident Assumptions	15-32
15.9 Steam Generator Tube Failure Accident Assumptions	15-33
15.10 Control Element Assembly Ejection Accident Assumptions.	15-34
15.11 Letdown Line Break Accident Assumptions	15-36
17.1 Regulatory Guidance for Quality Assurance	17-2

LIST OF FIGURES

	<u>PAGE</u>
2-1 Site Location in Southern California	2-2
2-2 Reactor Site	2-3
2-3 Exclusion Area	2-4
2-4 San Onofre Beaches	2-6
2-5 Bureau of Economic Analysis Areas	2-9
2-6 Nearby Industrial, Transportation and Military Facilities.	2-11
2-7 Coastal Low-Altitude Federal Airways	2-12
2-8 Directional Frequency of Onsite Winds.	2-20
17-1 Organizational Structure	17-3

1.0 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This report is a safety evaluation report on the application for operating licenses for the San Onofre Nuclear Generating Station, Units 2 and 3 (San Onofre 2 and 3 or the facility). This report was prepared by the United States Nuclear Regulatory Commission staff (the NRC staff or the staff), and summarizes the results of our radiological safety review of the facility. The application for operating licenses has been filed by the Southern California Edison Company (SCE or Edison) on behalf of itself and the San Diego Gas and Electric Company. The City of Anaheim, California, and the City of Riverside, California have recently been added as co-holders of the Construction Permits for San Onofre 2 and 3, and will soon request to be included as applicants for operating licenses. The four groups are co-owners of the facility, and are referred to herein as the applicants. The percentage of undivided co-tenancy ownership interest of each of the co-owners is: Edison, 76.55 percent; San Diego Gas and Electric Company, 20.00 percent; Anaheim, 1.66 percent; Riverside, 1.79 percent. The Southern California Edison Company is authorized to act as agent for the other co-owners and has exclusive responsibility and control over the physical construction, operation, and maintenance of San Onofre 2 and 3.

The application for construction permits for the facility was filed with the United States Atomic Energy Commission (now the Nuclear Regulatory Commission) on May 28, 1970. Following staff review and a public hearing before the Atomic Safety and Licensing Board, Construction Permits No. CPPR-97 and No. CPPR-98 were issued on October 18, 1973. The application for operating licenses was filed with the NRC in late 1976 and was docketed for review on March 23, 1977. The applicants have stated that construction of San Onofre Unit 2 will be complete and the plant ready for fuel loading by June, 1981. The staff independently estimates that the plant will be ready in the July to September, 1981 period.

Prior to issuing an operating license for a nuclear power plant, the NRC staff is required to conduct a review of the effects of the plant on public health and safety. Our safety review of San Onofre 2 and 3 has been based on the Final Safety Evaluation Report (FSAR) that accompanied the application for operating licenses, and Amendments 1 through 22 thereto. All of this information is available to the public for review at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the Local Public Document Room at the Mission Viejo Branch Library, 24851 Chrisanta Drive, Mission Viejo, California. During the course of our review we have held a number of meetings with the applicants, their suppliers, and their consultants to discuss the design, construction, and proposed operation of San Onofre 2 and 3. As a consequence, additional information was requested, which the applicants provided in Amendments 1 through 22 to the Final Safety Analysis Report. Meetings were also held with the intervenors, at their request, to obtain any information they might have pertinent to our review.

Following the Three Mile Island Unit 2 (TMI-2) accident, 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 TMI-2 became available. All available recommendations were correlated and assimilated into a "TMI Action Plan" now published as NUREG-0660, entitled "NRC Action Plan Developed as a Result of the TMI-2 Accident." Additional guidance relating to implementation of the Action Plan is given in NUREG-0737, "Clarification of TMI Action Plan Requirements." These licensing requirements have been established to insure incorporation of the lessons learned from the TMI-2 accident to provide additional safety margins.

Sections 2 through 21 of this report address our review and evaluation of non-TMI-related issues that have been considered during the course of our review of the application for operating licenses for San Onofre 2 and 3. The geology and seismology sections of this report (Sections 2.5.1 and 2.5.2) were published in a separate volume on December 31, 1980, and are repeated herein. Section 22 of this report is reserved for our review and evaluation of the applicants' response to our TMI-2 requirements; a supplement to this report completing our review of these issues will be issued at a later date. In reviewing this report it should be kept in mind that TMI-related requirements are not addressed in sections other than 22; only non-TMI-related requirements. In cases where the non-TMI requirements have been completely superseded by TMI-related requirements, that section will only reference Section 22. The conclusions of this report are given in Section 23.

Appendix A is a chronology of our principal actions related to the review of the application. Appendix B is a bibliography of the references used during the course of our review. Appendix C is a discussion of how various ACRS generic concerns relate to the San Onofre 2 and 3 application. Appendix D is an evaluation of onshore atmospheric dispersion at San Onofre. Appendices E, F and G are reports by our consultants relating to geology and seismology considerations. Appendix H is a summary of our review of the compliance with the preservice inspection requirements of 10 CFR 50.55a(g)(2).

As part of our review of San Onofre 2 and 3 for compliance with the Commission's regulations, we requested that the applicants verify that San Onofre 2 and 3 meet the applicable requirements in 10 CFR Parts 20, 50, and 100. The applicants' response to this request is expected to be submitted in the near future.

In accordance with the provisions of the National Environmental Policy Act of 1969, Draft and Final Environmental Statements which set forth the considerations related to the proposed construction and operation of San Onofre 2 and 3 were prepared by the staff and were issued prior to the issuance of the construction permits (November 1972 and March 1973, respectively). After receiving the application for operating licenses for San Onofre 2 and 3, the staff issued a Draft Environmental Statement (November 1978) and has recently issued a Supplement to the Draft Environmental Statement (January 1981). A Final Environmental Statement is scheduled to be issued in April 1981.

The review and evaluation of San Onofre 2 and 3 for operating licenses is only one stage in the continuing review by the staff of the design, construction and operating features of the facility. The proposed design of the facility was reviewed as part of the construction permit review. Construction of the facility has been monitored in accordance with the inspection program of the staff. At this, the operating license review stage, we have reviewed the final design to determine that the Commission's safety requirements have been met. If operating licenses are granted, San Onofre 2 and 3 must be operated in accordance with the terms of the operating licenses and the Commission's regulations and will be subject to the continuing inspection program of the staff.

1.2 General Plant Description

Units 2 and 3 of the San Onofre Nuclear Generating Station each utilize a nuclear steam supply system incorporating a Combustion Engineering pressurized water reactor and reactor coolant system. In each of the identical units the reactor core is composed of fuel rods made of slightly enriched uranium dioxide pellets enclosed in Zircaloy tubes with welded end caps that are grouped and supported into assemblies. The mechanical control rods consist of clusters of NiFeCr alloy-clad boron carbide absorber rods that are inserted into guide tubes located within the fuel assemblies. The core fuel is loaded in three regions, each utilizing fuel of a different enrichment of U-235, with new fuel being introduced into the outer region, moved inward at successive refuelings, and removed from the inner region to spent fuel storage.

Water will serve as both the moderator and the coolant, and will be circulated through the reactor vessel and core by four electric-motor-driven single-stage centrifugal pumps, one located in each of the two cold legs of each loop. The coolant water heated by the reactor will be circulated through the two steam generators where heat will be transferred to the secondary system to produce saturated steam, and then be returned to the pumps to repeat the cycle.

An electrically-heated pressurizer connected to the hot-leg piping of one of the loops will establish and maintain the reactor coolant pressure and provide a surge chamber and a water reserve to accommodate reactor coolant volume changes during operation.

The steam produced in the steam generators will be utilized to drive a tandem compound-impulse-reaction turbine and will be condensed in a double-shell, single-pass, multi-pressure, surface condenser. Cooling water drawn from the Pacific Ocean will be pumped through the tubes of the condenser to remove the heat from, and thus condense, the steam after it has passed through the turbine. The condensate will then be pumped back to the steam generator to be heated for another cycle. The cooling water will then be returned directly to the ocean.

The reactor will be controlled by a coordinated combination of a soluble neutron absorber (boric acid) and mechanical control element assemblies whose drive shafts will allow the plant to accept step load changes of 10 percent and ramp load changes

of 5 percent per minute over the range of 15 to 100 percent of full power under normal operating conditions. With steam bypass, the plant will also have the capability to accept a 50-percent step load rejection without reactor trip.

Plant protection systems are provided that automatically initiate appropriate action whenever a monitored condition approaches pre-established limits. These protection systems will act to shutdown the reactor, close isolation valves, and initiate operation of the engineered safety features should any or all of these actions be required.

Supervision and control of both the nuclear steam supply system and the steam and power conversion system for each unit will be accomplished from separate facilities within a shared control room.

The emergency core cooling system for each unit consists of safety injection tanks, and both high and low pressure injection subsystems with provisions for recirculation of the borated water after the end of the injection phase. Various combinations of these features will assure core cooling for the complete range of postulated coolant pipe break sizes.

The two nuclear steam supply systems are each housed in a separate prestressed concrete containment structure. Separate but adjoining auxiliary buildings located between the containment structures for Units 2 and 3 house the radioactive waste treatment facilities and various related auxiliary systems for each unit. Each unit has a separate safety equipment building housing engineered safety feature systems, and a separate fuel handling facility which contains a spent fuel pool and a new fuel storage facility.

The plant is supplied with electrical power by independent transmission lines from offsite power sources and is provided with independent and redundant onsite emergency power supplies capable of supplying power to shutdown the plant safely or to operate the engineered safety features in the event of an accident.

1.3 Comparison with Similar Facility Designs

Many features of the design of San Onofre 2 and 3 are similar to those we have evaluated and approved previously for other pressurized water reactor plants now under construction or in operation. To the extent feasible and appropriate, we have relied on our earlier reviews for those features that were shown to be substantially the same as those previously considered. Where this has been done, the appropriate sections of this report identify the other facilities involved. Our safety evaluation reports for these other facilities have been published and are available for public inspection at the Nuclear Regulatory Commission's Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the Local Public Document Room at the Mission Viejo Branch Library, 24851 Chrisanta Drive, Mission Viejo, California.

1.4 Identification of Agents and Contractors

Combustion Engineering, Incorporated (CE) is supplying the nuclear steam supply system (NSSS) including the first core of nuclear fuel for San Onofre 2 and 3. The Bechtel Power Corporation is the engineer-constructor for the facility. GEC Turbine Generators, Ltd., supplied the turbine generators for the plant. The Southern California Edison Company is the project manager for the applicants, and is responsible for the technical adequacy of the design, construction, and operation of the plant.

1.5 Summary of Principal Review Matters

Our technical review and evaluation of the information submitted by the applicants considered, or will consider, the principal matters summarized below:

- (1) The population density and land use characteristics of the site environs and the physical characteristics of the site (including seismology, meteorology, geology, and hydrology) to establish that these characteristics have been determined adequately and have been given appropriate consideration in the plant design, and that the site characteristics are in accordance with the Commission's siting criteria in 10 CFR Part 100, taking into consideration the design of the facilities, including the engineered safety features provided.
- (2) The design, fabrication, construction and testing criteria, and expected performance characteristics of the plant structures, systems, and components important to safety to determine that they are in accord with the Commission's General Design Criteria, Quality Assurance Criteria, Regulatory Guides, and other appropriate rules, codes and standards, and that any departure from these criteria, codes and standards have been identified and justified.
- (3) The expected response of the facility to various anticipated operating transients and to a broad spectrum of postulated accidents. Based on this evaluation, we determined that the potential consequences of a few highly unlikely postulated accidents (design basis accidents) would exceed those of all other accidents considered. We performed conservative analyses of these design basis accidents to determine that the calculated potential offsite radiation doses that might result, in the very unlikely event of their occurrence, would not exceed the Commission's guidelines for site acceptability given to 10 CFR Part 100.
- (4) The Southern California Edison Company's engineering and construction organization, plans for the conduct of plant operations (including the organizational structure and the general qualifications of operating and technical support personnel), the plans for industrial security, and the planning for emergency actions to be taken in the unlikely event of an accident that might affect the general public, to determine that the applicants are technically qualified to safely operate the facilities.

- (5) The design of the systems provided for control of the radiological effluents from the facilities to determine that these systems are capable of controlling the release of radioactive wastes from the facility within the limits of the Commission's regulations in 10 CFR Part 20, and that the equipment provided is capable of being operated by the applicants in such a manner as to reduce radioactive release to levels that are as low as is reasonably achievable within the context of the Commission's regulations in 10 CFR Part 50, and to meet the dose design objectives of Appendix I to Part 50.
- (6) The Southern California Edison Company's quality assurance program for the operation of the facilities to assure that the program complies with the Commission's regulations in 10 CFR Part 50, and that the applicants will have proper controls over the facility operations such that there is reasonable assurance that the facilities can be operated safely and reliably.
- (7) The financial data and information supplied by the Southern California Edison Company and its coapplicants as required by the Commission's regulations (Section 50.33(f) of 10 CFR Part 50, and Appendix C to Part 50) to determine that the applicants are financially qualified to operate the proposed facilities.

1.6 Modifications to the Facility During the Course of Our Review

During the review, we met a number of times (see Appendix A to this report) with the applicants' representatives, contractors and consultants to discuss various technical matters related to the facility. Also, we made a number of site visits to assess specific safety matters related to the station. The applicants made a number of changes to the facility design as a result of our review. We reviewed these design changes also. Special details concerning these changes are included in amendments to the Final Safety Analysis Report and in appropriate subsections of this report.

1.7 Summary of Outstanding Issues

At this time, three sections of this report (Sections 18, 20, and 22) have been set aside for completion at a later date. Section 18.0 is reserved for the report by the Advisory Committee on Reactor Safeguards (ACRS). This report will be issued by the ACRS following their review of the San Onofre 2 and 3 application and this Safety Evaluation Report (SER). The ACRS report is normally included in a supplement to the SER. Section 20.0 is reserved for an evaluation by the NRC staff of the applicants' financial qualifications. This evaluation is normally included in a SER supplement so that the information reviewed will be reasonably current at the time a decision is made on issuance of an operating license. Section 22.0 is reserved for issues that have been identified as a result of the accident at Three Mile Island Unit 2 (TMI). These items were identified and staff criteria for this evaluation were defined rather late in our review of San Onofre 2 and 3, and our review of them is incomplete. Therefore, they will be covered as a separate group in Section 22.0 of a supplement to this report.

As a result of our review of the non-TMI-related safety aspects of the San Onofre 2 and 3 application, a number of items remain outstanding at the time of issuance of this report. Since we have not completed our review and reached our final positions in these areas, we consider these issues to be open. Our review of these items will be completed prior to a decision on issuance of an operating license and will be reported in a supplement to this report. The open items, with appropriate references to subsections of this report, are listed below.

- (1) Explosion hazards. Section 2.2.2, page 2-13
- (2) Toxic gas hazards. Section 2.2.2, page 2-14
- (3) Systems Interaction. Section 3.8.6, page 3-22
- (4) Seismic qualification of equipment. Sections 3.10, page 3-28
- (5) Reactor internals analysis. Section 3.9.2.3, page 3-23
- (6) Independent piping analysis. Section 3.9.3.1, page 3-25
- (7) Environmental qualification of equipment. Section 3.11.2, page 3-29
- (8) Seismic plus LOCA loads on FEA. Section 4.2.2.10, page 4-7
- (9) Core protection calculator. Section 4.4, page 4-21; Section 7.2.2, page 7-3;
Section 15.1.1, page 15-3; Section 15.2.3, page 15-8
- (10) DNBR testing of revised FEA. Section 4.4, page 4-16
- (11) Containment Pressure Boundary Fracture Toughness. Section 6.2.1.4, page 6-8.
- (12) Emergency planning. Section 13.3., page 13-2
- (13) Industrial security. Section 13.6, page 13-15
- (14) Review of CENPD-183. Section 15.1.2, page 15-6
- (15) Review of Q-list. Section 17.3, page 17-4

Each of these issues is summarized below.

(1) Explosion Hazards

The applicants have not demonstrated that the explosion risks associated with transportation of hazardous materials past the site are sufficiently low to be acceptable. They have agreed to revise their probability analysis, and to evaluate the ability of plant structures to withstand overpressures greater than the tornado loading. We will require that any portions of the plant found to be vulnerable to significant blast damage be modified such that there will be reasonable assurance that they will retain their functional capability in the event of overpressure due to explosions.

(2) Toxic Gas Hazards

We are unable to verify the motor carrier accident rate which is presented in Section 6.4 of the FSAR. The value used in Section 6.4 is about four orders of magnitude less than the truck accident rate based on nationally averaged statistics used by the applicants in Section 2.2 analyses. Our position is that the applicants must substantiate the truck accident rate used in their toxic gas analysis or revise it accordingly, and protect the control room from any additional toxic gases that are a hazard to the plant operators.

(3) Systems Interaction

We have requested, and the applicants have provided, additional information concerning the objectives and scope of the applicants' systems interaction program, the methodology and criteria used to postulate the interactions, and the organization established to implement the program. We are evaluating the applicants' response to our request and plan to conduct an onsite audit of the applicants' program.

(4) Seismic Qualification of Equipment

Our review of the information presented in the FSAR is in progress. Our findings will be based on our review and on the information obtained during the September 1980 site visit by our Seismic Qualification Review Team. Our review is not yet complete.

(5) Reactor Internals Analysis

We have informed the applicants that the dynamic systems analysis described in FSAR Section 3.7.3.14 require further amplification and clarification. The applicants have agreed to provide the additional information.

(6) Independent Piping Analysis

We are performing an independent confirmatory analysis of the shutdown cooling line. This analysis will not only verify that this piping system meets the applicable ASME Code requirements, but will also provide a check on the applicants' ability to correctly model and analyze piping systems. We have contracted with the Energy Technology Engineering Center (ETEC) to perform the confirmatory analysis, and it is in progress.

(7) Environmental Qualification of Equipment

We requested that the applicants reassess their qualification documentation for equipment installed at the facility, to show that the qualification methods used and results obtained conform to the staff positions in NUREG-0588. We believe that this additional review will confirm our previously-reached conclusions that the San Onofre 2 and 3 qualification documentation is adequate. Nevertheless, we require that the additional review be completed prior to issuance of a full power operating license.

(8) Seismic plus LOCA Loads on Fuel Element Assembly (FEA)

The applicants have referenced the topical report CENPD-178, "Structural Analysis of Fuel Assemblies for Combined Seismic and Loss-of-Coolant Accident Loading," which addresses this matter. As a result of our preliminary review, we concluded that CENPD-178 did not contain an adequate model for analyzing lateral loads on

the fuel assembly nor did it present sufficient information on spacer grid tests. The applicants have stated that they will provide additional information on analytical methods and test results as an amendment to the Final Safety Analysis Report.

(9) Core Protection Calculator

We have required the San Onofre 2 and 3 applicants to submit a summary of any modifications for their core protection calculator as compared to the Arkansas Nuclear One Unit 2 core protection calculator, because of our significant review effort on the ANO-2 computer.

The applicants noted modifications in the following areas and for the following reasons:

- (1) Core protection calculator/control element assembly protection algorithms - these changes are a result of the change in the number of control element assemblies and control element assembly subgroups for San Onofre 2 and 3.
- (2) Core protection calculator/control element assembly data base constants - these changes are due to the specific core and coolant system characteristics.
- (3) Software changes related to thermal-hydraulic methods - the changes incorporate current Combustion Engineering methods.

Our review of these modifications is still in progress.

(10) DNBR Testing of Revised FEA

The departure from nucleate boiling correlation used for the design of the San Onofre 2 and 3 core is the Combustion Engineering CE-1 correlation. However, the San Onofre 2 and 3 reactors will use fuel assemblies with support grids which are thicker and wider than comparable grids for the 16x16 fuel design in Arkansas Nuclear One Unit 2 (ANO-2). Also, the grid spacing has been increased relative to the grid spacing for ANO-2 by using one less grid for the bundle. The effect of these changes in grid design may be to reduce the critical heat flux for San Onofre fuel relative to that for ANO-2 and other plants which use the same grid design as ANO-2. Therefore, we requested that the applicants provide data to justify the use of the CE-1 CHF correlation. This data has been submitted by the applicants, but our review of it is not yet complete.

(11) Containment Pressure Boundary Fracture Toughness

The San Onofre 2 and 3 containment pressure boundary is comprised of ASME Code Class 1, 2 and MC components. In late 1979, we generically reviewed the fracture toughness requirements of the ferritic materials of Class MC, Class 1 and Class 2 components which typically constitute the containment pressure boundary. Based on this review, we determined that the fracture toughness requirements contained in ASME Code Editions and Addenda, typical of those used in the design of the San Onofre 2 and 3 primary containment, may not ensure compliance with GDC 51 for all areas of the containment pressure boundary. We initiated a program to review fracture toughness requirements for containment pressure boundary materials for the purpose of defining those fracture toughness criteria that most appropriately address the requirements of GDC 51. Prior to completion of this generic study, we elected to apply in our licensing reviews the criteria identified in the Summer 1977 Addenda of Section III of the ASME Code for Class 2 components. These criteria were selected to ensure uniform fracture toughness requirements, consistent with the containment safety function, are applied to all components in the containment pressure boundary. Accordingly, we have reviewed the Class 1, 2 and MC components in the San Onofre 2 and 3 containment pressure boundary according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components. However, in order to complete our review we require additional information, because the San Onofre 2 and 3 FSAR does not provide the information necessary to characterize the fracture toughness of the reactor containment pressure boundary within the context of GDC 51. We have requested that the applicants provide the necessary information, and we will review it when it becomes available.

(12) Emergency Planning

We have reviewed the San Onofre site emergency plan against the criteria in NUREG-0654, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," November 1980. Based on our review, we conclude that the San Onofre site emergency plan, when revised in accordance with the applicants' commitments, will provide an adequate planning basis for an acceptable state of emergency preparedness, and meets the requirements of 10 CFR 50 and Appendix E thereto. However, the San Onofre site emergency plan must be revised to address the final criteria and implementation schedule for the emergency centers and their functions, emergency manpower levels, and meteorological systems.

The applicants have been requested to explicitly address protective action determination and implementation after an earthquake in the revised site plan. In addition, FEMA has been requested as part of their review of Federal, State, and local emergency plans to review the planning efforts for the areas around the site to assure that protective actions to be recommended by the applicants after earthquakes could be implemented and are adequate.

After receiving the findings and determinations made by FEMA on Federal, State, and local emergency response plans, and after reviewing the revised site plan from the applicants, we will provide our overall conclusions on the status of emergency preparedness for San Onofre and related emergency planning zones.

Our final approval of the state of emergency preparedness at San Onofre will be made following implementation of the emergency plans to include development of procedures, training and qualifying of personnel, installation of equipment and facilities, and a joint exercise of all the plans (site, Federal, State, and local).

(13) Industrial Security

The applicants submitted a Modified Amended Security Plan as required by 10 CFR Part 73.55 encompassing protection of the San Onofre Nuclear Generating Station Units 1, 2, and 3. The implementation of this plan at Units 2 and 3 is currently undergoing a review prior to the issuance of operating licenses for these units and will be reviewed throughout the plant's operating life to assure continuing compliance with the requirements of Part 73.55 of 10 CFR 73.

The identification of vital areas and measures used to control access to these areas, as described in the plan, may be subject to future amendments based upon a confirmatory evaluation of Units 2 and 3 to determine those areas where acts of sabotage might cause a release of radionuclides in sufficient quantities to result in dose rates equal to or exceeding 10 CFR Part 100 limits.

(14) Review of CENPD-183

The analysis method used for loss-of-flow transients is described in CENPD-183. This report originally was dependent on the approval of CENPD-177, but CENPD-177 was withdrawn from review at the request of Combustion Engineering (Scherer, 1980a). Therefore, the staff review of CENPD-183 was deferred. Subsequently, Combustion Engineering amended CENPD-183 and removed the dependence on CENPD-177 (Scherer, 1980b). We are currently in the process of rescheduling our review of CENPD-183.

(15) Review of Q-List

We have completed our review of the list of structures, systems, and components to which the quality assurance program applies (the Q-List), and have identified a number of systems which we believe should be added to the list. We have advised the applicants of our position on these items, and they plan to respond in the near future.

1.8 Confirmatory Issues

At this point in our review there are a few items which have essentially been resolved to the staff's satisfaction, but for which certain confirmatory information has not yet been provided by the applicants. In these instances, the applicants have committed to provide the confirmatory information in the near future. If upon staff review of the information it does not, as expected, provide confirmation of our preliminary conclusions, we will treat that item as open and report on its resolution in a supplement to this report.

The confirmatory items, with appropriate references to subsections of this report, are listed below.

- (1) Seismic margins format consistency, Section 3.9.3.1, page 3-25
- (2) ECCS re-analysis using NUREG-0630 model, Section 4.2.2.13, page 4-8

1.9 License Conditions

There are several issues for which a license condition may be desirable to insure that staff requirements are met during plant operation. These items, with appropriate references to subsections of this report, are listed below.

- (1) High burnup fuel rod pressure, Section 4.2.2.2, page 4-2
- (2) Low temperature overpressure protection, Section 5.2.2.2, page 5-3
- (3) Recalculation of pressure-temperature limits, Section 5.3.1.2, page 5-11
- (4) Secondary water chemistry, Section 5.4.2.3, page 5-19
- (5) Diesel generator modifications, Section 8.3.1, page 8-9
- (6) Turbine disc inspection, Section 10.2.2, page 10-3

1.10 Generic Issues

The Advisory Committee on Reactor Safeguards periodically issues a report listing various generic matters applicable to light water reactors. A discussion of these matters is provided in Appendix C to this report which includes references to sections of this report for more specific discussions concerning this facility.

We continuously evaluate the safety requirements used in our review against new information as it becomes available. In some cases, we take immediate action or interim measures to assure safety. In most cases, however, our initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether

our existing requirements should be modified. These issues being studied are sometimes called generic safety issues because they are related to a particular class or type of nuclear facility. A discussion of our program for the resolution of these generic issues is presented in a Appendix C to this report.

2.0 SITE CHARACTERISTICS

2.1 Geography and Demography

2.1.1 Site Description

The San Onofre 2 and 3 facility is located in San Diego County, California, on the coast of the Pacific Ocean, approximately 62 miles southeast of Los Angeles and 51 miles north of San Diego, California. The geographic location is shown in Figure 2-1 and 2-2. The 83.6-acre site (approximately 4,500 feet long and 800 feet wide) is located adjacent to San Onofre Unit 1 and is entirely within the boundaries of the United States Marine base, Camp Pendleton, California, near the northeast end of the 18-mile shoreline. San Clemente, California, is about 2.8 miles north of the site.

2.1.2 Exclusion Area Control

The exclusion area shown in Figure 2-3 has a minimum exclusion distance of 600 meters from the containment centerlines to the closest site boundary. The applicants' authority to control all activities within the exclusion area was acquired by a grant of easement from the United States of America made by the Secretary of the Navy in 1964 and modified by an amendment on September 18, 1975. The amendment to this grant of easement expires on May 12, 2024. All mineral rights in the land portion of the exclusion area are held by the United States Government. The exclusion area is traversed by old U.S. Highway 101, the San Diego Freeway (Interstate 5), and the Atchinson, Topeka and Santa Fe Railroad. The exclusion area on the ocean side extends over a narrow strip of beach and into the Pacific Ocean.

The applicants' control of the landward portion of the exclusion area extends up to the mean high tide line but does not include the strip of beach lying between high and low tide that is occasionally uncovered. This strip of "tidal beach" is owned by the State of California and is used primarily as a passageway for individuals walking along the beach. The applicants' lack of control of this strip of tidal beach has been adjudicated in a Commission proceeding (see ALAB-432) and has been declared "de minimis" on the basis of its occasional use, together with analyses which indicate that any radiation exposure to individuals in this zone will be within the guideline values of 10 CFR Part 100 in the event of emergency. We conclude that the applicants have the authority to determine all activities within the exclusion area as required by 10 CFR Part 100.

Activities within the exclusion area which are unrelated to plant operation include a gas pipeline, railroad traffic, through traffic on the San Diego Freeway, and local recreational traffic on old U.S. Highway 101. Recreational activities in the plant



**SAN ONOFRE
NUCLEAR GENERATING
STATION**

Figure 2-1

2-2



Figure 2-2

vicinity include swimming, camping and surfing. Recreational activities, such as sunbathing or picnicking, are discouraged by the applicants within the landward portion of the exclusion area (the area landward of the contour of mean high tide). The seaward portion of the exclusion area (the area seaward of the contour of mean high tide) may be used by small numbers of people for passageway transit between the public beach areas upcoast and downcoast from the plant. Additional small numbers of people may be anticipated to occasionally be in the water within the exclusion area.

Transient access to an approximately five-acre area at the southwest corner of the site for the purposes of viewing the scenic bluffs and barrancas will be on the unimproved walkway. The applicants have estimated that at any one time a maximum of 100 persons will be in the walkway and a five-acre barranca viewing area, and on the beach and water below mean high tide. The improved walkway affords landward passage between the two beach areas.

The San Onofre State Beach (Parcels 2 and 3) northwest and southeast of the San Onofre exclusion areas, as shown in Figure 2-4, represents a public waterfront recreation area within a five-mile radius of the plant. This figure shows the projected development of inland parkland. The beach south of the nuclear facility is used for swimming, hiking and vehicle parking. The 3,400-foot stretch of beach north of the site is used primarily for surfing.

In case of a radiological emergency, the applicants have made arrangements with agencies of the Federal, State and local governments to control all traffic on the railroad, roadways and waterways.

Chain link fences extending between the beach passageway and the mean high tide line, television monitoring, and plant security control will be used to control the population on the beach within the exclusion area.

2.1.3 Population and Population Distribution

The population in the vicinity of the San Onofre site is shown as a function of distance in Table 2.1.

The largest communities in the vicinity are San Clemente, located about 3 miles away, which had a 1976 estimated population of 23,000, and the U.S. Marine Corp base, Camp Pendleton, with a total estimated population of about 33,000. The Marine Corp base consists of several population clusters or camps located at distances from 1.5 miles to 12 miles away.

The San Onofre 2 and 3 low population zone outer radius is 1.95 miles. The 1976 resident population within the low population zone was about 1,400 persons and is projected to be about 1,500 persons in the year 2020.

TABLE 2.1

SAN ONOFRE POPULATION DISTRIBUTION

Distance:	0-1 miles	0-2 miles	0-3 miles	0-4 miles	0-5 miles
1976 population	0	1388	6672	14,504	24,102
1980 population	0	1462	6746	15,528	26,551
2020 population	0	1462	6746	19,848	37,351

The nearest population center (as defined in 10 CFR Part 100) is the city of San Clemente which had a 1976 estimated population of 23,000 persons and which is projected to reach or exceed a population of 25,000 persons in the early lifetime of the plant. The closest boundary of San Clemente is located about 2.85 miles to the north of Unit 2.

The San Clemente Planning Department has indicated that there is no potential for future residential population south of the San Clemente city limits, since this area is occupied by the U.S. Coast Guard reservation which lies between the city of San Clemente and the San Onofre 2 and 3 site. We conclude that the population center distance is at least 1-1/3 times the low population zone, as required by 10 CFR Part 100.

We have made an independent estimate of the 1970 population within a 50-mile radius of the San Onofre 2 and 3 site based upon the Bureau of Census data. Our value of 3,605,418 is lower than the 4,173,005 value listed by the applicants in the Final Safety Analysis Report.

The applicants' projected growth rate for the year 2020 for the area within a 50-mile radius of the site was compared with the population projections of the Bureau of Economic Analysis for Areas 164 and 165, as shown in Figure 2-5. This comparison showed a projected growth of about 11 percent per decade as compared with 22 percent per decade estimated by the applicants.

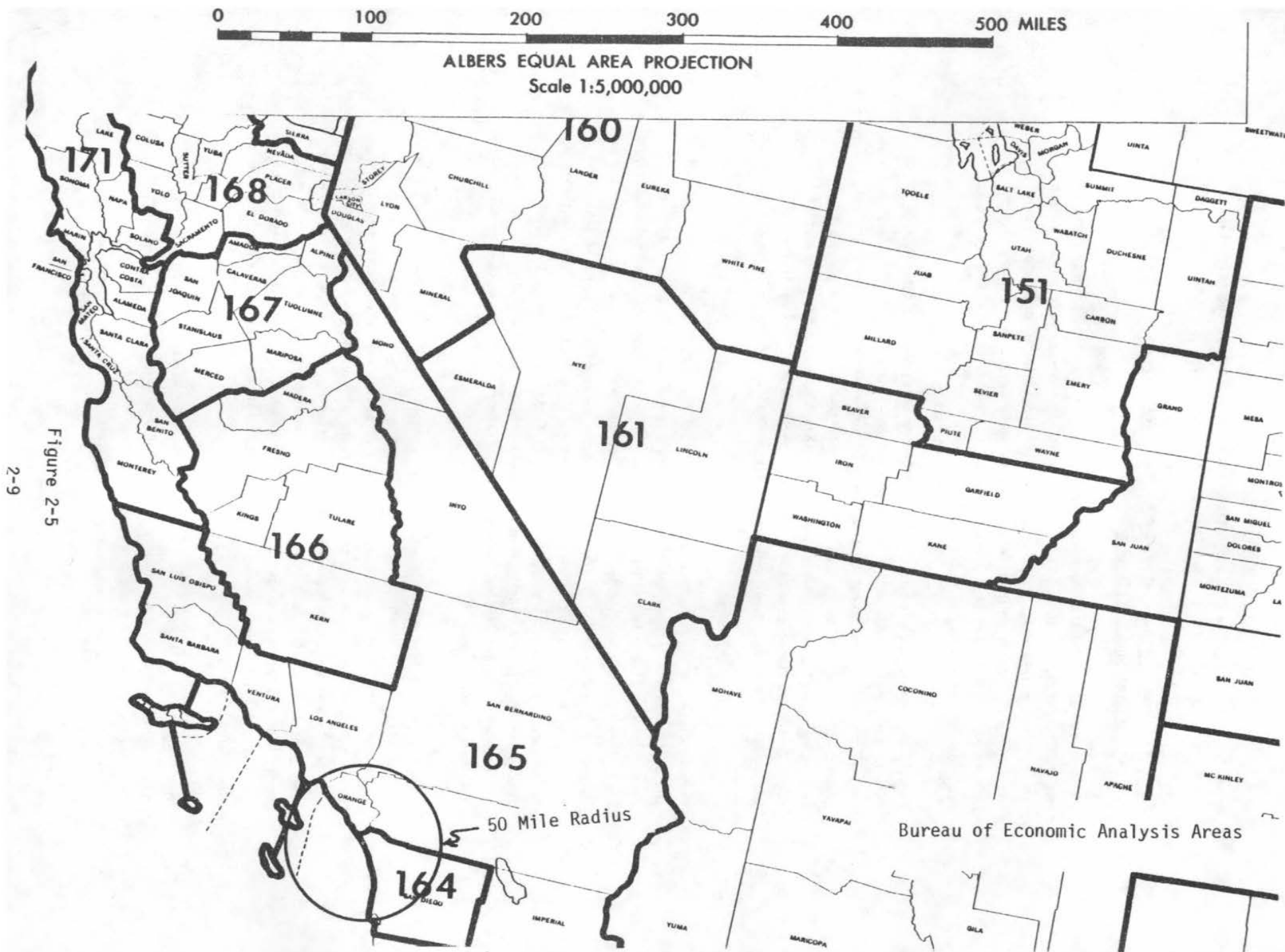
The applicants have estimated a peak transient population in tourist and recreational activities along Interstate 5 in a 10-mile radius of the plant to be 56,600 persons. This increase during the summer months is due to persons engaged in water sport recreation on the Pacific Ocean beach and coastal waters.

The population of Camp Pendleton is variable but averages approximately 33,000. We conclude that the applicants' population projections are reasonable, based on our independent review of the available demographic information.

Our evaluation of the emergency plan for the San Onofre Nuclear Generating Station and the steps that the applicants have taken to provide reasonable assurance that appropriate protective measures can and will be taken on behalf of the residents within the low population zone in the event of a serious accident is discussed in Section 13.3 of this report.

2.1.4 Conclusions

On the basis of the exclusion area and low population zone distances and the specified population center distance, our analysis of the onsite meteorological data from which atmospheric diffusion factors were calculated (see Section 2.3 of this report), and the calculated potential radiological dose consequences of design basis accidents (discussed in Section 15.0 of this report), we conclude that the exclusion



area, low population zone and population center distance meet the guidelines of 10 CFR Part 100, and that the San Onofre 2 and 3 site continues to be acceptable.

2.2 Nearby Industrial, Transportation and Military Facilities

2.2.1 Locations, Routes, and Descriptions

The nearest major land transportation routes are the San Diego Freeway (Interstate 5) and the Atchinson, Topeka and Santa Fe Railroad right-of-way east of the site between Highway 101 and Interstate 5 which pass through the exclusion area approximately 600 feet to 700 feet from Units 2 and 3 containment buildings. Old Highway 101 lies between Interstate 5 and the reactor site and is used as an entrance road to the south end of the San Onofre State Beach.

Three pipelines in the vicinity of the San Onofre Units 2 and 3 site include a 6-inch natural gas pipeline adjacent to Basilone Road and located 1-1/4 miles away, a 12-inch natural gas pipeline adjacent to Interstate 5, and a 10-inch refined petroleum products pipeline 2 miles to 5 miles northeast of the plant in Camp Pendleton. Commercial vessel shipping lanes are greater than 5 miles to the southwest of the plant in the Pacific Ocean. There are no airports within 5 miles of the San Onofre 2 and 3 site. There are no missile sites within 10 miles of the San Onofre 2 and 3 site.

Camp Pendleton is used by the U.S. Marine Corps for training and maneuvers on both the beach area and inland from the San Onofre 2 and 3 site. The military uses of areas within a five-mile radius of the site include three base camps, numerous firing areas (see Figure 2-6), and two ammunition storage areas. Most of the activities are conducted inland from San Onofre 2 and 3, in the range of coastal hills that parallel the coast. No amphibious landings will be made in the vicinity of the plant site due to an agreement between the applicants and the Marine Corps and to the location of fences surrounding the plant. A quarry is located in Camp Pendleton four miles north of the plant site for crushed rock used to surface roads on the base. No explosives are used at this quarry.

At a distance of five miles inland from the plant site, Marine Corps aircraft bombing and strafing ranges are located. Aircraft approaching the ranges do not pass near the plant. Firing of ground weapons is in a direction away from the San Onofre 2 and 3 site and located so that the maximum range of the weapons would not permit an impact closer than two miles from the plant, assuming that they were fired towards the plant instead of in a designated sector. No bombardment from the sea is ever permitted, and shore landings do not use live ammunition. We conclude that the military training operations at Camp Pendleton will not affect the safe operation of San Onofre 2 and 3.

Air traffic near the site (see Figure 2-7) includes Airway V-23 which passes 1/2 mile seaward of the San Onofre Units 2 and 3 site and is used by single- and twin-engine aircraft. Commercial and other high-speed aircraft fly along the coast (via V-25) 12 miles southwest of the plant. Military aircraft operations

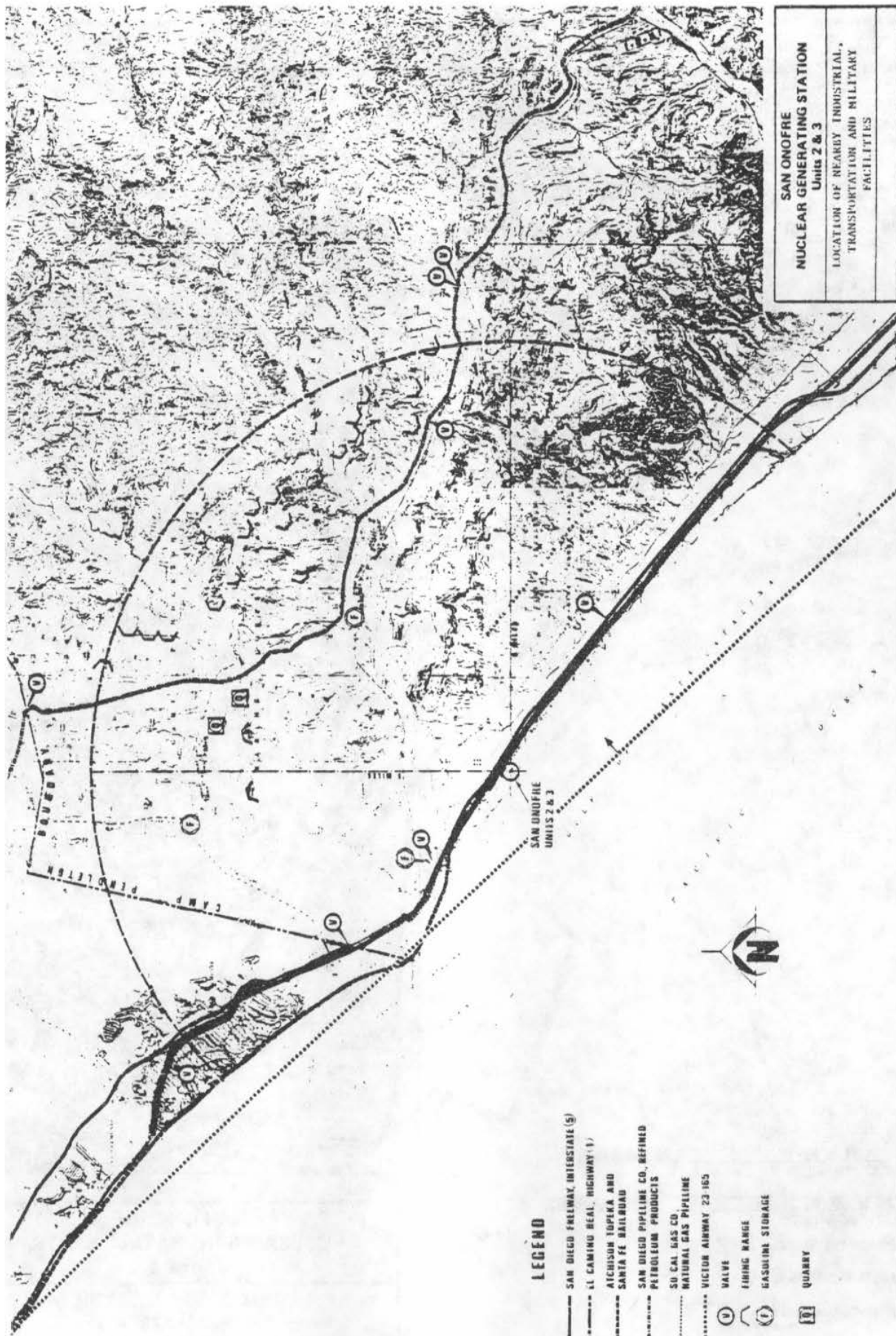


Figure 2-6



includes both helicopter flights associated with Camp Pendleton and high-speed jets associated with the El Toro Marine Corps Air Station. These latter operations are concentrated 7.5 miles northwest of the site in the El Toro landing corridor.

There are no plans for expansion of existing facilities or new industrial development within a five-mile radius of the plant.

2.2.2 Evaluation of Potential Accidents

The applicants have considered the shipment of hazardous materials including toxic, flammable and explosive materials along Interstate 5 (I-5) and the Atchison, Topeka and Santa Fe (ATSP) Railroad. The applicants have presented analyses which conclude that the probability of transportation accidents, leading to overpressures in excess of plant design criteria, is within NRC staff acceptance criteria and is sufficiently low so that the accidents need not be considered as design basis events. The applicants' conclusions stem from the analyses presented in the Final Safety Analysis Report (FSAR) and from revised analyses given in a study prepared by the Nuclear Utility Services (NUS) Corporation. Their analyses are based on considering the frequency of quantity of flammable or explosive material shipments, transportation accident statistics, and meteorology.

Although the applicants' analyses for overpressure events offer a reasonable approach and contain the basic elements necessary for a risk assessment, we do not agree with the applicants' conclusions for the following reasons:

- (1) We do not have assurance that the applicants' analyses are based on an appropriate interpretation and use of data on transportation accidents, and, therefore, that the risk level due to overpressures has been estimated appropriately. For example, our review indicates that the applicants' estimates of motor carrier and train accident rates are based on regionally adjusted data which are difficult to justify in view of unadjusted nationally averaged data. Data used to estimate motor carrier explosion probabilities in the event of a spill are questionable with respect to completeness. With respect to tank truck accident severity, the use of tandem trucks does not appear to have been factored into the analyses, yet during a site visit it was apparent to the staff that such traffic was fairly common on I-5. An accident involving a tandem truck would potentially double the spill size and, thus, raise the potential overpressure beyond that considered by the applicants.

The above considerations lead us to believe that the applicants' explosion probability estimates may be optimistic. Our own analyses indicate that correction of some of the factors used by the applicants would yield explosion risk estimates which are about 40 times higher than those reported by the applicants.

- (2) Even if the applicants' estimates are accepted, the resulting risk estimates, as described in the NUS study, are marginal at best. The applicants estimate that the annual probability of exceeding 3 psi overpressure at the plant is 7.7×10^{-7} , and contend that this is acceptable since it is less than 10^{-6} . The staff criterion for determining if an offsite hazard should be considered as a design basis event is described in Standard Review Plan (SRP) 2.2.3. The staff position is that a probabilistic risk estimate, when determined by conservative calculations, should not exceed 10^{-6} per year and, when combined with reasonable qualitative arguments, the realistic estimate should be shown to be lower. However, when realistic estimates are made, the criterion to be used is approximately 10^{-7} per year.

It is our view that the NUS study clearly represents a realistic analysis, wherein an in-depth and detailed assessment of each significant phase of an accident sequence (i.e., accident rate, spill probability, spill size, probability of ignition/detonation, meteorology) is made. Hence, the results of the study, assuming for the moment that they are not invalidated by inappropriate data, are closer to the 10^{-6} criteria of SRP 2.2.3 for a conservative analysis than the 10^{-7} per year that is acceptable for a realistic analysis.

In view of the above, we do not find that the applicants have demonstrated that the explosion risks associated with transportation of hazardous materials past the site are sufficiently low to be acceptable. As a result of recent discussions of this issue with the applicants, they have agreed to revise their probability analysis, and to evaluate the ability of plant structures to withstand overpressures greater than the design value of 3 psi (tornado loading). The applicants will evaluate the overall plant response, including the capability to carry out a safe shutdown for the spectrum of postulated transportation accidents. We will require that the portions of the plant found to be vulnerable to significant blast damage be modified such that there will be a reasonable expectation of their survival and retention of functional capability in the event of a design basis overpressure. We will report on the resolution of this issue in a supplement to this report.

With respect to the applicants' analysis of toxic gas hazards from transportation accidents, we are unable to verify the motor carrier accident rate which is presented in Section 6.4 of the FSAR. The value of 2×10^{-10} accidents per mile used in Section 6.4 is about four orders of magnitude less than the truck accident rate based on nationally averaged statistics used by the applicants in Section 2.2 analyses. Thus, the applicants' estimated need for control room operator protection may have to extend beyond the selected gases, namely chlorine, butane, carbon dioxide, and ammonia. Our position is that the applicants must substantiate the truck accident rate used in their toxic gas analysis or revise it accordingly. We will report on the resolution of this issue in a supplement to this report.

The applicants' initial analysis of the consequences to the plant in the event of a rupture of the 12-inch natural gas pipeline (about 450 feet from the nearest

plant structure) was limited to considering atmospheric diffusion with buoyancy effects. Staff review identified the potential for plume downwash, local entrainment and turbulence due to the topography of the site and the relative location of plant structures. The staff requested the applicants to provide a probabilistic assessment of the risk associated with potential ruptures of the pipeline. The applicant has responded by providing a risk analysis, complemented by an additional natural gas transport analysis which took potential topography effects into account. We have reviewed the revised analysis (Amendment 16) and agree with the applicants' approach and results which indicate that the probability of a pipe rupture and flammable concentrations of natural gas reaching the plant air intakes is well below 10^{-7} per year. Thus, the risk associated with the 12-inch pipeline is acceptably small.

2.3 Meteorology

In order to ensure that the San Onofre 2 and 3 safety-related plant design and operating bases are within NRC guidelines, we have evaluated the regional and local climatological information, including extremes of climate and severe weather occurrence, which may affect the safe design of a nuclear power plant. To determine that postulated accidental and routine operational releases are within these guidelines, we have evaluated the atmospheric diffusion characteristics of the site. Our evaluation and description of the meteorological characteristics of this site followed the procedures outlined in Sections 2.3.1 through 2.3.5 of NUREG-75/087 (the Standard Review Plan), except for one modification described in Section 2.3.4.

2.3.1 Regional Climatology

The climate of the coastal region of southern California is strongly influenced by the Pacific Ocean. Summers are relatively cool with daytime temperatures averaging between 70 degrees Fahrenheit and 80 degrees Fahrenheit; daytime seabreezes are frequent. Hot, dry desert air from east of the coastal mountains (Santa Ana winds) may intrude onto the coastal plain several times each year, primarily in the fall, but temperatures exceed 90 degrees Fahrenheit usually less than five days annually. The influence of the Pacific Ocean also results in mild winters, with daytime highs in the 60 degrees Fahrenheit to 70 degrees Fahrenheit range, and nighttime lows in the 40 degrees Fahrenheit to 50 degrees Fahrenheit range. Temperatures below freezing are rare.

The maximum and minimum dry-bulb temperatures selected by Southern California Edison Company for general plant design are 104 degrees Fahrenheit and 36 degrees Fahrenheit, respectively. The maximum temperature is equalled or exceeded less than 1 percent of the time for the summer months (June-August). The minimum temperature is equalled or exceeded 99 percent of the time for the winter months (December-February).

Precipitation along the coastal plain averages around 10 inches annually. The rainfall is very seasonally dependent with 85 percent of the total occurring from November through March; almost no rain falls during the summer months. Average

relative humidities range from above 80 percent during the early morning hours of summer and fall, down to around 55 percent during winter afternoons.

Snow, glaze and hail are almost nonexistent in the site vicinity. Therefore, we conclude that snow and ice loadings need not be considered for plant design.

Although they are infrequent, thunderstorms, tropical cyclones, tornados and dust storms can affect the site area. Thunderstorms occur less than five days annually. Tropical storms are also rare, with a storm entering the region on the average less than once every 10 years.

Table 2.2 lists the characteristics of the design basis tornado for which the San Onofre Units 2 and 3 facility was designed. These values are less severe than those recommended by Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants," for tornado intensity region II (in which the site is located). This is acceptable, as discussed by Regulatory Guide 1.76, provided the less severe design basis tornado can be justified by a site-specific analysis using regional data. To this end, the applicants provided regional tornado data to verify the site design basis tornado characteristics, and we independently evaluated these data. Between 1952 and 1975, 23 tornadoes and 21 waterspouts were reported within a 13,000 square mile area containing the site. Using the method described by Markee, et al. (1974), we calculated, for an expected tornado path area of about 0.1 square miles, a recurrence interval of about 70,000 years for any tornado or waterspout at the plant site, and a probability of occurrence of about 10^{-7} per year for the design basis tornado. Since our calculated site-specific design basis tornado characteristics were less severe than the design basis values, we conclude that the design basis tornado characteristics listed in Table 2.2 are acceptable for the site and meet the guidelines of Regulatory Guide 1.76.

Dust storms are relatively infrequent in the site region; between 1940 and 1970, dust or blowing dust and sand reduced visibility to under seven miles only about one hour annually.

We conclude that the applicants have sufficiently described the regional climatology and severe weather phenomena which are important to the safe design of San Onofre 2 and 3.

2.3.2 Local Meteorology

The San Onofre 2 and 3 site is located on the relatively narrow coastal plain, near the mouth of San Onofre Canyon. Coastal bluffs, nearby hills and valleys, and the Pacific Ocean contribute to make the site topographically complex. Within 5 miles of the site, elevations range from 1725 feet above sea level (about 3.5 miles east of the site) to sea level along the Pacific Ocean.

To assess the local meteorological characteristics of the San Onofre site, climatological data are available from San Diego, California (50 miles southeast of

TABLE 2.2

DESIGN BASIS TORNADO CHARACTERISTICS
SAN ONOFRE NUCLEAR GENERATING STATION,
UNITS 2 AND 3

<u>Tornado Parameter</u>	<u>Value</u>
Maximum Speed (miles per hour)	260
Rotational Speed (miles per hour)	220
Maximum Translational Speed (miles per hour)	40
Total Pressure Drop (pounds per square inch)	1.5
Rate of Pressure Drop (pounds per square inch)	0.3

The applicants have designed San Onofre Units 2 and 3 based upon these values. Based upon our evaluation of regional tornado data, we conclude that these values are acceptable for the site and meet the guidelines of Regulatory Guide 1.76.

the site), Los Angeles, California (60 miles northwest of the site), and from onsite collection. These data are reasonably representative of the climatological conditions expected in the vicinity of the site.

Based upon our review of regional data, we conclude that the design wind speed (defined as the "fastest mile" wind speed at a height of 30 feet above ground level with a return period of 100 years) of 100 miles per hour is an acceptable value. The "fastest mile" of wind recorded at Los Angeles was 62 miles per hour (March 1952).

In the site area, average daily maximum and minimum temperatures range between 77 degrees Fahrenheit and 64 degrees Fahrenheit in August, the warmest month, to between 65 degrees Fahrenheit and 46 degrees Fahrenheit in January, the coolest month. The extreme maximum temperature recorded was 111 degrees Fahrenheit (San Diego, September 1963); the extreme minimum temperature was 23 degrees Fahrenheit (Los Angeles, January 1937).

The area receives about 10 inches of rain annually; December, January and February, the wettest three-month period, average a total of about 6 inches, while June, July and August combined average less than 0.1 inch. The maximum 24-hour rainfall recorded among these stations has been 6.2 inches (Los Angeles, January 1956). Snowfall is a rarity, with a trace (less than 0.01 inch) being the most ever recorded. Heavy fogs (visibility 1/4 mile or less) occur on about 40 days each year along the coast with about half of the occurrences during October through January.

Wind flow at the site has a strong diurnal dependence, primarily due to the land/sea breeze effect. During daytime hours, the wind flow is predominantly onshore, while at night wind flow tends to be seaward. Table 2.3 shows the wind direction with the greatest frequency of occurrence for each hour of the day for the three-year period of January 25, 1973 through January 24, 1976, as measured at the 10-meter (33-foot) level of the onsite meteorological tower. Figure 2.8 shows the directional frequency of these onsite winds. About 25 percent of the total windflow over the site was from the northeast and north-northeast (principally nighttime offshore flow); 19 percent of the flow occurred from the west and west-northwest (daytime onshore flow). Winds were calm (wind speeds less than 0.75 mile per hour) less than 1 percent of the time at the 10-meter (33-foot) level.

We conclude that the applicants have described the local meteorological conditions which are important to the safe design of San Onofre 2 and 3.

2.3.3 Onsite Meteorological Measurements Program

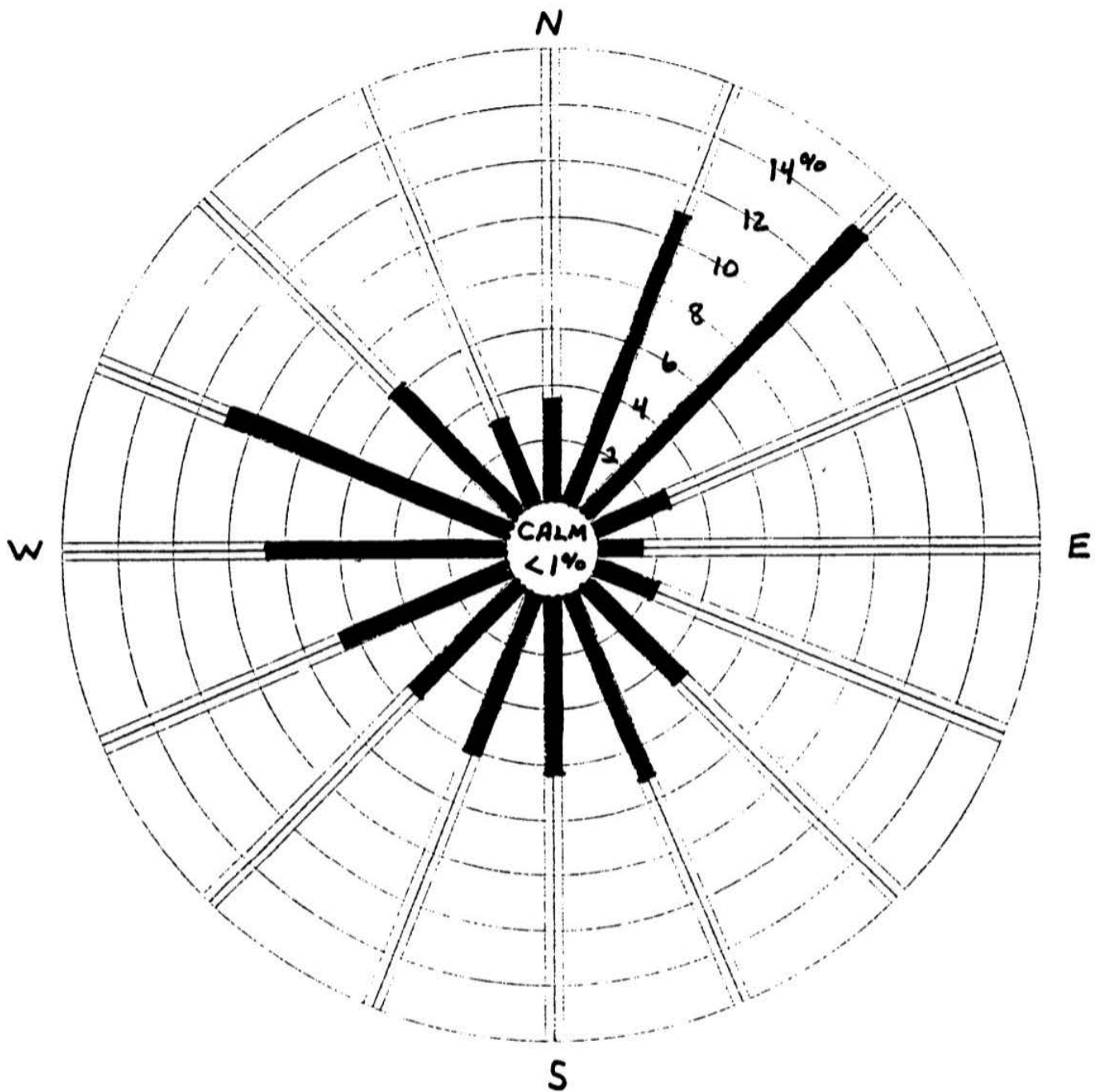
The original onsite meteorological program at the site began in late 1964 with wind measurements at the top of a 19.5-meter (64-foot) mast. In December 1970, the present meteorological monitoring program began with the installation of a 36.6-meter (120-foot) tower atop the coastal bluff about 100 meters (330 feet) west-northwest from the San Onofre Unit 1 containment and 420 meters (1,380 feet) west-northwest of the Unit 2 containment. In October 1975, the tower was extended to a height of about

TABLE 2.3

WIND DIRECTION WITH GREATEST FREQUENCY OF
OCCURRENCE BY TIME OF DAY
SAN ONOFRE UNITS 2 AND 3

<u>Hour</u>	<u>Wind Direction</u>	<u>Frequency (percent)</u>	<u>Hour</u>	<u>Wind Direction</u>	<u>Frequency (percent)</u>
1 a.m.	NE	28	1 p.m.	WNW	25
2	NE	26	2	WNW	27
3	NE	27	3	WNW	27
4	NE	28	4	WNW	27
5	NE	30	5	WNW	22
6	NE	30	6	WNW	16
7	NE	25	7	NW	14
8	NE	19	8	NE	13
9	S	12	9	NE	16
10	W	17	10	NE	20
11	W	20	11	NE	23
Noon	WNW	22	Midnight	NE	25

Date measured at 10-meter (33-foot) level of onsite meteorological tower.



DIRECTIONAL FREQUENCY OF WIND-SAN ONFORE SITE. Onsite data at 10 meters (33 feet) above ground level, January 25, 1973 through January 24, 1976. Bars show the direction from which the wind blows. Calms are those winds with hourly average speeds less than 0.75 miles per hour.

Figure 2-8

43 meters (140 feet). Table 2.4 describes the kinds of measurements and their evaluations on the tower between 1970 and the present. Section 2.3.3 of the Final Safety Analysis Report provides information regarding maintenance, calibrations, quality assurance, data handling and processing procedures, and the specific instrumentation used for the onsite program.

The applicants also conducted an onshore tracer test program at the San Onofre site. Among the objectives of the program were: (1) to characterize dispersion representative of meteorological conditions during accidental and routine plant releases; and (2) to evaluate the appropriateness of using data measured on the permanent site meteorological tower located on the coastal bluff for making dispersion estimates for onshore flows. Appendix D of this report contains our evaluation of the test data.

The applicants provided joint frequency distributions of wind speed and direction by atmospheric stability class, based upon the vertical temperature gradient, collected onsite during the period January 25, 1973 to January 25, 1976. The distributions were for wind speed and direction measured at both the 10-meter (33-foot) and 40-meter (131-foot) levels with the vertical temperature difference between the 6.1-meter (20-foot) and 36.6-meter (120-foot) levels. For our dispersion estimates in Sections 2.3.4 and 2.3.5, we used the joint frequency distributions with the 10-meter level wind data. The joint data recovery rate for the vertical temperature difference and the 10-meter level wind was 88 percent.

As discussed in Appendix D to this report, we originally concluded that the onsite meteorological data collection system on the permanent bluff tower did not meet the guidelines of Regulatory Guide 1.23, Revision 0, "Onsite Meteorological Programs." We came to this conclusion because the data produced by the bluff tower appeared to be anomalous compared to data from other sites that we had reviewed. Specific anomalies included a very high occurrence of the unstable wind stability classes and a decrease in wind speed with increasing height. To explain these anomalies, the applicants conducted an onsite atmospheric tracer gas release and measurement program. Based on our evaluation of the onsite tracer program (see Appendix D), we conclude that although some of the data from the permanent onsite tower appear anomalous, other data from the tower can be used to estimate site atmospheric diffusion conditions using the models in Regulatory Guide 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors." Specifically, we conclude that the wind and vertical temperature difference data measured on the permanent onsite tower are acceptable for use in making atmospheric dispersion estimates for the site vicinity using our models described in Sections 2.3.4 and 2.3.5, below. Therefore, on this basis we conclude that the San Onofre meteorological data collection program, including the tracer program and the permanent onsite tower data collection system, meets the guidelines of Regulatory Guide 1.23, Revision 0 and is acceptable.

TABLE 2.4

ONSITE METEOROLOGICAL INSTRUMENTATION
SAN ONOFRE UNITS 2 AND 3

<u>Period</u>	<u>Measured Parameter</u>	<u>Elevation Above Ground</u>	
		<u>Meters</u>	<u>Feet</u>
12/70 - 1/73	Wind: Direction, Speed and Standard Deviation	36.6	120
	Vertical Dry Bulb Temperature Gradient	36.6 - 6.1	120 - 20
1/73 - 10/75	Wind Direction and Speed	10, 36.6	33, 120
	Wind Direction Standard Deviation	36.6	120
	Dry Bulb Temperature (1)	6.1	20
	Dry Bulb Temperature (2)	6.1	20
	Vertical Dry Bulb Temperature Gradient	36.6 - 6.1	120 - 20
10/75 - present	Wind Direction and Speed	10, 20 ⁽³⁾ , 40	33, 66 ⁽³⁾ , 131
	Wind Direction Standard Deviation	10	33
	Dry Bulb Temperature	10	33
	Vertical Dry Bulb Temperature Gradient	40 - 10 ⁽⁴⁾ 36.6 - 6.1 ⁽³⁾	131 - 33 ⁽⁴⁾ 120 - 20 ⁽³⁾

(1) Installed 1/74

(2) Installed 1/74, removed 1/75

(3) Temporary

(4) Two sets of instruments

2.3.4 Short-Term (Accident) Diffusion Conditions

We estimated short-term relative concentration values for accidental releases from plant buildings and vents. These values are estimated for various time periods following a release and are applicable to the exclusion area boundary (580 meters from the outer edge of the containment buildings) and the outer boundary of the low population zone (3,140 meters). We used the applicants' meteorological data for the three years of onsite collection with wind direction and speed measured at the 10-meter level. We assumed a ground-level release and calculated values for the onshore (west-northwest clockwise through southeast) sectors only. Thus, our evaluation does not consider the atmospheric diffusion conditions in the over-water directions (south-southeast clockwise through west).

We conclude that the evaluation procedures we used for this site provide reasonable estimates of the variations in atmospheric dispersion that occur as a function of wind direction and distance from the source to a receptor. Certain air flow directions can exhibit substantially different diffusion conditions than others, and the wind can transport effluents in certain directions more frequently than in others. For these short-term relative concentration estimates, we modified the calculational procedures described in Section 2.3.4 of NUREG-75/087 (the Standard Review Plan). We used the concepts described in Regulatory Guide 1.145, which considers the variability of meteorological conditions by direction. Based upon our review of the onsite tracer program, we conclude that this model is suitable for this site. Appendix D of this report contains our assessment of the onsite tracer program and the application of its data to calculate diffusion estimates for the site.

Table 2.5 shows the 0-2 hour relative concentration values which we estimate will be exceeded no more than 27 hours per year (0.3 percent of the total time) on the average at the exclusion area boundary for each of the onshore sectors. The northwest downwind sector had the highest relative concentration values for both exclusion area boundary and low population zone calculations; the values from this sector were used in our evaluation of short-term accidental releases and are listed in Table 2.6. The 0-2 hour relative concentration value of 4.0×10^{-4} seconds per cubic meter from this maximum sector will occur or be exceeded no more than about 150 hours per year (1.7 percent of the total time) for all onshore directions.

Our current position, which is defined in Regulatory Guide 1.145, consists of a modification of the percentile at which the relative concentration values are calculated in the sector-dependent model from the 0.3 percent level to the 0.5 percent level. This would result in a reduction of the relative concentration value shown in Table 2.5. Therefore, we conclude that the application of the modification to the interim branch technical position for this site does not change our conclusion that the plant meets the dose requirements of 10 CFR Part 100.

TABLE 2.5

SHORT-TERM RELATIVE CONCENTRATIONS BY DOWNWIND DIRECTION
SAN ONOFRE UNITS 2 AND 3

The values are the 0-2 hour relative concentrations (which we estimate will be exceeded no more than 27 hours per year at the exclusion area boundary (a 580-meter radius from the containment buildings) in the downwind direction indicated (onshore directions only).

<u>Downwind Sector</u>	<u>Relative Concentration</u> <u>(seconds per cubic meter)</u>	<u>Downwind Sector</u>	<u>Relative Concentration</u> <u>(seconds per cubic meter)</u>
WNW	3.8×10^{-4}	NE	2.2×10^{-4}
NW	4.0×10^{-4}	ENE	2.4×10^{-4}
NNW	3.3×10^{-4}	E	2.5×10^{-4}
N	2.7×10^{-4}	ESE	3.0×10^{-4}
NNE	2.8×10^{-4}	SE	3.1×10^{-4}

TABLE 2.6

SHORT-TERM RELATIVE CONCENTRATION VALUES USED FOR ACCIDENT ANALYSIS
SAN ONOFRE UNITS 2 AND 3

The values are the short-term relative concentrations used to evaluate accident releases from plant buildings and vents. The values are for appropriate time periods following a release and are for the exclusion area boundary (580 meters) and the outer boundary of the low population zone (3,140 meters).

<u>Time Period</u>	<u>Location</u>	<u>Relative Concentration</u> <u>(seconds per cubic meter)</u>
0-2 hours	EAB	4.0×10^{-4}
0-8 hours	LPZ	2.7×10^{-5}
8-24 hours	LPZ	1.9×10^{-5}
1-4 days	LPZ	8.2×10^{-6}
4-30 days	LPZ	2.5×10^{-6}

2.3.5 Long-Term (Routine) Diffusion Estimates

Using the three years of onsite data with wind direction and speed measured at the 10-meter level as a basis, we estimated the annual average atmospheric dispersion conditions. We used our atmospheric dispersion model for long-term releases based upon the "Straight-Line Trajectory Model" described in Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors" (Revision 1).

The onsite tracer tests showed that ground-level normalized relative concentrations were similar whether the source of release was elevated or ground-level. For convenience we assumed that all plant releases were from ground-level, since this assumption does not affect concentration.

The calculations also include considerations of intermittent releases during more adverse atmospheric dispersion conditions than indicated by an annual/average calculation as a function of total duration of release. Based upon the guidelines of Regulatory Guide 1.111, the calculations include an estimate of the maximum increase in relative concentration and deposition due to the spatial and temporal variation of the air flow not considered in the straight-line trajectory model. Radioactive decay of effluents and depletion of the effluent plume were also considered as described in the guide.

Table 2.7 lists the relative concentration and relative deposition values used to estimate radiation doses as described in the San Onofre Units 2 and 3 Draft Environmental Statement, issued in November, 1978.

2.3.6 Conclusions

The applicants have provided sufficient information for us to evaluate the regional and local meteorological conditions of importance to the design of San Onofre 2 and 3. The three years (January 1973 - January 1976) of onsite meteorological data and the onsite atmospheric tracer test data provide acceptable bases for calculation of reasonably conservative relative concentration values of post-accident and annual/average atmospheric diffusion conditions.

2.4 Hydrology

2.4.1 Hydrologic Description

The San Onofre 2 and 3 site is located on the southern California coast of the Pacific Ocean near the city of San Clemente, California. The San Onofre 2 and 3 site is bordered on the northwest by Unit 1, on the east by Old U.S. Highway 101, on the southeast by the San Onofre State Beach, and on the west by the Pacific Ocean.

The San Onofre 2 and 3 site is situated on the coastal plain at the base of the western foothills of the Santa Margarita Mountain Range. In this area, elevations rise sharply from sea level to a fairly level terrace formation 100 feet to 200 feet

TABLE 2.7

SUMMARY OF RELATIVE CONCENTRATION AND
RELATIVE DEPOSITION VALUES FOR SELECTED LOCATIONS NEAR
SAN ONOFRE UNITS 2 AND 3

<u>Location</u>	<u>Source</u>	<u>Relative Concentration</u> <u>(seconds per cubic meter)</u>	<u>Relative Deposition</u> <u>(per square meter)</u>
Nearest Site Boundary			
580 meters	A	5.4×10^{-5}	2.1×10^{-7}
(0.36 miles)	B	2.4×10^{-5}	9.3×10^{-8}
west-northwest			
Nearest Residence/Garden			
2.1 kilometers	A	4.8×10^{-6}	2.0×10^{-8}
(1.3 miles)	B	1.7×10^{-6}	6.9×10^{-9}
north-northwest			

Key: "Nearest" refers to that type of location where the highest radiation is expected to occur from all appropriate pathways.

Sources: A - Gas decay tank, purge release
 (48 purges/year, 2 hours/purge)

B - Vent continuous release

above mean sea level. At the terminus of the terrace formation, some 7,500 feet inland, the foothills begin, rising with moderate to steep slopes to an elevation of 3,000 feet above mean sea level. The foothill belt extends approximately 28 miles inland and lies in a generally northwest-southeast direction.

There are no perennial streams in the general vicinity of the plant site. However, ephemeral streams and water courses do exist. The major streams are San Mateo Creek, about two miles northwest, and San Onofre Creek, about one mile northwest.

San Mateo Creek has a drainage area of 132 square miles. The drainage divide between San Mateo and San Onofre Creeks will preclude the site from influence by San Mateo Creek.

San Onofre Creek has a drainage of 43 square miles, is about 9.7 miles in length, and 4.7 miles in width. The origin of the basin is in the Santa Margarita Mountains to the northeast of the site. Elevations in the basin range from sea level at the Pacific Ocean to 3,187 feet above mean lower low water (U.S. Department of Commerce, 1978) in the mountain headwaters. There are no existing or proposed control structures within the basin. Camp Pendleton currently utilizes surface runoff infiltration for purposes of recharging the base well system. There are no other surface water users in the basin.

The foothills drainage basin is east of the site and could be a potential source of flooding. The basin drainage area is 0.86 square miles. Elevations in the basin range from about 100 feet above mean sea level near Interstate 5 to 1,200 feet above mean sea level at its origin.

There are no gauging stations or surface water records for this drainage area. There are two water control structures used to divert water under Interstate 5. They have diameters of 42 inches and 72 inches and capacities of about 180 cubic feet per second and 520 cubic feet per second, respectively. Additionally, there is an earthen channel on the east side of Interstate 5 with a capacity of about 1,850 cubic feet per second for diverting water north to San Onofre Creek.

2.4.2 Flood Design Considerations

(1) San Onofre Creek

A probable maximum flood analysis by the applicants resulted in an estimated maximum flood stage of 24.1 feet for a discharge of 71,000 cubic feet per second at the mouth of the creek. Topographical features of the basin will contain this flow and preclude flooding of the site from this source.

(2) Foothills Drainage Basin

The applicants computed the probable maximum flood based upon a probable maximum thunderstorm over the basin and the associated debris runoff. The combined

hydrograph results in a peak water and debris discharge of about 7,340 cubic feet per second. We have reviewed this analysis and find it to be conservative and acceptable. The applicants have proposed a berm and ditch on the east side on Interstate 5 to convey runoff to San Onofre Creek. The applicants used sediment transport principles to analyze deposition of a portion of the debris in the bottom of the ditch. Water surface profiles were then computed, using the aggraded bed, to determine the probable maximum flood water surface elevation. We have reviewed the proposed berm and ditch and find that these provisions to protect the facility from the probable maximum flood are acceptable and meet the criteria of Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants."

(3) Site Drainage

The site drainage facilities are designed to preclude loss of function of safety-related structures and equipment during a probable maximum thunderstorm on the plant area. All catch basins for the subsurface drainage system, roof drains, and exposed floor drains were assumed to be plugged for the purposes of determining water surface elevations arising during the thunderstorm probable maximum precipitation event. Swales are provided in the asphalt areas around the power block to convey the drainage to the seawall where it will discharge to the ocean. The maximum depth of flooding in the power block area is estimated at 0.8 feet on the east side of the auxiliary building. Maximum water depths decrease in the direction of the seawall, which is at elevation 30.0 feet above mean lower low water. Protection against site drainage flooding is discussed in Section 2.4.7 of this report. Drainage towards Units 2 and 3 from the Unit 1 power block area is prevented by a curb located at the slope interface between the two power block areas.

The applicants have provided (Final Safety Analysis Report, Figure 2.4-12A) the estimated depth of flooding on roofs of safety-related buildings and have stated that probable maximum precipitation water depths result in loads that are less than the design basis loads for roof design. We have reviewed the applicants' site drainage features and analyses, have made independent calculations, and conclude that the provisions meet the criteria of Regulatory Guide 1.59 and are acceptable.

2.4.3 Probable Maximum Surge, Seiche and Tsunami Flooding

This subject was reviewed and found acceptable during the construction permit review. No additional or new information was developed during the operating license review. Following is a brief description of the pertinent aspects of this design consideration.

The applicants calculated a maximum runup of 27.5 feet above mean lower low water, due to a 6 foot storm wave occurring during the design stillwater level of 15.6 feet above mean lower low water. This is 2.5 feet below the top of the seawall which is at elevation 30 feet. An independent analysis using our tsunami estimate showed that

a 6 foot storm wave would overtop the seawall and produce water depths at access doors of less than one foot for a very short time. The maximum depth would be against the structures which are adjacent and parallel to the seawall. Runup would be less at the diesel generator buildings because they are located about 300 feet behind the seawall. Protection against flooding is provided as described in Section 2.4-10 of this report.

Analysis of the flooding potential from distantly generated tsunamis was also evaluated during the Construction Permit review, and found to be less severe than the potential for locally generated events.

The spring high tide at San Onofre that has a 10 percent probability of exceedance is 7.0 feet above mean lower low water and the spring low tide with a 10 percent probability of exceedance is 1.75 feet below mean lower low water. The estimated sea level anomaly at the site (the likely difference between predicted high and low tides and likely actual values) is $\pm .33$ foot.

The applicants concluded from their analysis of wind-induced rises in water elevation that large surges will not develop in the vicinity of San Onofre. They predicted a maximum surge of about 2 feet and stated that this will not be the controlling design basis flood for the site. Based on our review of the applicants analysis, our experience and preliminary evaluations, we agree that a storm surge will not be the controlling design basis event for the site, although we believe that the probable maximum surge will be higher than the maximum surge predicted by the applicants.

The applicants analyzed the potential of flooding from both locally generated and distantly generated tsunamis. The locally generated tsunami was found to be the design basis flood for the San Onofre 2 and 3 site. The applicants predicted a locally generated tsunami stillwater level of 15.6 feet above mean lower low water. This level was determined by combining the 10 percent exceedance probability spring high tide, a 2 foot storm surge, a 0.33 foot sea level anomaly and the Probable Maximum Tsunami runup. We and our consultants predicted a level of 15.8 feet above mean lower low water. In our analysis, we used a surge level of 1.0 foot because we have previously accepted this level and had no additional or new information on which to base any change. The design bases for both the applicants' and our estimates are shown in Table 2.8, below.

TABLE 2.8
COMPONENTS OF THE
DESIGN BASIS FLOOD LEVEL

	<u>Depth (feet) or Elevation (feet above MLLW)</u>	
<u>Item</u>	<u>Applicants</u>	<u>Staff</u>
10% Exceedance Spring High Tide	7.0 feet	7.0 feet
Storm Surge	2.0 feet	1.0 feet
Sea Level Anomaly	.33 feet	.33 feet
Tsunami Runup	6.27 feet	7.5 feet
Design Stillwater Level	15.60 feet MLLW	15.83 feet MLLW
Annual Storm Wave Height	6.0 feet	6.0 feet

2.4.4 Ice Effects

Because of the mild climate, ice effects are not a safety consideration at this site.

2.4.5 Cooling Water Canals and Reservoirs

There are no cooling water canals or reservoirs for the San Onofre 2 and 3 site. The small onsite pond associated with Unit 1 is located well away from San Onofre 2 and 3 and its failure cannot influence San Onofre 2 and 3.

2.4.6 Channel Diversion

Not applicable to the San Onofre site. See Section 2.4.5, above.

2.4.7 Flood Protection Requirements

The flood design bases for the site are: (1) thunderstorm probable maximum precipitation on the site area, San Mateo Creek and the foothills drainage basin, and (2) the probable maximum tsunami coincident with the 10 percent exceedance spring high tide and wave runup.

The site drainage system is designed to convey runoff from a storm which is less severe than the probable maximum precipitation event so there will be some flooding in the power block area. As described in Section 2.4.2(3), above, the maximum depth of site drainage flooding in the power block area is estimated to be 0.8 foot above plant grade. This level is higher than exterior door entrances on some safety related structures. To preclude water from entering these structures, all doors except for the diesel generator building are watertight and open outward. Additional specific provisions for flood control include administrative procedures to ensure all watertight doors and hatch covers are locked-closed during normal operations. In addition, all watertight doors are alarmed and monitored on the security office console. Doors on the diesel building are not watertight but since the PMF level at elevation 30.8 feet is 0.3 foot (3.6 inches) higher than the floor, a curb with a minimum height of 4 inches will be placed to protect all safety-related electrical conduit penetrations below the PMF level. We did not agree that this low curb provided a conservative level of flood protection. To provide additional protection, the applicants state that administrative procedures will require that the access doors of the diesel buildings will be normally locked and alarmed and also that if a door is opened during normal operation, a guard will be posted. We conclude that this will provide adequate assurance that wave runup will not adversely affect the diesel generators.

Protection against severe foothills drainage basin runoff will be provided by a ditch and berm that will divert flows up to and including the probable maximum flood, away from the site and into San Onofre Creek. Similarly, the roofs of safety-related buildings are capable of safely storing or disposing of local precipitation as severe as the local probable maximum precipitation.

The reinforced concrete sea wall to elevation 30.0 feet above mean lower low water will provide protection from the probable maximum tsunami and coincident wave runup. The short duration and small depth of water that could occur in the plant area due to wave overwash will be provided for by watertight doors and other administrative procedures as discussed above.

We have reviewed these flood provisions and conclude that they meet the criteria of Regulatory Guide 1.59 and are acceptable.

2.4.8 Low Water Considerations

The most severe low water level that could be hypothesized would involve the worst tsunami drawdown combined with an hypothetical extreme low still water level. The extreme low still water level at San Onofre was estimated by the applicants to be -2.63 feet, mean lower low water. This included a Santa Ana wind-induced sea level depression of -0.55 feet, an isostatic anomaly of -0.33 feet, and a 10 percent exceedance astronomical tide of -1.75 feet, mean lower low water. The maximum tsunami drawdown of -12.3 feet, mean lower low water, when combined with the -2.63 feet, mean lower low water, tide level, yields a maximum low water level of -14.93 feet, mean lower low water. This level is well above the intake crest elevation of -20.75 feet, mean lower low water. We concur with this low water level estimated, find it acceptable, and conclude that such a condition will not constitute a threat to the safe shutdown capability of the plant.

2.4.9 Groundwater

The San Mateo formation underlies the site to a depth of about 900 feet. It consists of light brown to yellow, medium- to coarse-grained sandstone. The formation is massive to thickly bedded, poorly cemented and well consolidated. The average groundwater elevation beneath the site is elevation +5 feet, mean lower low water, and is the design basis groundwater level. Groundwater fluctuations on the site vicinity are controlled predominantly by the tides and do not exceed 1 foot. The groundwater gradient is about 3 feet per 1,000 feet or less. There are no groundwater users downgradient of the site. Camp Pendleton operates the only well in the area and its established drawdown level, to prevent saltwater intrusion, is above the elevation of the water table at the site. Thus, there is no potential for reversal of the groundwater gradient at the site.

2.4.10 Ultimate Heat Sink Dependability

The ultimate heat sink provides cooling water for use in the saltwater cooling system (See Section 9.2 of this report) during normal, shutdown, and accident conditions. The ultimate heat sink is the Pacific Ocean.

During normal conditions, cooling water for each unit is obtained from the ultimate heat sink by an intake conduit which connects the primary offshore intake structure with the onshore intake structure (pump house). In addition to the primary offshore

intake structure, there is also an auxiliary offshore intake structure which is capable of providing the shutdown cooling requirements (approximately 34,000 gallons per minute) for both units. Since one auxiliary intake structure can supply both units, a redundant withdrawal capability is provided. The auxiliary offshore intake structures are located about 90 feet shoreward of the primary offshore intake structures.

Seismic Category I structures include the pumphouse, the auxiliary offshore intake structure and the intake conduit from the pumphouse to one conduit segment seaward of the auxiliary offshore intake structure. The remainder of the intake conduit and the primary offshore intake structure are not seismic Category I.

During the course of our review we expressed concern that the primary offshore intake structure or the segment of the intake conduit which is not seismic Category I might fail and block the conduit with sand and gravel. In response to our concern, the applicants stated that the primary offshore intake structure is classified as seismic Category II, but it was designed to withstand Safe Shutdown Earthquake (SSE) loadings. An extreme seismic event would therefore not result in complete structural failure of the primary offshore intake structure. The seismic Category II portion of the intake conduit was also designed to withstand the SSE but, in actuality, the shop-handling loads governed the design, requiring three times more reinforcing than SSE design. Complete structural failure of this conduit is also extremely unlikely.

Although complete failure of the primary offshore intake structure and the intake conduit are highly unlikely, the applicants postulated a failure that would completely block the inflow of water from the primary intake structure. In this situation, the auxiliary intake structure would not be affected and would be fully capable of supplying the required shutdown cooling water for both units.

We reviewed the applicants' analysis and agree that complete blockage of the intake conduit is extremely unlikely. Based on this, we conclude that the San Onofre 2 and 3 safety-related water supply (UHS) meets the suggested criteria of Regulatory Guide 1.27, "Ultimate Heat Sinks for Nuclear Power Plants," and is acceptable.

2.5 Geology, Seismology, and Geotechnical Engineering

2.5.1 Basic Geologic and Seismic Information*

2.5.1.1 Introduction

The geology and seismology of the site was reviewed in detail prior to issuance of construction permits for San Onofre 2 and 3 by the staff of the U.S. Atomic Energy Commission (AEC), the predecessor to the U.S. Nuclear Regulatory Commission (NRC), and its geological advisors, the U.S. Geological Survey (USGS) and its seismological advisors, and the National Oceanic and Atmospheric Administration. The findings of that review were published on October 20, 1972 (U.S. Atomic Energy Commission, 1972)

* Note: This section has been published verbatim in a Safety Evaluation Report on San Onofre 2 and 3 Geology and Seismology, issued December 31, 1980, also under NUREG-0712.

as part of the Safety Evaluation Report relating to construction of San Onofre 2 and 3, and are summarized below.

Additional investigations made by the applicants after the issuance of construction permits for San Onofre 2 and 3 were prompted by discoveries of faulting in and around the site area and by the occurrence of new seismic activity in the site vicinity near the Cristianitos fault. The incidence of anomalous geologic features, consisting of linear shear zones, discovered during the excavation for San Onofre 2 and 3 into the San Mateo formation, is reported in "Safety Evaluation of the Geologic Features at the Site of the San Onofre Nuclear Generating Station," issued by the NRC on July 8, 1975 and is also summarized below. Other investigations made by the applicants were reviewed by NRC staff and the results of our review are discussed in the following sections.

Based on our review of the applicants' submittal of all new information which has become available since the CP review, we find no reason to change the conclusion reached in the Safety Evaluation Report for the Construction Permit approving a Safe Shutdown Earthquake (SSE) of 67g for San Onofre, Units 2 and 3.

2.5.1.2 Conclusions Reached Prior to Construction Permit Issuance

A comprehensive geologic investigation of the site region performed by the applicants included detailed examinations of excavations along the Cristianitos fault and of the sea cliff exposures, geologic mapping, and field examinations, and offshore seismic reflection profiles. The information and the data were presented to the AEC in the San Onofre 2 and 3 Preliminary Safety Evaluation Report with amendments, which we and our advisors reviewed.

We interpreted the geologic information and data to indicate the existence of a zone of deformation about five miles offshore from the San Onofre site which extends from the Newport-Inglewood fault zone to the north and to the Rose Canyon fault zone to the south. We concluded in the Safety Evaluation Report:

"The present evidence indicates an extensive, linear zone of deformation, at least 240 kilometers (km) long extending from the Santa Monica Mountains to at least Baja, California. We and our consultants consider this zone of deformation to be potentially active and capable of an earthquake whose magnitude could be commensurate with the length of the zone. Onshore, data does not show evidence that there are any faults immediately underlying the planned reactor facilities. Although the site is located within 1 mile of the Cristianitos fault zone, exposures of parts of this fault at the coast and at the Plano Trabuco excavations made by the applicant about 16 miles north of the coastal exposure, show that the overlying terrace deposits have not been offset by the fault at these locations. All of the available evidence indicates that the Cristianitos fault is inactive when evaluated using procedures described in the proposed 10 CFR Part 100, Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," November 25, 1971."

2.5.1.3 Geologic Features Found During Excavation for Plant Foundations

On June 5, 1974, the applicants advised NRC that anomalous geologic features had been discovered at the site during the excavation for San Onofre 2 and 3. On June 8, 1974 NRC and USGS staff examined the features at the site which consisted of a conjugate set of linear shear zones (designated A and B type features by the applicants) within the San Mateo formation, which exhibited minor mutual displacements of not more than 4 inches at their intersection. In order to assess the possibility of ground rupture under the plant structures, the applicants were requested on June 10, 1974, to perform a detailed study of these shears. On July 12, 1974 the applicants reported their findings and conclusions (Fugro, 1974a).

On September 11, 1974 the applicants informed NRC of the discovery of two additional geologic features, designated the C and D features, which we examined at the site on October 3, 1974. On November 1, 1974 the applicants submitted their report (Fugro, 1974b) of investigations of these features. A final report of all geologic features observed was submitted (Fugro, 1976). Sufficient information and analyses had been generated by the applicants in the interim reports to permit the NRC and our advisors, the USGS, to complete our evaluations prior to submittal of the final Fugro report.

We and our USGS advisors concurred in the Fugro findings and we concluded in our report (U.S. Nuclear Regulatory Commission, 1975) that all of the geologic features at the site are older than the wave-cut terrace which is estimated to be 70,000 to 130,000 years old. This conclusion is based on the observation that none of them displace the terrace/bedrock contact. Therefore, they are not capable faults as defined in Appendix A to 10 CFR Part 100.

2.5.1.4 Investigation of Trenching Across Cristianitos Fault

A condition, described in the literature (Fife, 1974) evidence suggestive of Holocene movement on the Cristianitos fault, was observed (photo 2 of the Fife report) in a trench excavated in colluvium where the main branch of the fault crosses Oso Creek. A single lime-filled fissure was found in the trench wall immediately over the fault contact between the Oso member of the Capistrano formation and the La Vida member of the Puente formation. The report stated that "No conclusive evidence of Holocene displacement was found on the Cristianitos fault in the study area. Undisturbed Holocene or earlier terrace deposits cap fault traces in Aliso Canyon, Plano Trabuco, and on the coast at San Onofre Bluff."

However, the report further states that the lime-filled vertical crack over the fault trace "is believed to have resulted from differential seismic shaking of Oso and La Vida beds on opposite sides of the fault. This may have occurred during any one of the historic earthquakes that were strongly felt locally." This could have indicated capability of the Cristianitos fault.

An apparently similar condition was observed on an April 9, 1975 site visit by the NRC staff in a bulldozer excavation, made to examine the proposed Viejo Substation site, which cut the Cristianitos fault at the north end of Alliso Valley approximately one mile north of the Oso Valley exposure. We observed in the excavation wall, a river terrace deposit with a linear separation or open crack (unfilled), which was located immediately above and along the projection of one of the principal traces of the Cristianitos fault observed in the bedrock.

Morton and others (1974) mention a backhoe trench, placed in 1971 by the California Division of Mines and Geology, which succeeded in exposing the western branch of the Cristianitos fault. He states that this trench showed apparent displacement of a two-foot thick slope-wash cover along two shears a few feet apart. Maximum dislocation of the soil-bedrock interface was approximately two feet. Additional trenching was placed in the same area by the applicants in June, 1974 in order to check this possibility.

Morton concludes:

"These excavations suggested that the apparent displacement of the soil cover may have been due to a combination of animal borings and differential erosion of the bedrock surface with subsequent soil deposition. However, Holocene movement has not been ruled out. To satisfactorily resolve the problem the authors believe that additional trenches exposing the base of Holocene alluvium are necessary."

In view of the coincidence and similarity of the phenomena observed by D. L. Fife and the NRC staff and the concern raised by P. Morton, we requested that the applicants perform a detailed investigation of the conditions observed and to demonstrate that with reasonable assurance the Cristianitos fault does not present a hazard to San Onofre 2 and 3. A log of the original excavation in the D. L. Fife report was obtained and the trench was re-excavated and logged during September, 1975. The findings reported (Southern California Edison Company, 1976, Enclosure 1 of Volume 1) were as follows:

- (1) The lime-filled crack does not coincide with the Cristianitos fault, but is located 10 to 12 feet west of the western edge of the fault. The crack is not likely due to consolidation creep or to downslope movements in the underlying debris.
- (2) Detailed mapping of the Viejo Substation excavation showed that fault displacement or shearing was not evidenced at the basal contact of the fluvial terrace nor do the overlying terrace deposits show any evidence of shearing.

The staff has reviewed the reports and examined the filed evidence. As a results, we concur in the applicant's findings and conclude that the evidence indicates that the Cristianitos fault does not present a hazard to San Onofre 2 and 3.

2.5.1.5 Stratigraphy and Mapping of the Site Area

During the course of our review of the application for operating licenses for San Onofre 2 and 3, we observed that Figure 2.5-9 of the Final Safety Analysis Report (FSAR) shows the San Mateo formation outcropping to the southeast of the Cristianitos fault, which is in contradiction to the geologic structural interpretation at the site. Consequently the applicants were requested to explain more completely the stratigraphic and structural relationship between the San Onofre Breccia, Monterey, Capistrano, and San Mateo formations. Of particular concern was the geometric configuration of these units with regard to the Cristianitos fault and the possibility of other branches of the fault southeast of the mapped location of the fault at the sea cliff. If other unobserved branches of the fault exist, they could exhibit evidence of movement on the fault which is more recent than that exhibited in the mapped fault at the sea cliff. The evidence could indicate that the Cristianitos fault is capable.

The applicants contracted with Dr. P. F. Ehlig to analyze the stratigraphy and to map the area adjacent to and south of the San Onofre site. He mapped in detail a 24 square mile area, extending from San Mateo Canyon on the northwest to Las Pulgas Canyon on the southeast and from the coast to the east side of the San Onofre Mountains. His report (Ehlig, 1977) provides new information on the relationship of the rock units, and geologic structure in the vicinity of the Cristianitos fault. The report concludes:

- (1) The costal area adjacent to the San Onofre site appears to have been tectonically stable since late Pliocene time except for regional uplift.
- (2) The Cristianitos fault is the only major fault within the area.
- (3) Four minor faults have been mapped on the northwest flank of the San Onofre Mountains to the east of the Cristianitos fault. None of these faults shows evidence of Quaternary displacement.
- (4) No other significant faults have been recognized within the area between the coast and the San Onofre Mountains from the Cristianitos fault southeastward to Las Pulgas Canyon. There is continuity in the geologic structure.

The analysis and mapping performed by Dr. Ehlig appear to be carefully derived and adequately represent those aspects of the geology pertinent to an evaluation of the safety of the site. Figure 2.5-9 of the FSAR is shown to be in error because the San Mateo formation does not exist south of the Cristianitos fault. We concur in the findings and conclusions presented in the report as stated above.

2.5.1.6 Investigation of Offset in Sea Cliff South of San Onofre 2 and 3

On May 20, 1977 a staff member of the California Energy Commission informed NRC of an apparent fault in the sea cliff approximately 3 miles south of the San Onofre plant.

The apparent fault, located within the margin of a large landslide, displaces the bedrock/marine terrace deposit contact at the top of the San Mateo formation a total of approximately 3 feet with reverse movement.

At our request the applicants performed a detailed geologic investigation, including trenching, to study the apparent fault and to determine its relationship to the landslide. They were asked to determine whether the displacements were tectonically induced or are related to landslides. We requested that the applicants, if feasible, trench along the trend of the apparent fault to where it intersects the failure plane along which the landslide slumped.

The exposures in the two trenches excavated along the principal fracture clearly show in the Fugro supplemental report (Fugro, 1977) the relationship of the fracture and the landslide rupture surface. The report concludes that the apparent fault is caused by failure of the landslide mass and is not related to tectonic stresses. The fracture that displaces the bedrock/marine terrace deposit contact is confined within the southeastern boundary of the landslide and therefore is not significant to the safety of San Onofre 2 and 3.

It is our opinion that the evidence demonstrates that displacement of the bedrock/marine terrace deposit contact by the fracture terminates at the landslide rupture surface, and that the displacement does not extend beyond the limits of landsliding. Therefore, we conclude that the displacement of the bedrock/marine terrace deposit contact is the result of landsliding and has no significance to the seismic design of the San Onofre plant structures.

2.5.1.7 Orange County Earthquakes of January 1975

Two small earthquakes of 3.3 and 3.8 magnitude occurred on January 3, 1975 near San Juan, Capistrano, California. The preliminary locations of the events were near the central portion of the Cristianitos fault. These events were of concern to us because if the Cristianitos fault had generated these events, this would constitute significant evidence that at least a portion of the fault might have moved during historic time and thereby the fault may be considered capable.

A program of investigations was conducted by the applicants (Southern California Edison Company, 1976) to evaluate the relationship of the two seismic events to the tectonics of the area. A number of studies of the area were undertaken, including a geomorphic study, an evaluation of microseismic events, a study of focal mechanism, the construction of a sub-surface contour map with appropriate geologic structure sections, an updating of historic seismicity, and geophysical surveys. The results are integrated to develop the relationship between historic seismicity, including the two recent events, and the regional tectonic structure, in particular the Cristianitos fault.

Biehler (1975) concluded that the two seismic events of January 3, 1975 cannot be located on the Cristianitos fault, using the best seismic model for the crustal

structure, but rather appear to be associated with a northeast-trending fault which parallels Trabuco Canyon. This conclusion is supported by the focal mechanism study which indicates that the sense of motion was left-lateral oblique thrust, which is opposite to the historic normal dip-slip motion on the Cristianitos fault. (See Section 2.5.2.2 for further discussion).

2.5.1.8 Tectonics of Capistrano Embayment

Another report (West, 1975) resulting from the applicants' studies evaluates the geologic structure and tectonics of the Capistrano Embayment. It concludes that no significant movement has occurred along the Cristianitos fault since late Pliocene time. The study indicates that the epicenters of the January 3, 1975 earthquakes did not occur on the Cristianitos fault. In fact, there was not substantial evidence that any structure as interpreted by the study is compatible with the epicenters. The report states that the earthquakes may be the result of differential settling within the embayment.

In the report, geophysical and well log data are analyzed by the author resulting in an interpretation of the age and noncapability of the structures in the Capistrano Embayment. Because of insufficient information supporting the bases for the interpretations of the geologic structure made in the report, additional information was requested. This request resulted in additional studies by West (1979) and Shlemon (January 1978, October, 1978) and new seismic reflection profiles by Woodward-Clyde Consultants supplementary report. West (1979) concluded that the structural interpretations made in his report suggest that the major tectonic activity within ten miles of San Onofre site took place prior to the termination of the Pliocene epoch, possibly two million years before present. Since that time the area has been tectonically quiet with the exception of the South Coast Offshore fault zone, along which some movement probably occurred in the Late Pliocene. He further states that the data examined by him revealed no additional faults of this or younger age within five miles of the San Onofre site.

Because of the relative concentration of seismic activity near the Capistrano Embayment and the faulting within the embayment, the applicants were requested to investigate and evaluate any terrace deformation across the embayment. In response, Shlemon (October, 1978) reported the result of a study of the Late Quaternary evaluation of the coastal area. Specific objectives of the study were to delineate the continuity and elevation of the 125,000 year old terrace contact, to determine Late Quaternary rates of deformation, and to locate possible Late Quaternary structural displacements between Laguna Beach and San Onofre State Beach in particular across the Capistrano Embayment.

The report concluded that within the resolution of the survey (1 meter), the 125,000 year old terrace is not displaced between San Onofre 2 and 3 and Dana Point. Regional uplift rates between Target Canyon and Dana Point increase northward from about 6 to 26 cm/1000 years; and indicate longitudinal up-to-the-northwest tilt of the coast across the Capistrano Embayment and toward the San Joaquin Hills. In terms

of local late Quaternary uplift, the 9 cm/1000 year rate at San Onofre 2 and 3 compares with approximately 11-16 cm/1000 years for the San Diego area, 40-50 and conceivably 500-800 cm/1000 years for Rancho La Brea and Baldwin Hills, respectively, and 620 cm/1000 years for the Ventura coast. Therefore, compared with late Quaternary uplift rates elsewhere, in California, the San Onofre region must be viewed as being one of the most tectonically stable coastal areas in Southern California.

2.5.1.9 Slip Rate Versus Magnitude and Its Application to the Offshore Zone of Deformation

For the Construction Permit, a Modified Mercalli intensity value was used to represent the Safe Shutdown Earthquake (SSE)* originating on the Offshore Zone of Deformation (OZD). Because the magnitude is a better measure of the size of an earthquake (see Section 2.5.2.3), we asked that the applicants use magnitude in defining the maximum earthquake potential for the OZD.

The applicants submitted a report (Woodward-Clyde Consultants 1979) which is to be used in partial support for the determination of the maximum earthquake magnitude on the OZD. It described a new method of determining earthquake magnitude by comparing the degree of fault activity on the OZD with that of faults of similar style around the world. According to Slemmons (1977), faults having higher degrees of activity produce larger magnitude earthquakes than faults having lower degrees of activity. The parameter chosen to represent the degree of activity is the fault slip rate. The method was used to estimate the maximum earthquake magnitude associated with the OZD by evaluating fault slip rates and historical seismicity of many faults of similar style around the world. Data was collected and plotted on magnitude versus slip rate (logarithmic) coordinates and a line enveloping the maximum historical earthquake was considered to represent the maximum earthquake associated with each slip rate. This was called the Design Earthquake Limit (DEL).

2.5.1.10 Evaluation of the Slip Rate and Magnitude Data Used in the WCC Report

Figure 7 of the Woodward-Clyde Consultants (WCC) report is a plot of the long-term slip rate measured on a fault versus the maximum historical earthquake magnitude observed on that fault. The slip rates and magnitudes were taken from the literature where there were often several values given for each fault as shown in Table G-1 of Appendix G. The slip rate on the Newport-Inglewood fault zone portion of the OZD, determined from analysis of electric well log data, was calculated to be 0.5 mm/yr. The 0.5 mm/yr was considered to be representative of the slip rate for the OZD which correlated with a maximum magnitude of 6 1/2 from the DEL in Figure 7. Thus, the applicants concluded that the maximum magnitude that can be associated with the OZD is $M_S = 6 \frac{1}{2}$.

* The SSE is also called the design basis earthquake (DBE).

A study of the data base in Table G-1 for Figure 7 of the WCC report showed that some inconsistencies occur among the various reports on slip rate and magnitude for a given fault. Since numerous publications were reviewed by WCC, a wide variation in the data is bound to exist due to the differences in approach and scope of work of the various investigators. Table G-1 presents the range of data and interpretations, but does not reflect any attempt to appraise the quality or validity of the data. Therefore, it was the opinion of the staff that the data selected for Figure 7 of the June 1979 WCC report were not adequate.

To compensate for the wide range of data, the applicants were requested (in question number 361.45; both the staff questions and the applicants' answers are given in the "Question and Response" section of the FSAR) to provide a detailed description of the method of selecting or rejecting basic data and to use error bands of variations which encompass all of the values of slip rate and magnitude determinations by the various investigators cited in Table G-1. As a result, the data selection process was described in greater detail and several modifications to the data were made in Amendment 18 to the FSAR. Extraneous or unverifiable data included in the WCC report were eliminated and new data obtained since publications of the WCC report were added. Also, in response to our request, preference was given to the slip rate values based on Quaternary data because they best represent the current tectonic environment and activity of the faults. The line bounding the augmented data set was called the Historic Earthquake Limit (HEL); while the line bounding all of the data established the Maximum Earthquake Limit (MEL) in Figure 361.45-4 in Amendment 18 to the FSAR. The applicants state, "The MEL is interpreted most conservatively by enveloping the lowest slip rate ranges and the maximum magnitude ranges of all the data points. The most conservative use of the line is to estimate a maximum earthquake by reading the MEL value based on the maximum slip rate value provided for each fault."

We concur that the MEL line represents a conservative estimate of the maximum magnitude of future earthquakes on these faults or faults of similar style. The maximum magnitude for the OZD is $M_S = 7.0$ applying the conservative interpretation of the MEL line and assuming the highest slip rate 0.68 mm/yr calculated for the Newport-Inglewood fault zone as part of and representative of the OZD. Although there is a paucity of data below 1.0 mm/yr, which reduces our confidence in the correlation in the range below that value, we agree that $M_S = 7.0$ is a conservative outcome for this method of approach to a determination of the SSE magnitude for the OZD.

Dr. David Slemmons, consulting geologist to the staff, was contracted to review the WCC report and responses to NRC questions which resulted from our initial review of the report. In his report to NRC, which is Appendix E to this report, he comments on the slip rate versus magnitude relationship, the adequacy of the WCC data base used in deriving this relationship, and the maximum earthquake magnitude assigned to the OZD. We concur with his recommendation that the new approach presented by WCC is the firmest, most quantitative approach for the evaluation of the maximum earthquake for San Onofre 2 and 3 but it should be one of several approaches in a balanced

multi-approach to the determination of the maximum earthquake magnitude. Dr. Slemmons concurred in the applicants fault slip rate for the Newport-Inglewood fault zone at 0.5 mm/yr and with the maximum magnitude of 7 for the OZD.

2.5.1.11 Determination of the OZD Rupture Length

Dr. Slemmons (Appendix E) also provided a discussion of other methods that relate fault parameters to estimating maximum earthquake magnitude on the OZD, with particular attention to those methods relying upon fault length. He provided an extensive discussion of the appropriate fault lengths to be used for the OZD and the tectonic relationship of the OZD to faulting in Baja California.

Physical characteristics of a fault zone have been used in the past to estimate the maximum earthquake potential. Typically a correlation is sought between earthquake magnitude and recorded or estimated rupture length. Generally, these correlations are poor because of the large scatter of data. While some of the scatter is due to the inability to arrive at accurate estimates of rupture and displacement over the whole fault plane, a great deal of uncertainty arises from the very complex nature of tectonic conditions that lead to earthquake occurrence. Variations in important elements such as local and regional stress conditions and specifics of fault geometry undoubtedly preclude good correlations.

The application of the earthquake magnitude versus surface fault rupture length procedure (Slemmons 1977) requires that brittle fracture occur and that total surface rupture length be observable. However, the surficial offshore materials near SAN Onofre 2 and 3 are such that plastic deformation conceals the tectonic effects along the OZD. In addition, water covers the offshore portion of the OZD. However, Dr. Slemmons (Appendix E) used indirect methods to apply this procedure. From the subsurface rupture lengths observed by means of seismic reflection profiles, he was able to use the earthquake magnitude versus surface rupture length method as another approach to determining the maximum magnitude for the OZD.

A most conservative approach used by Dr. Slemmons was to assume that the OZD is segmented and that the segments are indicated by the length of main rupture not at the surface or at shallow horizons, but at Horizon C, which is several thousand feet deep. The trace of the OZD at Horizon C is shown in Figure D-1 of WCC (1979). The segment of the OZD offshore of San Onofre 2 and 3 (the South Coast Offshore Zone of Deformation) has a total length of 62 km and, applying the relationship of strike slip faults of Slemmons (1977), leads to a maximum earthquake magnitude $M_S = 7.1$. Assuming the values for segment length of 36, 27, and 48 kms provided by the applicants in Table 361.66.1 of the FSAR, the maximum earthquake magnitudes are $M_S = 6.7$, $M_S = 6.6$, and $M_S = 6.9$, respectively.

Another approach to determining maximum earthquake magnitudes is to assume that a fraction of the total length of a causative fault will rupture. Since the fraction of the fault that is assumed to rupture varies over a wide range, Dr. Slemmons reviewed the world-wide data for strike-slip faults to determine the fraction of

total fault length that has accompanied earthquakes of $M_S = 6$ or greater (Appendix E). The mean of the highest percentage for each fault was determined to be 22 percent of the total length of strike-slip faults. He applied this method to the OZD, assuming that the zone extends from the Santa Monica fault to the San Diego Bay area. Based on a total length of 200 km, and assuming the mean fractional rupture length of 22 percent (44 km), a maximum magnitude $M_S = 6.9$ is obtained. Using the fractional rupture length corresponding to the mean plus one signer of 30 percent (60 km), a maximum maggitude of $M_S = 7.1$ results.

We concur with Dr. Slemmons that the north end of the OZD is truncated by the Santa Monica fault, however, the south end is not clearly defined. Here the tectonic style does appear to change from strike slip to normal faulting, which is the basis for Dr. Slemmons southern terminus, giving a total length of 200 km. However, Greene and others (1979) define the OZD as a discrete belt that extends at least 240 km from near the Santa Monica Mountains into Baja California. Legg and Kennedy (1979) state that the OZD "apparently merges with the Vallecitos-San Miguel fault zone, although a connection with the Tres Hermanos or Agua Blanca fault zones is also possible." The U.S. Geological Survey in their 1972 report to the AEC (now the NRC) concluded that the OZD appears to extend southeastward to at least the Mexican border and is at least 240 km in length (see Section 2.5.1.2 of this report).

The applicants (see FSAR response to Question 361.66) have argued that the OZD and the major Vallecitos-San Miguel faults in Baja California should not be associated structurally. In support of their view they point to an absence of faulting and an apparent age difference in faulting between the southern OZD and the northern Vallecitos-San Miguel. Seismicity and fault offsets vary greatly over both fault zones. The most seismically active segments being the northern end of the OZD (Newport-Inglewood fault zone) and southern section of the San Miguel fault.

Gastil (1979) discusses the evidence suggestive of a possible connection in the form of a northwest trending lineament which extends from the southernmost end of the known Rose Canyon segment of the OZD to the northernmost end of the known Calabasas-Vallecitos-San Miguel fault zone. Evidence for the lineament are:

- (1) Northwest trending faults in the San Ysidro area at the north end of the lineament.
- (2) Alignment of thermal springs.
- (3) Alignment of the Tijuana Valley.
- (4) Stratigraphic contrasts or facies changes across the lineament.
- (5) A set of northeast trending faults appears to be truncated by the lineaments.

- (6) Apparent offset (1 km) of the Pacific Boundary faults.
- (7) A Richter magnitude 3.5 seismic event toward the south end of the lineament.
- (8) Undocumented report of equivocal evidence for faulting in the Canon de la Presa, the epicentral location of the magnitude 3.5 earthquake, by Robert Washburn.

The primary evidence given by Gastil against the lineament being structurally controlled is that there is no photographic evidence of faulting in the bedrock exposures across the lineament. This would suggest that throughgoing faulting has not occurred in the area. The staff is of the opinion that the lineament is not an expression of faulting of the type that would be needed to connect the OZD with the Calabasas-Vallecitos-San Miguel fault zone.

The applicants argue that the evidence is not supportive of a throughgoing fault and that the occurrence of only one small earthquake (the 1978 event) near the proposed connection is evidence of an historically quiet seismic record. While the existence or non existence of this connection cannot be unequivocally demonstrated at this time, nor can the structural tectonic relationship between the southern OZD and Baja California be established, we conclude that, based upon the differences cited above, it is unwarranted to consider the combined OZD-Calabasas-Vallecitos-San Miguel fault zones capable of rupturing along major portions of its total length.

As further evidence of discontinuity, Dr. Slemmons states that the Vallecitos fault lacks geomorphic evidence for activity. Mesozoic dikes appear to be offset by only 100 m or so (Gastil 1979) which would indicate very low slip rate activity. He concludes that, "It is reasonable to interpret this zone in terms of separate, partly en echelon, individual faults with very low slip rates and low activity that may be activated independently, and the length of the zone should not be added to that of the OZD." Based on the available evidence, as discussed above, the staff agrees with Dr. Slemmons' interpretation that the Calabasas-Vallecitos-San Miguel fault zone should not be added to that of the OZD to form a continuous fault zone. It should be assumed that the two fault zones would rupture independently.

In response to question 361.66, the applicants provided a discussion of the comparable activity of the OZD and the Agua Blanca faults. The data are summarized in the FSAR in Table 361.66-1. The characteristics that most prominently distinguish the Agua Blanca fault from the OZD are the slip rate and the geomorphic features. The slip rate on the Agua Blanca is given as 2.7 mm/yr as compared to 0.5 mm/yr on the OZD. The geomorphic features of the Agua Blanca fault are characterized as considerably prominent with a strong linear trace in alluvium, offset streams, shutter ridges, and fault sags. These features are not characteristic of the OZD.

In the opinion of the staff, the tectonic activity of the Agua Blanca fault is distributed to the northwest via a connection (Legg and Kennedy, 1979) with the Coronado Banks fault. There probably is lesser distribution to the Maximinos fault, via a splay in the Agua Blanca near Valle Santo Tomas, and the San Clemente fault.

Activity may be indirectly distributed to the OZD as a branch or conjugate fault to the Coronado Banks fault. In view of the above, we agree with the applicants that the OZD should not be considered comparable to the Agua Blanca fault, but is of a lower order of tectonic activity.

Dr. Slemmons indicates a possible connection of the OZD with the Coronado Banks fault and ultimately to the Agua Blanca fault. If such a connection exists, the OZD would be 247 km long where it connected with the Coronado Banks fault, and 300 km long where it extended to the Agua Blanca fault. Assuming the mean fractional rupture length (22 percent of the fault length), the respective earthquake magnitudes would be $M_S = 7.0$ and $M_S = 7.1$. The mean plus one sigma fractional rupture length (30 percent of the fault length) results in estimated magnitude of $M_S = 7.2$ and $M_S = 7.3$, respectively.

The OZD changes from a southeasterly to a southwesterly direction and from strike-slip to normal faulting starting at San Diego Bay where it appears to continue offshore. Dr. Slemmons points out that such a change in strike and sense of movement may cause the OZD to break as independent segments to the north and south of San Diego Bay. He further concludes "If the OZD extends to the Agua Blanca fault, the branching relation, the different strike, and the possibly different slip mechanism suggest that it should be considered separately from the Agua Blanca fault; worldwide data on branching faults suggest major rupture on one does not immediately cause major rupture on the other."

The maximum earthquake magnitudes resulting from the various tectonic models characterizing the OZD are discussed in Section 2.5.2.3 of this report.

2.5.1.12 Investigation of Offshore Extension of the Cristianitos Fault

(1) Discussion of H. G. Greene, and others, Paper

In the publication entitled, "Earthquakes and Other Perils San Diego Region" edited by Abbott and Elliott, one of the articles in this reference, "Implication of Fault Patterns of the Inner California Continental Borderland Between San Pedro and San Diego" by Greene and others contains a map (page 22) which indicates a possible connection between the Cristianitos fault and the OZD. Recent movement on the fault is also indicated. A discussion with two of the authors, H. G. Greene and J. I. Ziony, confirmed the possibility of this connection. This postulation was based on limited reflection profiling by the USGS.

(2) Early NRC Staff Position

The staff was concerned that if the Cristianitos fault was deemed capable, a large earthquake on it could result in high amplitude ground motion at the site; however, the possibility of ground surface rupture under the San Onofre 2 and 3 plant facilities is negligible. Post Pliocene movements on the Cristianitos fault, if they occurred, are not reflected in the excellent exposure of San

Mateo formation between the fault and the site. Except for the minor shears which appeared in the plant excavations, discussed in Section 2.5.1.3, there are no visible faults within one-half mile of the plant site.

(3) USGS Evaluation of Seismic Reflection Profiles

A number of offshore seismic reflection surveys were performed by the applicant and by others in the vicinity of the site over the 10-year period beginning with the development of the safety analysis for the construction permit. The purpose was to investigate the structural features offshore.

On May 8, 1980, we requested that a comprehensive review be made by the USGS of all marine geophysical data relevant to the character and recency of faulting along the offshore extension of the Cristianitos fault in the vicinity of the San Onofre 2 and 3. This request was concerned specifically with a proposed structural relationship between the Cristianitos zone of deformation (CZD) and the OZD. The NRC requested that this review be made jointly by H. G. Greene of the USGS and M. P. Kennedy of the California Division of Mines and Geology, because of the extensive joint research effort then underway by Greene and Kennedy on aspects of the structural geology of the southern California borderland. Their review and a subsequent report were completed on July 18, 1980. Their report, "Review of Offshore Seismic Reflection Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California" is appended as Appendix F.

Plate 1 (Appendix F) shows the CZD extending offshore of the San Onofre 2 and 3 site and oblique to the OZD and to within less than 1 mile of the OZD. The segment of the CZD shown was made with a high degree of confidence; however, continuation to the OZD and its connection with the onshore Cristianitos segment are obscured due to data voids in these areas. The report concludes that their interpretation of the offshore seismic reflection profiles in the vicinity of San Onofre 2 and 3 indicates that two structural zones of deformation are present in this area. The first and most well defined zone is a segment of the OZD, a recognized Quaternary fault zone. The second, the CZD, is less well defined but nevertheless exhibits characteristics similar to those of the OZD. It consists principally of highly fractured and faulted asymmetrical anticlinal structures.

The CZD and associated folds to the east combine to form a broad structural zone (up to 3 km in width) which projects onshore to the north. The southeast end of the CZD could become incorporated with a major syncline of the OZD; however, the structural relationship of the CZD with the OZD is unconfirmed because of a data void. The authors interpret a data void as an area where data may be available but not able to be interpreted due either to structural complexity or poor reflections.

The age of most recent faulting along the CZD is unknown. All seismic profiles examined show that faults associated with the zone end at or near the surface of an apparent wave-cut platform that is overlain by Pleistocene sediment. Nowhere within the zone is there evidence of seafloor displacement.

The report concluded that a structurally deformed zone consisting of correlatable en echelon faults and folds, many extending into shallow subsurface strata (probably Neogene in age), is present along the expected offshore extension of the zone. The seismic reflection data reviewed show that a fairly continuous fault zone extends south to southeastward offshore from San Onofre 2 and 3 to within 1 km of the OZD, where a projected connection is possible.

(4) May 1980 Seismic Reflection Profiles by Nekton, Inc.

A seismic reflection profile survey was conducted by Nekton, Inc. for the applicant to provide higher resolution in the shallow offshore strata to help determine whether or not the Cristianitos fault projects toward the OZD. The report (Nekton, 1980) concludes:

- (a) The Cristianitos fault does not project far enough seaward (i.e., south-southeasterly) to be identified in the survey area. Where the fault may be projected to occur, there is no evidence of its existence. Nekton concluded that along its offshore projection, displacement diminishes and the Cristianitos Fault dies out, possibly in a number of lesser faults and small folds. It does not connect to the OZD.
- (b) The OZD was mapped parallel to the coastline for 8.8 kilometers in the central and northern oceanside survey area. In the central part, at least two branches of the fault occur and their width is limited. To the north, it broadens to a zone of deformation up to 0.6 kilometers (0.4 miles) wide. The OZD is not present in the Dana Point survey area.
- (c) Other faulting offshore - a number of minor faults are interpreted to be present offshore in the survey area. Minor faults in the area are short in length and occur below a Pleistocene erosion surface in Tertiary age beds.
- (d) Fault movement - none of the minor faults shows evidence of movement following the period of erosion which developed the Pleistocene erosion surface. Eighteen kilometers south of San Onofre, the OZD shows evidence for at least two periods of probable movements. Movements during one period have displaced the Pleistocene erosion surface and the movements during the other period appear (locally) to displace terrace deposits of probably Holocene age.

(5) USGS Evaluation of the History and Age of the Cristianitos Fault

On November 26, 1980, our advisors, the U.S. Geological Survey, transmitted to us, in response to our request, their review of the geologic and seismologic data submitted by the applicants in support of their position concerning San Onofre 2 and 3. The review is in the form of a letter report and was prepared by Mr. Robert H. Morris and Mr. James F. Devine, with assistance provided by Dr. H. G. Greene and Dr. Joseph S. Andrews. Attached to the report is an

addendum to: "Review of Offshore Seismic Reflection Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California," by H. G. Greene and M. P. Kennedy. This letter report is appended as Appendix G. The following excerpt contains the USGS conclusions regarding the history and age of the Cristianitos fault.

"In assessing the conclusions drawn by the applicant's consultants in contrast with those by Greene and Kennedy, there emerges a difference in the use of certain named structures. Apparently, the applicant's consultants restrict the use of the term "Cristianitos Zone of Deformation" (CZD), to refer to a zone of short discontinuous faults and folds. The applicant's consultants conclude that the Cristianitos fault dies out to the south whereas Greene and Kennedy project the Cristianitos Zone of Deformation southward to the OZD. SCE recognizes the southward projection by Greene and Kennedy but state in their conclusion that it does not represent an interconnection between the Cristianitos fault and the OZD. Both parties recognize younger undeformed, probably marine terrace, deposits capping the structures near shore. The range in age of these capping deposits is stated by Dr. Shlemon (oral discussion, September 23, 1980, and viewgraph) to be from 80,000 years before present (YBP) to 8,500 YBP. The 8,500 YBP date was obtained by C14 method and the 80,000 YBP was inferred based upon geomorphology and late Pleistocene history. Assuming that the inferred age is a reasonable conclusion, then the applicant's contention that the Cristianitos Fault (restricted use) is not capable is permissive. On land, the Cristianitos Fault is capped by the 125,000 year-old marine terrace, and the above conclusion then is consistent with that evidence.

Applicant's consultant, Dr. Perry Ehlig, discussed the origin of the Cristianitos Fault (restricted use) and concluded that the fault originated from 10 to 4 million years ago during a period of crustal extension and that the present stress regime of generally northeast-southwest compression represents a significant change; therefore, movement on the OZD would not trigger movement on the Cristianitos Fault.

The USGS, in general, concurs with the conclusions stated by the applicant and its consultants regarding the history and age of last movement of the Cristianitos Fault, its relation as one of several faults of the CZD of Greene and Kennedy, and its apparent lack of potential for movement in response to movement on the OZD."

The addendum attached to the above report concludes:

"The CZD merges with or is truncated by the OZD in the area offshore from SONGS (plate 1). Generally faults within the CZD with few exceptions (plate 1) displace shallow stratified sedimentary rock that lies beneath a prominent unconformity and younger poorly stratified sediments. The June 1980 NEKTON data support the conclusions reported previously by Greene and Kennedy (1980)."

(6) Evidence Regarding the Non-Capability of the Cristianitos Fault

- (a) Trenching across the Cristianitos fault and Plano Trabuco demonstrated that the segment of the fault observed was capped by non-marine terrace deposits which are older than 33,000 years.
- (b) The excellent sea cliff exposure of the fault shows it cutting the San Mateo formation but being truncated by marine and non-marine terrace deposits that are approximately 120,000 years old.
- (c) There is no historic seismicity associated with the fault.
- (d) Mapping by P. Ehlig and Jack Harris show the fault to be capped by Pleistocene (more than one million years old) or older strata.
- (e) Figure 5 of the report by Shlemon discussed in Section 2.5.1.8 of this report shows that the 120,000-year-old terrace is not displaced between Dana Point, north of the site, to Target Canyon south of the site. Furthermore, nowhere in the vicinity of the Cristianitos fault is the bedrock/ terrace contact observed to be faulted.
- (f) The numerous offshore seismic reflection profiles that cross the fault show that the Pleistocene terrace which is more than 13,000 years old and probably as old as 80,000 years is not offset by the fault.
- (g) Comparing the degree of fault activity for the CZD and OZD, we find that the slip rate on the OZD is greater than that on the CZD by a factor of 3. This assumes a vertical displacement of 600 ft since Miocene time (12 million years ago), which calculates to be 0.0015 cm/yr as the slip rate on the CZD. The slip rate on the OZD is that of the Newport-Inglewood fault zone which was given above as 0.5 cm/yr.

The faults are characterized as follows according to Slemmons (1977): The CZD is of low activity, and for the range of 0.001 to 0.01 cm/yr within which it falls, the recurrence interval between magnitude 7 earthquakes or larger is generally measured in many tens of thousands of years to hundreds of thousands of years for recurrence at a given point on the fault.

The OZD is of moderate activity. The slip rate range of 0.01 to 0.1 cm/yr within which the OZD falls has a recurrence interval for generation of magnitude 7 or higher earthquakes generally measured in thousands to few tens of thousands of years for a given point on the fault.

- (h) Dr. P. Ehlig's studies of the origin of the Cristianitos fault concluded that the fault originated from 10 to 4 million years ago during a period of crustal extension and that the present stress regime of generally north-

east-southwest compression represents a significant change; therefore, movement on the OZD would not trigger movement on the Cristianitos fault.

The above indicates at this time that there is considerable evidence for noncapability of the CZD. Furthermore, it has been amply demonstrated that the CZD fulfills the role of a non-capable fault even assuming a structural relationship between it and the OZD, based on the definitions in Appendix A, 10 CFR Part 100. In the definition of a capable fault, Appendix A states that in the case of a fault having a structural relationship to a known capable fault, the fault is considered capable if movement on the capable fault could be reasonably expected to be accompanied by movement on the fault in question. Movement on the OZD for at least the past 120,000 years has not been accompanied by movement on the CZD.

2.5.2 Seismology*

2.5.2.1 Background and Summary

In the seismological review conducted for the Construction Permit (CP) of the San Onofre Units 2 and 3 site, the staff relied primarily upon the evaluation provided by the National Oceanic and Atmospheric Administration (NOAA). They assumed the geological characteristics as defined by the USGS and described above. The "linear zone of deformation....extending from the Santa Monica Mountains to at least Baja California" passing "within 5 miles of the site" was considered to be of primary importance to the seismic evaluation of the site. NOAA then states that:

"An acceleration of $2/3g$, resulting from a strong X intensity (MM) event, (should) be used to represent the ground motion from the maximum earthquake likely to affect this site. However, the accelerogram may contain a few peaks between $2/3$ and $3/4g$ during the $2/3g$ interval. These accelerations could result from an earthquake occurring within a few miles from the site. Also, it must be assumed that a similar earthquake could occur at any point along this zone of deformation."

The staff agreed with the NOAA evaluation and on this basis approved the earthquake design bases (anchor points) of $0.67g$ and $0.33g$ for the Safe Shutdown Earthquake (SSE) and Operating Basis Earthquake (OBE), as being appropriately conservative. The FSAR refers to the SSE as the Design Basis Earthquake. The response spectra used in conjunction with the above acceleration values were developed from a scaled, smoothed, and modified set of real time histories. The development of these spectra is outlined in Appendix 2.5.B of the FSAR. The staff has reviewed the seismological information presented in the Final Safety Analysis Report (FSAR) and its amendments. Our review of the FSAR has concentrated on the following topics:

- (1) Seismicity in the site region since the CP review and additional information on historical earthquakes in southern coastal California and Baja California.

* Note: This section has been published verbatim in a Safety Evaluation Report on San Onofre 2 and 3 Geology and Seismology, issued December 31, 1980, also under NUREG-0712.

- (2) Determination of the maximum earthquake on the Offshore Zone of Deformation (OZD) from historic and instrumented seismicity and fault parameters.
- (3) Determination of the vibratory ground motion at the site due to occurrence of the maximum earthquake on the OZD thru the use of empirical methods, theoretical models and an examination of recent recordings of strong ground motion from earthquakes.
- (4) A comparison of the ground motion estimated above with the SSE approved for the construction permit.

These topics resulted from a review of the information that has been made available since the CP review, either in the literature or during subsequent analyses of the seismic conditions at the San Onofre site. The new information described in the following sections does not change the conclusions made following the CP review regarding the adequacy of the seismic design basis.

2.5.2.2 Seismicity

The seismic record in the southern California region extends back to the 18th century. Until the early part of this century, reports of earthquakes that were felt were the only records of those events. Few epicenters were reliably determined instrumentally prior to 1932. From 1932 to the present, however, a relatively complete listing of instrumentally determined epicenters is available. In the FSAR the applicants provided a listing of all non-instrumented events that had reported Modified Mercalli Scale Intensities of IV or greater and that could have reasonably occurred within a 320-kilometer (200-mile) radius of the San Onofre site. This list was compiled from a number of earthquake catalogs; the earthquake locations, undoubtedly influenced by population centers, should be considered very approximate. The grid like pattern shown in Figure 2.5-15 of the FSAR reflects locating these earthquakes at the nearest degree or half degree of latitude and longitude. It does not appear useful to attempt to correlate this biased pattern with known faults.

The applicants also provided listings of earthquakes of Richter Magnitude 5 or greater within 320 kilometers (200 miles) of the site and all listed earthquakes within 80 kilometers (50 miles) of the site for which instrumental records are available. The lists were taken from the Historical Earthquake Data File compiled by the National Geophysical and Solar-Terrestrial Data Center, Environmental Data Service, National Oceanic and Atmospheric Administration, Boulder, Colorado and contains events through 1975.

Those earthquakes of magnitude 6.0 or larger can be associated with specific faults such as the San Jacinto, San Fernando, White Wolf or Imperial Valley faults. Of particular interest to San Onofre is the 1933 Magnitude 6.3 earthquake on the Newport-Inglewood fault zone approximately 45 km northwest of the site. This fault zone and a proposed southward extension, the Offshore Zone of Deformation, is viewed as the major contributor to seismic hazard at San Onofre. Earthquakes in the range

of magnitude 5.0 to 6.0 appear to be associated with what the applicants call major "zones of faulting." Many of these earthquakes are aftershocks of larger events. Earthquakes smaller than magnitude 5.0 do not necessarily correlate well with specific faults or zones of faulting. The density of these events varies with location. The vicinity of the San Onofre site (within approximately 30 km) appears to be one of relatively low seismicity.

In subsequent amendments to the FSAR, and in response to staff question 361.41, the applicants have provided post-1975 (through September 1979) seismicity information for the region within 320 kilometers of the site. Earthquake activity for data sets greater than Local Magnitude (M_L) 3, 4, and 5 were examined. No distinctive new patterns of seismicity different than that evident in the pre-1975 data were observed.

Localized data sets of all magnitudes were also collected and evaluated in several reports submitted to the NRC and the applicants. The occurrence of two small earthquakes (magnitude 3.3 and 3.8) in 1975 several km west of the Cristianitos fault zone, 30 km north of the site, was discussed in a report to the applicant by Biehler (1975). Accurate locations, making use of new velocity data, placed the hypocenters too far west to be on the Cristianitos fault zone. Focal mechanism solutions derived for these events were not consistent with the north trending Cristianitos fault and both historical seismicity and micro-earthquake surveys conducted in 1975 showed no evidence of the Cristianitos fault being active.

Earthquake activity in the vicinity of the site was also examined in a report to NRC by Whitcomb (1978) and by the applicants in response to Question 361.36. The earthquake closest to the site ($M_L = 2.5$) occurred 14 km to the northwest. This event appears to be part of a broad band of low-level earthquake activity in the Capistrano Embayment. Part of this earthquake activity includes the 1975 events discussed above, and, in addition, a cluster of 5 smaller earthquakes ($1.9 \leq M_L \leq 2.7$) that also occurred within several km of the Cristianitos fault in 1977.

These and the other small earthquakes in the embayment appear to be scattered rather than aligned along faults. These scattered locations and the focal mechanisms discussed above do not indicate any direct relationship between seismicity and observed faulting (including the Cristianitos) within or on the boundaries of the Capistrano Embayment.

2.5.2.3 Magnitude of the Maximum Earthquake on the Offshore Zone of Deformation

In the CP review we and our seismological advisors (NOAA) used a Modified Mercalli Intensity of X to characterize the maximum earthquake that could affect the San Onofre 2 and 3 site. This earthquake was assumed to occur along the Offshore Zone of Deformation five miles from the site. During the OL review the staff concluded that magnitude is a better indicator of earthquake source strength than intensity. Intensity is a measure of observed damage and felt effects. It depends upon the size of the earthquake, its depth, the distance from the earthquake source, the nature of

the geologic materials between the source and the point of observation and the geologic conditions at the point of observation itself. Although an attempt is made in the intensity scale to account for differences in structural design, it is only done in a very general way. Particular problems are associated with determination of intensities greater than VIII. Very often these intensities are based upon ground failure (landslides, soil liquefaction, etc.) which are very much dependent upon local conditions rather than ground shaking. Many investigators (for example, Nason, 1978; and Tocher and Hobgood, 1978) have suggested great caution in assigning these high intensities. In addition strong motion data at high intensities is practically nonexistent. Ground motion estimates at these levels are based upon highly non-unique extrapolations from the more abundant data at lower intensities.

Magnitude is a measure of earthquake source size using instrumental recordings of ground motion at different distances. Different magnitude scales measure different components of motion in different frequency ranges and care must be exercised in choosing the appropriate scale for the intended purpose. Local Magnitude (M_L), the original magnitude scale, was developed from recordings of small earthquakes ($M_L < 5.0$) at distances between 20 and 600 km in southern California. It is determined utilizing the largest ground motion recorded on the Wood-Anderson seismograph. As a result, it is particularly sensitive to short period (about 0.8 seconds) horizontal motion. It is not applicable at distances greater than 500 or 600 km and must be used with great care outside of California. Surface wave magnitude (M_S) was developed subsequently to complement M_L for earthquakes of greater size and at different locations. It is determined from longer period (20 second) motion. Richter magnitude (M) as it is commonly, but very often not precisely, used is equal to M_L for magnitudes less than about 6 and M_S for larger earthquakes (Nuttli, 1979). The reason M_L cannot be used for larger earthquakes is the apparent saturation of the scale at around 7 1/4. The great San Francisco earthquake of 1906, for example, had an estimated M_S of 8 1/4 while the M_L is only estimated to have been between 6 3/4 and 7 (Jennings and Kanamori, 1979). M_L saturates because the amplitude of the shorter period waves which determine M_L do not simply increase as the fault length increases. As Kanamori (1978) states, "The amplitude of seismic waves represents the energy released from a volume of crustal rock whose representative dimension is comparable to the wave length." Seismic waves used in the determination of M_L may only reach wave lengths of 6 km. Thus, they cannot be expected to adequately reflect the energy release of earthquakes associated with ruptures tens of kilometers long. Similarly, they do not adequately reflect the seismic moment of such earthquakes. Seismic moment, defined as being equivalent to the product of rigidity, fault area, and fault displacement, is the measure most easily related to geologic fault parameters.

In the range of interest for San Onofre (magnitude 6 to 7.5), M_S , determined from waves whose lengths are about 60 Km, is more related to seismic moment than M_L . According to Kanamori (1979), at magnitudes greater than 6, the average M_L begins to deviate and becomes less than the average M_S for the same earthquake until the M_L

reaches the previously mentioned saturation point of about 7 1/4.* According to this estimate, an M_S of about 7 would have an average M_L of 6.6 or 6.7. By assuming a simple linear relationship between M_S and M_L , Nuttli (1979) arrives at a similar result.

Thus, in estimating earthquake size from fault studies in southern California, the most directly relateable magnitude scale based upon rupture lengths less than hundreds of kilometers would be M_S . Similarly the saturation of M_L indicates that the amplitude of strong ground motion at periods less than 1 second (periods of interest to nuclear power plants) cannot be assumed to scale simply as M_S or fault size increase. Increases in estimates of maximum earthquake size around or above the saturation level do not necessarily imply increased hazard to nuclear power plants.

We asked the applicants to specify the maximum magnitude of an earthquake on the OZD. In the following subsections, we review several methods of determining the maximum magnitude earthquake on the OZD, including the method used by the applicants. Considerable research effort has been expended in an attempt to define more precisely the maximum size of an earthquake that can be associated with various types of faults and tectonic environments. However, in evaluation of the seismological characteristics of a nuclear plant site, we must use theories and empirical data cautiously until sufficient data have established their validity. Our discussions will note areas of uncertainty and areas where we have used conservatism.

2.5.2.3.1 Maximum Magnitude from Historical Seismicity

A consideration of historical seismicity for the determination of the maximum earthquake on the Offshore Zone of Deformation should include south coastal California and postulated extensions of this zone of deformation into Baja California. In the southern coastal region of California, there have been three earthquakes in historical time which could have had a major impact upon the San Onofre 2 and 3 site. These occurred on November 22, 1800, December 8, 1812, and March 11, 1933. The California Division of Mines and Geology (CDMG) has estimated epicenters and magnitudes for the 1800 and 1812 earthquakes based upon felt reports (Toppozada and others, 1979). The 1800 event was located near San Diego and the 1812 event was located near San Juan Capistrano where the mission was destroyed. Because there were few European settlements (mostly missions) in California at this time, locations based upon felt reports should be considered as very approximate. Both these earthquakes were estimated to have had magnitudes of 6.5. It is not quite clear whether this is M_S or M_L , but since the calibration function used to determine magnitude (Toppozada, 1975) used mostly M_S for larger events we can assume that M_S is the appropriate measure.

* M_S also saturates at about 8.3 and does not reflect the energy release in a truly great earthquake where fault rupture reaches hundreds of kilometers. For this purpose, a new magnitude scale M_W was developed (Kanamori, 1978). For example, the great Chilean Earthquake of 1960 had an M_W of 9.5 while its M_S was only 8.3.

The 1933 earthquake had both an M_S and an M_L of 6.3 and is the largest instrumentally recorded event within the south coastal area of California. Its epicenter was located on the Newport-Inglewood fault zone, the northern seismically active section of the OZD. The rupture length associated with this earthquake (about 30 km) was based upon aftershock data as there was no surface breakage (Woodward-Clyde, 1979).

In Baja California, the largest instrumental earthquake of postulated significance to the San Onofre site is the El Alamo earthquake of February 9, 1956, which is associated with the San Miguel fault. Evidence for and against a connection between the OZD and the San Miguel fault is discussed in Section 2.5.1.8 above. M_S for this earthquake is reported to be 6.8 while M_L is estimated as 6.6 (see FSAR response to Question 361.68). The length of surface rupture for this event was at least 19 km.

On February 24, 1892, a large earthquake occurred which was felt strongly in southern California, southwestern Arizona, and Baja California. Information on this earthquake is limited to felt reports. Based upon felt reports in Los Angeles, Hanks, and others (1975) suggested a seismic moment of 5×10^{27} dyne-cm and assumed a location on the Agua Blanca fault south of the San Miguel fault. Seismic moments of this size are usually associated with earthquakes of surface wave magnitude close to 8. However, recent and more detailed work by Topozada and others (1979) states that the 1892 event had a magnitude of 6.9 (probably M_S) and was located in the Peninsular Range of northern Baja California near the Sierra Juarez fault system. This fault system is believed to be related to the spreading of the Gulf of California (Gastil and others, 1979) rather than the San Miguel Fault Zone or other postulated extensions of the OZD into Baja California. Thus, the largest historical earthquakes which have an impact upon the assessment of the maximum earthquake on the OZD are $M_S = 6.3$, 6.5, and 6.5 in southern coastal California and possibly $M_S = 6.8$ in Baja California.

2.5.2.3.2 Maximum Magnitude from Fault Parameters

Much of the material relating earthquake magnitude to fault parameters has been discussed in the geology section of this Safety Evaluation Report. In the following paragraphs, we will review the maximum magnitude estimates discussed in that section and discuss other estimates of magnitude based on additional fault parameters.

Typically the most utilized method of estimating earthquake potential has been the use of fault rupture length. As our consultant, Dr. Slemmons, has pointed out (Appendix E) direct application of this method "is not possible for the OZD as surface faulting is rare along the zone." Indirect application of fault rupture length earthquake magnitude methodology by our consultant as described in Section 2.5.1.9, must rely upon subsurface estimates of individual rupture lengths or appropriate percentages of estimated total fault length.

Utilizing Slemmons (1977), over 10 different estimates were made (Appendix E) for the maximum magnitude on the OZD. These estimates ranged from $M_S = 6.6$ to 7.3 depending upon the specific approach, level of conservatism and fault length assumed. The

lowest estimate was derived using an inferred subsurface rupture length on the segment of the OZD nearest the site while the largest estimate was derived assuming a total fault length of 300 km (from Santa Monica to the Agua Blanca fault in Baja California) and that a fraction of this length would rupture consistent with the mean plus one sigma fraction of observed strike-slip faults. The inability in this case to use this method directly, the uncertainty associated with the assumed fault lengths, and the scatter of resulting estimates preclude placing much weight on the fault length versus magnitude approach.

Slemmons (1977) has also developed correlations between magnitude and fault displacement. It is not possible to apply this method directly to surface displacement on the OZD because of the plastic deformation of tertiary sediments (Appendix E). We also find it inappropriate to take total displacement along the OZD that relates to the past few million years and assume that it or any significant portion of it could occur during one earthquake. However, the applicants have developed a correlation between the average yearly displacement (slip-rate) and maximum magnitude which has been reviewed in Section 2.5.1.8 and will be discussed below.

For the purpose of estimating maximum magnitude, Wyss (1979) advocated the use of source length rather than surface rupture length, also postulated that fault area (source length multiplied by fault width) would provide a more accurate and appropriate estimate than length alone. Bonilla (1980) has pointed out some problems associated with this technique. In order to compare Wyss' proposal with estimates derived using fault length, maximum magnitude for the OZD was computed assuming a conservative fault width (depth) of 15 km and the range of fault lengths proposed by our consultant in Appendix E. A similar range of maximum magnitudes ($6.8 \leq M_S \leq 7.2$) was calculated. Because this method also relies upon indirect estimates of fault or source length and an assumed fault width, little additional consideration should be given to this approach.

The applicants have developed a methodology (Woodward-Clyde, 1979) relating maximum earthquake magnitude to slip rate or degree of fault activity. As previously discussed, it is our consultants' (Appendix E) and the staff's opinion that an appropriate application of this approach results in an estimated maximum magnitude of $M_S = 7.0$ for the OZD. In a test of consistency between slip-rate and fault-length estimates for maximum magnitude, the applicants developed a correlation between slip-rate and fault-length from selected data. Half-lengths were conservatively assumed to be the portion of total fault-length capable of rupturing in one earthquake. This correlation was then used in conjunction with Slemmons (1977) proposed relationship between fault-length and magnitude for strike-slip faults. The resulting plot of magnitude versus slip-rate called the Synthetic Earthquake Limit (SEL) was then compared to the direct slip-rate estimates. This estimate had a somewhat steeper slope than the direct estimate, that is, lower maximum magnitude for high slip-rates and higher maximum magnitude for very low slip-rates. In the range of interest for the OZD (slip-rate of 0.5 mm/year), the SEL was slightly less than the applicants' conservative Maximum Earthquake Limit.

The applicants have presented an additional argument as to the conservatism of the slip-rate estimate. Assuming a constant b value of 0.85 and utilizing Anderson's (1979) method, recurrence curves were computed from slip-rates and fault-lengths assuming different maximum magnitudes (6.0, 6.5, 7.0 and 7.5). It is proposed that the occurrence of the 1933 Long Beach and possibly the 1800 and 1812 earthquakes is consistent with an assumed maximum magnitude of 6.5, while assuming a maximum magnitude of 7.5 results in return periods (270 years for $M_S = 6.0 \pm 0.25$, 720 years for $M_S = 6.5 \pm 0.25$) longer than the historical data would suggest.

Our consultant, Dr. Slemmons, has stated that the "fault-slip rate method is the firmest, most quantitative approach for state-of-the-art assessment of the maximum earthquake on the OZD." In a limited review of the applicants' slip-rate method, the USGS (Appendix G) states that because of the limited data base at low geologic slip-rates this technique "cannot be considered definitive in assessing maximum magnitude." However, it "is helpful, when considered along with other procedures for estimating earthquake size to assess the potential impact of earthquakes on the SONGS site." Our evaluation of the applicants' slip-rate methodology can be stated as follows:

- (1) Correlation of maximum earthquake potential and degree of fault activity is in itself a geological reasonable and intuitively sound idea.
- (2) Use of present estimates of slip-rate to establish maximum earthquake magnitude based upon the limited geological and seismological data requires both caution and conservatism. This limited data set and limited understanding of the physical basis between maximum magnitude and slip-rate preclude the exclusive use of this technique in establishing maximum magnitude.
- (3) The most appropriate slip-rate estimate used by the applicants is the Maximum Earthquake Limit. This estimate ($M_S = 7.0$ for the OZD) makes a specific attempt to account for uncertainties.

As with many geologic and seismological assessments, estimation of maximum magnitude for the OZD from fault parameters is not an unequivocal procedure. No single technique, be it fault-length, fault-displacement, fault-area or slip-rate should be considered as adequate in itself. Based upon the above discussions, it is our position that $M_S = 7.0$ is a reasonable, yet conservative, estimate of maximum earthquake potential based upon fault parameter evaluation.

2.5.2.3.3 Maximum Magnitude from Intensity

In the CP review, the staff adopted the position of its seismological consultant (NOAA) that "an acceleration... for a strong MM intensity X be used to represent ground motion from the maximum earthquake likely to affect the site." Various correlations relating magnitude to intensity have been proposed. Assuming an intensity X would yield, for example, magnitude 7.7 from Gutenberg and Richter (1942), 7 from Richter (1958), 7.1 from Krinitzky and Chang (1975) and 6.75 from

Topozada (1975). It is not always clear which magnitude scale is being referred to but, since the data sets rely upon surface wave magnitudes for the larger events, we assume that M_S is the appropriate measure. However, we do not believe it is appropriate to relate epicentral or maximum intensity to magnitude at high intensities because of the paucity of data at these intensities and the presence of other factors such as site conditions which have a strong effect upon all intensity estimates. In addition, most estimates are based upon linear fits to scattered data at lower intensities extrapolated to few, if any, points at higher intensities.

2.5.2.3.4 Conclusions

Based upon our evaluation of the various approaches outlined above, we conclude that an appropriate representation of the maximum earthquake on the OZD to be used in determining the SSE at San Onofre is $M_S = 7.0$. This conclusion rests upon the combined results from the following approaches:

(1) Evaluation of Historical Seismicity -

- (a) largest earthquake in southern coastal California: $M_S = 6.3$ (1933); possible $M_S = 6.5$ (1800, 1812)
- (b) largest earthquake on postulated extensions of the OZD into Baja California: $M_S = 6.8$ (1956).

(2) Evaluation of Fault Parameters (in order of relative importance)-

- (a) Slip-rate: utilizing the estimator called Maximum Earthquake Limit which incorporates uncertainty in both magnitude and slip-rate results in $M_S = 7.0$.
- (b) Fault-length: utilizing the range of inferred fault lengths results in estimates ranging from $6.6 \leq M_S \leq 7.3$.
- (c) Fault-area: utilizing the range of inferred fault lengths with an estimated fault width of 15 km results in magnitudes of $6.8 \leq M_S \leq 7.2$.

While it is impossible to absolutely rule out the occurrence of an earthquake larger than $M_S = 7.0$ on the OZD, it is the staff's position that a maximum magnitude of $M_S = 7.0$ is based upon a reasonable and conservative interpretation of all available geological and seismological information.

2.5.2.4 Vibratory Ground Motion

The SER for the San Onofre 2 and 3 CP approved an SSE (then designated the DBE) defined by a response spectrum shape derived from a scaled and modified study of real earthquakes anchored at 0.67g. It was also required that consideration be given to peaks of ground motion between 0.67 and 0.75g. In this section we will evaluate that

spectrum with respect to ground motion from the controlling event defined as an earthquake of $M_S = 7.0$ occurring on the OZD at its closest location to the site (8 km).

Determination of ground motion in the near field of large earthquakes is a difficult and problematic task. Although "near field" has several definitions it is being used here in the context of the "geometrical near field"; that is, at distances less than the dimensions of the earthquake source. Since the earthquake assumed to occur on the OZD is also assumed to result from a rupture tens of kilometers long and at least 10 km wide (deep), estimation of ground motion at a distance of 8 km from the fault can be clearly considered a "near field" problem.

The sources of uncertainty in near-field ground motion estimation are several. First of all, there has been a relative lack of data recorded close in (less than 10 km) from earthquakes, particularly those larger than $M_S = 6.0$. The vast majority of data was recorded at distances greater than 20 km. Simple extrapolation of the data to close-in distances is not easily accomplished since ground motion at these distances is less sensitive to factors such as gross source strength, geometric spreading, and seismic wave attenuation which affect far field motion and is more sensitive to source geometry and details such as localized stress conditions and direction of faulting. The interpretation of these near-field effects and the type of "best fit" curve one uses can lead to large differences in the near field. Those seismologists who may agree with each other within a factor of two in predicting ground motion from a magnitude 7 earthquake at 30 km, also find more than an order of magnitude differences in their predictions for the same earthquake at a distance of 5 km (Swanger and others, 1980).

Recently, a great deal of effort has been placed on theoretical models of earthquake sources and attempts have been made to theoretically predict ground motion at various distances. While these efforts are certainly encouraging they are controlled by assumptions about the physical nature of the earthquake source. Different assumptions such as the size of the stress drop and the effect of local inhomogeneities have a major impact upon ground motion particularly at those frequencies (greater than 2 Hz) of concern to nuclear power plants. As of this time, no consensus with sufficient detail exists within the seismological community that would allow the exclusive use of theoretical models in order to estimate ground motion in the near field. In face of the problems (not necessarily the same) associated with either the empirical or theoretical approaches in estimating near field ground motion, it is our position that the most appropriate way to arrive at an estimate involves the pursuit of both approaches and a conservative comparison. As there are characteristics of ground motion not directly related to nuclear power plant safety (for example, low frequency motion and isolated high frequency peaks) it is important to take into account engineering considerations so as to concentrate the analysis on those elements which have a direct bearing upon safety.

A final confirmatory element can also be used to evaluate the adequacy of the ground motion estimate. The October 1979 Imperial Valley earthquake ($M_S = 6.9$, $M_L = 6.6$)

has provided an unprecedented set of data from an earthquake of the appropriate size at distances as close as 1 km from the fault rupture. In the sections below we discuss the applicants effort at predicting ground motion from the controlling earthquake using both empirical and theoretical approaches and a comparison of their results with data from the October 1979 Imperial Valley earthquake. We find that the ground motion specified in the SER for the San Onofre 2 and 3 CP exceeds a conservative representation of ground motion expected at the site from an occurrence of the controlling earthquake; that is an $M_S = 7.0$ on the OZD at a distance of 8 km.

2.5.2.4.1 Empirical Approach

In order to estimate the ground motion at the site, the applicants (Woodward-Clyde, 1979) collected all available high quality digitized and processed horizontal strong motion recordings from the western United States recorded at site conditions similar to San Onofre (deep, stiff soil) from earthquakes of magnitude approximately equal to 6.5. This collection, which was assembled prior to the 1979 Imperial Valley event, yielded 56 recordings from 7 earthquakes. The M_L of the earthquakes ranged from 6.3 to 6.5 with 48 of the records coming from earthquakes of $M_L = 6.4$. The M_S of the earthquakes ranged from 6.3 to 6.7 with 46 of the records coming from earthquakes of $M_S = 6.6$. In order to reduce the bias from the heavily represented San Fernando earthquake of 1971, a weighing procedure was applied so that each earthquake had equal influence in any given distance interval where recordings were available. The data (peak accelerations and response spectrum values at periods of 0.04 to 2.0 seconds at 2 percent damping) were then fit to a regression curve of a widely used form first proposed by Esteva (1970).

Curves were computed for the mean and 84th percentile (mean plus one sigma) of each period, and extrapolated to 10 km. This distance was used assuming the center of energy release occurred on a vertical fault 8 km away at depth of 6 km. A 2 percent damped response spectrum of horizontal ground motion for an $M_S = 6.5$ earthquake was then constructed from these extrapolated values. A response spectrum for $M_S = 7.0$ was estimated (see FSAR response to Question 361.54) by multiplying the peak acceleration and spectra by scaling factors. These factors were determined from several published ratios of peak accelerations at 10 km for $M_S = 6.5$ to $M_S = 7.0$ events and an empirical study of the effects of magnitude on spectral shape. The peak accelerations associated with the mean and 84th percentile of $M_S = 6.5$ are 0.42g and 0.57g while those associated with $M_S = 7.0$ are 0.47g and 0.63g. As expected, larger differences exist in the response spectra at long periods. The SSE spectrum approved in the CP SER exceeds the 84th percentile $M_S = 7.0$ spectrum at all frequencies.

During the review of the applicants methodology, several issues were raised. The most important of these were:

- (1) The adequacy of the assumed attenuation relationship, that is, that acceleration is proportional to $(R+C)^B$ where R is distance, B determines attenuation in the far field, and C determines the flattening of the regression line in the near

field. Based upon examination of the data, $C = 20$ was judged to be appropriate. A smaller value of C would tend to increase near field values. $C = 0$, for example, implies infinite acceleration at the fault.

- (2) The effect of focusing upon the assumed results. Focusing is the effect caused by a propagating rupture which results in increased seismic amplitudes in the direction of propagation and lower amplitudes in the opposite direction.
- (3) Use of distance to the center of energy release rather than distance to the fault.
- (4) Inclusion of data within the analysis which may have been recorded on buildings with large foundations and may, as a result, have lower peak accelerations than the free field.
- (5) The impact of including data from northwest California earthquakes whose locations are subject to large uncertainties.

The applicants' response to these issues follows:

- (1) The appropriateness and degree of conservatism for the choice of $C = 20$ was evaluated using a theoretical model of Hadley and Helmberger (1980) which simulates the effects of large earthquakes through the mathematical superposition of small, well-recorded earthquakes. These studies show that for a magnitude 6.5 earthquake, the best choice of C is 22 while for a magnitude 7.0, the best choice would be 30. The use of the smaller $C = 20$ would, according to these studies, be conservative see FSAR (response to Question 361.53). In addition a recent study by TERA Corporation (TERA, 1980), was submitted by the applicants. This study gathered all recent earthquake data between magnitudes 4 and 8 at distances less than 50 km. One hundred and ninety-two peak accelerations from 22 earthquakes were used. Of these, 31 were from $M_S = 6.5$ or greater events recorded at distances less than 10 km. Regressions on this data set using different assumptions as to the choice of B and C indicated little variation in predictions for $M_S = 7.0$ at 8 km. Predicted peak accelerations ranged from 0.50g to 0.55g for the mean plus one standard deviation.
- (2) The data set used includes in it much data recorded under conditions of above average focusing (see FSAR response to Question 361.56). In addition, it was argued from a theoretical point of view that at a distance of 8 km the effect of changing radiation pattern as seen by the station would rapidly diminish the effect of focusing (see FSAR response to Question 361.53).
- (3) The applicants believe that the closest distance to the center of energy release is more appropriate. However, the data was also plotted assuming closest distance to the fault. The original curves assuming closest distance to center of energy release were shown to be more conservative at moderate and close distances (see FSAR response to Question 361.62).

- (4) The applicants concur with proponents of differences between small and large structures (Boore and others, 1978) who state that "the differences between the data from the large structures and the small structures are relatively small compared with the range of either data set, and we do not believe that firm conclusions are warranted solely on the basis of formal statistical tests. The differences may be due to soil-structure interaction, but more study would be required to demonstrate this" (see FSAR response to Question 361.55).
- (5) Removal of data from northwest California earthquakes would result in lower peak accelerations at 10 km than those originally proposed.

We find their answers to the questions raised and the proposed spectra reasonable as long as the general limitations inherent in empirical extrapolation into the near field as outlined above are taken into account. The conservatism of the estimated ground motion can also be judged when compared to the theoretical estimates and recent earthquake data as discussed below.

2.5.2.4.2 Theoretical Estimates of Ground Motion

As part of the Systematic Evaluation Program of older operating plants, the staff is reviewing the design of the San Onofre Nuclear Generating Station, Unit 1 (San Onofre 1). This review is still underway and a final evaluation will be published in the future. However, in support of the seismic reevaluation of San Onofre 1, the licensee has submitted a series of theoretical studies whose purpose is the prediction of ground motion at the site from an earthquake caused by a rupture along the Offshore Zone of Deformation.

These studies (Del Mar Technical Associates, 1978, 1979a, 1979b, 1980a, and 1980b) are described below and in Section 2.5.2.4.5 and discussed with reference to the conservatism of the SSE adopted for San Onofre 2 and 3.

For the San Onofre 1 studies, a kinematic source model was assumed. The procedure for modeling ground motion was accomplished in three steps:

- (1) Fault-slip is characterized in terms of fault type, rupture velocity, dynamic stress drop (slip velocity at the onset of rupture at each point on the fault) static stress drop (fault offset), and duration of slip at each point. Random processes are included to approximate irregularities in actual earthquake rupture.
- (2) Propagation characteristics (Green's functions) are calculated for the particular earth structure, that is, surface motions are computed for several hundred point sources along the fault plane. These earth response calculations include all wave types up to frequencies of 20 Hz.
- (3) Ground motion is calculated by convolving in time and space the fault-slip characterization from Step 1 with the earth response functions from Step 2. By

specifying hypocentral location, rupture extent and site location, the different source site configurations can be examined.

For the initial study (Del Mar Technical Associates, 1978) the model (particularly the slip-function) was calibrated using the 1966 Parkfield Earthquake ($M_S = 6.0$, $M_L = 5.8$). Prior to 1979 this was the best recorded earthquake in the near field. In addition, the recordings from the 1940 Imperial Valley Earthquake ($M_L = 6.5$, $M_S = 7.1$) and the 1976 Brawley earthquake ($M_S = 4.9$) were modeled. Utilizing subsurface knowledge of the San Onofre site, P and S wave velocity, density, attenuation, and layer thickness were computed. Green's functions were calculated to predict propagation characteristics from source depths extending to 15 km, out to epicentral distances of 60 km. The ground motion modeling centered about the effects of a 40 km long rupture at a distance of 8 km from the site. This is an approximate representation of an $M_S = 7.0$ earthquake on the OZD. Sensitivity tests were conducted to test the effect of variations in site distance, fault length, and fault location along the OZD (focusing), fault depth, hypocentral depth, changes in dynamic and static stress drop, duration of slip, and changes in earth structure, upon estimated ground motion.

In response to the staff's and its consultants' (Dr. Keiiti Aki, M.I.T.; Don L. Bernreuter, Lawrence Livermore Labs; Dr. Robert Herrmann, St. Louis University; and Dr. J. Enrique Luco, University of California-San Diego) review, a revised model and additional studies were submitted (Del Mar Technical Associates 1979a). The revisions in the model included:

- (1) Utilization of additional randomness.
- (2) Revision of the three parameter slip-function.

Additional studies were conducted with respect to:

- (1) The effect of grid spacing used in the numerical modeling procedure upon results.
- (2) The assumption of a two parameter slip-function.
- (3) Sensitivity of the results to changes in earth structure and fault parameters.

In response to other concerns, the licensee submitted (Del Mar Technical Associates, 1979b) calculations and discussions relating to magnitude and moment estimates of the proposed numerical estimates of ground motion and estimated ground motion at distances greater than 20 km. Utilizing a relationship between seismic moment and surface-wave magnitude, the M_S of the hypothesized offshore earthquake was calculated to be 6.94. An M_L of about 6 was calculated using the technique developed by Kanamori and Jennings (1978) to estimate M_L from strong motion records.

In addition to the above mentioned consultants, the staff initiated a separate study carried out on the Illiac Computer by Systems, Science, and Software (Day, 1979) to investigate slip-functions. Making use of the unique capabilities of the Illiac, numerical dynamic studies were carried out to test the sensitivity of earthquake slip functions to fault geometry, functional strength, and prestress configuration. Ground motion at different distances from the fault was not examined.

The revised model (Del Mar Technical Associates, 1979a) used by the licensee in generating the proposed response spectra at the San Onofre 1 site assumes a 40 km rupture maximally focused at the site with a fault offset of 130 cm and a rupture velocity nine-tenths the shear wave velocity. Mean and 84th percentile spectra have peak accelerations of 0.31 and 0.37g respectively. These spectra fall below the empirically-derived spectra for $M_S = 7.0$ and well below the SSE. The staff's consultants reviewed the revised model and assumptions. Generally it was concluded that there was an improvement but questions still remained regarding various aspects, in particular, the slip function. All felt that the proposed spectra were good representations of ground motion from rupture on the OZD. There was some question whether this motion was appropriate for an $M_L = 6.0$ or for a larger earthquake. In general, the consultants suggested multiplication of the spectra by a factor of about 2 to account for uncertainties in the modeling process or an increase in magnitude. Doubling the mean theoretical spectra would place it below the SSE at approximately the 84th percentile level of the $M_S = 7.0$ empirical estimate discussed previously.

It is the staff's position that the modeling procedure utilized demonstrate the conservatism of the empirically derived spectra and particularly the SSE.

2.5.2.4.3 Comparison of Estimated Ground Motion with Recent Earthquake Data - The 1979 Imperial Valley Earthquake

The occurrence of an earthquake in the Imperial Valley in October 1979 provided an excellent opportunity to judge the adequacy and conservatism of the previous ground motion estimates and the SSE approved for the San Onofre 2 and 3 CP. This earthquake of $M_S = 6.9$ and $M_L = 6.6$ occurring on the same fault (Imperial) that produced the 1940 $M_S = 7.1$, $M_L = 6.5$ earthquake resulted in approximately 31 km of surface rupture. Rupture at depth was undoubtedly larger. It was a predominantly strike-slip earthquake with some vertical movement at the northern end of the fault and possibly some simultaneous movement on the adjacent Brawley Fault. The fault and vicinity were heavily instrumented and provided the most extensive set of near-field ground motion recordings available at distances as close as one kilometer. Aside from a difference in site conditions (the Imperial Valley is a deep, alluvial valley) this event is similar to the proposed $M_S = 7.0$ maximum earthquake on the OZD.

2.5.2.4.4 Comparison with the Empirical Approach

A comparison (see FSAR response to Question 361.55) of the mean and 84th percentile empirical attenuation curves with the horizontal peak accelerations recorded during this event indicate the general conservatism of the empirical approach. While the

mean and 84th percentile peak accelerations of the new data at 8 km from the fault are 0.32 and 0.44g, the mean and 84th percentile estimated for a magnitude 6.5 at the SONGS site are 0.42g and 0.57g. Only 4 horizontal peak accelerations at any distance exceed 0.57g. These were from the two components at Bonds Corners (0.81g and 0.66g) at three km from the fault, 0.72g from one record at Station #6 one kilometer from the fault, and 0.61g from one record at Station #4 seven km from the fault.

A compilation of horizontal response spectra from the October 15 earthquake (see FSAR response to Question 361.55) shows that the mean and 84th percentile of 14 response spectra recorded at distances between 6 and 13 km fall well below the predicted mean and 84th percentile spectra for a magnitude 6.5 earthquake at almost all frequencies. Between 5 and 10 Hz, the Imperial Valley spectra approach the level of the predicted spectra.

2.5.2.4.5 Comparison with Theoretical Models

The theoretical model used to estimate ground motion for San Onofre 1 is currently being evaluated with respect to its ability to predict observed ground motion from the 1979 Imperial Valley earthquake (Del Mar Technical Associates, 1980b).

In order to better fit the observed data further refinements, mostly additional randomness, were introduced into the earthquake model. As a result of these refinements, better fits are obtained to the data particularly with respect to high frequency vertical and close-in horizontal ground motion. Sensitivity tests were carried out with respect to changes in the character of slip, inclusion of rupture along the Brawley Fault, and proximity of the rupture to the surface.

Although this refined model produced better results for this earthquake than the previous model, no comparison was made with respect to the original predictions for the 1940 Imperial Valley earthquake, the 1966 Parkfield earthquake, and the 1976 Brawley earthquake (Del Mar Technical Associates, 1979a); additional events shown in Supplement II (Del Mar Technical Associates, 1980a). Supplement II showed estimates of ground motion for the 1933 Long Beach earthquake and 1971 San Fernando earthquake based upon the original (revised) model and some, but not all, of the refinements introduced above. It is difficult to judge as to the relative validity of the original and refined models without a comparison of at least several different earthquakes. However, computation of ground motion at San Onofre using the refined model provided an assessment as to the significance of these differences with respect to estimation of ground motion from the occurrence of an earthquake on the OZD. These comparisons show rough equivalence of horizontal ground motion from both models. At different frequency bands a different model may be more conservative. With respect to vertical motion higher ground motion is predicted at high frequencies utilizing the refined model. This is to be expected since the model was calibrated with the Imperial Valley earthquake in which several stations produced anomalously high vertical accelerations. These accelerations are discussed below in Section 2.4.2.4.6.

As with the response spectra estimated at San Onofre from the original (revised) model response spectra estimated using the refined model fall below the applicants empirically derived spectra for an $M_S=7.0$ earthquake occurring on the OZD. Thus, while our review of the modeling study has not been completed and there may be uncertainty as to the appropriateness of the different theoretical models proposed, those examined do indicate conservatism in the empirical approach.

2.5.2.4.6 Comparison with the SSE

A direct comparison of ground motion recorded from the 1979 Imperial Valley event with the SSE has been made by the applicants (see FSAR responses to Questions 361.57 and 361.64). The major difference between the $M_S = 6.9$ October 1979 event and the controlling $M_S = 7.0$ assumed to occur at the OZD is the difference in site conditions. As indicated above, the Imperial Valley is a deep-alluvial (soft soil) valley, while San Onofre is a stiff soil site that is more rock-like in character. Boore and others (1978) compared ground motion from the San Fernando earthquake at rock and soil sites. They found that while there was no significant difference in peak accelerations, soil sites systematically recorded higher peak velocities and peak displacements. This observation relates to response spectra in that peak accelerations can be correlated with high frequency motion and peak velocities and displacements can be correlated with motion at intermediate and low frequencies. In other words, the major difference we would expect between similar size earthquakes occurring in the Imperial Valley and near San Onofre would be a higher level of ground motion recorded at frequencies of 1 Hz and less in the Imperial Valley.

A comparison of the recorded horizontal motions with the horizontal SSE (anchored at 0.67g) indicates the following:

- (1) The mean plus one standard deviation level of ground motion at distances between 6 and 13 km is well below the SSE.
- (2) The envelope of all response spectra in this distance range is below the SSE except for some small exceedances. This exceedance is broadest at Bonds Corner some 2 to 3 km from the fault.

A comparison of recorded vertical motion with the vertical SSE (anchored at 0.44g) indicates the following:

- (1) The mean spectral level at distances between 6 and 13 km falls below the SSE.
- (2) The mean plus one standard deviation of response spectra in this distance range exceeds the SSE by small amounts at frequencies greater than 2 Hz.
- (3) There is some significant exceedance of the SSE by vertical response spectra at stations at distances less than 6 km. Most notable is that of Station #6, one km from the fault. The uncorrected peak vertical acceleration recorded at

this site was 1.74g the highest acceleration recorded anywhere from any earthquake.

The applicants indicate that these exceedances are not significant and points out the following:

- (1) Within a distance of 10 km the fault maximum vertical peak acceleration is substantially higher than other peaks of vertical ground motion in recordings with very high peak accelerations.
- (2) Within 15 km of the fault maximum vertical motion occurs early in the recorded motion approximately 2 to 4 seconds before the corresponding horizontal peaks.
- (3) Algebraic and vectorial combination of ground motion records from all three components of motion show that vertical and horizontal motions dominate at different times during the ground motion (vertical ≤ 5 seconds, horizontal ≥ 5 seconds).

With respect to the above, the applicants also indicate that in the design of San Onofre 2 and 3 the significant ground motion from all components was assumed to occur at the same time and the assumed duration of this motion including repetition of high peaks of acceleration was much longer (80 seconds versus 15 seconds or less) than that recorded at Imperial Valley. We agree with the applicants' assessment of the significance of the high vertical motions particularly in light of the following additional information which indicates that these motions are most likely related to the particular site conditions in the Imperial Valley and not directly applicable to San Onofre:

- (1) Station #6 (which recorded high peak accelerations) has systematically recorded high peak accelerations from other earthquakes at other locations (Boore and Fletcher, 1980).
- (2) Those high vertical accelerations occurring at certain stations within 10 km of the fault did not occur at all stations near the fault and are believed to be related to the interaction of the propagating rupture with the thick sedimentary cover (Archuleta, 1980).
- (3) Those strong motion records from other earthquakes in the past which have shown relatively high vertical peak accelerations appear also to be related to site and fault conditions not present at San Onofre. For example, the 1976 Gazli earthquake caused strong vertical motion because the fault beneath the site ruptured vertically up towards the site (Hartzell, 1980), and the 1979 Coyote Lake earthquake resulted in high vertical acceleration at one station because of S to P wave conversion at the interface between the soft alluvium and firm bedrock at depth (Angstman and others, 1979).

In conclusion, it is our position that the analysis of records from the extremely well-recorded October 1979 event indicates that the SSE is a conservative representation of ground motion to be expected at the San Onofre site from occurrence of a similar size earthquake on the OZD at a distance of 8 km.

2.5.2.5 Summary

Our position with regard to the SSE approved for the CP can be summarized as follows:

- (1) Specification of the controlling earthquake for determining the SSE at San Onofre as an $M_S = 7.0$ on the OZD is conservative.
- (2) The applicants' estimate of horizontal ground motion from this earthquake utilizing an empirical methodology is reasonable and conservative and results in an estimated response spectra less than the SSE, for which the facility was designed, at all frequencies.
- (3) The conservatism associated with this estimate is supported by a comparison with those estimates computed from San Onofre 1 using theoretical models and with the extensive near-field data set recently recorded from a $M_S = 6.9$ earthquake in the Imperial Valley.
- (4) The SSE for vertical motion is considered to be appropriately conservative. Exceedence of the vertical SSE at some stations in the Imperial Valley earthquake is not considered to be significant due to the short duration of the high acceleration and the lack of correlation between horizontal and vertical peaks of motion. In addition these conditions which are believed to have caused the anomalous high vertical ground motion in the Imperial Valley are not present at San Onofre.

Therefore, based upon our review of the applicants' submittal of new information which has become available since the San Onofre 2 and 3 CP review, we reaffirm our conclusion reached at that time that the San Onofre 2 and 3 SSE high-frequency acceleration anchor point (0.67g) and design spectrum are acceptable.

2.5.2.6 Operating Basis Earthquake (OBE)

The OBE for San Onofre 2 and 3 is 1/2 the SSE. This is conservative with respect to the stipulation in Appendix A that the OBE be that earthquake which could reasonably be expected to affect the plant site during the operating life of the plant. The OBE for San Onofre 2 and 3 also meets the other criteria in Appendix A, which states that it should be at least 1/2 the SSE. We see no reason for changing the conclusion reached in the SER for the CP approving the OBE for San Onofre 2 and 3.

2.5.3 Stability of Subsurface Materials and Foundations

2.5.3.1 Introduction

The applicants have presented in the FSAR information concerning the properties and stability of soils and rock which may affect the San Onofre 2 and 3 facility. The FSAR considers both static and dynamic conditions including the vibratory ground motions associated with the safe shutdown earthquake. In a series of separate reports the applicants have presented information regarding dewatering well cavity investigations and dewatering well demobilization.

The San Onofre site is located on the sea coast in the gently sloping coastal plains. The plains are terminated at the beach and form a line of seacliffs. The near vertical sea cliffs in the immediate vicinity of the plant site range from 60 to 130 feet above sea level and have a narrow band of beach sand along the coast.

Two lithologic units are exposed in the excavations for the plant facilities. The units are the Pliocene age San Mateo formation and the overlying Pleistocene terrace deposits. The San Mateo formation is described as a massive, light brown to light gray sandstone with scattered interbeds of gravel and layers of silty sandstone and siltstone. The San Mateo formation can also be described as a poorly cemented but very dense sand. The terrace deposits consist of a series of crudely stratified mixtures of brown to gray sand, silt and clay underlain by a mixture of gravel, cobbles and boulders in a red-brown silty sand matrix.

2.5.3.2 Subsurface Explorations

The engineering properties of the materials underlying the site were investigated by drilling, sampling, laboratory testing, and geophysical techniques. The upper portions of the terrace deposits between elevation +80 and +115 feet are generally cohesive soils. Typically these soils are clayey sands to silty clays with unconfined compressive strength between 6 and 10 kips per square foot. The lower portions of the terrace deposits between elevations +50 and +80 feet are gravelly sand with low cohesion (0.2 kips per square foot) and a high angle of shearing resistance (Typically 38°). The measured compressional and shear wave velocities for the terrace deposits ranged from 1000 to 3100 feet per second and 330 to 1000 feet per second, respectively.

The plant facilities are underlain by the very dense, well graded sands of the San Mateo formation to a depth of about 900 feet. Laboratory testing shows that these sands have a high value of effective cohesion (typically 800 pounds-per-square-foot), and a very high angle of shearing resistance (typically 41°). The measured compressional and shear wave velocities for the San Mateo sand range from 3,000 to 7,500 feet per second and 1,000 to 2,750 feet per second, respectively.

2.5.3.3 Site Preparation

Site preparation consisted of the removal of all terrace and San Mateo deposits down to elevation +30 for plant grading. Major plant structures, including all seismic Category I structures, are founded in the San Mateo formation. The terrace deposits remain only in the area of switchyard slopes and support only switchyard structures.

2.5.3.4 Foundation Excavation

The foundation excavations below elevation +30 were made with conventional earth-moving equipment in the San Mateo formation. Excavation depths extended up to 60 feet below plant grade depending on foundation dimensions and embedment depth. All foundation excavations were protected against disturbance, and where over-excavation was required, lean concrete or compacted backfill was placed to support structures. All soil backfill used in seismic Category I areas consists of San Mateo sand. Structural backfill was compacted to a minimum density of 95% of the maximum dry density determined in accordance with ASTM D1557-70 specifications.

2.5.3.5 Groundwater

The average groundwater level at the site is elevation +5. The normal groundwater level beneath the site is stable. Dewatering was required during construction to lower the groundwater level below the excavations required for deeply embedded structures. The dewatering system consisted of 12 deep wells with turbine pumps rated at 1,500 gpm. In addition to the deep wells a supplementary system of wellpoints was required in the intake area. Dewatering well cavities are discussed in Section 2.5.4 of this report.

2.5.3.6 Bearing Capacity and Settlement

All Seismic Category I structures were analyzed for static loading conditions. Foundation bearing capacity and settlement were evaluated considering the unloading due to the excavation and the design loads due to the plant structures. Lateral earth pressures on structures from backfills were considered in the design of the structures.

The pre-excavation surface elevation in the plant area was between elevation +95 and +115. The finished plant grade elevation of +30 was achieved by excavating over 65 feet of terrace deposits and San Mateo sand. Therefore, the foundation soils have been unloaded by at least 8,000 pounds per square foot. Reloading of the foundation soils due to structural loads is less than the weight of overburden removed. Due to the relatively high shear strength properties of the San Mateo formation and the low ratio of construction loads to overburden removal, the bearing capacity of the foundation material is well in excess of the design loads. In addition, calculations show that the dense sand will settle between 1/2 to 1 inch, and maximum differential settlements are expected to be less than 1/2 inch. Measured settlements have been less than 1/2 inch.

We concur with the applicants' assessment of bearing capacity and settlement potential for the undisturbed in-situ San Mateo sand. We agree that the above predicted settlement values are reasonable and conservative.

2.5.3.7 Liquefaction Potential

The San Mateo sand is the only natural soil deposit that is below the water table (elevation +5). The liquefaction potential of the undisturbed sand was evaluated and the results show that the in-situ dense sand is not susceptible to liquefaction. This evaluation included field measurements, extensive laboratory testing and analysis of dynamic shear stresses. We agree with the applicants' conclusions that the in-situ undisturbed San Mateo sand is not susceptible to liquefaction.

2.5.3.8 Slope Stability

All seacliffs and cut slopes to the north and south of the plant are far enough away that slope failure would not affect the plant facilities. The switchyard slopes east of San Onofre 2 and 3 are the only permanent slopes in the vicinity of plant structures. The cut slopes in the switchyard are 2 horizontal to 1 vertical. The overall height of these slopes is about 90 feet with two benches cut at elevation +55 and +78 feet. The average slope including the benches is greater than 3 horizontal to 1 vertical.

The upper portions of the switchyard slope consists of terrace deposits. Above the bench cut at elevation +78, the soils are predominantly terrace clays. The lower bench is cut into the terrace sands and gravels. The toe of the slope is cut into the very dense San Mateo sand.

The applicants' analyses and design criteria for the switchyard slopes considered static and dynamic loading conditions. These analyses included use of the modified Bishop method of slices for static analyses and the finite-element method for dynamic analyses. The applicants concluded that the factors of safety against slope instability are adequate and that no adverse consequences would result for dynamic loading conditions. We agree with these conclusions.

2.5.4 Dewatering Well Cavities

As noted in Section 2.5.3.1, above, the applicants have identified, investigated and treated a number of cavities associated with dewatering wells for Units 2 and 3. The first unmistakable evidence of dewatering cavities was observed on May 6, 1977 by the applicants. Since that date, there have been numerous meetings, reports, site visits, etc., that have addressed the identification and treatment of these cavities. These activities and some of the more significant items are discussed herein. This discussion is limited to our assessment of whether the cavities caused by the applicants' temporary dewatering of the San Onofre 2 and 3 site will have an unacceptable adverse effect on the capability of structures and equipment of San Onofre 2 and 3 to withstand the design basis seismic events.

The deepwell dewatering system included 12 wells. Each well generally consisted of a 200 foot deep, 30-inch diameter boring with a 14-inch diameter steel casing. The lower part of the casing was perforated. A gravel filter was placed in the annular space between the sidewall and the casing. At wells 6, 7, and 8 a problem developed during the well operation and the well casing deteriorated due to corrosion. The gravel filter migrated through the enlarged holes and resulted in erosion of the surrounding material.

The first relatively detailed report on this condition was transmitted in a letter report dated August 22, 1977, from the applicants to the NRC Office of Inspection and Enforcement in Region V. This report discussed the background, investigation, cause, and safety implications as of that date. This report was identified as an interim report, subject to further investigation and analyses. This type of a foundation problem encountered during construction requires that the staff review evolve with the investigation, analyses and treatment of the problem.

The next significant step in the review process was a meeting held at the request of the NRC staff, so that we could obtain a first-hand summary of the current status of the dewatering well systems and the observed cavities. In addition, the applicants presented the planned future activities to investigate and fill the cavities, and demobilize the wells. This meeting was held on November 29, 1977 in Bethesda, Md. In addition to this initial meeting, the staff met with the applicants on three other occasions (March 10, 1978, June 22, 1978, and December 1, 1978) and made two site visits (February 14, 1978 and April 13, 1978) to further understand and review the dewatering well cavity conditions. The culmination of all these meetings, investigations and interim reports is provided in a series of reports placed on the docket by the applicants which describe the results of (1) deep exploration drilling, (2) shallow exploration and grouting, and (3) analyses of the potential effects of seismic shaking on the cavity at dewatering Well 8. A summary report dated July, 1979 provides a compilation of the data and conclusions of the investigation of the dewatering wells.

Deep exploration drilling was accomplished with borings drilled to about 200 feet. These holes were closely-spaced to assure that all cavities larger than 3 feet in width and adjacent to the well, would be detected. These borings were also used to locate the maximum depth of each cavity. Shallow exploration borings were drilled 50 to 120 feet deep to define any cavities or zones of disturbed material, and delineate their extent and shape. These borings also were used as grout holes. Grout was placed in the drill holes using both gravity and pressure injection methods. Gravity grouting filled any open voids. Pressure grouting was used to fill any remaining voids.

Truck-mounted drill rigs were used to advance borings for exploration and grouting. Rotary drilling methods were utilized with Revert drilling fluid to remove cuttings from the hole. Standard penetration tests were taken at regular intervals to help define the limits of the disturbed zones. Gyroscopic and slope indicator surveys were performed to determine the direction and drift of borings with depth. The

combinations of these techniques and procedures to adequate to detect, define and describe the properties of cavities in and around the site dewatering wells.

The above-described exploration drilling, mechanical measurements and geophysical surveys were performed by the applicants to identify and define the location and extent of each and every cavity at the site. These techniques are in conformance with Regulatory Guide 1.32 entitled "Site Investigations for Foundations of Nuclear Power Plants," dated September 1977.

In the investigations of the twelve dewatering wells at the site, the most intensive effort was applied to wells 6, 7 and 8, the only cavities of sufficient size and proximity to the San Onofre Units to have an impact on seismic category I structures. All other wells were free of large cavities. This intensive effort was due to the close location of these cavities to Seismic Category I structures and the size of the cavities present at these locations.

Grout was placed in cavities to fill any void spaces and provide some densification of the in-fill sand within the disturbed zone. Grouting was performed in stages on a grid pattern. The water-cement ratio varied from 5:1 to 3/4:1 for the grout mixes used. Grout pressures were generally limited to one psi per foot of depth. These grouting procedures and the close spacing of the grout holes are common foundation treatment techniques and provide adequate assurance that cavities have been filled. We find that these procedures are adequate and that the results have been satisfactorily documented.

The cavities at wells 6, 7, and 8 were evaluated to determine the effects on adjacent seismic Category I structures. These structures included the auxiliary building, fuel handling buildings and the Unit 3 containment structure.* These evaluations were made by calculating the potential reduction in stiffness and support characteristics of the foundation soil caused by an increase in pore water pressure in an adjacent grouted cavity. These evaluations were provided in a report titled "Report on the Results of Analyses Performed on Well 8 at the SONGS Units 2 and 3, San Onofre, California." This report provides analyses of the potential effects of seismic shaking on the cavity at Well 8, and the resulting potential effects on the adjacent structures. The results of the analyses for Well 8 were extrapolated to the Well 6 and 7 cavities. There are two basic elements to this report: (1) the evaluation of the generation and dissipation of excess pore pressure in the soil foundation during seismic loading; and (2) evaluation of the overall reduction in stiffness of the soil supporting the containment structure.

Two very conservative assumptions were considered with respect to excess pore water pressure generation and dissipation. These assumptions were: (1) the geometry of the sand fill within the cavity at Well 8 is two-dimensional (plane strain or

* Unit 1 structures and the Unit 2 containment building are located too far from the cavities to be affected by them.

axisymmetric) and (2) the shortest drainage path beneath the containment structure is equal to the diameter of the basemat. The first assumption implies that the volume of the pore pressure generating source is much greater than the actual size of the cavity. For the axisymmetric case which is considered to model the cavity size more realistically than that of the plane strain case, the volume of the cavity is calculated to be more than one order of magnitude larger than the actual cavity size. The second assumption increases time required for dissipation of excess pore pressures and overestimates pore pressure at any given time during periods of dissipation as compared to the actual field condition. Regarding the applicants' assessment of the generation and dissipation of excess pore pressure, although many assumptions are required in this analysis, it is conservative and we conclude that it is a reasonable assessment of the expected conditions. The report concludes that the maximum effects on the Unit 3 containment building is a 4 to 5% reduction in overall soil stiffness. The effects of the cavity on settlement (less than 1/10-in. increase) and bearing capacity of the containment structure are very small and will not affect the containment or other structures on site. Our review of that report has shown that conclusion to be conservative.

In addition to the above structure, a tunnel passes over the Well 8 cavity and for that reason has been assessed by the applicants. The effect of the cavity on the tunnel was based on the assumption that the tunnel would be unsupported in the area of the cavity. We find that this is a conservative assumption for geotechnical engineering considerations for the tunnel. Structural spanning capabilities of the tunnel are discussed in Section 3.8.4 of this report.

For the reasons listed above, we find that the applicants have performed acceptable geotechnical investigations, treatment and analyses to determine the extent of all the cavities existent at the site and to assess their potential impact on adjacent structures during seismic or other conditions. Based on the above discussion and the electrical tunnel evaluation given in Section 3.8.4, we conclude that the dewatering well cavities at San Onofre 2 and 3, in their present, grouted condition, do not significantly impair the ability of safety-related structures to withstand the safe shutdown earthquake.

3.0 DESIGN CRITERIA - STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

3.1 Conformance With General Design Criteria

In Section 3.1 of the Final Safety Analysis Report, the applicants state that the San Onofre 2 and 3 design complies with all General Design Criteria, with no exceptions. We have assessed the final design of San Onofre 2 and 3 against the General Design Criteria (GDC) of Appendix A to 10 CFR Part 50, and we conclude that the facility is in conformance with these criteria, with the possible exception of General Design Criterion 51 (See Section 6.2.1.4 of this report). We will require conformance to GDC 51 prior to issuance of an operating license for the facility. We will discuss the resolution of this issue in a supplement to this report.

3.1.1 Conformance With Industry Codes and Standards

Our review of structures, systems and components relies extensively on the application of industry codes and standards that have been used as accepted industry practice. These codes and standards, as cited in this report and attached bibliography, have been previously reviewed and found acceptable by us; and have been incorporated into our Standard Review Plan (NUREG 75/087).

3.2 Classification of Structures, Components, and Systems

3.2.1 Seismic Classification

Criterion 2 of the General Design Criteria requires that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena including earthquakes without loss of capability to perform their safety function. This refers to the plant features necessary to assure (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to 10 CFR Part 100 guideline exposures. Structures, systems, and components that are designed to remain functional if a safe shutdown earthquake (SSE) occurs are classified as seismic Category I.

We have reviewed the Final Safety Analysis Report and conclude that with one exception, the safety-related structures, systems, and components at San Onofre 2 and 3 have been classified by the applicant as seismic Category I items in accordance with the recommendations of Regulatory Guide 1.29 (Revision 2), "Seismic Design Classification." The one exception is the letdown line of the chemical and volume control system from isolation valves 004-C-105 and 023-C-105 (adjacent to back pressure control valves 2PV-0201A and 2PV-0201B) to the volume control tank outlet valve 2LV-0227B. This line is not designed to seismic Category I requirements.

In response to our inquiry, the applicants have demonstrated that in the event of a safe shutdown earthquake, there is an adequate plant procedure for achieving a cold shutdown condition without use of the letdown line. In this situation, safe shutdown can be achieved without letdown flow since the letdown line is not required for boron injection and is also not required to function for post-accident operation. The letdown line is isolated and the charging pumps are used to inject concentrated boric acid into the reactor coolant system from either the boric acid makeup tanks or the refueling water storage tank. These seismic Category I components assure an adequate supply of boron solution to accommodate reactor coolant shrinkage. At our request the applicants have developed an emergency procedure for achieving cold shutdown without use of the letdown line. For the above reasons, we conclude that this alternate method of plant shutdown is acceptable, and that the classification of the letdown line as non-seismic Category I is acceptable.

All other structures, systems, and components that may be required for operation of the facility are designed to other than seismic Category I requirements, including those portions of Category I systems such as vent lines, fill lines, drain lines, and test lines that are on the downstream side of isolation valves and that are not required to perform a safe function. Structures, systems, and components important to safety that are designed to withstand the effects of a safe shutdown earthquake and remain functional are identified in an acceptable manner in Table 3.2-1 of the Final Safety Analysis Report (FSAR). The basis for acceptance in our review is conformance of the applicant's designs, design criteria, and design bases for structures, systems, and components important to safety with the Commission's regulations as set forth in General Design Criterion 2 and to Regulatory Guide 1.29, and industry codes and standards.

Except for the letdown line of the chemical and volume control system that is not designed to seismic Category I requirements, but which we find to be acceptable as discussed above, we conclude that structures, systems, and components important to safety of San Onofre 2 and 3, that are designed to withstand the effects of a safe shutdown earthquake and remain functional, are properly classified as seismic Category I items in conformance with the Commission's regulations, the applicable Regulatory Guides, and industry codes and standards and are acceptable. Design of these items in accordance with seismic Category I requirements provides reasonable assurance that in the event of a safe shutdown earthquake, the plant will not endanger the health and safety of the public.

3.2.2 System Quality Group Classification

Criterion 1 of the General Design Criteria requires that nuclear power plant systems and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Fluid system pressure-retaining components important to safety will be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. The applicants have identified those fluid-containing components which are part of the reactor coolant pressure

boundary and other fluid systems important to safety. Specifically, such systems: (1) prevent or mitigate the consequences of accidents and malfunctions originating within the reactor coolant pressure boundary, (2) permit shutdown of the reactor and maintain it in a safe shutdown condition, and (3) contain radioactive material. These fluid systems are classified in an acceptable manner in Table 3.2-1 of the FSAR and on system piping and instrumentation diagrams.

The applicants have applied Quality Groups A, B, C, and D in Regulatory Guide 1.26, "Quality Group Classifications and Standards" (Revision 3) to the fluid system pressure-retaining components important to safety. These components that are classified Quality Group A, B, C, and D will be constructed to the codes and standards identified in Table 3.2-2 of the FSAR as follows:

Quality Group	Component Code
	ASME Section III, Division 1
A	Class 1
B	Class 2
C	Class 3

Quality Group A components comply with Section 50.55a of 10 CFR Part 50. Quality Group B and C components comply with subsection NA-1140 of the ASME Code.

Components that are classified Quality Group D are constructed to the following codes as appropriate: ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, ANSI B31.1.0, Power Piping Code, Manufacturer's Standards, API-620, API-650, AWWA-D100 or ANSI B96.1.

The basis for acceptance in our review is conformance of the applicant's designs, design criteria, and design bases for pressure-retaining components such as pressure vessels, heat exchangers, storage tanks, pumps, piping, and valves in fluid systems important to safety with the Commission's regulations as set forth in General Design Criterion 1, the requirements of the Codes specified in Section 50.55a of 10 CFR Part 50, Regulatory Guide 1.26, and industry codes and standards.

We conclude that fluid systems pressure-retaining components important to safety that are designed, fabricated, erected, and tested to quality standards in conformance with these requirements are acceptable and provide reasonable assurance that San Onofre 2 and 3 will perform in a manner providing adequate safeguards to the health and safety of the public.

3.3 Wind and Tornado 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 100 mph based on a recurrence interval of 100 years.

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 "Wind Forces on Structures" Paper No. 3269, American Society of Civil Engineers, 1961. This document is referenced in SRP 3.3.1 as describing an acceptable methodology.

The procedures that were utilized to determine the loadings on seismic Category I structures induced by the design wind specified for the plant are acceptable since these procedures provide a conservative basis for engineering design to assure 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 San Onofre 2 and 3 seismic Category I structures will not be impaired and, in consequence, seismic Category I systems and components located within these structures are adequately protected and will perform their intended safety functions, if needed. Conformance with these procedures is an acceptable basis for satisfying, in part, the requirements of General Design Criterion 2.

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 220 mph tangential wind velocity and a 40 mph translational wind velocity. The simultaneous atmospheric pressure drop was assumed to be 1.5 psi in 4.5 seconds. Tornado missiles are also considered in the design as discussed in Section 3.5.1.4 of this report.

The procedures that were used to transform the tornado wind velocity into pressure loadings are similar to those used for the design wind loadings as discussed in Section 3.3.1 of this report. The tornado missile effects were determined using procedures that are discussed in Section 3.5.1.4 of this report. The total effect of the design tornado on seismic Category I structures was determined by the appropriate combinations of the individual effects of the tornado wind pressure, pressure drop and tornado associated missiles. Structures are arranged on the San Onofre 2 and 3 site and protected in such manner that collapse of structures not designed for tornado forces will not affect other safety-related structures.

The procedures utilized to determine the loadings on structures induced by the design basis tornado specified for the plant are acceptable since the procedures provide a conservative basis for engineering design to assure that the structures withstand such environmental forces.

The use of these procedures provides reasonable assurance that in the event of a design basis tornado, the structural integrity of the San Onofre 2 and 3 structures that are required to be designed for tornadoes will not be impaired. As a result, safety-related systems and components located within these structures will be adequately protected and may be expected to perform all necessary safety functions as

required. Conformance with these procedures is an acceptable basis for satisfying, in part, the requirements of General Design Criterion 2.

3.4 Water Level (Flood) Design

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 of this report. The hydrostatic and hydrodynamic effects were considered in the design of all seismic Category I structures as appropriate.

We have reviewed the procedures utilized to determine the loadings on seismic Category I structures induced by the design flood or highest groundwater level specified for the plant. We find these procedures acceptable since they provide a conservative basis for engineering design to assure that the structures will withstand such environmental forces.

The use of these procedures provides reasonable assurance that in the event of floods of 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. Conformance with these design procedures is an acceptable basis for satisfying, in part, the requirements of General Design Criterion 2.

We have reviewed the design features provided to protect safety-related systems, structures, and components from flood damage and to maintain the capability for a safe plant shutdown during a design basis flood.

The probable maximum flood (PMF) level is calculated to be at elevation +30.8 feet mean lower low water (MLLW). This flood level is based on the probable maximum precipitation in the San Onofre area. The applicants identified all the openings and penetrations in safety-related buildings that are below PMF level. All openings and penetrations below the PMF level are either sealed, protected by watertight doors or hatches, protected by waterstops, or the applicants' analysis has shown the PMF does not impact safety-related equipment.

One safety-related structure that was of concern was the diesel generator building. In this building the floors are located slightly below the PMF level. The building exterior doors are not watertight. In response to our request the applicants, in FSAR Amendment 15, agreed to provide curbing to protect safety-related electrical conduit penetrations below the PMF level, for those penetrations that are not protected by watertight seals. We also requested that additional protection be provided for the effect of storm wave runup, which could cause splashing of safety-related equipment above the PMF level. The applicants agreed to institute administrative procedures to ensure that the diesel generator building doors are normally locked and an alarm provided in the permanently manned central alarm station to alert the security personnel in the event the doors are opened. We find that

these administrative measures are acceptable, and conclude that the issue of flooding of the diesel generator building has been resolved.

Another structure of concern was the seawall. The flood protection design of seismic Category I structures was based on the assumption that the seawall which is parallel to the shore line is capable of withstanding the safe shutdown earthquake (SSE). This wall was not originally classified as a seismic Category I structure and we had no assurance that the appropriate requirements of quality control and quality assurance had not been applied during its construction. In response to our questions, the applicants stated that the seawall was designed for the SSE and demonstrated that the wall satisfied the strength requirements for this loading condition. Since the wall was not designed for the operating basis earthquake (OBE) we requested that the applicants perform a confirmatory analysis to determine the adequacy of the wall for OBE conditions. In response to our request, the applicants performed an analysis of the seawall for horizontal OBE input motion. Vertical OBE results were estimated from calculations performed for the SSE, because the effect of vertical input is small compared to the effect of horizontal input.

The FLUSH computer code was used for both OBE and SSE analyses. This code has been used in similar applications in the past, and was approved by the staff. The criteria used in the FLUSH analyses were consistent with those used in analyzing the effect of the SSE on other seismic Category I plant structures. We reviewed the results of the applicants analysis of the seawall and found them acceptable, because the seawall was shown to be capable of withstanding the OBE without losing the ability to perform its safety function.

On the basis of our review as described above, we conclude that the design of the facility for flood protection meets the requirements of Criterion 2 of the General Design Criteria with regard to protection against the effects of natural phenomena, and the guidelines in Regulatory Guide 1.102 "Flood Protection for Nuclear Power Plants" with regard to provision of protection by incorporated barriers. On these bases, we conclude that the San Onofre 2 and 3 water level (flood) design is acceptable.

3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

Missile protection is provided to ensure safe shutdown capability of the reactor facility. Pressurized components and rotating machines have the potential to become internal missile sources. Protection against missiles outside containment is achieved by proper orientation of components and systems, by the use of missile barriers, and by physically separating redundant safety-related systems or components from each other and from non-safety-related systems.

As a result of our review, we conclude that the San Onofre 2 and 3 design is in conformance with General Design Criterion 4 as it relates to structures housing essential systems and to the systems being capable to withstand the effects of internally generated missiles, Regulatory Guide 1.13, "Spent Fuel Storage Facility

Design Basis," as it relates to protection of spent fuel pool systems and fuel assemblies from internal missiles, and is acceptable.

3.5.1.2 Internally Generated Missiles (Inside Containment)

The applicants have evaluated the potential of internally generated missiles to affect the function of safety related equipment inside containment and containment itself. Potential sources of missiles have been identified including rotating machinery, high energy fluid system failures, and missiles due to gravitational effects.

Non-seismic structures and equipment which could fail and impact seismic Category I equipment were evaluated to confirm that the impacted seismic Category I equipment will not collapse or fail.

The applicants analyzed the equipment within containment which has the potential to become missiles, and have identified the following equipment as potential missile generators:

- (1) Control Rod Drive Assemblies.
- (2) Resistance Temperature Detectors.
- (3) Sump Pump Impeller.
- (4) Reactor Coolant Drain Tank Pump Impeller.
- (5) Normal Air Conditioning Unit Fan Blades.
- (6) Containment Dome Circulator Fan Blades.
- (7) Reactor Cavity Supply Fan Blades.
- (8) Recirculation Filter Fan Blades.
- (9) Lower Circulation Fan Blades.

The applicants also identified the systems and components requiring protection from these missiles and the design features that provide the required protection. These features include enclosing the potential missile sources in casings with sufficient thickness or locating them in individual missile-proof compartments. The applicants have shown that the systems and components requiring protection from potential missiles are provided with proper missile barriers.

The staff has expressed concern regarding the possible gravity missiles generated by the possible dropping of the reactor vessel seal ring. In response to our request for additional information, the applicants, in Amendment 19 to the FSAR, stated that during normal plant operation, the reactor vessel seal ring is stored and clamped on the vessel head storage stand and cannot become a gravitational missile. The clamps are designed to prevent the seal ring from being dislodged during a safe shutdown earthquake. Protection against missiles inside containment is achieved by physically separating the safety-related equipment from the potential missiles using adequate barriers or distance.

The applicants have stated in the FSAR that all valves within the containment have been eliminated as primary sources of missiles because of the presence of secondary

retention features (e.g., bolted valve bonnets and valve stems with back seats). The likelihood of all bolts experiencing a simultaneous complete severance failure is considered very remote. Nuts, bolts, and nut and bolt combinations have only a small amount of stored energy and thus are of no concern as potential missiles. We are in agreement with the applicant's evaluation.

As a result of our review, we conclude that the San Onofre 2 and 3 design is in conformance with General Design Criterion 4 as it relates to structures housing essential systems and to the systems being capable of withstanding the effects of internally generated missiles, and is acceptable.

3.5.1.3 Turbine Missiles

The applicants have arranged the turbine generators in a non-peninsular orientation relative to the containment buildings for San Onofre 2 and 3. This configuration is not the preferred orientation recommended by Regulatory Guide 1.115. However, the applicants received a Construction Permit in 1973, prior to the issuance of the guide. We performed an independent analysis of the turbine missile risks for San Onofre 2 and 3 and find that the only hazard of any significance is the potential for missiles ejected from the low pressure turbine rotors damaging the primary system pressure boundary within the containment. A conservative estimate of the probability for damaging the primary system pressure boundary is 1.8×10^{-6} per turbine year. The following conservatisms are intrinsic to this probability estimate:

- (a) The turbine wheels are assumed to always break into four equal segments. In actuality, there are other potential wheel burst modes with lesser damage potential (e.g., one large piece plus many small fragments).
- (b) The probability for destructive overspeed is based on an historically observed data base involving some turbines which were not subject to frequent overspeed trip testing. The Technical Specifications will require that the turbine steam valves be tested weekly, so that the probability for a destructive overspeed due to a valve malfunction will be reduced significantly, i.e., at least by a factor of ten.

In view of the estimated probability for turbine missile damage and in consideration of the above conservatisms including frequent turbine steam valve testing, we conclude that the turbine missile hazards with respect to the safety related plant systems for San Onofre 2 and 3 are significantly less than the conservative estimate given above and are acceptably low.

3.5.1.4 Tornado Missiles

The applicants have assessed the potential for tornado generated missiles that could pose a hazard to safety-related structures, systems, and components. The postulated missile spectrum includes, among other missiles, a steel rod and utility pole. We have independently verified the assessment of the applicant and find the tornado missile design spectrum acceptable.

We have reviewed the safety-related structures and equipment for San Onofre 2 and 3 with respect to tornado missile protection. The structures housing the safety-related systems for the plant are constructed of reinforced concrete walls of 18 inches thickness with reinforced concrete roofs of a minimum thickness of 14 inches and a 3/4-inch minimum thickness for steel covers for safety-related openings. These are sufficient to resist the postulated tornado missiles.

Details of the San Onofre 2 and 3 design for the protection against tornado generated missiles are discussed in Section 3.3.2 of this report. We conclude that the plant is adequately protected against the effects of design basis tornado missiles postulated for the San Onofre site in accordance with General Design Criterion 4.

3.5.2 Barrier Design Procedures

The San Onofre 2 and 3 seismic Category I structures, systems and components are shielded from, or designed to withstand 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.

Information has been provided by the applicants to show 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 accomplished by estimating the depth of penetration of the missile into the impacted structure. Furthermore, secondary missiles were prevented by fixing the target wall thickness above that determined for penetration. In the second step of the analysis, the overall structural response of the target when impacted by a missile was determined using established methods of impactive analysis. The equivalent loads of missile impact, whether the missile is environmentally generated or accidentally generated within the plant, were combined with other applicable loads as is discussed in Section 3.8 of this report.

The procedures that were utilized to determine the effects and loadings on seismic Category I structures, missile shields and barriers, induced by design basis missiles selected for the plant, are acceptable since, as discussed above, these procedures provide a conservative basis for engineering design to assure that the structures or barriers are adequately resistant to and will withstand the effect of such forces.

The use of these procedures provides reasonable assurance that in the event of design basis missiles striking seismic Category I structures or other missile shields and barriers, the structural integrity of the structures, shields, and barriers will not be impaired or degraded to an extent that will result in a loss of required protection. Seismic Category I systems and components protected by these structures are, therefore, adequately protected against the effects of missiles and will perform their intended safety function, if needed. Conformance with these procedures is an

acceptable basis for satisfying, in part, the requirements of General Design Criteria 2 and 4.

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping
3.6.1 Postulated Piping Failures in Fluid Systems Outside of Containment

•
The staff's guidelines for protection against postulated piping failure in high- and moderate-energy fluid systems outside containment are given in Section 3.6.1 of NUREG-75/087, the Standard Review Plan (SRP) and Branch Technical Position (BTP) ASB 3-1 and MEB 3-1. In accordance with BTP ASB 3-1, plants for which construction permits were tendered before July 1, 1973, and for which operating licenses are issued after July 1, 1975, should follow the guidance of Appendix B of BTP 3-1 (letter by A. Giambusso, December 1972, "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment") and also provide moderate energy piping failure analyses in accordance with BTP ASB 3-1.

The San Onofre 2 and 3 applicants have proposed criteria in the Final Safety Analysis Report for determining the location, type, and effects of postulated pipe breaks or cracks in high energy piping systems and postulated pipe cracks in moderate energy piping systems. The applicants analyzed high energy piping systems for the effects of pipe whip, jet impingement, and environmental effects on safety-related systems and structures. For moderate energy systems, protection of safety related systems from effects due to critical cracks, including flooding, were analyzed. Using these postulated effects, the applicants evaluated their design of systems, components, and structures necessary to safely shut the plant down and to mitigate the effects of these postulated piping failures. Protection for the systems, components, and structures is accomplished by use of physical separation, enclosure in suitable compartments, pipe whip restraints, and jet impingement barriers. The applicants' analysis included consideration of a single active failure in systems necessary to mitigate the consequences of a postulated pipe break in high energy systems, in accordance with BTP ASB 3-1 and MEB 3-1.

The applicants have examined safety related areas outside containment for the effects of high energy pipe failures. The San Onofre 2 and 3 design provides two physically separated main steam isolation and pressure relief valve enclosures per unit, each containing one main steam and one main feedwater train. The applicants have provided the results of an analysis which indicated that these enclosures have been designed to withstand the environmental effects of the limiting failure within the enclosure, i.e., a main steam line break. Vent areas and blowout panels have been provided to dissipate the blowdown energy. Safety related components located in these enclosures have been environmentally qualified for the steam line break. Other safety related areas examined by the applicants for the effects of high energy pipe breaks and moderate energy pipe cracks include the auxiliary building, penetration building, and safety equipment building. We conclude that the applicants have provided sufficient information in their analysis to demonstrate that safety related systems and components located in these areas will not lose the capability to provide safe shutdown due to the effects of a high energy pipe break or moderate energy pipe

crack, including flooding, primarily by separation of redundant safety related trains.

The applicants' original design provided for one motor driven and one steam turbine driven auxiliary feedwater (AFW) train (see section 10.4.6 of this report), both located in a common enclosure in the condensate storage tank building with 15 feet of separation between trains. The applicants did not perform a complete high energy pipe break analysis for this location, i.e., discrete pipe breaks were not assumed, pipe whip dynamic analyses and jet impingement analyses were not performed. In FSAR Amendment 21, the applicants presented a revised design including two motor driven pump trains and one turbine driven pump train. The applicants have also submitted a revised high energy pipe break analysis for the AFW area. The effects of pipe whip and jet impingement, and environmental effects were analyzed, assuming the failure of steam high-pressure nitrogen piping in the condensate storage tank building. The most severe environmental effects would occur in the event of failure of the 6-inch section of the AFW turbine steam supply line. This break would result in a maximum pressure of 2.76 psig and a maximum temperature of 302°F within the room in the building in which the break occurred. The applicants state that this pressure will not compromise the structural integrity of the building, and that safety-related components located in this area are qualified for the above environmental conditions.

For the AFW pump discharge lines, pipe whip analyses were not performed by the applicants because no fluid reservoir exists that would sustain thrust after a pipe break for sufficient time to result in pipe whip. We have reviewed the San Onofre 2 and 3 design and we concur that pipe whip analyses are not required for these lines for the above reason. The applicants have performed a jet effect analysis for a critical pipe crack and based on the results, has found the results acceptable, since no safety-related equipment would be damaged.

Based on our review, we find that the applicants have adequately designed and protected areas and systems required for safe plant shutdown following postulated events, including the combination of pipe failure and single active failure. The plant design meets the requirements of General Design Criterion 4 regarding protection against the dynamic effects of pipe whip and discharging fluids, and the guidelines of SRP 3.6.1 and BTP's MEB 3-1 and ASB 3-1 with regard to the protection of safety-related systems and components from postulated high energy line breaks, and moderate energy line cracks. We, therefore, conclude the plant design for the protection of the safety-related equipment from the effects associated with the postulated failure of piping outside containment is acceptable.

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

The applicants have defined, in the San Onofre 2 and 3 FSAR, the criteria used for postulating pipe breaks in high and moderate energy lines both inside and outside containment. Based on our review and evaluation of these criteria, we conclude that they are consistent with the criteria of Regulatory Guide 1.46 and Section 3.6.2 of the Standard Review Plan (NUREG 75/087).

The applicants have referenced topical report CENPD-168, Revision 1, September, 1976, to describe their analytical methods for determining reaction loads on the reactor coolant system (RCS) piping and components due to postulated RCS pipe breaks. Topical report BN-TOP-2, Revision 2, May, 1974, is also referenced to describe analytical methods for dynamic effects of postulated pipe breaks on balance-of-plant (BOP) piping and components. Both CENPD-168, Rev. 1, and BN-TOP-2, Rev. 2, have been reviewed and found to be acceptable references by the staff.

Because the pipe break criteria meet the above-referenced staff criteria, we find that

- (1) The proposed design of piping restraints and measures to deal with jet impingement effects upon the reactor coolant pressure boundary and other safety-related systems provide adequate protection for the containment structure, reactor coolant pressure boundary elements, and other systems important to safety.
- (2) The provisions 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 sequential failures of safety-related piping, and emergency core cooling system performance will not be degraded by these dynamic effects.
- (3) The proposed piping arrangement and applicable design considerations for high and moderate energy fluid systems inside and outside of containment will provide adequate assurance that the unaffected system components, and those systems important to safety which are in close proximity to the systems in which postulated pipe failures are assumed to occur, will be protected. San Onofre 2 and 3 design will mitigate the consequences of a pipe break so that the reactor can be safely shut down and maintained in a safe shutdown condition in the event of a postulated failure of a pipe carrying a high or moderate energy fluid inside or outside of containment.

3.7 Seismic Design

3.7.1 Seismic Input

The safe shutdown earthquake (SSE) spectrum for San Onofre 2 and 3 is anchored at a zero-period acceleration of 0.67g. The seismic input design response spectrum was developed by requiring it to envelope the peaks of the ground response spectra which were in turn developed from site-specific earthquake acceleration time-histories scaled to produce a 0.67g ground surface acceleration at zero periods. The vertical motion spectra have the same shape as the horizontal motion spectra, but are 2/3 times the horizontal. The operating basis earthquake (OBE) response spectra have the same shape as those of the SSE and one-half times the spectral values of the SSE at corresponding frequencies. The acceptability of these site-specific response spectra is discussed in Section 2.5.2. Note that the DBE postulated by the applicants is identical to the safe shutdown earthquake described in Appendix A to 10 CFR 100.

A synthetic time history of 80-second duration was used for seismic design of seismic Category I structures, systems and components. The response spectrum of this time history approximates the SSE response spectrum. The specific percentage of critical damping values used in the seismic analysis of seismic Category I structures, systems and components are equal to or less than those recommended in Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." Spatial soil damping values actually used were limited to 10% for the SSE analysis and to 8% for OBE analysis.

3.7.2 Seismic System and Subsystem Analysis

The scope of our review of the seismic system and subsystem analyses for the plant included the seismic analysis methods for all seismic 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 seismic Category I structure overturning, and determination of composite damping. The review included design criteria and procedures for evaluation of interaction of non-Category I structures and piping with seismic Category I structures and piping, and the effects of parameter variations on floor response spectra.

The system and subsystem analyses were performed by the applicants on an elastic basis. Modal response spectrum and time history methods form the bases for the analyses of all major seismic Category I structures, systems and components. When the modal response spectrum method was used, governing response parameters were combined by the square root of the sum of the squares (SRSS) rule. However, the absolute sum of the modal responses was used for modes with closely spaced frequencies.

The FSAR indicates that the seismic design of structures is based upon an SRSS combination of the response due to a single axis horizontal excitation in combination with the vertical excitation (2 component SRSS). However, during the course of design development, three distinct methods were employed: (a) three-component SRSS combination, (b) two-component absolute summation, (c) two-component SRSS combination. Most of seismic Category I structures were designed by methods (a) and (b) and it has been demonstrated that method (b) generally provides conservatism equal to or greater than that of method (a). Method (c) was only used in developing in-structure response spectra where equipment and components are supported. Less than a 3% increase in the horizontal response levels is expected due to torsional effects of the orthogonal horizontal excitation. About a 15% increase in vertical spectral response levels at the periphery of the structure due to rocking effect of the orthogonal horizontal excitation are expected. However, these increases would be more than compensated for by decreases in response level resulting from (1) utilization of actual soil damping characteristics rather than the upper bound limit of 10% used in current analysis and by (2) the fact that the time history utilized to develop the in-structure response spectra conservatively envelopes the design spectra.

Floor spectra inputs used for design and test verification of structures, systems and components were generated using the time history method, taking into account variation of parameters by peak widening. A vertical seismic system dynamic analysis was used

for all structures, systems and components where analyses show significant structural amplification in the vertical direction. Torsional effects and stability against overturning were considered.

Depending upon the degree of embedment, either the lumped-parameter or the finite element approach was used to evaluate soil-structure interaction effects upon seismic responses. For the finite element analysis, appropriate nonlinear stress strain and damping relationship for the soil were considered.

We conclude that the seismic system and subsystem analysis procedures and criteria utilized by the applicants provide an acceptable basis for seismic design.

3.7.3 Seismic Instrumentation Program

The type, number, location and utilization of strong motion accelerographs used at San Onofre 2 and 3 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 recommendations of Regulatory Guide 1.12, "Instrumentation for Earthquakes." Supporting instrumentation is being installed on Category I structures, systems and components in order to provide data for the verification of the seismic responses determined analytically for such seismic Category I items.

The installation of the specified seismic instrumentation in 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 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 Regulatory Guide 1.12.

3.8 Design of Category I Structures

During the course of our review of San Onofre 2 and 3, we conducted an audit of the detailed calculations and calculational methods used in the analysis of seismic Category I structures. From December 4 through 8, 1978, we met with the applicants and their contractors and consultants in Los Angeles, California, to conduct the seismic and structural audit. The audit covered each major safety-related structure at San Onofre 2 and 3.

We conducted the audit in order to accomplish the following objectives:

- (1) To investigate in detail the manner in which the applicants have implemented the structural and seismic design criteria that they committed to use, prior to obtaining construction permits for the facility.
- (2) To verify that the key structural and seismic design and the related calculations have been conducted in an acceptable way.
- (3) To identify and assess the safety significance of these areas where the plant structures were designed and analyzed using methods other than those recommended by the NRC Standard Review Plan (NUREG-75/087).

During the audit we identified a number of items for which additional information was needed. Following our request, the applicants provided the needed information. As a result of our review of this information, we concluded that the manner in which design criteria were implemented was acceptable and that the methods of analysis used and the results of the analysis are consistent with staff criteria, and are therefore acceptable.

3.8.1 Concrete Containment

The Reactor coolant system is enclosed in a prestressed concrete containment described in Section 3.8.1 of the FSAR. We identified the deviations of the FSAR from NUREG-75/087 (the Standard Review Plan, or SRP), and requested that the applicants provide additional information to provide a basis for evaluating the criteria. To demonstrate that the criteria used in the actual design of the containment structure are equivalent to those presently acceptable by the staff, the applicants re-analyzed the critical sections of the outer shell and the foundation mat of the containment using the applicable subsections of the ASME Boiler and Pressure Vessel Code, Section III Division 2 (ACI-359), 1977 edition. The results of this analysis show that the stresses imposed on the structure by various load combinations are within the allowables.

Since the present position of the staff reflects the provisions contained in the ACI-359 Code, we concluded that the re-analysis was sufficiently representative to accept the design.

The design incorporated various combinations of dead loads, live loads, environmental loads including those due to wind, tornadoes, OBE, SSE and loads generated by the design basis accident including pressure, temperature and associated pipe rupture effects.

Static analysis for the containment shell and base was based on methods previously applied. Likewise, the liner for the containment was designed using methods similar to those previously accepted.

The choice of the materials, the arrangement of the anchors, the design criteria and design methods are similar to those evaluated for previously licensed plants, taking into account the high seismic loads for San Onofre 2 and 3 compared to most plants. Materials, construction methods, quality assurance and quality control measures are covered in the FSAR and, in general, are similar to those used for previously accepted facilities.

With regard to the San Onofre 2 and 3 tendon surveillance program, the applicants have stated that the program will be consistent with the recommendations of Revision 3 to Regulatory Guide 1.35 and Revision 1 of Regulatory Guide 1.35.1 (both published for comment at this time). The applicants also state that if the exceptions to these guides proposed by Bechtel Power Corporation are approved by the staff they will propose that the approved exceptions be incorporated into the surveillance program for San Onofre Nuclear Generating Station, Units 2 and 3.

Based on our review of the information provided by the applicants we conclude that the in-service tendon surveillance program satisfies, in part, the requirements of General Design Criteria 2, 4, 16 and 50, and is acceptable.

During November 1980, the containment was subjected to an acceptance test in accordance with Regulatory Guide 1.18, "Structural Acceptance Test for Concrete Primary Reactor Containments," during which the internal pressure was 1.15 times the containment design pressure.

The quality control program described in the FSAR is different from that which is specified in the corresponding sections of the SRP. On the basis of the information provided by the applicants we have established that the testing program proposed by the applicants provides the required degree of assurance that the materials of construction satisfy design requirements thus allowing structures to perform their intended functions.

The criteria that were used in the 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 lifetime are in conformance with established criteria, codes, standards, guides, and specifications acceptable to the NRC staff.

The use of these criteria as defined by applicable codes, standards, guides, and specifications; the loads and loading combinations; the design and analysis procedures; the structural acceptance criteria; the materials, quality control programs and special construction techniques; and the testing and in-service surveillance requirements provided reasonable assurance that, in the event of winds, tornadoes, earthquakes and various postulated accidents occurring within the containment, the structure will withstand the specified design conditions without impairment of structural integrity of safety function. Conformance with these criteria constitutes an acceptable basis for satisfying, in part, the requirements of General Design Criteria 2, 4, 16, and 50.

3.8.2 Steel Containment

Not applicable for this facility.

3.8.3 Concrete and Structural Steel Internal Structures

The containment interior structures consist of walls, compartments and floors. The major code used in the design of concrete internal structures is ACI 318-71, "Building Code Requirements for Reinforced Concrete." For steel internal structures the AISC Specification, "Specification, for the Design, Fabrication and Erection of Structural Steel for Buildings," is used.

The containment concrete and steel internal structures were designed to resist various combinations of dead and live loads, accident induced loads, including pressure and jet loads, and seismic loads. The load combinations used cover those cases likely to occur and include all loads which may act simultaneously. The design and analysis procedures that were used for the internal structures are the same as those on previously licensed applications and, in general, are in accordance with procedures delineated in the ACI 318-71 Code and in the AISC Specification for concrete and steel structures, respectively. During the course of our review we found that the load combination equations contained in the FSAR were different from those which are in the Section 3.8.3 of the Standard Review Plan. We identified these differences as deviations from the SRP and requested the applicants to provide sufficient information to enable us to justify their acceptance. In response to our request the applicants compared for the key sections the capacities of members required by the loading conditions with those which these members could develop as designed. In all cases presented by the applicants, which we consider to be the critical ones, the members are capable to withstand the loading conditions imposed by the loads. On the basis of this comparison we conclude that the design of the internal structures is acceptable.

The containment internal structures were designed and proportioned to remain within limits established by the Regulatory staff under the various load combinations. These limits are, in general, based on the ACI 318-71 Code and on the AISC Specification for concrete and steel structures, respectively, modified as appropriate for load combinations that are considered extreme.

The materials of construction, their fabrication, construction and installation, are in accordance with the ACI 318-71 Code and AISC Specification for concrete and steel structures, respectively.

The criteria that were used in the design, analysis, and construction of the containment internal structures to account for anticipated loadings and postulated conditions that may be imposed upon the structures during their service lifetime are in conformance with established criteria, and with codes, standards, and specifications acceptable to the Regulatory staff.

The use of these criteria as defined by applicable codes, standards, and specifications; the loads and loading combinations; the design and analysis procedures; the structural acceptance criteria; the materials, quality control programs, and special construction techniques; and the testing and in-service surveillance requirements provide 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. Conformance with these criteria constitutes an acceptable basis for satisfying in part the requirements of General Design Criteria 2 and 4.

3.8.4 Other Category I Structures

All seismic Category I structures other than containment and its interior structures are constructed of structural steel and concrete. No masonry walls are used at San Onofre 2 and 3. The structural components consist of slabs, walls, beams and columns. The major code used in the design of concrete seismic Category I structures is the ACI 318-71, "Building Code Requirements for Reinforced Concrete." For steel seismic Category I structures, the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," is used.

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

The design and analysis procedures that were used for these seismic Category I structures are the same as those approved on previously licensed applications and, in general, are in accordance with procedures delineated in the ACI 318-71 code and in the AISC Specification for concrete and steel structures, respectively.

The various seismic Category I structures were designed and proportioned to remain within limits established by the staff under the various load combinations. These limits are, in general, based on the ACI 318-71 Code and on the AISC Specification for concrete and steel structures, respectively, modified as appropriate for load combinations that are considered extreme.

The materials of construction, their fabrication, construction and installation, are in accordance with the ACI 318-71 Code and the AISC Specification for concrete and steel structures, respectively.

During the course of our review we found that the load combination equations contained in the FSAR were different from those which are in the Section 3.8.4 of the Standard Review Plan. We identified these differences as deviations from the SRP and requested that the applicants provide sufficient information to justify their use. In response to our request the applicants compared the capacities of key sections of

structural members required by the loading conditions with those which these members could develop as designed.

As a result of this comparison we found that the structural members can withstand the SSE loading condition. Stresses during the OBE would exceed levels that are acceptable for continued operation after the OBE without inspection to assure that degradation had not taken place. In this regard the applicants pointed out that the structures, systems and components (i.e., seismic Category I) designed for the SSE can also withstand the OBE. We believe that the requirement to design the plant for the OBE is not as severe as the requirement to design the plant for safe shutdown after the SSE.

A seismic Category I structure requiring special analysis is the electrical tunnel connecting the Unit 3 diesel generator building with the other Unit 3 structures. This tunnel required special analysis because of the cavity created beneath the future location of the tunnel by the dewatering system. Dewatering well cavities are discussed in Section 2.5.4 of this report. Of the cavities created by the dewatering system, the applicants concluded, and we concur, that the only one that could affect seismic Category I systems is the cavity beneath the Unit 3 electrical tunnel. As discussed in Section 2.5.4, all the dewatering well cavities were completely filled with soil and grout. Nevertheless, the applicants analyzed the Unit 3 electrical tunnel as if the cavity had not been filled, to show that the tunnel would not be affected if the grout did not completely fill the cavity. Specifically, they analyzed the capability of the tunnel to span the cavity, a distance of 25 feet. This was accomplished by reducing the stiffness of the foundation material to zero.

The analysis incorporated soil-structure interaction between the tunnel, the Unit 3 containment structure, and the grout- and soil-filled cavity. The artificial time history of acceleration representing the postulated safe shutdown earthquake (SSE) previously developed for the San Onofre 2 and 3 was used as the control motion for response computations. The control motion was specified at the finished grade of the plant site. A peak acceleration of $2/3g$ and total duration of 80 seconds was used.

The structural analysis of the tunnel was performed using the conservative assumptions listed below:

- (1) The stiffness of the foundation material was reduced to zero within the area where the pore pressure ratio is greater than 0.3. The span of 25 feet, for the tunnel, was estimated on that basis.
- (2) The three components of seismic response were combined using the method described in the NUREG/CR-0098, "Development of Criteria for Seismic Review of Selected Nuclear Power Plants" by N. M. Newmark Consulting Engineering Services, Urbana, Illinois, May 1978.
- (3) The tunnel was assumed to behave as a box-type beam for flexural considerations. The change in cross-section was disregarded.

- (4) Seismic loading was calculated using 1.5 times the peak response of the applicable response spectrum. The response spectra used are the same as those used for other Category I structures at San Onofre 2 and 3.

As a result of our review we requested that the applicants provide additional information regarding assumptions (2) and (3), for the reasons given below.

With respect to assumptions (2), the calculations did not use the method approved by SRP 3.7.2, i.e., the square root of the sum of the squares (SRSS). Consequently, we felt that combination of the three-dimensional components of seismic motion should not be based entirely on these criteria. In view of the above, we requested that the applicants perform a confirmatory analysis based on the criteria delineated in the Standard Review Plan, Section 3.7, in order to verify that the method used by the applicants to combine the three components of ground motion was conservative.

With respect to assumption (3), we concur with the applicants' assumption that the tunnel has a uniform cross-section which will result in a lower fundamental frequency. This is significant because it results in the highest amplitude of vibratory motion and hence produces the highest stresses. However, we felt that the stresses in the area of discontinuity of the tunnel may be higher when the abrupt change in the cross-section is considered, and for this reason we believed that the actual configuration of the tunnel should be investigated. This conclusion was based on the fact that a break in uniformity of the cross-section of a member produces "stress risers" and very often it becomes the critical section from the point of view of structural design. Furthermore, the analysis did not consider stresses due to longitudinal wave propagation.

In response to our requests for additional analyses, the applicants demonstrated that the technique of combination of three components of seismic responses based on the NUREG/CR-0098 methodology is equivalent to the square root of the sum of the squares (SRSS) method. Also, the tunnel was reanalyzed for the condition with one end fixed and the other simply supported. This condition represents the tunnel as it is attached to the gallery structure, which provides complete fixity due its mass. The applicants also performed another analysis which accounted for the stresses due to longitudinal wave propagation. On the basis of the above analyses, we conclude that the structural design of the tunnel is conservative and will not be adversely impacted by dewatering well cavities.

For the reasons listed above, we find that the applicants have adequately performed structural investigations and analyses which provide reasonable assurance that the electrical tunnel, when exposed to the specified adverse loading conditions, will perform the intended function without undue risk to public safety.

On the basis of the above and in view of the information presented by the applicants we conclude that the design of the Category I structures other than containment is acceptable.

Thus, we find that the criteria that were used in the analysis, design, and construction of all the plant 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 Regulatory staff.

The use of these criteria as defined by applicable codes, standards, and specifications; the loads and loading combinations; the design and analysis procedures; the structural acceptance criteria; the materials, quality control, and special construction techniques; and the testing and in-service surveillance requirements provide 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. Conformance with those criteria, codes, specifications, and standards constitutes an acceptable basis for satisfying, in part, the requirements of General Design Criteria 2 and 4.

3.8.5 Foundations

Foundations of seismic Category I structures are described in Section 3.8.5 of the FSAR. Primarily, these foundations were reinforced concrete of the mat type. The major code used in the design of these concrete mat foundations is ACI 318-71. These concrete foundations have been designed to resist various combinations of dead loads; live loads; environmental loads including winds, tornadoes, OBE and DBE; and loads generated by postulated ruptures of high energy pipes.

The design analysis procedures that were used for these seismic Category I foundations are the same as those approved on previously licensed applications and, in general, are in accordance with procedures delineated in the ACI 318-71 Code. The various seismic Category I foundations were designed and proportioned to remain within limits established by the Regulatory staff under the various load combinations. These limits are, in general, based on the ACI 318-71 Code modified as appropriate for load combinations that are considered extreme. The materials of construction, their fabrication, construction and installation, will be in accordance with the ACI 318-71 Code.

The applicants' FSAR did not include the load combination equations which are contained in the SRP Section 3.8.5. The applicants have established, however, that the load combinations used for design of foundations of the containment as well as of other seismic Category I structures contained in the other sections of the FSAR are equivalent to those which are in the SRP, Section 3.8.5. Consequently, we have accepted load combinations proposed by the applicants.

The criteria that were used in the analysis, design, and construction of all the plant seismic Category I foundations to account for anticipated loadings and postulated conditions that may be imposed upon each foundation during its service lifetime are in conformance with established criteria, codes, standards, and specifications acceptable to the NRC staff.

The use of these criteria as defined by applicable codes, standards, and specifications; the loads and loading combinations; the design and analysis procedures; the structural acceptance criteria; the materials, quality control, and special construction techniques; and the testing and in-service surveillance requirements provide 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. Conformance with these criteria, codes, specifications, and standards constitutes an acceptable basis for satisfying in part the requirements of General Design Criteria 2 and 4.

3.8.6 System Interaction

The applicants have undertaken a systems interaction program to ensure that non-seismic Category I systems will not interact adversely with seismic Category I systems as a result of a seismic event. We have requested additional information concerning the objective and scope of the applicants' program, the organization established to implement the program, the methodology used in the program and the criteria used to postulate the interactions. We are evaluating the applicants' response to our request for additional information and plan to conduct an onsite audit of the applicants' program. We will report on the results of our review of the applicants' seismic systems interaction program in a supplement to this report.

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

The criteria used in the methods of analysis that the applicants have used in the design of all seismic Category I ASME Code Class 1, 3, and CS components, component supports, reactor internals and other non-Code items are in conformance with Section 3.9.1 of the Standard Review Plan. These criteria are acceptable to the staff and satisfy the applicable portions of General Design Criteria 14 and 25. The use of these criteria in defining the applicable transients, computer codes used in analyses, analytical methods, and experimental stress analysis methods provides assurance that the stresses, strains, and displacements calculated for the above noted items are as accurate as the current state-of-the-art permits and are adequate for the design of these items.

3.9.2 Dynamic Testing and Analysis

3.9.2.1 Preoperational Vibration and Dynamic Effects Piping Tests

The preoperational vibration test program which will be conducted during startup and initial operation on all safety-related Nuclear Steam Supply System and Balance-of-Plant piping systems, restraints, components, and component supports classified as ASME Class 1, 2, and 3 and non-ASME classed portions of the main steam and feedwater piping systems is an acceptable program and is consistent with Section 3.9.2 of the Standard Review Plan. The tests will provide adequate assurance that the piping and piping restraints of the system have been designed to withstand vibrational dynamic effects due to valve closures, pump trips, and other operating modes associated with

the design basis operational transients. The planned tests will develop loads similar to those experienced during reactor operation. Compliance with this test program constitutes an acceptable basis for fulfilling, in part, the requirements of General Design Criterion 15.

3.9.2.2 Snubber Operability Program

At our request, the applicants have recently provided additional information regarding the San Onofre 2 and 3 snubber operability program (see FSAR response to Question 112.41). As requested, the snubber operability program will be documented on data sheets which list all safety-related hydraulic and mechanical snubbers. This list of snubbers will be identical to that in Tables 3.4-4(a) and 3.7-4(b) of Section 3/4.7.9 of the San Onofre 2 and 3 Technical Specifications. A preservice inspection within six months of preoperational testing is specified by the applicants as a prerequisite, and will insure that the snubbers are properly installed.

3.9.2.3 Reactor Internals

Maine Yankee and Fort Calhoun are designated jointly as the prototype for the San Onofre 2 and 3 reactor internals and the design similarities are noted in the FSAR. However, both Maine Yankee and Fort Calhoun have thermal shields, whereas San Onofre 2 and 3 do not. The Arkansas Nuclear One - Unit No. 2 (ANO-2) reactor, like the San Onofre 2 and 3 units has no thermal shield, is also a two loop plant and parameters cited in the FSAR as significant such as mass flow rate and pump characteristics are similar. The prototype designation is conditionally acceptable to the staff. The basis for the conditional acceptance is that the staff review of the results of the ANO-2 augmented internals inspection is in progress; results to date indicates that the inspection will probably verify satisfactory performance of the ANO-2 internals. However, should the completion of our review of the ANO-2 inspection indicate the need for any corrective action to ANO-2, we will review the San Onofre 2 and 3 applicants' evaluation of the need for similar corrective action on San Onofre 2 and 3. We will require that appropriate corrective changes, if any are required, be implemented for the San Onofre 2 and 3 reactor internals design.

The preoperational vibration program planned for the reactor internals 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 provide adequate assurance that the reactor internals will, during their service lifetime, withstand the flow-induced vibrations of reactor operation without loss of structural integrity. The integrity of the reactor internals in service is essential to assure the proper positioning of reactor fuel assemblies and unimpaired operation of the control rod assemblies to permit safe reactor operation and shutdown. The preoperational vibration tests conform with the provisions of Regulatory Guide 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Startup Testing," and constitute an acceptable basis for demonstrating design adequacy of the reactor internals, and satisfy the applicable requirements of General Design Criteria 1 and 4.

The applicants have stated in the FSAR that: (1) The nonlinear response analysis of the reactor internals due to horizontal and vertical DBE excitation have been completed and is described in Paragraph 3.7.3.14 of the FSAR; and (2) The adequacy of the reactor internals to accommodate the loads, stresses and deformations resulting from these analyses is described in Subsection 3.9.5 of the FSAR. Section 3.9a.3.2.3 of the FSAR states that model definitions used for the dynamic systems analysis employ the procedures established in Combustion Engineering Topical Report CENPD-42. This appears to include both LOCA and seismic analyses. The models for the seismic analysis are also presented in 3.7.3.14. Another set of models were presented at a meeting at Whittier, California, on May 28, 1980. It was interpreted that these models were used for both the LOCA analysis and the seismic analysis. The staff will require that clarification be given as to the models actually used in the final dynamic systems analysis (both LOCA and seismic).

The staff requires that the dynamic system analysis confirm the structural design adequacy of the reactor internals and unbroken piping loops to withstand the combined dynamic response loads of postulated loss-of-coolant accident (LOCA), normal operation loading and the safe shutdown earthquake (SSE). The analysis must demonstrate 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 of 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 should be compatible with those used for the systems analysis. Results of the dynamic analysis must verify structural integrity of the reactor internals under postulated LOCA conditions combined with normal operation loading and the SSE and provide added assurance that the design will withstand a spectrum of lesser pipe breaks and seismic loading events. Satisfactory completion of the dynamic system analysis will constitute an acceptable basis for satisfying the applicable requirements of General Design Criteria 2 and 4. The applicants have committed to provide the results by April 1981. We will report on the completion of our review of the reactor internals in a supplement to this report.

3.9.3 ASME Code Class 1, 2 and 3 Components, Component Supports and Core Support Structures
3.9.3.1 Loading Combinations and Stress Limits

The specified design basis combinations of loadings as applied to safety-related 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, or an upset, emergency, or faulted plant transient occurring during normal plant operation, the resulting combined stresses imposed on systems, components, and their supports 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.

We have reviewed the methods used for combining dynamic responses and conclude that the use of these methods provides an acceptable level of assurance of structural

integrity and operability of all ASME Code Class 1, 2, and 3 components and their supports. We conclude that the load combination methods are consistent with Section 3.9.3 of the Standard Review Plan (NUREG-75/087) and also satisfy the applicable portions of General Design Criteria 1, 2, and 4, and are acceptable.

Based on the staff review as outlined above, the criteria for design of all safety-related components, equipment and their supports is considered adequate without further review. However, in addition to the above review, we evaluated the implementation of the design criteria of this relatively high seismic acceleration design (.67g for the SSE). This evaluation concentrated on the primary loop and all other Category I components, equipment and their supports which are required for safe shutdown of the plant and continued shutdown heat removal. The evaluation was conducted at the offices of the utility and the architect engineer, and included representatives of the nuclear steam supply system vendor. In addition, site visits were conducted to (1) inspect the installed systems, (2) compare the analytical models and techniques used in the design with the actual as-installed systems, and (3) assure that failure of non-Category I items will not impede satisfactory performance of Category I systems, components and equipment. On the basis of the above-described evaluation, we conclude that sufficient margin is available in these systems to accommodate seismic input that is even greater than that used in the design of San Onofre 2 and 3. At our request, the applicants' have committed to revise the format of their FSAR response to Question 112.39 to provide a consistent basis for the presentation of the seismic margins evaluation results for both NSSS items and balance-of-plant items.

Based on the reviews described above, we conclude that the criteria used for the design of all ASME Class 1, 2 and 3 components and equipment, and their supports, are acceptable.

In addition to the above reviews, we are performing an independent confirmatory analysis of the shutdown cooling line. This analysis will not only verify that the sample piping system meets the applicable ASME Code requirements, but will also provide a check on the applicants' ability to correctly model and analyze its piping systems. We have contracted with the Energy Technology Engineering Center (ETEC) to perform the confirmatory analysis. The results of their evaluation will be presented in a supplement to this report.

3.9.3.2 Pump and Valve Operability Assurance

The component operability assurance program for ASME Code Class 1, 2 and 3 active valves and pumps provides adequate assurance of the capability of such active components (a) to withstand the imposed loads associated with normal, upset, emergency, and faulted plant and component operating conditions without loss of structural integrity, and (b) to perform necessary "active" functions (e.g., valve closure or opening, pump operation) under accident conditions and conditions expected when plant shutdown is required. The specified component operability assurance test program is consistent with Section 3.9.3 of the Standard Review Plan and constitutes an

acceptable basis for satisfying applicable portions of General Design Criteria 1, 2, and 4 and is acceptable to the staff.

3.9.3.3 Design of Pressure Relief Valve Mounting

The criteria used in the design of the mountings for ASME 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 of the mountings for the devices to withstand these loads without loss of structural integrity or impairment of the overpressure protection function. The criteria used for the design of the mountings for ASME Class 1, 2 and 3 overpressure relief devices constitute an acceptable basis for meeting the applicable requirements of General Design Criteria 1, 2 and 4 and are consistent with those specified in Regulatory Guide 1.67.

3.9.3.4 Asymmetric Blowdown Loads on Reactor Coolant System

The applicants have performed a dynamic structural analysis to evaluate the effects of asymmetric blowdown loads on the reactor coolant system. These loads result from the postulated pipe breaks discussed in Section 3.6.2 of this report. In the dynamic analysis, the pipe break thrust force, asymmetric subcompartment pressurization forces and asymmetric reactor internals hydraulic forces were applied as simultaneous time-history forcing functions. The resultant component and support reactions from these forces were combined with the appropriate normal operating and seismic reactions to arrive at maximum support loads. These maximum loads were all less than the specified design loads which had been calculated by using ASME Section III design rules.

As a part of NRC Task Action Plan A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" the staff has performed an independent dynamic structural analysis using the San Onofre 2 and 3 reactor coolant system as a model. The staff's analysis confirmed the applicants' conclusions and therefore we conclude that the applicants' analysis is acceptable.

3.9.4 Control Rod Drive Systems

The design criteria and the testing program conducted for verification of the mechanical operability and life cycle capabilities of the reactivity control system described in the FSAR conforms with the guidelines outlined in Standard Review Plan, Section 3.9.4, "Control Rod Drive Systems" and is acceptable to us. The use of these criteria provides reasonable assurance that the system will function reliably when required, and is an acceptable basis for satisfying the mechanical reliability stipulations of General Design Criterion 27.

3.9.5 Reactor Pressure Vessel Internals

Subject to resolution of the issues discussed in Section 3.9.2.3 of this report, our findings are as follows:

The specified transients, design and service loadings and combination of loadings as applied to the design of San Onofre 2 and 3 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 deformation limits for the materials of construction. Limiting the stresses and deformations under such loading combinations provides an acceptable basis for the design of these structures and components to withstand the most adverse loading events which have been postulated to occur during service lifetime without loss of structural integrity or impairment of function. The facility design procedures and criteria meet the requirements of Standard Review Plan, Section 3.9.5, "Reactor Pressure Vessel Internals" and constitute an acceptable basis for satisfying the applicable requirements of General Design Criteria 1, 2 and 4.

3.9.6 Inservice Testing of Pumps and Valves

To ensure that all ASME Code Class 1, 2 and 3 safety-related pumps and valves will be in a state of operational readiness to perform necessary safety functions throughout the life of the plant, a test program will be conducted which includes baseline preservice testing and periodic inservice testing. The program provides for both functional testing of the components in the operating state and for visual inspection for leaks and other signs of distress.

The applicants have stated that the preservice and inservice testing programs for the above mentioned pumps and valves will meet the requirements of 10 CFR 50.55a(g), including the 1977 edition of the ASME Boiler and Pressure Vessel Code, Section XI through the Summer 1978 Addenda and would comply, where appropriate, with the NRC guidance document issued as part of question 112.27. The applicants requested relief from these code requirements pursuant to 10 CFR 50.55a(g)(1) for certain pump and valve tests.

At this time we have not completed our detailed review of the applicants' submittal. However, we have evaluated their request for relief and based on our review, we find that it is impractical within the limitations of design, geometry, and accessibility for the applicants to meet certain of the ASME Code requirements. Imposition of those requirements would, in our view, result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. Therefore, pursuant to 10 CFR 50.55a(g)(1), we believe that the relief that the applicants have requested from the pump and valve testing requirements of the 1977 Edition of ASME Section XI through the Summer 1978 Addenda should be granted until our detailed review is complete. If completion of our review results in additional testing requirements, we will require that the applicants comply with them.

One area of concern during our review was the periodic leak testing of pressure isolation valves.

There are several safety systems connected to the reactor coolant pressure boundary that have design pressure below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suction below RCS pressure. In order 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 systems. 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 and thus cause an inter-system LOCA. Periodic leak testing of pressure isolation valves shall be performed after all disturbances to the valve are complete. The pressure isolation valves to be tested are listed in the Technical Specifications.

The applicants have agreed to categorize the San Onofre 2 and 3 pressure isolation valves as A or AC according to IWV-2100 of Section XI of the ASME Code, for the safety injection and shutdown cooling systems. This categorization meets our requirements and is acceptable.

The Technical Specifications will contain limiting conditions for operation which will require plant shutdown or system isolation when the leakage limits are not met. The Technical Specifications will include surveillance requirements which state the acceptable frequency of leak rate testing. The above Technical Specifications will be based on the latest revision of NUREG-0212, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors." Based on these Technical Specifications and the applicants' commitment to perform periodic leak rate testing of pressure isolation valves between the reactor coolant system and low pressure systems, we conclude that there is reasonable assurance that the design pressure of the low pressure systems will not be exceeded, and, therefore, an inter-system LOCA will not occur. This meets, in part, the requirements of General Design Criterion 55 of Appendix A to 10 CFR Part 50.

3.10 Seismic Qualification of Seismic Category I Mechanical and Electrical Equipment

The FSAR describes the seismic qualification testing and analysis program for seismic Category I mechanical, electrical, and instrumentation equipment at San Onofre 2 and 3. Our review of this information is in progress, and our findings will be based on our review and on the information obtained during the September, 1980 site visit by our Seismic Qualifications Review Team.

A seismic qualification testing and analysis program acceptable to the staff for seismic Category I mechanical and electrical equipment, including their supports will provide adequate assurance that such equipment will function properly during the excitation from vibratory forces imposed by the safe shutdown earthquake and under the conditions of post-accident operation. Such a program will constitute an acceptable basis for satisfying the applicable requirements of General Design

Criterion 2. However, our review is not yet complete. Resolution of this issue will be presented in a supplement to this report.

3.11 Environmental Design of Mechanical and Electrical Equipment

3.11.1 Environmental Conditions

The applicants have described the normal and post-accident radiation environment that engineered-safety-features equipment is qualified for in Section 3.11 of the FSAR. We conclude, based upon consideration of equipment location, the effect of shielding due to containment equipment and structures and the magnitude of the radiation levels given in the FSAR, that these levels provide an adequate degree of qualification for the normal and post-accident radiation environment, and are acceptable.

3.11.2 Environmental Qualification

Our criteria for environmental qualification of electrical equipment are given in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." Recognizing that the equipment qualification review for San Onofre 2 and 3 has been an effort spanning several years, we recently requested that the applicants reassess their qualification documentation for equipment installed at the facility, to show that the qualification methods used and results obtained conform to the staff positions in NUREG-0588. We believe that this additional review will confirm our previously-reached conclusions that the San Onofre 2 and 3 qualification documentation is adequate. Nevertheless, we require that the additional review be completed prior to issuance of a full power license. We will report on the resolution of this issue on a supplement to this report.

4.0 REACTOR

4.1 Introduction

Criterion 10 of the General Design Criteria requires that the reactor core and associated systems be designed to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. We have reviewed the information provided in the Final Safety Analysis Report in support of the San Onofre 2 and 3 reactor design. Our evaluation is contained below.

Each unit's nuclear steam supply system is supplied by Combustion Engineering and is designed to operate at a maximum core thermal output of 3390 megawatts, with sufficient margin to allow for transient operation and instrument error, without causing damage to the core and without exceeding the pressure settings of the safety valves in the coolant system.

The reactor will be cooled and moderated by light water at a pressure of 2,250 pounds per square inch, absolute. The reactor coolant will contain soluble boron for neutron absorption. The concentration of the boron will be varied, as required, to control relatively slow reactivity changes, including the effects of fuel burnup. Additional boron, in the form of burnable poison rods, will be employed to establish the desired initial reactivity. Part-length control element assemblies may be used for axial power shaping, and full-length control element assemblies will be used for reactor shutdown.

The design of the San Onofre 2 and 3 reactors is similar to that of the Arkansas Nuclear One, Unit 2 facility, Docket No. 50-368. We have approved the latter plant for operation. Both of these facilities utilize the 16x16 fuel assembly.

4.2 Fuel System Design

The objectives of the fuel system safety review are to provide assurance that (a) the fuel system is not damaged as a result of normal operation and anticipated operational occurrences, (b) fuel system damage is never so severe as to prevent control rod insertion when it is required, (c) the number of fuel rod failures is not underestimated for postulated accidents, and (d) coolability is always maintained. We have reviewed the information provided in the Final Safety Analysis Report in support of the San Onofre 2 and 3 reactor design to determine if these objectives have been met. Our evaluation is described below.

4.2.1 Description

The San Onofre 2 and 3 reactor core design is similar to that previously approved (NUREG-0308) for the Arkansas Nuclear One, Unit 2 facility. The major differences between the core mechanical designs of San Onofre 2 and 3 and Arkansas Nuclear One, Unit 2 are in the number of fuel assemblies comprising the core, the number and construction of the fuel rod spacer grids, and the number of control element assemblies employed.

The San Onofre 2 and 3 cores are each composed of 217 fuel assemblies of a 16x16 fuel rod array design. Each fuel assembly will have 10 Zircaloy-4 fuel rod spacer grids and 1 Inconel-625 bottom spacer grid. Four of the Zircaloy grids which are located along the mid length of the fuel assemblies will have higher crushing strengths to improve lateral resistance to seismic and LOCA loading conditions. Each core will employ a total of 91 full- and part-length control element assemblies.

4.2.2 Design Evaluation

Evaluation of the Combustion Engineering 16x16 fuel mechanical design is based upon engineering analyses, tests, and in-reactor operating experience. In addition, the performance of the design will be subject to continuing surveillance of operating reactors by Combustion Engineering and licensees having Combustion Engineering reactors. These programs continually provide confirmatory and current design performance information.

4.2.2.1 Fuel Densification

One of the major thermal analysis considerations reviewed by the staff is related to fuel densification. In our evaluation of the thermal performance of the reactor fuel, we assume that densification of the uranium oxide fuel pellets may occur during irradiation in light water reactors. Briefly stated, in-reactor densification (shrinkage) of oxide fuel pellets (a) may reduce gap conductance, and hence increase fuel temperatures, because of a decrease in pellet diameter; (b) may increase the linear heat generation rate because of the decrease in pellet length; and (c) may result in gaps in the fuel column as a result of pellet length decreases (these gaps produce local power spikes and sites for cladding creep collapse).

Combustion Engineering has conducted an extensive study of fuel densification and has developed a conservative time-dependent description of the densification process as described in the Combustion Engineering topical report CENPD-118, "Densification of Combustion Engineering Fuel." Our review of the Combustion Engineering densification model along with other general information on fuel densification is given in NUREG-0085.

4.2.2.2 Fission Gas Release at High Burnups

The densification kinetics expression, along with data on fuel swelling, thermal expansion, fission gas release, fuel relocation, thermal conductivities, cladding

creep, and other properties, have been combined in a detailed fuel performance evaluation model called FATES, which is presented in the Combustion Engineering topical report CENPD-139, "Fuel Evaluation Model." This model is used to calculate fuel temperature and stored energy, changes in linear thermal output, and augmentation (power spikes) factors. We have reviewed CENPD-139 and had previously concluded that the fuel performance evaluation model was a generically acceptable method of describing the fuel behavior, as discussed in our safety evaluation that is bound into CENPD-139-A, and that this model would be applicable to San Onofre 2 and 3 fuel.

However, we have recently questioned (NUREG-0418) the validity of fission gas release calculations in most fuel performance codes including FATES for burnups greater than 20,000 megawatt days per metric ton of uranium. Combustion Engineering was informed of this concern, and NUREG-0418 provided a method of correcting gas release calculations for burnups greater than 20,000 megawatt days per metric ton of uranium. Since there was no question of the adequacy of FATES for burnups below 20,000 megawatt days per metric ton of uranium, the San Onofre 2 and 3 calculations would be acceptable for operation early in life until the peak local burnup reaches 20,000 megawatt days per metric ton of uranium. For burnups in excess of that value, FATES calculations (and other affected analyses) would have to be redone using the correction method mentioned above or such modified methods that might be submitted by the applicants or Combustion Engineering and approved by NRC.

The applicants have stated in Amendment 18 to the Final Safety Analysis Report that the maximum calculated end-of-life fuel rod pressure has been redone using the NRC burnup enhancement factor and tolerances which were biased to maximize the rod pressure. The resulting pressure was found to be acceptable inasmuch as it remained less than the nominal primary system pressure. Other affected analyses have not been provided to NRC so that this issue remains unresolved. Because gas release for burnups less than 20,000 megawatt days per metric ton of uranium is not in question, we do not require resolution of this issue prior to the cycle of operation that will result in peak pellet burnups greater than this value. Accordingly, the San Onofre Unit 2 operating license will be conditioned to reflect this limitation, as was the operating license for Arkansas Nuclear One, Unit 2. If the issuance of the San Onofre Unit 3 operating license precedes the final resolution of the enhanced fission gas release issue, then that license will also be conditioned similarly.

4.2.2.3 Cladding Collapse

Combustion Engineering has written a computer code that calculates time-to-collapse of Zircaloy cladding in a pressurized water reactor environment. This code is described in the report CENPD-187, "CEPAN Method of Analyzing Creep Collapse of Oval Cladding." We have reviewed this code and found it acceptable as described in our safety evaluation, which is bound into CENPD-187. The applicants have performed time-to-cladding-collapse calculations using the CEPAN code and the worst-case combination of material properties and component dimensions including the allowable manufacturing tolerances. The results of this analysis showed that the minimum time-to-collapse is in excess of the design batch-average discharge lifetime of the

fuel. We conclude, therefore, that the fuel rod cladding will not collapse and is acceptable in this regard.

4.2.2.4 Flow-Induced Vibration

Mechanical tests to demonstrate the effects of flow-induced vibration and consequent fretting and corrosion have been performed on 4x4 test assemblies and on full-size 14x14 fuel assemblies to demonstrate that flow-induced vibration, fretting and wear are acceptably low. Similar full-scale, hot-flow testing of 16x16 assemblies has been performed to substantiate these results for the new 16x16 design. The staff has reviewed the summary report PED-76-033P, "16x16 Fuel Assembly Flow Test," prepared by Combustion Engineering on the results of the flow test of a 16x16 fuel assembly similar to that used in Arkansas Nuclear One, Unit 2 and San Onofre 2 and 3. The submittal was adequate with the exception that insufficient information was provided on the determination of hydraulic loss coefficients for fuel assembly entrance, exit, and spacer grids. In response to our request for information, additional information (Williams, 1977) was provided that acceptably (Ross, 1977) confirms that the local loss coefficients for the spacer grids and the fuel assembly entrance and exit are consistent with the design values used in the thermal-hydraulic analyses.

4.2.2.5 CEA Guide Tube Wear

A wear tendency that was not originally observed in the above-described flow tests has been observed (for example see Scherer, 1977; Johnson, 1978; Lundvall, 1978) in irradiated fuel assemblies taken from operating Combustion Engineering reactors. These observations detected unexpected degradation of guide tubes that are under control element assemblies. Coolant turbulence was responsible for inducing vibratory motions in the normally fully withdrawn control rods and, when these vibrating rods were in contact with the inner surface of the guide tubes, a wearing of the guide tube wall has taken place. Significant wear has been found to be limited to the relatively soft Zircaloy-4 guide tube because the Inconel-625 cladding on the control rods provides a relatively hard wear surface. The extent of the observed wear has appeared to be plant dependent and has in some cases extended completely through the tube wall.

In response to our request, the applicants, in Amendments 17 and 21 to the FSAR described two permanent and one temporary hardware modifications that will be effected to mitigate guide tube wear in the San Onofre 2 and 3 cores. First, permanent flow channel extensions will be placed on the lowermost portion of each core's 87 upper guide tube structures that accommodate 5-element CEAs. These extensions will extend to the bottom of the fuel alignment plate and thereby minimize flow turbulence near the control rods by isolating the interior of the control rod shroud from much of the flow exiting the fuel assembly. This design alteration lead to a configuration similar to that in the older Combustion Engineering NSSS plants that use 14x14 fuel assembly designs. Also, a nearly identical modification was made to the first Combustion Engineering NSSS plant to the 16x16 fuel assembly design (i.e., Unit 2 of Arkansas Nuclear One).

The second permanent modification consists of placing flow bypass inserts in the lowermost portion of each core's 4 upper guide structures that accommodate 4-element CEAs. The function of these inserts is the same as that of the flow channel extensions, namely to divert a portion of the fuel assembly flow directly to the outlet plenum, thus away from control rods and the CEA shroud cavities.

The third modification is the attachment of sleeve inserts to the interior of the uppermost portions of fuel assembly guide tubes. These sleeve inserts are chrome-plated, stainless steel inserts that are mechanically attached to guide tubes that are to reside under CEA banks. The function of the sleeve inserts is not to eliminate CEA vibratory motion, but rather to protect the guide tubes by providing relatively fretting resistant barriers. In the initial San Onofre 2 and 3 core loadings, all fuel assemblies will be sleeved except 9 assemblies in Unit 2. These 9 unsleeved assemblies constitute a demonstration program. They will be strategically placed in locations that will represent the full range of flow conditions in the core. It is anticipated that the fretting wear rates in these demonstration assemblies will be found insignificant and, consequently, that further use of sleeve inserts may be determined to be unnecessary.

We conclude that the three hardware modifications described above are potentially effective methods of mitigating guide tube wear. In regard to the first modification, we have previously approved the addition of flow channel extensions in Unit 2 of Arkansas Nuclear One. The San Onofre 2 and 3 flow channel extensions are conceptually and dimensionally similar to those previously approved. We regard the second modification as an innovative design change that is similar in concept to other modification, inasmuch as its use should result in less flow-induced control rod vibration due to the additional shielding and flow diversion. Should the performance of this modified design not be as satisfactory as anticipated, the overall degradation to the core performance would be insignificant due to the limited application of this modified design and its employment only in core periphery locations. Further confidence on the effectiveness of both of these designs has been initially demonstrated in two separate 250 hour out-of-pile flow tests of full-sizes 16x16 fuel assemblies.

Finally, we have previously concluded for other plants that the use of sleeve inserts is an acceptable means of mitigating guide tube wear and does not produce undesirable changes in the fuel assembly structural properties. In addition, confirmatory CEA scram testing has not revealed any significant occurrences where the use of sleeve inserts produced unacceptable scram times. Our previous approvals for use of sleeve inserts in Combustion Engineering plants were for Calvert Cliffs, Units 1 and 2; Millstone, Unit 2; Arkansas Nuclear One, Unit 2; and St. Lucie, Unit 1. Should the applicants desire to discontinue the use of sleeve inserts for future cycles of San Onofre, Units 2 and 3, the adducible justification should include guide tube wear measurements taken on previously rodged, unsleeved fuel assemblies that were discharged from either unit of San Onofre 2 and 3 or a similar plant.

4.2.2.6 Fuel Rod Waterlogging

We have reviewed the safety aspects of waterlogging fuel rod failures. A recent survey (NUREG-0303) of available information included (a) the results of tests in the capsule driver core at the SPERT facility and the Japanese test reactor NSRR, and (b) observations of waterlogging failures in test and commercial reactors. This survey indicated that the rupture of waterlogged fuel rods should not result in failure propagation or significant fuel assembly damage that would affect coolability of the fuel rod assembly. The San Onofre 2 and 3 applicants have addressed the potential and consequences of operating with waterlogged fuel rods. We have found the evaluation, as presented in the Final Safety Analysis Report, to be in agreement with our independent evaluation and, thus, to be acceptable.

4.2.2.7 Pellet/Cladding Interaction

The Combustion Engineering 16x16 fuel rod design used in San Onofre 2 and 3 incorporates features that, when compared with the older 14x14 design, reduce cladding strain due to pellet/cladding interaction. Based on the available experimental and commercial reactor data, these design features should result in a reduction or delay of pellet/cladding interaction failures to later in the fuel design life. Although the failure thresholds are probably lower at high burnup than at low burnup, the fuel duty is also less severe. There are presently no licensing requirements that deal with small-strain PCI failures.

The effects of pellet/cladding interaction have not been restricted solely to fuel rods, but have also been observed (CEN-50) in burnable poison rods. In burnable poison rods, pellet/cladding interaction has predominately resulted in excessive axial growth of the rod, rather than perforation of the cladding wall. To reduce the potential for poison rod growth, Combustion Engineering has made several pertinent modifications and manufacturing process changes. These revisions consist of the following: (a) increased pellet-to-cladding gap, (b) chamfered pellets, (c) increased rod pressurization, and (d) reduced plenum spring preload. We have reviewed these revisions and agree that they should significantly reduce pellet/cladding interaction in poison rods.

4.2.2.8 Poison Rod Primary Hydriding

In the past, some Combustion Engineering burnable poison rods have experienced failures due to primary hydriding (CEN-77). Subsequently, Combustion Engineering proposed changes to the poison rod design and manufacturing processes. The revisions included reduced pellet moisture limit and revised manufacturing processes aimed at reducing moisture ingress to the poison rod. We have approved (NUREG-0308) such modifications and agree that they will reduce the potential for primary hydriding of burnable poison rods. No further failures of this kind have been reported.

4.2.2.9 Poison and Fuel Rod Bowing

Because fuel rod bowing in pressurized water reactors affects neutronic and thermal-hydraulic safety margins, the applicants were required to analyze the anticipated extent of rod bowing in their plant. The consideration of both fuel and poison rod bowing in the 16x16 design was previously analyzed by Combustion Engineering and documented in the topical report CENPD-225, "Fuel and Poison Rod Bowing." In this report, Combustion Engineering has documented its rod bowing experience, which, to date, is based on the inspection of discharged fuel assemblies from three operating plants. This surveillance experience has demonstrated an exposure (burnup) dependence of rod bowing; accordingly, the proposed Combustion Engineering bowing predictions have been based on a burnup dependence.

CENPD-225 has not yet been approved by the staff, but is still under review. For interim acceptance of methods by which rod bowing analyses can be made, the staff has issued two reports (Ross and Eisenhut, 1976; Ross and Eisenhut, 1977) in which we have (a) given approval of the burnup-dependent approach to rod bowing, (b) presented a formulation to be used in extrapolating bow magnitudes to new designs (i.e., 16x16), and (c) described the factor that increases the cold rod bow magnitudes (which are determined from cold-measured gap closures in spent fuel pools) to account for hot rod bow magnitudes that occur in-reactor during hot-operating conditions. These interim methods will be used for San Onofre 2 and 3 prior to completion of our review of CENPD-225. The effects of rod bowing on thermal-hydraulic effects (departure from nucleate boiling) due to reduction in hot channel pitch are discussed in Section 4.4 of this report.

4.2.2.10 Combined LOCA and Seismic Loads

An important aspect of the behavior of the reactor core during a loss-of-coolant accident is the calculation of the combined loads on the fuel due to blowdown forces and the safe shutdown earthquake. The applicants have referenced the topical report CENPD-178, "Structural Analysis of Fuel Assemblies for Combined Seismic and Loss-of-Coolant Accident Loading," which addresses this matter. As a result of our preliminary review, we concluded that CENPD-178 did not contain an adequate model for analyzing lateral loads on the fuel assembly nor did CENPD-178 present sufficient information on spacer grid tests. The applicants have stated that they will provide additional information on analytical methods and test results as an amendment to the Final Safety Analysis Report. We will report on the resolution of this issue in a supplement to this report.

4.2.2.11 Zircaloy Growth

The San Onofre 2 and 3 Final Safety Analysis Report references a Combustion Engineering topical report, CENPD-198, "Zircaloy Growth In-Reactor Dimensional Changes in Zircaloy-4 Fuel Assemblies," in support of a discussion on the dimensional stability of Zircaloy. We have reviewed the topical report and approved it for referencing, provided specific instructions (Kniel, 1976) are followed for application of the

burnup-dependent growth relationships. Combustion Engineering later submitted Supplement 1 to CENPD-198 to support their request for the removal of our restrictions. To complete the review of Supplement 1, additional information was requested (Baer, 1978) and provided by Combustion Engineering in Supplement 2 to CENPD-198. Our final evaluation (Baer, 1979) of CENPD-198 and its Supplements removed the previous staff-imposed restrictions. However, our approval was limited to an axially averaged fast neutron fluence of 4×10^{21} n/cm², which corresponds to a maximum assembly exposure of 22500 megawatt days per metric ton of uranium. This is an exposure above which Combustion Engineering has not reported data on their core components.

4.2.2.12 Fuel Assembly Inspection Program

Assurances on the acceptability of the San Onofre 2 and 3 fuel design beyond an exposure of 22500 megawatt days per metric ton of uranium will be furnished by the detailed visual fuel assembly inspection program (see Section 4.2.1.5.1 of the Final Safety Analysis Report), which will be performed on all of the fuel assemblies after they are discharged to the spent fuel pool. Thus any trend toward unanticipated growth or mechanical interference will be evident during inspection. In addition, during the first three refueling outages of the Arkansas Nuclear One, Unit 2 facility (a plant whose fuel design was also based on the CENPD-198 methods), the length of the fuel assembly and peripheral fuel rods will be precisely measured in six assemblies (two from each fuel region) that have been extensively precharacterized (see the ANO-2 FSAR). Thus, we will be able to compare the measured values versus those calculated as the burnup progresses. If a non-conservative gap closure is observed, remedial action can be taken before safety is affected.

4.2.2.13 ECCS Analysis Using NUREG-0630 Model

The NRC staff has been generically evaluating three materials models that are used in ECCS evaluations. Those models predict cladding rupture temperature, cladding burst strain, and fuel assembly flow blockage. We have (a) discussed our evaluation with vendors and other industry representatives (Denise, 1979), (b) published NUREG-0630, "Cladding Swelling and Rupture Models for LOCA Analysis," and (c) required licensees to confirm that their operating reactors would continue to be in conformance with 10 CFR 50.46 if the NUREG-0630 models were substituted for the present materials models in their ECCS evaluations and certain other compensatory model changes were allowed (Eisenhut, 1979; Denton, 1979).

Until we have completed our generic review and implemented new acceptance criteria for cladding models, we will require that the ECCS analyses in the Final Safety Analysis Report be supplemented by calculations to be performed with the materials models of NUREG-0630. The applicants have agreed to provide these supplemental calculations in the near future, and have provided the complete ECCS analysis required by current regulations. The applicants state that the revised analysis will result in little, if any, penalty on plant operational limits. Further, we believe that any such penalty could easily be accommodated by adjustment of the Technical Specifications prior to their being issued (the Technical Specifications will be issued in final

form as an Appendix to the Operating License). Based on the above, we consider this item to be resolved, subject to confirmatory documentation of the revised analysis in a formal submittal by the applicants.

4.2.3 Testing, Inspection, and Surveillance Plans

Testing and inspection plans for the new core components include verification of cladding integrity, fuel system dimensions, fuel enrichment, burnable poison concentration, and absorber composition. Details of the Combustion Engineering testing and inspection programs are documented, referenced, and summarized in the Final Safety Analysis Report. On-site inspection of new fuel and control assemblies after they have been delivered to the plant is also described. These testing and inspection programs are similar to those for the previously approved Arkansas Nuclear One, Unit 2 facility.

4.2.3.1 Fuel Surveillance Program

Combustion Engineering has instituted a fuel surveillance program for the 16x16 fueled reactor core. This program is being conducted in Arkansas Nuclear One, Unit 2 and involves the irradiation of six standard 16x16 fuel assemblies-- two in each fuel loading region. Each assembly includes a minimum of 50 precharacterized, removable rods. Interim examination of all remaining test assemblies will be conducted during the first three refueling outages.

We conclude that the design-oriented surveillance program originally proposed by Combustion Engineering will adequately demonstrate the performance of the 16x16 fuel assembly if that program is supplemented with a more comprehensive but less detailed surveillance program in the first two Combustion Engineering plants to use a core load of 16x16 fuel assemblies. The first two plants to use the Combustion Engineering 16x16 fuel assemblies are Arkansas Nuclear One, Unit 2 and San Onofre 2. Hence, we required that a supplemental surveillance be used for San Onofre 2. The applicants have described an acceptable supplemental surveillance program in Section 4.2.1.5.1 of the Final Safety Analysis Report. The supplemental program will not be required for San Onofre 3, which is currently scheduled to load fuel 18 months after fuel is loaded into San Onofre 2.

The supplemental program will provide visual inspection of all the peripheral rods on 100 percent of the initial fuel assemblies once they are moved from the core to the spent fuel pool. A minimum of 10 to 15 fuel assemblies will be examined prior to power ascension, and, if any anomalies are detected, further examinations will be performed. This supplemental surveillance program, which is being required for all new pressurized water reactor fuel designs, will be a proof test to give final reassurance that no long-term detrimental behavior has occurred.

4.2.3.2 CEA Surveillance Program

Surveillance of the B₄C-filled control rods is needed to insure that poison is not lost through leaching by the coolant in the event of loss of cladding integrity. At our request, the applicants submitted a control element assembly surveillance program for San Onofre 2 and 3 that is similar to the program we approved for the Arkansas Nuclear One, Unit 2 reactor. While this program involves no additional testing, we find that the planned control element assembly symmetry tests described in Section 14.2.12.82 of the Final Safety Analysis Report are adequate because they are capable of detecting reactivity anomalies that would result from the loss of poison material prior to significant loss of shutdown capability. These low-power physics tests will be conducted prior to plant startup and at the beginning of each refueling cycle. We conclude that the above tests satisfy control element assembly testing and surveillance requirements.

4.2.4 Fuel Design Conclusions

Two outstanding issues remain to be resolved prior to completing our review. These are:

- (1) Combined seismic and LOCA loads analysis (Section 4.2.2.10).
- (2) Supplemental ECCS calculations with NUREG-0630 models (Section 4.2.2.13).

When these issues are resolved, we will be able to conclude that the San Onofre 2 and 3 plants have been designed such that (a) the fuel system will not be damaged as a result of normal operation and anticipated operational occurrences, (b) fuel damage during postulated accidents will not be so severe as to prevent control rod insertion when it is required, (c) the number of fuel rod failures will not be underestimated for postulated accidents, and (d) core coolability will always be maintained, even after severe postulated accidents. The applicants will have provided sufficient evidence that these design objectives have been met based on operating experience, prototype testing, and analytical predictions. The applicants have also provided for testing and inspection of new fuel to ensure that it is within design tolerances. We will be able to conclude that the applicants have met all the requirements of the applicable regulations, current regulatory positions, and good engineering practice. We will report on the resolution of the outstanding issues in a supplement to this report.

All applicable requirements related to the reactor fuel are described in Section 4.2, "Fuel System Design," of the Standard Review Plan (NUREG-75/087). The applicable Regulations and Regulatory Guides are: 10 CFR 50.46; 10 CFR 50 Appendix A (GDC-10); 10 CFR 50 Appendix K; Regulatory Guide 1.3; Regulatory Guide 1.4; Regulatory Guide 1.25; Regulatory Guide 1.77; and Regulatory Guide 1.126. Some of these requirements are satisfied in Chapter 15 of the Final Safety Analysis Report rather than in Section 4.2.

4.3 Nuclear Design

The nuclear design of the San Onofre 2 and 3 reactors is in many respects similar to the Arkansas Nuclear One, Unit 2 design previously reviewed and approved by the staff. The principal difference is that the Arkansas Nuclear One, Unit 2 core consists of 177 fuel assemblies where as the San Onofre 2 and 3 design utilizes 217 fuel assemblies. The core average linear heat generation rate at 100 percent of rated power is 5.34 kilowatts per foot.

4.3.1 Design Bases

We have reviewed the design bases used by the applicants to establish the core design and the designs of the reactivity and power distribution control systems. We have established that these design bases are consistent with General Design Criteria 10, 11, 12, 13, 20, 25, 26, 27, and 28 of 10 CFR 50, Appendix A. Those design bases that are important to the safety of the plant are discussed below.

4.3.2 Power Distribution Control

The applicants' basis for power distribution control is that the power distributions produced during all phases of normal operation are no worse than those assumed as initial conditions in the safety analyses. Specifically, the peak linear heat generation rate must be maintained below the value of 13.9 kilowatts per foot used as the initial condition in the loss-of-coolant analysis. Also, the power distribution must be controlled to maintain the departure from nucleate boiling ratio initial condition in the loss-of-flow analysis and certain control element assembly drop analyses.

The applicants have established a value of 2.28 as the design limit on the three-dimensional heat flux peaking factor at full power. This value is based on a design radial peaking factor of 1.55 and an assumed maximum axial peaking factor of 1.47.

The applicants have performed extensive power distribution calculations to demonstrate that the design limits described above can be met during normal operation. These calculations simulated the reactor behavior during both steady-state operation and during typical load-following maneuvers. The results of these calculations show that the maximum steady-state peaking factor, excluding uncertainties, is 1.85. This value occurs near beginning of life.

The uncertainties to be applied in comparing the expected power distributions and implied peak linear heat generation rate produced by analysis with the design limits include a power level uncertainty factor of 1.02, an engineering factor of 1.03, and an augmentation factor of 1.03 to account for power spiking associated with fuel densification. In addition, the applicants have supplied an estimate of the calculational uncertainty which we are reviewing as a part of our overall evaluation of the core protection calculator system. Pending completion of our review, we have established that a value of 1.10 is acceptably conservative.

Recently refined Combustion Engineering physics calculations have resulted in increased first-cycle local pin power peaking in assemblies with control element assembly (CEA) water holes. These multigroup transport theory calculations indicate that the current standard design model is underpredicting the power in fuel pins adjacent to control element assembly water holes by about 4.5 percent for 14x14 fuel assembly design cores and by about 4 percent for the 16x16 cores (such as San Onofre 2 and 3).

In Amendment 13 to the FSAR, the applicants state that the power peaking predicted by the design model for all fuel pins adjacent to a CEA water hole was increased by a factor of 1.05 to account for the underestimation. The values of local power peaking used in the safety analysis were confirmed to conservatively envelop the adjusted calculations, including all appropriate uncertainties. Furthermore, the constants used in the reactor protective system and monitoring systems will be based upon power peaking values which have been increased by the factor 1.05.

We conclude that applying this increase of 5% to all pins adjacent to CEA waterholes is acceptable and conservative and, therefore, consider this matter to be resolved.

4.3.3 Core Operating Limit Supervisory System

The applicants plan to employ a reactor monitoring system, designated the core operating limit supervisory system (COLSS). This system, which is in use at ANO-2, is used to continuously monitor important reactor characteristics and establish margins to operating limits. This system, which consists of software executed on the plant computer, will utilize the output of the incore detector system to synthesize the core average axial power distribution. Rod positions taken from the control rod position indication system, together with precalculated radial peaking factors, will be used to construct axially dependent, radial power distributions. By using this information, together with measured primary coolant flow, pressure, and temperature, the core operating limit supervisory system will establish the margin to the operating limits on maximum linear heat generation rate and minimum departure from nucleate boiling ratio (DNBR). The system will also monitor azimuthal flux tilt and total power level and will generate an alarm if any of these limits are exceeded. The margins to all of these limits except azimuthal tilt are continuously displayed to the operators; the tilt can be displayed at the request of the operator. The operator will monitor these margins and take corrective action if the limits are approached. These actions include improving the power distribution by moving full-length or part-length rods, reducing power, or changing thermal-hydraulic conditions, i.e., coolant inlet temperature and primary system pressure.

A description of the core operating limit supervisory system algorithms and an uncertainty analysis of the calculations performed by the core operating limit supervisory system is presented in Combustion Engineering topical report CENPD-169-P, "COLSS-Assessment of the Accuracy of PWR Operating Limits as Determined by the Core Operating Limit Supervisory Systems." We have reviewed this report and conclude that the methods employed in the core operating limit supervisory system to determine

power distributions are acceptable because they will result in the core thermal-hydraulic parameters being maintained within the Technical Specifications and core protection calculator limits. The axial power distribution synthesis methods are the same as those used at existing Combustion Engineering plants for periodic processing of incore detector data. Similarly, the use of precalculated information to determine radial peaking factors is consistent with the approach now used to establish monitoring limits on existing reactors.

4.3.4 Reactivity Coefficients

The reactivity coefficients are expressions of the effect on neutron multiplication of changes in core conditions such as power, temperature, pressure, and void content. These coefficients vary with fuel burnup. The applicants have presented calculated values of these coefficients and have also evaluated the accuracy of these calculations.

We have reviewed the calculated values of the reactivity coefficients and conclude that they adequately represent the full range of expected values. We also conclude that the reactivity coefficients used in the safety analysis conservatively bound the expected values including uncertainties.

The predicted total power coefficient is strongly negative for all reactor conditions through core life, thus satisfying the requirements of Criterion 11 of the General Design Criteria. The applicants will measure the moderator temperature coefficient and the power coefficient during startup tests to check the calculated values and to further ensure that conservative coefficient values were used in the accident analysis.

4.3.5 Control

To allow for changes of reactivity due to reactor heatup, changes in operating conditions, fuel burnup, and fission product buildup, a significant amount of excess reactivity will be built into the core. The applicants have provided sufficient information relating to core reactivity balance for the first core and have shown that means are incorporated into the design to control excess reactivity at all times.

Control of both excess reactivity and power level will be achieved with movable control element assemblies and through the variation of boron concentration in the reactor coolant. In addition, the chemical and volume control system will be capable of shutting down the reactor by adding soluble boron poison and maintaining the reactor at least five percent subcritical when refueling. The combination of control systems satisfies the requirements of Criterion 26 of the General Design Criteria.

The plant will be operated at steady-state full power with only one bank of the full-length control element assemblies slightly inserted. Limited insertion of the full-length control rods will permit compensating for fast reactivity changes (e.g., that required for power level changes and for the effects of minor variations in moderator temperature and boron concentrations) without impairing shutdown capability.

Rod insertion will be controlled by the power dependent insertion limits that will be specified in the technical specifications. These limits will (1) ensure that there is sufficient negative reactivity available to permit the rapid shutdown of the reactor with ample margin, and (2) ensure that the worth of a control rod that might be ejected in the unlikely event of an ejected rod accident will be no worse than that assumed in the accident analysis.

Soluble boron poison will be used to compensate for slow reactivity change including those associated with fuel burnup, changes in xenon and samarium concentration, buildup of long-life fission products, burnable poison rod depletion, and the large moderator temperature change from cold shutdown to hot standby. The soluble boron poison system will provide the capability to take the reactor at least ten percent subcritical in the cold shutdown condition.

We have reviewed the calculated rod worths and the uncertainties in these worths, based upon appropriate comparison of calculations with experiments. On the basis of our review, we conclude that the applicants' assessment of reactivity control is suitably conservative and that adequate negative reactivity worth has been provided by the control system to assure shutdown capability, assuming that the most reactive control element assembly is stuck in the fully withdrawn position. We conclude that the control element assembly and soluble boron worths are acceptable for use in the accident analysis.

4.3.6 Stability

The stability of the reactor to xenon-induced power distribution oscillations and the control of such transients have been discussed by the applicants. Due to the negative power coefficient, the reactor is inherently stable to oscillations in total reactor power.

The core may be unstable to axial xenon oscillations during the first cycle. The applicants have provided sufficient information to show that axial oscillations will be detected and controlled before any safety limits are reached, thus preventing any fuel damage. The core will be stable to both radial and azimuthal xenon oscillations throughout core life.

4.3.7 Vessel Irradiation

Maximum fast neutron fluxes having energies greater than 1 million electron volts incident on the vessel and shroud inside diameters are presented. For reactor operation at the full power rating and an 80 percent capacity factor, the calculated vessel fluence greater than 1 million electron volts at the vessel wall does not exceed 3.68×10^{19} neutrons per square centimeter over the 40-year design life of the vessel. The calculated exposure includes a 10 percent uncertainty factor. We conclude that the vessel fluence is acceptable because it is less than the 10^{20} neutrons per square centimeter criterion given in the Standard Review Plan (NUREG-75/087).

4.3.8 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer and storage facilities. The applicants have presented information on calculational techniques and assumptions in Section 9.1 of the Final Safety Analysis Report that were used to assure that criticality is avoided. We have reviewed this information and the criteria to be employed and find them to be acceptable.

4.3.9 Analytical Methods

The applicants have described the computer programs and calculational techniques used to calculate the nuclear characteristics of the reactor design and have provided examples to demonstrate the ability of these methods to predict experimental results. We conclude that the information presented adequately demonstrates the ability of these analytical methods to calculate the reactor physics characteristics of the San Onofre 2 and 3 cores.

4.3.10 Nuclear Design Conclusions

To allow for changes of reactivity due to reactor heatup, changes in operating conditions, fuel burnup, and fission product buildup, a significant amount of excess reactivity is designed into the core. The applicants have provided substantial information relating to core reactivity balances for the first cycle and have shown that means have been incorporated into the design to control excess reactivity at all times. The applicants have shown that sufficient control rod worth is available to shut down the reactor with at least a 1.0 percent $\Delta k/k$ subcritical margin 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 our review, we conclude that the applicants' assessment of reactivity control requirements over the first core cycle is suitably conservative and that adequate negative worth has been provided by the control system to assure shutdown capability. Reactivity control requirements will be reviewed for additional cycles as this information becomes available. We also conclude that nuclear design bases, features, and limits have been established in conformance with the requirements of Criteria 10, 11, 12, 13, 20, 25, 26, 27, and 28 of the General Design Criteria.

The applicants have described the computer programs and calculational techniques used to predict the nuclear characteristics of the reactor design and have provided examples to demonstrate the ability of these methods to predict experimental results. We conclude that the information presented adequately demonstrates the ability of these analyses to predict reactivity and physics characteristics of the San Onofre 2 and 3 plant.

4.4 Thermal and Hydraulic Design

The principal criterion for the thermal-hydraulic design of a reactor is avoidance of thermally induced fuel damage during normal steady-state operation and during anticipated operational occurrences. At San Onofre 2 and 3, the following design limits are used to satisfy this criterion:

- (1) The margin to departure from nucleate boiling will be chosen to provide a 95 percent probability with 95 percent confidence that departure from nucleate boiling will not occur on a fuel rod having the minimum departure from nucleate boiling ratio during steady-state operation and anticipated operational occurrences. The CE-1 correlation is used in conjunction with the TORC code to provide this probability and confidence at a minimum departure from nucleate boiling ratio of 1.19.
- (2) Operating conditions are selected to ensure hydraulic stability within the core, thereby preventing premature departure from nucleate boiling.
- (3) The peak temperature of the fuel will be less than the melting point (5080°F unirradiated and reduced by 58°F per 10,000 megawatt days per metric ton of uranium during steady-state operation and anticipated operational occurrences).

The thermal and hydraulic design parameters for the reactor are listed and compared with those of Arkansas Nuclear One, Unit 2 in Table 4.1, below. The principal differences include increases in the allowable power, flow rate, and number of fuel assemblies. Hot channel thermal-hydraulic conditions are comparable. Predictions of the hydraulic characteristics are based on model tests for the San Onofre 2 and 3 reactor configuration.

4.4.1 DNBR Considerations

The margin to departure from nucleate boiling at any point in the core is expressed in terms of the departure from nucleate boiling ratio (DNBR). The departure from nucleate boiling ratio is defined as the ratio of the heat flux required to produce departure from nucleate boiling, at the calculated local coolant conditions, to the actual local heat flux. The departure from nucleate boiling correlation used for the design of the San Onofre 2 and 3 core is the Combustion Engineering CE-1 correlation. Combustion Engineering was requested to use applicable 16x16 fuel assembly departure from nucleate boiling data to support the thermal hydraulic design basis used for steady-state and limiting transient analyses. The Combustion Engineering departure from the nucleate boiling test program was previously conducted with an axially uniform heat flux distribution applied to electrically heated rod bundles representative of 14x14 and 16x16 fuel assemblies. The assemblies utilized standard Combustion Engineering spacer grids. The CE-1 correlation was developed from the data from these tests. Based on our review of the results of the tests, we established 1.19 as an acceptable value for the minimum DNBR (Parr, 1976a).

TABLE 4.1
REACTOR DESIGN COMPARISON

Thermal & Hydraulic Design Parameters (Nominal)	San Onofre 2 and 3	Arkansas Nuclear One Unit 2
Performance Characteristics:		
Reactor Core Heat Output, thermal megawatts	3390	2815
System Pressure, pounds per square inch, absolute	2250	2250
Minimum Departure From Nucleate Boiling Ratio (full power)	2.07 (CE-1)	2.14 (W-3)
Coolant Flow:		
Total Flow Rate (10^6 pounds per hour)	148.0	120.4
Effective Flow Rate for Heat Transfer (10^6 pounds per hour)	142.8	116.2
Average Mass Velocity Along Fuel Rods, feet per second	16.3	16.4
Average Mass Velocity (10^6 pounds per hour per square foot)	2.61	2.6
Coolant Temperature, °F:		
Nominal Reactor Inlet	553	553.5
Nominal Reactor Outlet	611	612.0
Average in Vessel	582	582.75
Nominal Hot Channel Outlet	642	652
Heat Transfer, 100 percent Power:		
Active Heat Transfer Surface Area, square feet	62,000	51,000
Average Heat Flux, British thermal units per hour per square foot	182,400	185,000
Maximum Heat Flux, British thermal units per hour per square foot	428,000	433,800
Average Linear Heat Rate, kilowatts per foot (based on heat deposited in fuel only)	5.34	5.41
Maximum Thermal Output, kilowatts per foot	12.5	12.7
Clad Surface Temp, Maximum, °F	657	657
Fuel Temperature, Maximum, °F	3180	3420
Rod Energy Deposition Factor	.975	.974
<u>Core Mechanical Design Parameters</u>		
Fuel Rod Array	16x16	16x16
Number of Fuel Assemblies	217	177

TABLE 4.1 (continued)

<u>Core Mechanical Design Parameters (cont'd)</u>	<u>San Onofre 2 and 3</u>	<u>Arkansas Nuclear One Unit 2</u>
Fuel Assembly Overall Dimensions, inches	7.97x7.97	7.97x7.97
Spacer Grids per Assembly	11	12
Fuel Rods:		
Number	49,580	40,644
Outside Diameter, inches	0.382	0.382
Clad Thickness, inches	0.025	0.025
Clad Material	Zircaloy 4	Zircaloy 4
Fuel Pellets:		
Material	Sintered UO ₂	Sintered UO ₂
Length, inches	0.390	0.390
Fuel Enrichment, weight percent U-235:		
Region 1	1.87	1.93
Region 2	1.87/2.41	2.27
Region 3	2.41/2.91	2.94
Control Element Assemblies:		
Number of Control Element Assemblies, Full/Part Length	83/8	73/8
<u>Nuclear Design Parameters</u>		
Heat Flux:		
Total Heat Flux Factor	2.35	2.35
Enthalpy Rise:		
Nuclear Enthalpy Rise Factor	1.55	1.55

The departure from nucleate boiling test program was extended by Combustion Engineering to include axially non-uniform heat flux data using the TORC analysis code and the CE-1 critical heat flux correlation, with the addition of the Tong F-factor to account for the non-uniform heat flux. Our generic review of the CE-1 correlation as applied to non-uniform heat flux distributions is incomplete pending completion of the review of the topical report CENPD-207. Until our generic review is complete, we will impose a five percent penalty on the CE-1 correlation described in CENPD-162. This penalty is included in the 1.19 DNBR limit used in the San Onofre 2 and 3 thermal-hydraulic analysis and is acceptable for use in conjunction with the Tong F-factor for non-uniform flux shapes.

In addition to the other DNBR considerations discussed herein, the San Onofre 2 and 3 reactors will use fuel assemblies with support grids which are thicker and wider than comparable grids for the 16x16 fuel design in ANO-2. Also, the grid spacing has been increased relative to the grid spacing for ANO-2 by using one less grid for the bundle. The effect of these changes in grid design may be to reduce the critical heat flux for San Onofre fuel relative to that for ANO-2 and other plants which use the same grid design as ANO-2. Therefore, we requested that the applicants provide data to justify the use of the CE-1 CHF correlation. This data has been submitted by the applicants, but our review of it is not yet complete. We will report on the resolution of this issue in a supplement to this report.

The reactor core was designed using the TORC code, an open-core analytical method based on the COBRA-IIIC mode. The TORC code solves the conservation equations for mass, axial and lateral momentum, and energy for a collection of parallel flow channels that are hydraulically open to each other. Combustion Engineering has submitted a topical report (CENPD-161) describing TORC and including a description of data used to verify the TORC code on a subchannel basis. Combustion Engineering has provided an additional report (CENPD-206, discussed below) that uses existing reactor data to verify the TORC code on a core-wide basis. These topical reports have been reviewed for adequacy and we have found the TORC computer code described in CENPD-161 to be acceptable for performing steady state calculations of the reactor core thermal hydraulic performance. The application should be limited to conditions of single phase flow or homogeneous two-phase flow (such as the bubbly flow regime). When used the analysis of flow blockage conditions, the blockage must be assumed to occur in the high power fuel assembly.

The applicants have provided a summary of test data from the hydraulic tests on a 1/5 scale reactor vessel model and a 1/8 scale model. The data are applicable to the San Onofre 2 and 3 vessel configuration. Data from the 1/5 scale flow test were used to determine the core inlet flow distribution used in the San Onofre 2 and 3 design. The data are referenced in the Combustion Engineering topical report CENPD-206, "Comparison of TORC Code Predictions with Experimental Data," December 1976. We have reviewed these comparisons and we find that they satisfy our requirements, and are acceptable.

4.4.2 Fuel Rod Bowing

With regard to rod bowing of Combustion Engineering 16x16 fuel, there is no data base for direct evaluation of rod bowing as a function of burnup. Consequently, rod bow measurements on 14x14 fuel have been extrapolated by us to 16x16 fuel with methods which are generally conservative. This extrapolation was based on methods developed by the staff for interim evaluation of rod bowing and combines the Combustion Engineering data on the effect of rod bow on departure from nucleate boiling with rod bow magnitude versus exposure. Credit has been given for thermal margin due to a multiplier of 1.05 on the hot enthalpy rise used to account for pitch reduction due to manufacturing tolerances. Also, the effect of modifications in grid design, including the increased grid spacing over that used in ANO-2, has been accounted for. The resultant reduction in the departure from nucleate boiling ratio due to rod bow is given by:

<u>Burnup (gigawatt-days per metric ton of uranium)</u>	<u>Departure from Nucleate Boiling Ratio Penalty (percent)</u>
0-2.4	0
2.4-5	3.0
5-10	7.1
10-15	10.3
15-20	12.9
20-25	15.3
25-30	17.4
30-35	19.4
35-40	21.2

The applicants have presented to the staff an acceptable method of accommodating the thermal margin reduction shown above so that appropriate provisions may be incorporated in the Technical Specifications.

4.4.3 Crud Deposition

Crud deposition in the core and an associated change in core pressure drop and flow have been observed on some pressurized water reactors. The applicants have stated that the effects of possible crud deposits are included in the San Onofre 2 and 3 design in the form of adjustments to (1) the fuel assembly design uplift forces and (2) the pressure differentials used in the determination of design hydraulic loads on the reactor vessel internal components. In addition, the core flow will be continuously monitored by the core operating limits supervisory system using pump casing differentials and pump speed as input. Any reduction in core flow rate due to crud deposits will be accounted for in the core operating limits supervisory system thermal margin assessment. We will include in the plant Technical Specifications the requirement that the actual reactor coolant system total flow rate shall be greater than or equal to the value indicated by the core protection calculator system.

4.4.4 Hydrodynamic Stability

The applicants have discussed the San Onofre 2 and 3 analysis of hydrodynamic stability. We are performing a generic study of the hydrodynamic stability characteristics of pressurized water reactors, including the evaluation methods used for San Onofre 2 and 3. The results of our study will be applied to the acceptability of the stability methods used by the applicants. In the interim, we conclude that past operating experience, flow stability experiments, and the inherent thermal-hydraulic characteristics of light water reactors provide a basis for accepting the San Onofre 2 and 3 stability evaluation for normal operation and anticipated transient events.

4.4.5 Loose Parts Monitoring System

The applicants have provided a description of the loose parts monitoring system to be provided for San Onofre 2 and 3. The design will include two sensors at each selected natural collection region. The system will be capable of detecting a loose part having an impact energy greater than or equal to 0.5 foot-pounds. The applicants have stated that the system will be designed to remain functional for a seismic event up to and including the operating basis earthquake and will be qualified to function in the normal service environment inside containment. Alarm settings will be established based on baseline data taken during startup testing at selected nominal power levels. We have evaluated the San Onofre 2 and 3 loose parts monitoring system in comparison with the equipment and procedures used on other comparable plants and, taking into account pertinent differences, find that the San Onofre 2 and 3 system is acceptable.

4.4.6 Core Protection Calculator Algorithms

The data base constants and changes to the algorithms (from Arkansas Nuclear One, Unit 2) for the core protector calculator system for San Onofre 2 and 3 will be reviewed by the staff and addressed in the supplement to this report.

4.4.7 Conclusion

We conclude that, with the exceptions noted, the thermal-hydraulic design of San Onofre 2 and 3 conforms to the Commission's regulations and to applicable regulatory guides and staff technical positions and is acceptable.

4.5 Reactor Materials

4.5.1 Reactor Internals Materials

The materials for construction of components of the San Onofre 2 and 3 reactor internals have been identified by specification and found to be in conformance with the requirements of Section III of the ASME Code.

The materials for reactor internals exposed to the reactor coolant have been identified and all of the materials are compatible with the expected environment, as proven by

extensive testing and satisfactory performance. General corrosion on all materials is expected to be negligible.

The controls imposed on reactor coolant chemistry provide reasonable assurance that the reactor internals will be adequately protected during operation from conditions which could lead to stress corrosion of the materials and loss of component structural integrity.

The welding controls imposed upon components constructed of austenitic stainless steel, as used in the reactor internals, satisfy the requirements of the ASME Code Section III. Austenitic stainless steel welding filler materials are controlled to deposit from 8 to 25 percent delta ferrite, except for 309 and 309L welding filler materials, which are controlled to deposit from 5 to 15 percent delta ferrite and are used when welding ferritic steel to austenitic stainless steel. All austenitic stainless steel materials are furnished in solution heat treated condition in accordance with the applicable ASME material specification. Sensitization is avoided by not permitting heat treatment in the temperature range of 800 to 1500°F.

The nondestructive examination of tubular products is performed in accordance with the provisions of the ASME Code, Section III.

Material selection, fabrication practices, examination procedures, and protection procedures performed as stated above provide reasonable assurance that the austenitic stainless steel used for reactor internals will be in a metallurgical condition which precludes susceptibility to stress corrosion cracking during service. The use of materials proven to be satisfactory by actual service experience and conformance with the requirements of the ASME Code constitutes an acceptable basis for meeting, in part, the requirements of Criteria 1 and 14 of the General Design Criteria.

4.5.2 Control Rod System Structural Materials

The mechanical properties of structural materials selected for the control rod system components exposed to the reactor coolant satisfy Appendix I of Section III of the ASME Code, Part A of Section II of the Code, and also the NRC staff position that the yield strength of cold worked austenitic stainless steel should not exceed 90,000 pounds per square inch.

The controls imposed upon the austenitic stainless steel of the system satisfy the requirements of the ASME Code, Section III. All austenitic stainless steel materials are furnished in solution heat treated condition in accordance with the applicable ASME material specification. Sensitization is avoided by not permitting heat treatment in the temperature range of 800 to 1500°F. Fabrication and heat treatment practices performed as stated above provided added assurance that stress corrosion cracking will not occur during the design life of the components.

The compatibility of all materials used in the control rod system in contact with the reactor coolant satisfies the criteria for Articles NB-2160 and NB-3120 of Section III

of the Code. Both martensitic and precipitation-hardening stainless steels have been given tempering or aging treatments in accordance with NRC staff positions. Cleaning and cleanliness control are in accordance with American Nuclear Standards Institute (ANSI) Standard N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components During the Construction Phase of Nuclear Power Plants," and Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants."

Conformance with the codes, standards, and regulatory guides indicated above and with the staff positions on the allowable maximum yield strength of cold worked austenitic stainless steel and minimum tempering or aging constitutes an acceptable basis for meeting the requirements of Criterion 26 of the General Design Criteria.

4.6 Functional Design of Reactivity Control System

The San Onofre 2 and 3 reactivity control systems are designed to meet certain basic types of control requirements. First is the requirement that the reactor must be capable of operation in the unrodded, critical, full power mode throughout plant life. Second is the requirement that power level and power distribution control must be sufficient to allow the power to be varied from full power to hot shutdown and sufficient to assure the power distributions at any power level may be controlled within acceptable limits. Third is the requirement that shutdown reactivity control capability be sufficient to mitigate the effects of postulated events discussed in Section 15 of this report.

The reactivity of the reactor core is controlled by three separate active systems; (1) the chemical and volume control system, (2) the full-length control element assemblies, and (3) the part-length control element assemblies. The chemical and volume control system is designed to control slow or long-term reactivity changes such as that caused by fuel burnup or by variation in the xenon concentration resulting from changes in reactor power level. The chemical and volume control system controls reactivity by adjusting the dissolved boron concentration in the moderator (see Sections 4.3.5 and 9.3.3 of this report).

The boron concentration is controlled to obtain optimum control element assembly positioning, to compensate for reactivity changes associated with variations in coolant temperature, core burnup, xenon concentration, and to provide shutdown margin for maintenance and refueling operations or emergencies. A portion of the chemical and volume control system (the charging pumps, the boric acid pump discharge, or the boric acid makeup tanks) injects a high concentration boron solution into the reactor coolant system to help ensure plant shutdown in the event of a safety injection actuation signal. The boric acid concentration in the reactor coolant system is controlled by the charging and letdown portions of the chemical and volume control system.

The chemical and volume control system can be used to maintain reactivity within the required bounds by means of the automatic makeup system which replaces minor coolant

leakage without significantly changing from the boron concentration in the reactor coolant system. Dilution of the reactor coolant system boron concentration is required to compensate for the reactivity losses occurring as a result of fuel and burnable poison depletion. This is accomplished by manual operation of the chemical and volume control system.

The concentration of boron in the reactor coolant system is changed manually under the following operating conditions:

- (1) Startup -- boron concentration decreased to compensate for moderator temperature and power increase.
- (2) Load follow -- boron concentration increased or decreased to compensate for xenon transients following load changes.
- (3) Fuel burnup -- boron concentration decreased to compensate for burnup.
- (4) Cold shutdown -- boron concentration increased to compensate for increased moderator density due to cooldown.

Soluble poison concentration is used to control slow operating reactivity changes. If necessary, control element assembly movement can also be used to accommodate such changes, but assembly insertion is used mainly to mitigate anticipated operational occurrences (the analysis assumes a single malfunction such as a stuck rod). In either case, fuel design limits are not exceeded. The soluble poison control is capable of maintaining the core subcritical under conditions of cold shutdown which conforms to the requirements of Criterion 26 of the General Design Criteria.

The regulating control element assembly groups (full- and part-length) may be used to compensate for changes in reactivity associated with power level changes or variations in moderator temperature or changes in boron concentration (see Sections 3.9.4 and 4.3.5 of this report).

No reactivity credit toward shutdown margin is taken for the part-length control element assemblies. The eight part-length control element assemblies provide a strong neutron absorber in the top 10 percent of their active length which on reactor trip offsets any positive reactivity insertion due to the shift in axial flux distribution between full and zero power. The part-length control element assemblies help control power distribution and suppress xenon-induced power oscillations. Full-length control element assemblies provide shutdown for accidents and normal operation and control power level and power distributions.

Full-length control element assemblies are the primary shutdown mechanism for transients and are inserted automatically. Concentrated boric acid solution is injected by the emergency core cooling system in the event of a loss-of-coolant accident, steam line break, loss of normal feedwater flow, steam generator tube rupture, or control element assembly ejection, thereby complying with General Design Criterion 20, which requires that automatic protective systems be provided (1) to assure that specified acceptable fuel design limits are not exceeded and (2) to sense accident conditions and to initiate operation of systems and components important to safety.

The ability of each control element assembly to change position is tested every 31 days during power operation. At every refueling shutdown each control element assembly is stepped over its entire range of movement, and drop tests are performed to demonstrate the ability of the assemblies to meet required drop times. A single failure will not result in loss of the protection system nor will a loss of redundancy occur as a result of removal of a channel or component from service. The foregoing periodic testing, reliability, and redundancy conform to the requirements of Criterion 21 of the General Design Criteria.

Failure of electrical power to any control element drive mechanism will cause insertion of that assembly. A single failure of the control element drive mechanism is included in transient and accident analyses by assuming the most reactive control element assembly is stuck outside the core. Analysis of accidental withdrawal of a control element assembly is found to have acceptable results. This conforms to Criteria 23 and 25 of the General Design Criteria.

The reactivity control systems, including the addition of concentrated boric acid solution by the emergency core cooling system, are capable of controlling all anticipated operational changes, transients, and accidents, including the full spectrum of loss-of-coolant accidents. All accidents are calculated with the assumption that the most reactive control element assembly is stuck and cannot be inserted, which complies with the requirements of Criterion 27 of the General Design Criteria.

Compliance with General Design Criterion 28 is discussed in Sections 4.3 and 15 of this report.

We find that the San Onofre 2 and 3 reactivity control systems meet the applicable General Design Criteria and are acceptable.

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 Summary Description

The reactor in each unit at San Onofre 2 and 3 is a pressurized water reactor (PWR) with two coolant loops. The reactor coolant system (RCS) circulates water in a closed cycle, removing heat from the reactor core and internals and transferring it to a secondary (steam generating) system. In a pressurized water reactor, the steam generators provide the interface between the reactor coolant (primary) system and the main steam (secondary) system. The steam generators are vertical U-tube heat exchangers in which heat is transferred from the reactor coolant to the main steam system. Reactor coolant is prevented from mixing with the secondary system by the steam generator tubes and the steam generator tube sheet, making the RCS a closed system thus forming a barrier to the release of radioactive materials from the core of the reactor to the containment building.

Major components of the reactor coolant system are the reactor vessel; two parallel heat transfer loops, each containing one steam generator and two reactor coolant pumps; a pressurizer connected to one of the reactor vessel outlet pipes; and associated piping. All components are located inside the containment building. Effluent discharges from the pressurizer safety valves are condensed and cooled in the quench tank.

System pressure is controlled by the pressurizer, where steam and water are maintained in thermal equilibrium. Steam is formed by energizing immersion heaters in the pressurizer, or is condensed by the pressurizer spray to limit pressure variations caused by contraction or expansion of the reactor coolant.

The average temperature of the reactor coolant varies with power level and the fluid expands or contracts, changing the pressurizer water level.

The charging pumps and letdown control valves in the chemical and volume control system (CVCS) are used to maintain the programmed pressurizer water level. A continuous but variable letdown purification flow is maintained to keep the RCS chemistry within prescribed limits. Two charging nozzles and a letdown nozzle are provided on the reactor coolant piping for this operation. The charging flow is also used to alter the boron concentration or correct the chemical content of the reactor coolant.

Other reactor coolant loop penetrations are the pressurizer surge line in one reactor vessel outlet pipe; the four safety injection inlet nozzles, one in each reactor vessel inlet pipe; one outlet nozzle to the shutdown cooling system in one

reactor vessel outlet pipe; two pressurizer spray nozzles; vent and drain connections; and sample connections and instrument connections.

Overpressure protection for the reactor coolant pressure boundary is provided by two spring-loaded ASME Code safety valves connected to the top of the pressurizer. These valves discharge to the quench tank, where the steam is released under water to be condensed and cooled. If the steam discharge exceeds the capacity of the quench tank, it is relieved to the containment atmosphere through a rupture disc.

Overpressure protection for the secondary side of the steam generators is provided by 18 spring-loaded ASME Code safety valves located in the main steam system upstream of the steam line isolation valves.

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.1 Compliance with Codes and Regulations

5.2.1.1 Compliance with 10 CFR 50.55a

We have reviewed the San Onofre 2 and 3 application and find that the components of the reactor coolant pressure boundary, as defined by the rules of 10 CFR Part 50, Section 50.55a, have been properly identified and classified as ASME Section III, Class 1 components in Table 5.2.1 of the FSAR. These components within the reactor coolant pressure boundary are constructed in accordance with the requirements of the applicable codes and addenda as specified in 10 CFR Part 50, Section 50.55a, Codes and Standards.

We conclude that construction of the components of the reactor coolant pressure boundary in conformance with the ASME code and the Commission's regulations provides adequate assurance that component quality is commensurate with the importance of the safety function of the reactor coolant pressure boundary and is acceptable.

5.2.1.2 Applicable Code Cases

The ASME Code Cases specified in Section 5.2.1.2 of the San Onofre 2 and 3 FSAR whose requirements have been applied in the construction of pressure retaining ASME Section III, Class 1, components within the Reactor Coolant Pressure Boundary (Quality Group Classification A), are in accordance with those code cases that are generally acceptable to the Commission. We conclude that compliance with the requirements of these code cases, in conformance with the Commission's regulations, is expected to result in a component quality level that is commensurate with the importance of the safety function of the reactor coolant pressure boundary and is acceptable.

5.2.2 Overpressurization Protection

Overpressure protection of the primary coolant system is designed to accommodate both low and high temperature operation. High temperature overpressure protection is designed to limit transient pressures to below 110 percent of design pressure.

Low temperature overpressure protection is designed to prevent the reactor coolant system (RCS) from exceeding 10 CFR 50, Appendix G limits.

5.2.2.1 High Temperature Overpressure Protection

The San Onofre 2 and 3 high temperature overpressure protection system is designed to maintain secondary and primary operating pressures within 110 percent of design by means of 2 primary safety valves, 18 secondary safety valves, and the reactor protection system. The secondary safety valves are sized to pass a steam flow equivalent to a power level of 3580 MWt, which is greater than the proposed licensed power level of 3410 MWt. The reactor is designed to trip at an RCS pressure of 2400 psia while the primary pressurizer safety valves are designed to lift at a pressure of 2500 psia, which is system design pressure.

The design basis event for the sizing of this system is a loss-of-load with a delayed reactor trip. The applicants have indicated that the loss-of-load analysis was done with preliminary plant system parameters and initial conditions. In the analysis provided, no credit was taken for operation of the following:

- (1) Pressurizer level control system,
- (2) Pressurizer spray,
- (3) Secondary turbine bypass control system,
- (4) Feedwater flow after turbine trip.

In order to justify the conservatism of the high temperature overpressure design for the as-built system parameters and initial conditions, the applicants referenced Chapter 15 overpressure events where conservative as-built values were used in the calculations. In the limiting pressure transient, the loss of condenser vacuum, the initial core power level was assumed to be 102% of the design power level, the core and system parameters input to the calculation were chosen to maximize pressurizer pressure, protection system setpoints and response times included the maximum uncertainties or delays, and the first reactor trip signal was ignored. The calculated pressurizer safety valve flow rate was less than the rated capacity of the two pressurizer safety valves. We find the high temperature overpressure protection system acceptable.

Testing and inspection of the primary safety valves is based on ASME Section XI, Subsection IWV. The secondary safety valves are individually tested during initial startup operation by checking actual lift and blowdown point. Periodic in-service testing of the secondary safety valves will be defined in the Technical Specification.

5.2.2.2 Low Temperature Overpressure Protection

The applicants propose to use the shutdown cooling system (SDCS) safety/relief valve (2PSV-9349) to provide low temperature overpressure protection while on shutdown cooling. The stated capacity of this spring-loaded (bellows) liquid relief valve is

3089 gallons per minute at 417 psia with 10 percent accumulation. The most limiting transients calculated were inadvertent safety injection (mass input) and reactor coolant pump start when a positive steam generator to reactor vessel ΔT exists (energy input). Calculations show that this relief system can mitigate these transients and prevent violation of 10 CFR 50, Appendix G.

System design criteria required by the staff include no credit for operator action for 10 minutes; the mitigating system must meet single active failure criteria; the system must be testable; the system must be able to withstand an operating basis earthquake (OBE); and the system must be capable of functioning following loss of offsite power. The applicants have met all the design criteria of our position on water solid overpressure protection provided the following staff requirements are implemented and the additional staff concerns are satisfactorily resolved:

- (1) The Technical Specifications will include requirements to ensure that the RCS is on shutdown cooling system with all suction line valves open whenever the RCS temperature is below 280°F;
- (2) Valves 2HV9337, 2HV9339, 2HV9377, and 2HV9378 must be locked open in the control room when on the SDCS;
- (3) The Technical Specifications will prohibit actuation of a reactor coolant pump if the associated steam generator to reactor coolant system ΔT is greater than 100°F;
- (4) The set point for the automatic isolation of the SDCS must be raised to 700 psig.

The applicants have committed to bench test valve PSV-9349, the SDCS safety/relief valve, at intervals not to exceed thirty months in order to provide increased assurance of valve operability. We find this testing interval acceptable. The applicants discussed various analyses which show that flashing at the safety/relief valve discharge does not prevent the valve from passing its rated flow. We find the relief capacity of the valve acceptable. The applicants stated that PSV-9349 is designed to operate during and after an operating basis earthquake since it is constructed to Seismic Category 1, Quality Class II, and ASME Section III, Class 2 criteria. We find the capability of PSV-9349 to withstand an operating basis earthquake acceptable.

The Technical Specification requirements described above for steam generator/RCS ΔT and SDCS initiation temperature limits are only valid for the first 10 years of plant operation and must be reexamined in the future to ensure they are still suitably conservative. Subject to the above requirement for reexamination, which will be enforced by a license condition, we find the design of the San Onofre 2 and 3 low temperature overpressure mitigation system acceptable.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications and Compatibility with Reactor Coolant

The materials used for construction of components of the reactor coolant pressure boundary (RCPB), including the reactor vessel and its appurtenances, have been identified by specification and found to be in conformance with the requirements of Section III of the ASME Code. Special requirements of the applicants with regard to control of residual elements in ferritic materials have been identified and are considered acceptable.

The RCPB materials of construction that will be exposed to the reactor coolant have been identified and all of the materials are compatible with the expected environment, as proven by extensive testing and satisfactory performance. General corrosion of all materials except carbon and low alloy steel will be negligible. For these materials, conservative corrosion allowances have been provided for all exposed surfaces of carbon and low alloy steel in accordance with the requirements of the ASME Code, Section III. The external nonmetallic insulation to be used on austenitic stainless steel components conforms with the requirements of Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steels."

Further protection against corrosion problems will be provided by control of the chemical environment. The composition of the reactor coolant will be controlled. The proposed maximum contaminant levels have been shown by tests and service experience to be adequate to protect against corrosion and stress corrosion problems.

The controls imposed on reactor coolant chemistry are in conformance with the recommendations of Regulatory Guide 1.44, "Control of Sensitized Stainless Steel," and provide reasonable assurance that the RCPB components will be adequately protected during operation from conditions that could lead to stress corrosion of the materials and loss of structural integrity of a component.

The instrumentation and sampling provisions for monitoring reactor coolant water chemistry provide adequate capability to detect significant changes on a timely basis. The use of materials of proven performance and the conformance with the recommendations of the regulatory guides constitutes an acceptable basis for satisfying the requirements of NRC General Design Criteria 14 and 31, Appendix A of 10 CFR Part 50.

5.2.3.2 Fabrication and Processing of Ferritic Materials

Materials selection, toughness requirements, and the extent of the materials testing proposed by the applicants provide assurance that the ferritic materials used for pressure retaining components of the reactor coolant boundary, including the reactor vessel and its appurtenances, will have adequate toughness under test, normal operation, and transient conditions.

The ferritic materials are specified to meet the toughness requirements of the ASME Code, Section III. In addition, materials for the reactor vessel are specified to meet the additional test requirements and acceptance criteria of Appendix G, 10 CFR Part 50.

The fracture toughness tests and procedures required by Section III of the ASME Code, as augmented by Appendix G, 10 CFR Part 50, for the reactor vessel, provide reasonable assurance that adequate safety margins against the possibility of nonductile behavior or rapidly propagating fracture can be established for all pressure retaining components of the reactor coolant boundary.

The results of the fracture toughness tests performed in accordance with the ASME Code and NRC regulations provide adequate safety margins during operating, testing, maintenance, and postulated accident conditions. Compliance with these code provisions and NRC regulations constitutes an acceptable basis for satisfying the requirements of NRC General Design Criterion 31, Appendix A of 10 CFR Part 50.

The controls imposed on welding preheat temperatures and weld cladding satisfy the recommendations of Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel," and Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steels." These recommendations provide reasonable assurance that cracking of components made from low alloy steels will not occur during fabrication.

All welding conducted in limited access areas is performed by welders qualified in accordance with the requirements of Section IX of the Code. The completed welds are volumetrically inspected by either radiography or ultrasonic examination method. The ultrasonic method for examination of ferritic steel tubular products satisfy the requirements of the ASME Code, Section III. The fabrication practices and examination procedures performed as stated above provide reasonable assurance that welds in the reactor coolant pressure boundary (RCPB) will be satisfactory in locations of restricted accessibility, and that unacceptable defects in tubular components of the RCPB will be detected.

Conformance with the code and regulatory guides mentioned constitutes an acceptable basis for meeting the requirements of NRC General Design Criteria 1 and 14, Appendix A of 10 CFR Part 50.

5.2.3.3 Fabrication and Processing of Austenitic Stainless Steel

Within the reactor coolant pressure boundary, no components of austenitic stainless steel have a yield strength exceeding 90,000 psi, in accordance with our requirements.

The controls imposed upon components constructed of austenitic stainless steel used in the reactor coolant pressure boundary and for the reactor vessel and its appurtenances satisfy the requirements of the ASME Code, Section III. Austenitic

stainless steel welding materials are controlled to deposit from 8 to 25% delta ferrite, except for 309 and 309L welding materials which are controlled to deposit from 5 to 15% delta ferrite. All austenitic stainless steel materials are furnished in the solution heat treated condition in accordance with the applicable ASME material specification. Sensitization is avoided by not permitting heat treatment in the temperature range of 800 to 1500°F. Cleaning and cleanliness controls procedures satisfy the recommendations of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants." All welding conducted in limited access areas is performed by welders qualified in accordance with the requirements of Section IX of the Code. The completed welds are volumetrically inspected by either radiography or ultrasonic examination method. The nondestructive examination of tubular products is performed in accordance with the recommendation of the ASME Code, Section III.

Materials selection, fabrication practices, examination procedures, and protection procedures performed in accordance with these recommendations provide reasonable assurance that the austenitic stainless steel in the reactor coolant pressure boundary will be free from hot cracking (microfissures) and in a metallurgical condition which precludes susceptibility to stress corrosion cracking during service. Conformance with the code and regulatory guide mentioned constitutes an acceptable basis for meeting the requirements of General Design Criteria 1 and 14, Appendix A of 10 CFR Part 50.

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity.

To ensure that no deleterious defects develop during service, selected welds and weld heat-affected-zones will be inspected periodically at San Onofre 2 and 3. The design of the ASME Code Class 1 and 2 components of the reactor coolant pressure boundary at San Onofre 2 and 3 incorporates provisions for access for inservice inspection in accordance with Section XI of the ASME Code. Methods have been developed to facilitate the remote inspection of those areas of the reactor vessel not readily accessible to inspection personnel.

Section 50.55a(g), 10 CFR Part 50, defines the detailed requirements for the preservice and inservice inspection programs for light water cooled nuclear power facility components. Based upon a construction permit date of October 18, 1973, this section of the regulations requires that a preservice inspection program be developed and implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect six months prior to the date of issuance of the construction permit. Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect twelve months

prior to the date of issuance of the operating license, subject to the limitations and modifications listed in Section 50.55a(b) of 10 CFR Part 50.

Our evaluation review of the applicants' preservice inspection program indicates that program meets the requirements of 10 CFR Part 50, Paragraph 50.55a. As a result of our review of this program for San Onofre 2 and 3, we have determined that certain preservice examination requirements are impractical and performing these examinations would result in hardships or unusual difficulties without a compensating increase in quality and safety. Our evaluation of the applicants' relief requests and a supporting technical justification are presented in Appendix H to this report. The inservice inspection program will be evaluated after the applicable ASME Code Edition and Addenda have been determined and before the initial inservice inspection.

The conduct of periodic inspections and hydrostatic testing of pressure retaining components of the reactor coolant pressure boundary in accordance with the requirements of Section XI of the ASME Boiler and Pressure Vessel Code and will provide reasonable assurance that evidence of structural degradation or loss of leaktight 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 inservice inspections required by this code constitutes an acceptable basis for satisfying the inspection requirements of General Design Criterion 32.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection System

A limited amount of leakage is to be expected from components forming the reactor coolant boundary. Components such as valve stem packing, circulating pump shaft seals, and flanges are not completely leak tight. This type of leakage (identified leakage) is monitored, limited, and separated from other leakage (unidentified) as required by Section C.1 of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems."

The sources and disposition of identified leakage are:

- (1) Stem leakoffs from valves 2PV0100A, 2TV0221, 2PV0100B, and 2HV-9201 inside containment to the reactor coolant drain tank;
- (2) Reactor coolant pump seals to volume control tank;
- (3) Pressurizer safety relief valves and reactor coolant pump bleedoff safety valves to the quench tank;
- (4) Safety injection tank drains, hot leg injection line drains, reactor vessel head seals, reactor coolant loop cold leg drains, reactor pump seal leakoffs, incore detector transfer machine drain, pressurizer spray control line isolation valve stem leakoff, and the quench tank drain to the reactor coolant drain tank.

Leakage rates for (1) through (4) are monitored by flow meters and alarmed in the control room.

Unidentified leakage, which includes steam generator tube or tube sheet and intersystem leakage, is monitored by several devices as required by Regulatory Guide 1.45 (Sections C.2, 3, 4).

Steam generator tube leakage is detected by condenser air removal system monitors, blowdown system monitors, or routine steam generator water samples. The method of detection of intersystem leakage depends on the particular interfacing system. Leakage from the RCPB to the suction side of the SDCS is discharged from the relief valve and is detected by an increase in the emergency sump level which is alarmed in the control room. Leakage from the RCPB to the high pressure safety injection (HPSI) discharge lines is detected by pressure transmitters and alarmed in the control room. Leakage past the safety injection tank (SIT) check valves is indicated by SIT level and pressure which are alarmed in the control room. Leakage past drain valves 2HV9341, 2HV9351, 2HV9361 and 2HV9371 is detected by a temperature alarm which annunciates in the control room. Leakage past the safety injection system (SIS) line second check valves and past SIS header isolation valves is indicated in the control room by pressure sensors. Should leakage be alarmed and confirmed in a flow path with no flow meters, the Technical Specifications will require that a water inventory material balance be begun within 1 hour to determine the extent of the leakage.

Indication of unidentified leakage from the reactor coolant boundary into the containment is provided by two sources. The first is containment atmosphere radiation indicators and alarms. The second is containment sump flow with its associated alarms. The particulate and gaseous air activity monitors operate continuously to detect radiation in the containment atmosphere. The containment particulate monitor uses a scintillation counter-filter paper detector assembly with a continuously moving paper surface while the containment gas monitor measures containment air samples directly. Both systems are Seismic Category 1, testable, and may be calibrated as required by Sections C.6, 7 and 8 of Regulatory Guide 1.45. The applicants indicate that the sensitivity of the particulate and gaseous monitors is such that leaks of 1 gallon per minute or less are detectable in less than 1 hour. If a break were to occur in the primary system, the resulting coolant flow would pass to the containment and go to the containment sump or would be condensed by the containment air coolers and control element drive mechanism cooling units and directed to the sump. Each path has a separate flow meter. These flow transmitter signals are summed and sent to a recorder. An increase in flow of 1 gallon per minute above normal flow rates is alarmed in the control room. The sump flow measuring system is testable and can be calibrated as required. The sensitivity of these measuring systems meet the requirements of Section C.5 of Regulatory Guide 1.45.

Additional sources of indication of unidentified leakage include containment pressure indicators, pressurizer level indicators, containment temperature and humidity, and low pressure safety injection header pressure.

The RCPB leakage detection systems are diverse and the applicants' design conforms to the requirements of Regulatory Guide 1.45 as noted above.

We conclude that the San Onofre 2 and 3 design provides reasonable assurance that primary system leakage will be detected as required by General Design Criterion 30 and is acceptable.

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

General Design Criterion 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires that the reactor coolant pressure boundary be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions the boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires that the reactor coolant pressure boundary be designed to permit an appropriate material surveillance program for the reactor pressure boundary.

We have reviewed the San Onofre 2 and 3 materials selection, toughness requirements, and extent of materials testing in accordance with the above General Design Criteria. The ferritic materials were specified to meet the toughness requirements of the 1971 Edition of the ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components."

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Requirements," of 10 CFR Part 50, specify the fracture toughness requirements for the ferritic materials of the reactor coolant pressure boundary. The ferritic materials of San Onofre 2 and 3 were qualified by impact testing in accordance with the 1971 ASME Code, Section III, and pursuant to paragraph 50.55a(c)(2) of 10 CFR Part 50, the reactor vessel ferritic materials were evaluated in accordance with the 1971 edition of the ASME Code through 1971 Summer Addenda.

5.3.1.1 Compliance with Appendix G to 10 CFR 50

We have evaluated the information in the San Onofre 2 and 3 FSAR to determine the degree of compliance with the fracture toughness requirements of Appendix G, 10 CFR Part 50. Our evaluation indicates that the applicants have met all requirements of Appendix G, 10 CFR Part 50, except for paragraph III.B.4, for which the applicants have supplied sufficient data and analyses to justify an exemption. Our evaluation of deviations from the explicit requirements of Appendix G is given below.

Paragraph III.B.4 requires that the testing personnel shall be qualified by training and experience and should be competent to perform the tests in accordance with written procedures. For San Onofre 2 and 3, no written procedures for component

testing were in existence as required by the later regulation; however, the applicants have supplied sufficient information to demonstrate that the intent of Paragraph III.B.4 has been met. The applicants have stated that individuals who conducted the testing were qualified by education, training, and years of experience and were certified by qualified supervisory personnel. Because these tests are relatively routine in nature and are continually being performed in the laboratory, we conclude that it is unlikely that the tests were conducted improperly. Consequently, we conclude that an exemption for not performing the tests in accordance with written procedures is justified, and that such an exemption will not endanger life or property or the common defense and security and is otherwise in the public interest.

5.3.1.2 Compliance with Appendix H to 10 CFR 50

The toughness properties of the reactor vessel beltline materials will be monitored throughout the service life of San Onofre 2 and 3, by a materials surveillance program that must meet the requirements of ASTM Standard E-185-73, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactors," and Appendix H, 10 CFR Part 50. We have evaluated the applicants' information for degree of compliance with these requirements. We conclude that the applicants have met the requirements of Appendix H, 10 CFR Part 50, except for Paragraph II.B, for which the applicants have provided sufficient information to justify an exemption. Our evaluation of the deviation from the explicit requirements of Paragraph II.B is given below.

Paragraph II.B requires the beltline region of the reactor vessel to be monitored by a surveillance program complying with ASTM Standard E-185-73. According to this standard the base material and weld metal to be included in the program should represent the material that may limit the operations of the reactor during its lifetime. This selection is based on initial transition temperature, upper shelf energy level, and estimated increase in transition temperature considering chemical composition (copper and phosphorous) and neutron fluence.

According to our evaluation, plates C-6404-2 and C-6802-1 are the most limiting base materials in Units 2 and 3, respectively. The San Onofre 2 and 3 surveillance program contains material from both plates C-6404-2 and C-6802-1. However, the applicants have identified the weld metal used in the surveillance program as being that of weld seam 9-203, the intermediate-to-lower shell girth weld for both vessels. According to our evaluation the most limiting weld seams in Unit No. 2 are 3-203A and 3-203B, and in Unit No. 3, weld seams 2-203A, 2-203B, and 2-203C. Because weld seam 9-203 is not the most limiting weld in the beltline region, the applicant's materials surveillance program is not in full compliance with Appendix H, 10 CFR Part 50. To have an acceptable surveillance program for San Onofre 2 and 3, the applicants must use the following analysis for every capsule removed and tested.

During the plant's life the applicants must recalculate the pressure-temperature operating limits based on the greater of the following:

- (1) the actual shift in reference temperature for plates C-6404-2 (Unit No. 2) and C-6802-1 (Unit No. 3) as determined by impact testing, or
- (2) the predicted shift in reference temperature for either weld seams 3-203A or 3-203B in Unit No. 2 and for weld seams 2-203A, 2-203B, or 2-203C of Unit No. 3, as determined by Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials."

If the applicants do not commit to the above requirement prior to issuance of an operating license, we will condition the license accordingly. Although material from the most limiting weld seams is not contained in the San Onofre 2 and 3 materials surveillance program.

Based on the above-required recalculation of pressure-temperature limits, we find that an exemption to Paragraph II.B of Appendix H, 10 CFR Part 50, is justified for the following reasons.

- (1) the applicants have included in the surveillance program each vessel's beltline material predicted to be the most limiting, and
- (2) we have conservative methods of analysis contained in Regulatory Guide 1.99 to determine the radiation characteristics of the limiting beltline weld.

For these reasons we conclude that the integrity of the reactor coolant pressure boundary will be ensured during all normal plant operations, and thus, the exemption to Paragraph II.B, Appendix H, 10 CFR Part 50, is justified. We find that such an exemption will not endanger life or property or the common defense and security and is otherwise in the public interest.

5.3.1.3 Conclusions

Our technical evaluation has not identified any practical methods by which the existing San Onofre 2 and 3 reactor vessels can comply with the specific requirements of Paragraphs III.B.4 of Appendix G and Paragraph II.B of Appendix H, 10 CFR Part 50. However, the alternate methods proposed to demonstrate compliance with these paragraphs of Appendices G and H have been reviewed and evaluated, and have been found to demonstrate that the safety margins required by Appendices G and H have been achieved. Compliance with Appendices G and H and the fracture toughness requirements of Section III of the ASME Code ensures that the ferritic components in the primary coolant pressure boundary will behave in a nonbrittle manner, that the probability of rapidly propagating fracture is minimized and that an appropriate material surveillance program exists to monitor radiation damage for the reactor pressure boundary. Compliance with the requirements of the NRC regulations and the specified codes and standards satisfies the requirements of the Commission's General Design Criteria 31 and 32.

Based on the foregoing, pursuant to 10 CFR, Section 50.12, exemptions from specific requirements of Appendices G and H of 10 CFR Part 50, as discussed above, are authorized by law and can be granted without endangering life or property or the common defense and security and are otherwise in the public interest. We conclude that the public is served by not imposing certain provisions of Appendices G and H of 10 CFR Part 50 that have been determined to be either impractical or would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

Furthermore, we have determined that the granting of these exemptions does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. We have concluded that these exemptions would be insignificant from the standpoint of environmental impact and pursuant to 10 CFR 51.5(d)(4) that an environmental impact statement, or negative declaration and environmental appraisal, need not be prepared in connection with this action.

5.3.2 Pressure-Temperature Limits

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Program Requirements," 10 CFR Part 50, describe the conditions that require pressure-temperature limits for the reactor coolant pressure boundary and provide the general bases for these limits. These appendices specifically require that pressure-temperature limits must provide safety margins for the reactor coolant pressure boundary at least as great as the safety margins recommended in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G, "Protection Against Non-Ductile Failure." Appendix G, 10 CFR Part 50, requires additional safety margins 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 non-ductile behavior or rapidly propagating failure of ferritic components as required by General Design Criterion 31:

- (1) Preservice hydrostatic tests,
- (2) Inservice leak and hydrostatic tests,
- (3) Heatup and cooldown operations, and
- (4) Core operation.

Appendices G and H, 10 CFR Part 50, require the applicants to predict the shift in reference temperature due to neutron irradiation. The shift in RT_{NDT} due to neutron irradiation is then added to the initial RT_{NDT} to establish the adjusted reference temperature. The base plate and weld seam having the highest adjusted reference temperature are considered the most limiting materials for which the pressure-temperature operating limits are based on. In the case of San Onofre 2 and 3, the most limiting materials are plate C-6404-2 and C-6802-1, respectively. Once in service, the pressure-temperature limits must be revised to reflect the actual

neutron radiation damage as determined for the results of the reactor vessel materials surveillance program.

According to our evaluation the proposed heatup and cooldown pressure-temperature limits (FSAR, Figures 16.3-7A and 16.3-7B) are acceptable for the first ten (10) effective full power years. Although these limits have been established for only Unit No. 2, they are also acceptable for Unit No. 3, because they provide equivalent margins of safety to those required by Appendix G, 10 CFR Part 50. However, the applicants are not required to use the Unit No. 2's pressure-temperature limits for operation of Unit No. 3. The applicants may submit in the future a separate set of limits for Unit No. 3, and we will evaluate these pressure-temperature limits at that time.

Subsequent to operation, the applicants must recalculate the pressure-temperature operating limits based on the greater of the following:

- (1) the actual shift in reference temperature for plates C-6404-2 (Unit No. 2) and C-6802-1 (Unit No. 3) as determined by impact testing, or
- (2) the predicted shift in reference temperature for weld seams 3-203A or 3-203B in Unit No. 2, and for weld seams 2-203A, 2-203B, or 2-203C in Unit No. 3, as determined by Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials."

The above requirements are discussed in Section 5.3.1, above.

The data obtained must be compared to that used to develop the pressure-temperature limit curves in the Technical Specifications. If this information indicates anomalies to the then existing predictions, the curves must be redrawn to reflect the actual or predicted shift in RT_{NDT} as discussed in items(a) and (b) above.

The pressure-temperature limits to be imposed on the reactor coolant system for all operating and testing conditions, to ensure adequate safety margins against non-ductile or rapidly propagating failure, are in conformance with established criteria, codes, and standards acceptable to the staff. The use of the operating limits based on these criteria, as defined by applicable regulations, codes, and standards, provides reasonable assurance that nonductile or rapidly propagating failure will not occur and constitutes an acceptable basis for satisfying the applicable requirements of General Design Criterion 31.

5.3.3 Reactor Vessel Integrity

We have reviewed the following FSAR sections related to the reactor vessel integrity of San Onofre 2 and 3. 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.

We have 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 are:

- (1) Design (Section 5.3.1 of this report)
- (2) Materials of Construction (Section 5.3.1)
- (3) Fabrication Methods (Section 5.3.1)
- (4) Operating Conditions (Section 5.3.2)

We have reviewed the above factors contributing to the structural integrity of the reactor vessel and conclude that the applicants have complied with Appendices G and H, 10 CFR Part 50, except for Paragraphs III.B.4, Appendix G, and Paragraph II.B of Appendix H, for which the applicants have provided sufficient information to justify an exemption.

Paragraph III.B.4, Appendix G, requires the applicants to conduct impact testing according to specific written procedures. Although the tests were not conducted to formal written procedures for San Onofre 2 and 3 impact tests, the applicants have supplied sufficient information to demonstrate that the tests were conducted correctly, and therefore, we conclude that an exemption to Paragraph III.B.4, Appendix G, is justified.

Paragraph II.B, Appendix H, requires per ASTM 185-73 that the applicants use surveillance specimens from the most limiting base material and weld metal. The materials in the San Onofre 2 and 3 surveillance program did not include the limiting weld material; however, the materials that are in the program, together with methods for predicting radiation damage provide sufficient information for us to conclude that an exemption to Paragraph II.B, Appendix H, is justified.

We have reviewed all factors contributing to the structural integrity of the reactor vessel and conclude there are no special considerations that make it necessary to consider potential reactor vessel failure for San Onofre 2 and 3.

5.3.4 Reactor Vessel Installation, Unit 2

The San Onofre Unit 2 reactor vessel was installed on April 26 and 27, 1977. On November 15, 1977, the reactor vessel was discovered to be installed on its four-vessel support columns rotated 180 degrees from the orientation planned by Combustion Engineering, Incorporated (CE), the nuclear steam supply system manufacturer.

San Onofre Plant Units 2 and 3 are mirror images of each other in layout of the structures and components. If a layout drawing of Unit 3 were flipped over with the stationary side of the drawing taken to be the dividing line separating Units 2 and 3, the layout would describe the Unit 2 arrangement. This would mean that the reference mark on the Unit 2 vessel should face south while the Unit 3 reference mark should face north.

The architect-engineer-constructor's (Bechtel Power Corporation) standard practice at this site was to orient items with the reference mark north unless otherwise noted. The Bechtel drawings for the Unit 2 vessel did not contain a note advising that the reference mark was to face south; therefore, following the standard practice the Unit 2 reactor vessel was positioned with the reference mark north. The review by CE site personnel of the Bechtel reactor vessel installation procedures did not reveal this oversight. This was not discovered during further work involving the vessel because the vessel is symmetrical about its east-west axis, i.e., the northern half of the vessel is externally identical to the southern half.

When the installation of the Unit 3 vessel was being made, Bechtel representatives made a check of the Unit 2 vessel installation, and knowing that Units 2 and 3 were planned images of each other, discovered that both vessels were being installed with the reference mark north.

It has been determined by the applicants that the Unit 2 reactor vessel, the reactor vessel head, and the reactor vessel internals, except for the flow skirt, are symmetrical and therefore the 180 degree misorientation is of little consequence. The only changes required will be the installation of the flow skirt with the reference mark north to agree with the installed vessel and a change in the fuel loading procedures to agree with the installed vessel. None of the electrical or piping connections to the vessel are affected.

The NRC Office of Inspection and Enforcement reviewed this issue and, as a corrective measure for the future, required that installation drawings and procedures relating to CE-provided equipment be sent to CE-Windsor for concurrence/approval before activities on site are initiated. We have reviewed the issue and conclude that with the proposed modification in the flow skirt installation and fuel loading procedures discussed above, the reactor vessel will operate effectively and safely despite the 180° misorientation in its installation.

5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pumps

5.4.1.1 Pump Flywheel Integrity

General Design Criterion 4, "Environmental and Missile Design Bases," of Appendix A to 10 CFR Part 50, requires that nuclear power plant structures, systems, and components important to safety be protected against the effects of missiles that might result from equipment failures. Because flywheels have large masses and rotate at speeds of approximately 1200 revolutions per minute during normal operation, a loss of flywheel integrity could result in high energy missiles and excessive vibration of the reactor coolant pump assembly. The safety consequences could be significant because of possible damage to the reactor coolant system, the containment, or the engineered safety features. Adequate margins of safety and protection against the potential for damage from flywheel missiles can be achieved by the use of suitable material, adequate design, and inspection.

The applicants' selection of materials, fracture toughness tests, design procedures, and inspection procedures have been reviewed to determine conformance with Safety Guide 14, "Reactor Coolant Pump Flywheel Integrity," (10/27/71).

The reactor coolant pumps have been designed for a speed 125% that of the normal synchronous speed of the motor (approximately 1500 rpm). The minimum speed for ductile failure is estimated to be much higher than 125% of operating speed for flywheels of the design used at San Onofre 2 and 3. The pump flywheels are made from ASTM 543, Grade I, Type B steel which has been Charpy-impact tested in the transverse direction to establish an upper shelf energy of at least 50 ft-lbs. The applicants have also provided sufficient data to demonstrate that the NDTT of the flywheel material is no higher than +10 degrees Fahrenheit and that the minimum fracture toughness at the normal operating temperature of the flywheel (120°F) is equivalent to a dynamic stress intensity of at least 100 ksi \sqrt{In} .

Based upon our evaluation, we conclude that San Onofre 2 and 3 is in compliance with Safety Guide 14. Compliance with the recommendations of Safety Guide 14 constitutes an acceptable basis for satisfying the requirements of General Design Criterion 4, Appendix A of 10 CFR Part 50.

5.4.2 Steam Generators

5.4.2.1 Steam Generator Materials

The materials used in Class 1 and Class 2 components of the steam generators were selected and fabricated according to codes, standards, and specifications acceptable to the staff. The steam generator pressure retaining parts are designed and manufactured to meet the ASME Code, Section III. The reactor coolant pressure boundary materials comply with the fracture toughness requirements of Article NB-2300 of Section III. The onsite cleaning and cleanliness controls during fabrication conform to the recommendations of Regulatory Guide 1.37, "Cleaning of Fluid Systems and Associated Components during the Construction Phase of Nuclear Power Plants." The controls placed on secondary coolant chemistry are in agreement with established staff technical positions. Conformance with applicable codes, standards, staff positions, and regulatory guides constitutes an acceptable basis for meeting in part the requirements of General Design Criteria 14, 15, and 31.

Recent operating experience with some Combustion Engineering, Inc. (CE) plants has revealed problem areas associated with steam generator tube deformation in the form of reduction in tube diameter (i.e., phenomenon known as a tube denting). Tube denting is a term which describes a group of related phenomena resulting from uncontrolled corrosion of the carbon steel in the crevices formed between the tubes and the tube support plates or tubesheet. In CE designed plants, denting has been observed at locations at which the steam generator tubes pass through drilled carbon steel support plates. Denting has not been detected in steam generators utilizing the full "egg crate" design support system. The "egg crate" support system precludes denting because, (1) it eliminates the circumferential annular gap that can be plugged with corrosion products, and (2) the system is flexible and this prevents the

accumulation of nonprotective magnetite around the tubes (the accumulation of the nonprotective magnetite that is necessary to cause denting is prevented from building up at any localized location).

The tube supports for the San Onofre 2 and 3 steam generators are of the "egg crate" type which provide no crevice or low flow areas that might promote tube denting. Tube expansion into the tube sheet is total with no voids or crevices occurring along the length of the tube in the tube sheet.

Additional assurance against corrosion problems is provided by the high quality of the condenser system design. Ingress of impurities due to corrosion of the condenser is minimized through the use of titanium tubes, aluminum bronze tube sheets and water boxes which have a corrosion resistant coating. The use of full "egg crate" tube support, total tube expansion into the tube sheet and the use of corrosion resistant materials in the condenser provides reasonable assurance of satisfactory corrosion resistant performance of steam generator tubing.

5.4.2.2 Steam Generator Inservice Inspection

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary or other components important to safety be designed to permit periodic inspection and testing of critical areas for structural and leaktight integrity.

The components in a steam generator are classified as ASME Boiler and Pressure Vessel Code Class 1 and 2 depending on their location in either the primary or secondary coolant systems respectively. The San Onofre 2 and 3 steam generators have been designed to permit inservice inspection of the Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program should follow the recommendations of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, NUREG-0212, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors," Revision 1, and comply with the requirements of Section XI of the ASME Code, with respect to the inspection methods to be used, provisions for a baseline inspection, selection and sampling of tubes, inspection intervals, and actions to be taken in the event defects are identified.

We have reviewed the information provided by the applicants concerning the San Onofre 2 and 3 steam generator tube inspection program. We conclude that the program is in compliance with the guidelines of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, without exceptions, and NUREG-0212, Revision 1, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors," with one exception. That is that the preservice examination of the steam generator tubes was performed before rather than after the hydrotest. Because inspection prior to the hydrotest meets the major objective of the preservice inspection, i.e., to define the condition of the tubes

prior to power operation, we conclude that the essential requirements of NUREG-0212 will be met. The program will also comply with the inspection requirements of Section XI of the ASME code.

Conformance with Regulatory Guide 1.83, NUREG-0212 and ASME Code Section XI will constitute an acceptable basis, in part, for meeting the requirements for General Design Criterion 32.

5.4.2.3 Secondary Water Chemistry

(1) Background

In late 1975 we 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 pressurized water reactor plants that have been issued an operating license since 1974 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 Technical Specifications have significantly restricted the operational flexibility of some plants with little or no benefit with regard to limiting degradation of steam generator tubes and the tube support plates. Based on this experience and the knowledge gained in recent years, we have concluded that Technical Specification limits are not the most effective way of assuring that steam generator degradation will be minimized.

Due to the complexity of the corrosion phenomena involved and the state-of-the-art as it exists today, we are of the opinion that, in lieu of specifying limiting conditions in the Technical Specifications, a more effective approach would be to institute a license condition that required the implementation of a secondary water chemistry monitoring and control program containing appropriate procedures and administrative controls.

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 chemistry conditions in the steam generators. In our view, plant operation following such procedures would provide 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, we requested, in a letter dated August 24, 1979, that the applicants propose a secondary water chemistry program which will be referenced

in a condition to the license. In the letter, we concluded that such a license condition, in conjunction with existing Technical Specifications on steam generator tube leakage and inservice inspection, would provide the most practical and comprehensive means of assuring that steam generator tube integrity would be maintained.

(2) Discussion

By letter dated November 25, 1980, the applicants provided a secondary water chemistry monitoring and control program. At our request, the applicants provided additional information by letters dated January 9 and 14, 1981. The proposed program addresses the six program criteria of our August 24, 1979 letter as discussed below, and is based on the steam generator water chemistry program recommended by the NSSS vendor (Combustion Engineering).

The proposed program monitors the critical parameters to inhibit steam generator corrosion and tube degradation. The limits and sampling schedule for these parameters have been established for steam generator blowdown and feedwater/condensate under power operation, startup, shutdown, and wet layup conditions. The control points for the critical parameters and the process sampling points have been identified in the submittals. The analytical techniques for measuring the values of the critical parameters are indicated in the submittals, and reference to the plant chemical procedures is given for the complete procedures. The procedure for recording and management of data is stated in each analytical procedure for a given parameter. For the procedure defining corrective actions for off-control point chemistry conditions and the procedures identifying the sequence and timing of administrative events to initiate corrective actions either they are given in the submittals, or reference is made to the current Combustion Engineering report, "Chemistry Manual CENPD-28," revision 2, and Branch Technical Position MTEB 5-3, "Monitoring of Secondary Side Water Chemistry in PWR Steam Generators," revision 1. The authority ultimately responsible for interpretation of secondary-side water chemistry data is the site Chemical-Radiation Protection Engineer.

(3) Evaluation

We find that the applicants' secondary water chemistry monitoring and control program:

- (a) is capable of reducing the probability of abnormal leakage in the reactor coolant pressure boundary by inhibiting steam generator corrosion and tube degradation, and thus meets the requirements of General Design Criterion 14;
- (b) adequately addresses all of the program criteria delineated in the NRC staff August 24, 1979 letter;

- (c) is based on the NSSS vendor's recommended steam generator water chemistry program;
- (d) monitors the secondary coolant purity in accordance with Branch Technical Position MTEB 5-3, revision 1, and thus meets acceptance criterion 3 of Standard Review Plan Section 5.4.2.1, "Steam Generator Materials," revision 1;
- (e) monitors the water quality of the secondary side water in the steam generators to detect potential condenser cooling water in-leakage to the condensate, and thus meets Position 2 of Branch Technical Position MTEB 5-3, revision 1;
- (f) describes the methods for control of secondary side water chemistry data and record management procedures and corrective actions for off-control point chemistry, and thus meets Position 3 of Branch Technical Position MTEB 5-3, revision 1. However, the applicant proposed an alternate approach for meeting the 96-hour corrective action requirement of Position 3.a.(6) in an event of a condenser leak. The alternate approach consists of (a) implementing corrective actions and limiting operation under transient chemistry conditions of feedwater and steam generator blowdown for up to four hours, and (b) chemistry limits for immediate shutdown. Immediate shutdown will also be considered if the transient limits are exceeded for longer than four hours. We find this alternative approach to Branch Technical Position MTEB 5-3 acceptable since:
 - (i) it establishes a specific continuously monitored condensate sample point for confirming a condenser leak,
 - (ii) it provides an early indication of impurities entering the steam generator before the entire steam generator secondary side reaches or exceeds its operational limits, and
 - (iii) it provides an effective limit to the quantity of impurities entering the steam generator.

(4) Conclusion

On the basis of the above evaluation, we conclude that the proposed secondary water chemistry monitoring and control program for San Onofre 2 and 3 meets (1) the requirements of General Design Criterion 14 insofar as secondary water chemistry control assures primary boundary material integrity, (2) Acceptance Criterion 3 of Standard Review Plan Section 5.4.2.1, revision 1, (3) Positions 2 and 3 of Branch Technical Position MTEB 5-3, revision 1, and (4) the program criteria in the staff's August 24, 1979 letter, and therefore, is acceptable. We will condition the San Onofre 2 and 3 operating licenses to require that the proposed secondary water chemistry monitoring and control program be carried out.

5.4.3 Shutdown Cooling (Residual Heat Removal) System

The shutdown cooling system (SDCS) is used in conjunction with the main steam and main or auxiliary feedwater systems to reduce reactor coolant system (RCS) temperatures from normal operating temperatures to the refueling temperature.

Initially, heat is rejected from the steam generators to the condenser or atmosphere. When the RCS temperature and pressure have been reduced to approximately 350°F and 360 psig, the SDCS is put into operation to reduce the reactor coolant temperature to the refueling temperature and to maintain this temperature during refueling.

When the SDCS is in operation, the system takes its suction from hot leg number 4 via a system of parallel lines and valves forming redundant trains. From the discharge of the two pumps, a portion of the coolant is diverted to the shutdown cooling heat exchangers which are cooled by component cooling water. The diverted flow is then mixed with the main SDCS flow stream and discharged into the four reactor cold legs. No single active failure to the SDCS system can cause the total loss of shutdown cooling or restrict the cooling ability such that the RCS cannot be brought to or maintained at refueling temperature (assuming operator action to correct single failure).

Besides cooldown and cold shutdown, the SDCS operates in several other modes. These are:

- (1) Startup - connected to chemical and volume control system (CVCS), acting as an alternate letdown path to control reactor coolant system pressure.
- (2) Refueling - used for refilling the refueling canal.
- (3) Emergency Core Cooling - the low pressure safety injection (LPSI) pumps which drive the SDCS are aligned during power operation and hot shutdown for low pressure coolant injection into the RCS as an integral part of the emergency core cooling system.
- (4) Containment Spray - During normal operation the containment spray pumps are aligned to discharge through the shutdown cooling heat exchangers. This is the required alignment for emergency operation following a loss-of-coolant-accident (LOCA). During shutdown cooling, the heat exchangers are isolated from the containment spray system.

SDCS leak detection is discussed in Section 5.2.5. If onsite electric power is available and offsite electric power is unavailable, the SDCS is capable of cooling the RCS given a single active failure. Each of the two SDCS trains may be isolated independently from the other while allowing the nonisolated 100 percent capacity train to perform its safety function, which is in compliance with General Design Criteria 34.

The SDCS is housed in a structure that is designed to withstand tornadoes, floods, and seismic phenomena in accordance with GDC 2. Flood protection is discussed in Section 3.4 of this report.

The SDCS is designed to meet the environmental requirements for normal operation and for operation during or following LOCA where required. Missile protection and the protection against dynamic effects of pipe whip and discharging fluid are discussed in Sections 3.5 and 3.6 of this report.

The SDCS is designed to comply with Regulatory Guide 1.29, "Seismic Design Classification," Regulatory Guide 1.26, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and Regulatory Guide 1.48, "Design Limits and Loading Combinations for Seismic Category I Fluid System Components" as discussed in Sections 3.2 and 3.9 of this report.

Since no components of the SDCS are shared between Units 2 and 3, the SDCS meets General Design Criteria 5.

We have reviewed the containment isolation capability of the San Onofre 2 and 3 SDCS and find that adequate containment isolation capability exists and find that the SDCS design meets GDC 55, 56 and 57. We have reviewed the component cooling water system to assure that sufficient cooling capability is available to shutdown cooling heat exchangers. The cooling capability was found acceptable, as discussed in Section 9.2 of this report.

The SDCS is designed to provide adequate isolation between the SDCS and the safety injection tanks or the RCS when the RCS is above the design pressure of the SDCS (435 psig) as follows:

- (1) There are two parallel paths with two isolation valves per path inside containment on the suction line to the SDCS pumps. Each valve has a separate, independent power source and each valve is interlocked with a separate and independent pressurizer pressure signal. Valve opening is prevented until the RCS pressure falls to a value of 361 psig. We require that the setpoint for automatic closure of the SDCS suction line isolation valves be increased to 700 psig to preclude premature isolation of the SDCS and loss of water-solid overpressure protection.
- (2) Safety injection tank (SIT) pressure will be lowered to 361 psig by the operator when RCS pressure reaches 650 psig. An interlock with pressurizer pressure will prevent the SIT isolation valves from being closed until RCS pressure drops to 375 psig.
- (3) There are two check valves and an open (closed when not on SDC; open on SIS) motor-operated isolation valve on each line from SDCS discharge to the four cold legs to protect the system from RCS pressure. The applicants have provided

design features to permit leak testing of each check valve separately during plant operation to fulfill staff requirements for high/low pressure isolation.

Overpressure protection of the SDCS is provided by relief valves in the suction line and valves in the LPSI pump discharge header. Three relief valves are in the SDCS suction line to protect isolated pipe lengths against transient thermal effects. Each valve has a 5 gallon per minute flow capacity and a setpoint consistent with the piping design pressure. Further protection is provided by relief valve PSV-9349 between the inside and outside containment isolation valves. The relief valve protects the SDCS from inadvertent RCS pressurization during SDCS operation. The valve is sized and designed to provide protection against water-solid overpressure transients as discussed in Section 5.2.2 of this report. Low temperature water-solid overpressure protection is discussed in Section 5.2.2.2 of this report. The setpoint and valve capacity for PSV-9349 are 417 psia and 3089 gpm, respectively. This valve is capable of passing full safety injection flow. The relief valve at the discharge of the LPSI pumps protects the header from pressure developed by temperature changes to the trapped water. The setpoint for the relief valve is 615 psig with a capacity of 5 gallons per minute.

Preoperational tests are conducted to verify proper operation of the SDCS. The preoperational tests include testing of the automatic flow control, verification of adequate shutdown cooling flow, and verification of the operability of all associated valves. In addition, a preoperational hot functional performance test is made on the installed shutdown cooling heat exchangers. Flow tests complying with Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Reactor Power Plants," will be performed during preoperational testing to verify the design performance of the system and its individual components. In addition, preoperational hydrostatic tests will be performed per Section III of the ASME Boiler and Pressure Code while in-service hydrostatic testing will be performed per Section XI of the ASME Code.

During the course of our review, we requested that the applicants demonstrate how the requirements of Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System" have been met by the San Onofre 2 and 3 design. Specifically, the applicants were asked to demonstrate that the plant could be brought to a cold shutdown condition in less than thirty-six hours using only seismic Category I equipment, assuming the most limiting single failure, and with only onsite or only offsite power available. We requested that the applicants demonstrate that the seismic Category I auxiliary feedwater system has sufficient inventory to maintain the plant at hot shutdown conditions for four hours. In addition, supporting analysis was requested which would:

- (1) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions. The analysis must include an estimate of the times required to achieve such mixing and,
- (2) confirm that the cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures.

The applicants' response identified the systems which would be used to meet these requirements. Cooldown to cold shutdown conditions employs the auxiliary feedwater system, the main steam system, the chemical and volume control system, the component cooling water system, the saltwater cooling system, and the shutdown cooling system. The initial plant cooldown is accomplished by heat rejection to the atmosphere by the steam generator atmospheric dump valves. Two safety grade atmospheric dump valves, one per steam generator, are provided for each unit at San Onofre Units 2 and 3. The atmospheric dump valves, valve operators, nitrogen supply, nitrogen supply regulator valves, instrument lines, and power supplies are all built in accordance with seismic Category I, Quality Class II requirements. Atmospheric dump valve HV8419 and its solenoid operator HV8419A are supplied from vital bus A; the other atmospheric dump valve HV8421 and its solenoid operator HV8421A are supplied from vital bus B. The valves are also supplied with handwheels to allow them to be operated manually. Should a single failure occur making one atmospheric dump valve inoperable, the other valve may be used to release steam from either or both steam generators.

During loss of offsite power the reactor coolant system is depressurized using auxiliary spray. The auxiliary spray is safety grade and has vital power supplied by emergency onsite power (4160 volt ac bus, diesel generator). The applicants have agreed to a staff request to install a bypass around the auxiliary spray valve to allow depressurization if the valve should fail.

Boration is accomplished using the chemical and volume control system. This system incorporates redundant charging pumps, boric acid makeup tanks and charging pump suction and delivery paths. This system satisfies the single failure criterion and can function without offsite power.

When the plant reaches the appropriate temperature and pressure, the shutdown cooling system is aligned, and the cooldown proceeds by rejecting heat to the shutdown cooling system heat exchangers. Assuming loss of offsite power, the most limiting single failure associated with the thirty-six hour criterion is the failure of a diesel generator. This failure disables the auxiliary spray valve and one train of components associated with the chemical and volume control system, the auxiliary feedwater system, the component cooling water system, the salt water cooling system, and the shutdown cooling system. In addition, the "swing" charging pump is assumed to be aligned to the inoperable diesel generator. The sequence of operator actions described below is required to cool down to the shutdown cooling system entry conditions.

Thirty minutes after initiation of the event the "swing" charging pump is realigned to the operating diesel generator and boration has begun using two charging pumps. Two hours after initiation of the event boration is complete and the cooldown is begun. The two atmospheric dump valves are opened to control the rate of cooldown.

According to the present procedure, five hours after initiation of the event the operator manually closes the charging line valves HV9202 and HV9203 and opens the auxiliary pressurizer spray valve HV9201 to begin depressurization of the reactor

system. However, we are presently investigating problems of inadequate circulation in the reactor vessel head which may cause a steam bubble to form in the vessel during depressurization. If it is determined that this is a problem for San Onofre 2 and 3, this procedure will be changed. Approximately six hours after initiation of the event the reactor coolant system reaches the temperature and pressure necessary for transfer to the shutdown cooling system.

In the original San Onofre 2 and 3 design, realignment of the reactor coolant system to the shutdown cooling system was accomplished via a combination of manual/local and remotely (from the control room) operated valves. The staff concluded that because it is necessary to leave the control room to align the shutdown cooling system, this design did not comply with Branch Technical Position RSB 5-1. We have informed the applicants that the design must be modified so that realignment of the RCS to the shutdown cooling system can be accomplished from the control room. Correction of the design will require significant changes to the shutdown cooling and emergency core cooling systems. However, we are not requiring compliance before the scheduled issuance of an operating license. We believe that this schedule is consistent with the recommendations of BTP RSB 5-1 for "Class 2" plants (plants for which BTP 5-1 requires only partial implementation) such as San Onofre 2 and 3. This implementation schedule will not compromise plant safety because all the functions recommended by RSB 5-1 can be performed manually prior to the above-described modifications being made. If accident conditions should preclude normal operations outside the control room, the steam generator and feedwater systems could be used to achieve and maintain a cold shutdown condition.

The applicants' have agreed to make the necessary design modifications by the end of the first refueling outage. These modifications include installation of motor operators on existing valves, installation of check valves, installation of additional motor operated valves, procedural changes in aligning the ECCS and shutdown cooling systems, and modifications to the control room and motor control center. These modifications provide control room operability of all valves required to initiate and control the shutdown cooling system to achieve safe shutdown conditions.

Power removal is not being used on the controls to selected valves to satisfy single failure considerations for the emergency core cooling function. Power restoration is required prior to initiating the use of the system for shutdown cooling. This is done in the motor control center which is immediately above the control room. This area is remote from the process piping and is in a low radiation area. The action requires is of short duration and repeated access is not required. We have reviewed these design modifications and conclude that the requirement for remote operation of the shutdown cooling system is now met. We have also reviewed the changes which this modification makes on the emergency core cooling system and have determined that ECCS reliability has not been adversely affected.

We requested and have received from the applicants a description of the control room and local instrumentation required by the operator to perform a safe and orderly shutdown and cooldown of the plant. We have reviewed this description and finds that

the instrumentation and controls needed meet the requirements of branch technical position RSB 5-1.

We require that a natural circulation test be performed at San Onofre Unit 2 to demonstrate the capability to cooldown the plant to shutdown cooling system initial conditions within several hours under minimum cooldown capability. This test should also demonstrate that the boron mixing capability attained during natural circulation is consistent with the assumptions used in the evaluation. The applicants have agreed to perform the test during the power ascension phase of the startup test program.

Branch technical position RSB 5-1 requires that a seismic Category I auxiliary feedwater supply be provided with sufficient inventory to permit operation at hot shutdown conditions for at least four hours, followed by a cooldown to the conditions permitting operation of the shutdown cooling system. The inventory needed for the cooldown shall be based on the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure. The San Onofre Units 2 and 3 design provides a 150,000 gallon seismic Category I condensate storage tank as the primary source of water for the auxiliary feedwater system. This is insufficient to meet our requirements. The applicants have shown that seismic Category I reinforced concrete walls around the 500,000 gallon seismic Category II condensate storage tank would retain sufficient water after the safe shutdown earthquake (SSE) to meet our criteria. Our evaluation of the capability of the above Seismic Category I reinforced concrete walls in retaining water after an SSE is addressed in Section 9.2.4 of this report.

Based on the discussion given above, we conclude that San Onofre 2 and 3 meet the requirements of branch technical position RSB 5-1 as appropriate for Class 2 plants.

We requested additional information regarding the effect of a major pipe break in the shutdown cooling system. The applicants provided an analysis of the most limiting pipe break accident, a break at the discharge of the low pressure safety injection pump. Using conservative initial conditions for reactor coolant system temperature, pressure, and pressurizer level, the applicants have calculated that the operator has ten minutes from receipt of the first alarm (low pressurizer level) to initiate the procedure for loss of shutdown cooling. Specifically, the operator stops the running LPSI pump(s) and shuts the SDC suction isolation and LPSI header stop valves. By the time the operator has isolated the pipe break and the loss of reactor coolant has stopped, the remaining primary coolant level will be below pressurizer level indication but above the elevation corresponding to the inlet and outlet reactor vessel nozzles. When pressurizer pressure has stabilized, the leak has been isolated within the boundaries of the SDCS. The plant is now in a controlled status. The watch section of the emergency procedure will proceed to restore plant parameters to the desired level, establish temperature control and institute troubleshooting and repair activities for the fault. At the end of this procedure the applicants conclude that although pressurizer level indication is lost, primary water inventory is sufficient to prevent the core from being uncovered. We find that the analysis of this event is

in accordance with branch technical position APCS 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment" and is acceptable.

We conclude that the San Onofre 2 and 3 design provides reasonable assurance that the SDCS will function and that the design meets the requirements of GCD 5 and 34 as well as conforming to the recommendations of Regulatory Guides 1.26, 1.29, and 1.68, as noted above. On these bases, we find the design of the SDCS to be acceptable.

6.0 ENGINEERED SAFETY FEATURES

6.1 Engineered Safety Feature Materials

6.1.1 Metallic Materials

The mechanical properties of materials selected for the engineered safety features satisfy Appendix I of Section III of the ASME Code and Parts A, B or C of the Code, and the position of Section 6.1.1 of the SRP that the yield strength of cold worked stainless steels shall be less than 90,000 psi. Fracture toughness of the ferritic materials meets the requirements of the Code.

The controls on the pH of the reactor containment sprays and the emergency core cooling water following a postulated loss-of-coolant accident or other design basis accident are adequate to reduce the probability of stress corrosion cracking of the austenitic stainless steel components and welds of the engineered safety features systems, in containment, throughout the duration of the postulated accident to completion of cleanup. The controls on the use and fabrication of the austenitic stainless steel of the systems satisfy the requirements of Regulatory Guide 1.31, "Control of Ferritic Content of Stainless Steel Weld Metal", and Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel". Fabrication and heat treatment practices performed in accordance with these requirements provide added assurance that the probability of stress corrosion cracking will be reduced during the postulated accident time interval. The controls placed on concentrations of leachable impurities in nonmetallic thermal insulation used on components of the Engineered Safety Features are in accordance with Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel." The control of the pH of the sprays and cooling water, in conjunction with controls on selection of containment materials, is in accordance with Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident." and provides assurance that the sprays and cooling water will not give rise to excessive hydrogen gas evolution resulting from corrosion of containment metal or cause serious deterioration of the materials in containment. The protective coating systems have been qualified by tests acceptable to the staff. This qualification provides reasonable assurance that the coating systems will not degrade the operation of the ESF by delaminating, flaking or peeling. Conformance with the Codes and Regulatory Guides and with the staff positions mentioned above, constitute an acceptable basis for meeting, in part, the requirements of General Design Criteria 16, 34, 35, 38, 41 and 44.

6.1.2 Organic Materials

The protective coatings used inside the containment, except for components limited by size and/or exposed surface area, meet the recommendations of ANSI N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and of Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied

to Water-Cooled Nuclear Power Plants." Based on our review we conclude that the amount of unqualified paints used inside containment is insignificant. Sump filter screens are provided to filter off the solid debris that may be produced from the organic materials under design basis accident conditions. Because it meets the criteria specified above, we conclude that the protective coatings inside the San Onofre 2 and 3 containments are acceptable.

6.1.3 Post-Accident Chemistry

The San Onofre 2 and 3 containment spray system is designed to inject into the containment atmosphere a boric acid solution buffered to a pH between 9 and 10 with sodium hydroxide for the purpose of removing iodine following a loss-of-coolant-accident (LOCA) or main steam line break inside containment. After mixing in the containment sump with primary system coolant, borated safety injection water, and borated water from the refueling water storage tank the long term sump pH will be greater than 8. This sump pH level will provide assurance that the possibility of stress corrosion cracking of mechanical systems and components is minimized and significant re-evolution of iodine from the sump solution will not occur.

6.2 Containment Systems

The containment systems for San Onofre 2 and 3 include the containment structure, containment heat removal system, containment isolation system, containment combustible gas control systems, and provisions for containment leakage rate testing.

6.2.1 Containment Functional Design

The containment structure is a cylindrical, carbon steel lined, prestressed, reinforced concrete structure with a net free volume of 2,305,000 ft³. The containment structure houses the nuclear steam supply system, which includes the reactor vessel, reactor coolant piping, reactor coolant pumps, pressurizer, and steam generators, as well as certain components of the plant's engineered safety feature systems. The containment structure is designed to withstand internal pressurization resulting from postulated high energy pipe breaks inside containment and external pressurization due to inadvertent actuation of the containment heat removal systems. The containment structure is designed for an internal pressure of 60 psig and a temperature of 300°F. The containment structure is designed for an external differential pressure of 5 psi.

6.2.1.1 Containment Pressure Analysis

The applicants have analyzed the containment pressure response to postulated accidents in the manner described below.

Mass and energy release rate data were used in conjunction with the Bechtel COPATTA computer code to perform the containment pressure response analysis. The data for mass and energy release to the containment following a postulated primary system rupture were calculated using the CEFLASH-4 code for the blowdown period and the FLOOD-2 code for the reflooding period. The Combustion Engineering, Inc. (CE) post reflood model was used to calculate the steam boil-off, considering energy from the core and also the steam generators, until all steam generator sensible heat was removed. These methods are designed to conservatively maximize containment pressure. The methods are documented in Section 6.2.1 of the Preliminary Safety Evaluation Report for CESSAR, System 80, and were approved by the NRC staff in the Safety Evaluation Report for CESSAR dated December 1975. Since San Onofre 2 and 3 is not a CESSAR design, the inputs to the mass and energy release methods were modified in an acceptable manner for San Onofre 2 and 3.

The applicants analyzed a spectrum of reactor coolant system pipe breaks, considering various single failures, to identify the containment design basis loss-of-coolant-accident. The containment design basis loss-of-coolant-accident was identified as the postulated double-ended rupture at the pump suction of the reactor coolant system, which resulted in a peak calculated pressure of 55.1 psig. For the containment peak pressure analysis the safety injection system and the containment heat removal systems were assumed to operate in modes that maximize the containment peak pressure. For the containment heat removal systems, the most severe single active failure was determined to be the loss of one diesel generator train, which results in the loss of one containment spray train and one containment emergency fan cooler train. However, for the safety injection system, maximum safety injection flow was conservatively assumed.

We have also analyzed the containment pressure response to a postulated double-ended rupture at the pump suction of the reactor coolant system using the CONTEMP-LT MOD 26 computer code. Our confirmatory analysis was based on the mass and energy release, containment structural heat sinks, and containment heat removal systems performance data provided by the applicants. Conservative condensing heat transfer coefficients to the structures inside the containment were used. Our analysis of the pressure response resulted in a peak calculated pressure of 59.2 psig. Although we calculate a higher peak pressure than the applicants, our analysis confirms the acceptability of the containment design pressure (60 psig). There is still adequate margin in the design because of such factors as the assumption of a double-ended pipe rupture in the primary system and the calculation of conservatively low heat transfer to the containment structural heat sinks. Additionally, the applicants have demonstrated the containment design adequacy by performing a structural integrity test at 115 percent of design pressure.

The applicants have analyzed a spectrum of main steam line breaks to determine the containment pressure response. Mass and energy releases for these steam line breaks were calculated using the SGN-III code that is described in Appendix 6B of

CESSAR. The SGN-III code describes the primary and secondary systems of a pressurized water reactor including the core and the power excursion which may occur in the core following a main steam line break. The code calculates heat flow from the intact steam generator into the primary system and heat flow from the primary system into the broken steam generator. The primary system heat flow produces additional steam which is added to the containment.

The SGN-III code was found to be acceptable for mass and energy release calculations in the staff's Safety Evaluation Report for CESSAR dated December 1975. Since San Onofre 2 and 3 is not a CESSAR type plant, the SGN-III analyses were modified with input information specifically for San Onofre 2 and 3.

Following rupture, steam was assumed to flow into the containment from both steam generators until isolation of the main steam lines. Feedwater flow was assumed to continue into the affected steam generator at twice the runout flow until isolation of that system. The unisolated mass in the steam and feedwater systems was also included in the analyses. As discussed above, we conclude that the applicants' calculations for main steam line break mass and energy release are conservative and therefore acceptable.

The applicants have identified the worst case main steam line break, with respect to containment pressure, to be a 7.47 ft² slot rupture at 102% full power. The applicants have also performed a single-failure analysis and determined the limiting single failure to be the loss of one containment cooling train, which corresponds to the failure of one containment spray train and one train of containment fan coolers. For this worst case main steam line break the applicants calculated a peak containment pressure of 55.7 psig. We have performed confirmatory analysis of the containment pressure response to the worst case main steam line break identified by the applicants and calculate a peak pressure of 57.3 psig. Our results confirm the acceptability of the containment design pressure.

The applicants have also demonstrated that the San Onofre 2 and 3 design prevents the auxiliary feedwater pumps from operating at runout flow while feeding the affected steam generator. This is accomplished by the use of an emergency feedwater actuation signal logic that will rapidly identify the affected steam generator and isolate it from the auxiliary feedwater pumps following a large main steam line break. The affected unit is identified when pressure in the affected unit drops below the 700 psig setpoint. Since the affected unit identification and isolation occurs before water from the auxiliary feedwater pumps could reach the unit there is no flow to the affected unit. We conclude that this aspect of the San Onofre 2 and 3 design prevents the auxiliary feedwater pumps from feeding the affected steam generator while pumping at run out flow rate, and is, therefore, acceptable.

The applicants have determined the maximum external differential pressure on the containment structure due to inadvertent operation of the containment spray systems.

For this analysis the applicants assumed that the containment is cooled to a temperature of 40°F, resulting in an external differential pressure of 3.4 psi. We have reviewed the applicants' calculation of the maximum differential pressure and find it acceptable. We, therefore, conclude that the containment external design pressure of 5 psi is acceptable, because it is less than the maximum differential pressure determined analytically, as described above.

6.2.1.2 Containment Subcompartment Analysis

The applicants have analyzed the pressure response of subcompartments inside the containment to the postulated high energy line breaks identified in Table 6.2-1 of the FSAR.

The blowdown rates from postulated primary system ruptures within containment subcompartments were calculated using the CEFLASH-4A code. This code uses the Henry-Fauske correlation to calculate flow when the break fluid is subcooled and the Moody slip flow model to calculate flow when the break fluid is saturated. Stagnation conditions at the break are approximated by removing the momentum flux option from the CEFLASH-4A code. This method is also documented in Section 6.2.1 of the CESSAR, System 80 Preliminary Safety Evaluation Report and was approved by the NRC staff in our Safety Evaluation Report dated December 1975. Based on our review of San Onofre 2 and 3, we conclude that this method is also applicable to San Onofre 2 and 3.

We have reviewed the postulated pipe break sizes and locations and found them to be acceptable. The mass and energy release data were then used with the Bechtel COPDA code to perform the subcompartment analysis. A comparison of the applicants' results with the results of our confirmatory analysis are provided in Table 6.1 of this report. As can be seen from the table, the applicants generally calculate slightly higher differential pressures across the walls of the reactor cavity and steam generator compartments. Furthermore, there is considerable design margin above the peak calculated differential pressures.

The applicants have also performed nodalization sensitivity studies for the reactor cavity and steam generator compartments. These studies show, by further subdividing the nodes, that there are no substantial pressure gradients within the nodes used in the subcompartment analysis. These studies showed that subdividing the nodes caused the pressure distribution on the structural walls to vary only slightly. Consequently, we conclude that the total load on the structural walls, due to pressurization of the subcompartments, was calculated in an acceptable manner for the reactor cavity and steam generator compartments. For the above reasons we conclude that the noding models and calculated pressure transients are acceptable for use in the subcompartment structural analysis.

The applicants have provided the results of nodalization sensitivity studies to show that conservative loads were used in the design of the component supports. This

Table 6.1
Subcompartment Pressure Analysis

Location	Postulated Pipe Break	Peak Calculated ΔP (psid) Across Wall		Design ΔP	Nodes	
		Applicant	STAFF		From	To
Reactor Cavity	350 in ² Cold Leg Guillotine	92	83.9	228.9	1	17
		20.2	26.7	228.9	2	17
		16.7	15.2	228.9	3	17
		8.3	4.5	228.9	4	17
		16.7	14.	228.9	5	17
		17.4	14.2	228.9	6	17
		14.7	12.4	228.9	14	17
		12.1	10.2	228.9	16	17
Steam Generator Compartment	592 in ² Suction Leg Guillotine	20.6	20.3	28.8	1	19
		12.9	12.3	28.8	5	19
		8.2	8.3	28.8	7	19
		7.0	6.3	28.8	11	19
		4.0	5.1	28.8	13	19
		4.9	4.2	28.8	15	19

information shows that reactor cavity pressurization accounts for 30 percent of the asymmetric LOCA load on the reactor vessel, and that there is enough margin in the reactor vessel support design to accommodate an increase of approximately 100 percent in the loads due to reactor cavity pressurization. Because of this margin in the pressure loads, and the modalization information presented by the applicants, we conclude that the nodalization studies used to justify that the loads used for the design of the reactor vessel supports are conservative and acceptable.

6.2.1.3 ECCS Containment Pressure Evaluation

Appendix K to 10 CFR Part 50 of the Commission's regulations requires that the effect of the operation of all installed containment pressure reducing systems and processes be included in the emergency core cooling system evaluation. For this evaluation, it is conservative to minimize the containment pressure since this will increase the resistance to steam flow in the reactor coolant loops and reduce the reflood rate in the core. Following a loss-of-coolant accident, the pressure in the containment building will be increased by the addition of steam and water from the primary reactor system to the containment atmosphere. After initial blowdown, heat transfer from the core, primary metal structures, and steam generators to the emergency core cooling system water, will produce additional steam. This steam, together with any emergency core cooling system water spilled from the primary system will flow through the postulated break and into the containment. This energy will be released to the containment during both the blowdown and later emergency core cooling system operational phases; i.e., reflood and post-reflood.

Energy removal occurs within the containment by several means. Steam condensation on the containment walls and internal structures serves as a passive heat sink that becomes effective early in the blowdown transient. Subsequently, the operation of the containment sprays and fan coolers will remove steam from the containment atmosphere. When the steam removal rate exceeds the rate of steam addition from the primary system, the containment pressure will decrease from its maximum value.

The calculations of containment backpressure for the emergency core cooling system were performed with the Combustion Engineering, Inc. emergency core cooling system evaluation model. We have reviewed this model and concluded that it is acceptable for the evaluation of the containment backpressure subject to the review of the plant dependent input parameters used in the analysis. We have reviewed the San Onofre 2 and 3 plant parameters used for the analysis of the containment pressure for emergency cooling system evaluation and find them to be suitably conservative. The analysis of the containment atmosphere pressure did not include the reduction in pressure due to concurrent operation of the containment mini-purge system. The applicants, however, have considered the effect of the mini-purge system operation and concluded that the impact on the emergency core cooling system backpressure analysis is negligible. Based on the size of the purge lines (8 inch diameter) and the short closure time of the purge system isolation valves, we find that the effect of concurrent purging on the containment backpressure analysis is negligible.

We, therefore, conclude that the containment pressure analysis for the emergency core cooling system evaluation is acceptable and meets the requirements of Appendix K to 10 CFR Part 50.

6.2.1.4 Containment Pressure Boundary Fracture Toughness

We have assessed the ferritic materials that are part of the containment pressure boundary in the San Onofre 2 and 3 containment systems to determine if the material fracture toughness is in compliance with the requirements of General Design Criterion 51, "Fracture Prevention of Containment Pressure Boundary."

General Design Criterion (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 San Onofre 2 and 3 primary containment is a reinforced concrete structure with a thin steel liner on the inside surface which acts as a leaktight membrane. The ferritic materials of the containment pressure boundary which were considered in our assessment were those applied in the fabrication of the equipment hatch, personnel and escape locks, penetrations and piping system components, including the isolation valves required to isolate the systems. These components are the parts of the containment system which are not backed by concrete and must sustain loads.

The San Onofre 2 and 3 containment pressure boundary is comprised of ASME Code Class 1, 2 and MC components. In late 1979, we generically reviewed the fracture toughness requirements of the ferritic materials of Class MC, Class 2 and Class 1 components which typically constitute the containment pressure boundary. Based on this review, we determined that the fracture toughness requirements contained in ASME Code Editions and Addenda, typical of those used in the design of the San Onofre 2 and 3 primary containment, may not ensure compliance with GDC 51 for all areas of the containment pressure boundary. We initiated a program to review fracture toughness requirements for containment pressure boundary materials for the purpose of defining those fracture toughness criteria that most appropriately address the requirements of GDC 51. Prior to completion of this generic study, we elected to apply in our licensing reviews the criteria identified in the Summer 1977 Addenda of Section III of the ASME Code for Class 2 components. These criteria were selected to ensure uniform fracture toughness requirements, consistent with the containment safety function, are applied to all components in the containment pressure boundary. Accordingly, we have reviewed the Class 1, 2 and MC components in the San Onofre 2 and 3 containment pressure boundary according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components. However, in order to complete our review we require additional information, because the San Onofre 2 and 3 FSAR does not provide the information necessary to characterize the fracture toughness of the reactor containment pressure boundary within the context of GDC 51. We have requested that the applicants provide the necessary information, and we will review it when it becomes available. We will report on the resolution of this issue in a supplement to this report.

6.2.1.5 Conclusions, Containment Functional Design

We have evaluated the containment system functional design for conformance with the General Design Criteria stated in 10 CFR Part 50 of the Commission's regulations and, in particular, Criteria 16, and 50. We conclude that the containment external design pressure is acceptable and that the subcompartment analysis is adequate for the determination of loadings on subcompartment structural walls.

We required the applicants to perform an analysis of the main steam line break to account for the effects of the auxiliary feedwater pumps feeding the affected steam generator after a main steam line break inside containment. We have reviewed the applicant's analysis and conclude that the San Onofre 2 and 3 design for preventing the auxiliary feedwater pumps from feeding the affected steam generator is acceptable.

We completed our review of the subcompartment analysis for evaluation of the adequacy of component supports and find it acceptable. Our review of the containment pressure boundary fracture toughness is incomplete at this time. We will report on the resolution of this issue in a supplement to this report.

6.2.2 Containment Heat Removal Systems

The containment heat removal systems for the San Onofre 2 and 3 consists of the containment spray system and the containment emergency fan cooler system.

The containment heat removal systems return the containment pressure to a low value following a break in either the primary or secondary system piping inside the containment. Heat is transferred from the containment atmosphere to the spray water and the component cooling water by the containment spray system and the containment emergency fan cooler system, respectively. In addition, spray water drawn from the containment engineered safety feature sump is cooled by component cooling water via the shutdown cooling heat exchangers in the recirculation mode of safety injection system operation.

The containment spray system consists of two redundant and independent trains. The containment spray system serves as an engineered safety feature and will not be used for normal plant operation. The system is safety grade (Quality Group B and seismic Category I) and all active components are located outside of the containment vessel.

The containment spray system is automatically initiated by a containment spray actuation signal (CSAS) that is initiated by the combination of any two high-high containment pressure signals with a setpoint of 12 pounds per square inch gauge and a safety injection actuation signal (SIAS). The CSAS, which may also be initiated manually in the control room, opens the spray control valves to the containment (the containment spray pumps are started by the SIAS). The spray water is discharged into the containment upper region through spray nozzles arranged on headers. The containment spray pumps initially take suction from the refueling water storage tank. When a predetermined low level is reached in the refueling water storage tank the containment spray

pump suction is switched from the refueling water storage tank to the containment emergency sump. Containment spray water drawn from the sump is cooled in the shutdown cooling heat exchanger by component cooling water before discharge into the containment atmosphere.

We have reviewed the design of the containment emergency sump for conformance with the guidelines of Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and Containment Spray Systems." Table 6.2 of this report presents a comparison of the San Onofre 2 and 3 sump design features with the design criteria of Regulatory Guide 1.82. As can be seen from Table 6.2 the major deviation from the sump design criteria recommended in Regulatory Guide 1.82 is that only one emergency sump is provided in each reactor building (as opposed to two sumps recommended in Regulatory Guide 1.82). For the San Onofre 2 and 3 plant, however, the single sump is divided into two redundant compartments by an 8-inch-thick concrete structural barrier. This barrier precludes damage to both sump intakes from whipping pipes or high velocity jets of water or steam. Based on our review we conclude that the sump design is adequate and will provide a sufficient supply of water, with a minimum amount of particulate matter reaching the containment spray system.

Sufficient net positive head (NPSH) will be available for both the injection and recirculation modes of operation. The applicants' evaluation for the available net positive suction head is consistent with the guidelines of Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." The applicants' results show that the available NPSH for the containment spray pumps in the injection and recirculation modes are 36.5 and 26 ft, respectively. The required NPSH for a spray pump is 24 ft.

The containment emergency fan cooler system consists of four separate fan cooler units inside the containment. The containment emergency fan cooler system is an engineered safety feature system that is not in use during normal plant operation. The emergency fan cooler system is separated into two trains with two fan cooler units on each train. The two trains are supplied from separate component cooling water trains and power sources.

Operation of the containment emergency fan cooler system is initiated automatically following a containment cooling actuation signal (CCAS). The containment cooling actuation signal is initiated by either two-out-of-four low pressurizer signals or two-out-of-four high containment pressure (4.0 psig setpoint) signal. Operation of the containment emergency fan coolers may also be manually initiated from the control room.

Based on our review of the containment heat removal system, we conclude that the system design is in accordance with the requirements of General Design Criteria 38, 39, 40 and the recommendations of Regulatory Guides 1.1 and 1.82, and is acceptable.

6.2.3 Secondary Containment Functional Design

The San Onofre 2 and 3 does not employ a secondary containment.

Table 6.2
Comparison of Containment Emergency Sump Design
With Regulatory Guide 1.82

Regulatory Guide 1.82 Paragraph	Emergency Sump Design	Remarks
C.1	Not consistent with recommendations	A single emergency sump is provided.
C.2	Consistent with intent of recommendations	The single emergency sump is provided with a barrier installed between the safeguards pumps suction lines.
C.3	Consistent with recommendations	
C.4	Consistent with intent of recommendations	As an alternative to a sloping floor in the vicinity of the sump, a 4-inch-high curb is provided to prevent high-density particles from entering the sump
C.5	Consistent with recommendations	
C.6	Consistent with recommendations	
C.7	Consistent with recommendations	The design coolant velocity into the fine inner screen, assuming 50% screen obstruction, is 0.23 ft/s.
C.8	Consistent with recommendations	
C.9	Consistent with recommendations	
C.10	Consistent with recommendations	
C.11	Consistent with recommendations	
C.12	Consistent with recommendations	
C.13	Consistent with recommendations	
C.14	Consistent with recommendations	

6.2.4 Containment Isolation System

The containment isolation system is designed to automatically isolate the containment atmosphere from the outside environment under accident conditions. Double barrier protection, in the form of closed systems and isolation valves, is provided to assure that no single active failure will result in the loss of containment integrity. The containment isolation provisions are of safety grade design (Boiler and Pressure Vessel Code Section III Class 2 and seismic Category I) and are missile protected.

General Design Criteria 54 through 57 explicitly state the isolation requirements for all systems that penetrate the containment. However, the General Design Criteria also allow for deviations from the explicit isolation requirements if the isolation provisions can be found acceptable on some other defined basis. In this regard, the isolation provisions for lines have been found acceptable for the reasons given in the following sections.

6.2.4.1 Containment Emergency Sump Recirculation

General Design Criterion 56 requires each line that connects directly to the containment atmosphere and penetrates primary reactor containment to have two containment isolation valves, one inside containment and one outside containment. The containment isolation valves must be locked closed or capable of automatic isolation.

The containment sump suction lines are part of the emergency core cooling system and the containment heat removal system, and must be opened following a loss of coolant accident to satisfy their post-accident functional requirements, which is to permit long term cooling of the reactor core and the containment atmosphere. As a result, automatic isolation of these lines is not desirable and remote manual isolation capability is provided for both isolation valves. We conclude that the isolation provisions for these lines provide an acceptable defined basis for meeting the requirements of General Design Criteria 56 regarding the actuation provisions for these isolation valves.

6.2.4.2 ECCS Safety Injection Lines

General Design Criterion 55 requires each line that is part of the reactor coolant boundary and penetrates primary reactor containment to have two containment isolation valves, one inside containment and one outside containment. The containment isolation valves must be either locked closed or capable of automatic isolation.

The containment isolation provisions for the ECCS high pressure safety injection lines consist of a check valve inside containment and a remote manual valve outside containment. A remote manual isolation valve is provided in lieu of an automatic isolation valve because the lines which are part of the emergency core cooling system have a post-accident safety function. We conclude that the isolation provisions for these lines provide an acceptable defined basis for meeting the requirements of General Design Criteria 55 regarding the actuation provisions for the valves outside containment.

6.2.4.3 Charging Line to Regenerative Heat Exchanger

The containment isolation provisions for the charging line to the regenerative heat exchanger consist of a check valve inside containment and a remote manual isolation valve outside containment. Both valves are open in normal operation and are required to stay open under post-accident conditions. We have therefore concluded that the isolation provisions for this line provide an acceptable defined basis for meeting the requirements of General Design Criteria 55 regarding the actuation provision for the valve outside containment.

6.2.4.4 Diversity of Parameters for Initiation of Isolation

Our review of the containment isolation system includes verification that there is diversity of parameters sensed for the initiation of containment isolation, as called for by Standard Review Plan Section 6.2.4, "Containment Isolation System." The San Onofre 2 and 3 containment isolation system design criteria did not initially meet this requirement because the majority of the automatic containment isolation valves did not receive a containment isolation actuation signal which is based on the sensing of diverse parameters. Rather, the containment isolation actuation signal was initiated on high containment pressure only. Since this design did not meet the staff's requirements, we found the isolation actuation signal to be unacceptable. We required the applicants to redesign the containment isolation actuation system to provide for the sensing of diverse parameters, such as containment pressure and pressurizer pressure, and containment radiation for lines which provide an open path to the environs. This issue will be addressed in Section 22.2 of this report or its supplement(s) under item II.E.4.2, Containment Isolation Dependability.

6.2.4.5 Containment Purge System

Our review of the containment isolation system has also included a review of the containment purge system which will be used to reduce airborne radioactivity in the containment and allow personnel entry during normal operations. San Onofre 2 and 3 was originally designed with a purge system having 42-inch-diameter purge lines designed for intermittent purging during plant operation. Subsequently, a mini-purge system having 8-inch-diameter purge lines was added. The mini-purge system was designed to meet Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations." The accident analyses in Section 15 of this report are based on the use of the mini-purge system on a continuous basis during plant operation. This assumption is conservative due to the 90 hour limitation discussed below.

In a letter date January 14, 1981, the applicants committed to the use of the mini-purge system a total of no more than 90 hours per year, per reactor unit, during the normal plant operating modes of startup, power operation, hot standby, and hot shutdown. The normal (42-inch diameter) purge system will be restricted to use during the cold shutdown and refueling modes. In these modes, all purge systems may be used simultaneously and without time limitation. We will include this requirement

in the plant Technical Specifications. We find the purge systems at San Onofre 2 and 3 to be acceptable, based on the 90 hour limit of operation and the demonstration that the mini-purge system meets BTP CSB 6-4.

The applicants have also demonstrated that the containment purge system design assures that blockage of purge isolation valves will not occur. The 42-inch purge line valves are closed during normal plant operating modes 1 through 4 (startup, power operation, hot shutdown and hot standby). The mini-purge valves are the only valves that remain open during normal plant operating modes. To prevent potential blockage of the mini-purge valves by debris in the event of a LOCA, the applicants have installed screens in both the inlet and outlet lines of the mini-purge system inside containment. The screens have 3/8 inch square openings and consist of 0.12 inch diameter wire of 2 3/16 inch bars spaced on 1 3/16 inch centers. This design is similar to that used on other plants.

6.2.4.6 Conclusions, Containment Isolation System

Based on our review, we conclude that the containment isolation system design conforms to GDC 54, 55, 56 and 57; and that the provisions of Standard Review Plan 6.2.4, with the exception of the criterion for diversity of parameters, have been satisfied.

6.2.5 Combustible Gas Control System

Following a loss-of-coolant accident, hydrogen may accumulate inside the containment as a result of (1) chemical reaction between the fuel rod cladding and the steam resulting from revaporization of emergency core cooling water, (2) corrosion of construction materials by the spray solution, and (3) radiolytic decomposition of the cooling water in the reactor core and the containment sumps.

In order to limit the hydrogen accumulation in the containment, the applicants have provided a combustible gas control system and a backup purge system. The combustible gas control system consists of a hydrogen monitoring subsystem that measures the containment atmosphere hydrogen concentration and a hydrogen recombiner subsystem that provides the means of reducing the containment hydrogen concentration.

The hydrogen recombiner subsystem is designed to meet the quality assurance, redundancy, energy source, and instrumentation requirements of an engineered safety feature described by the Westinghouse topical report WCAP 7709-L, "Electrical Hydrogen Recombiner for Water Reactor Containments." The staff has previously reviewed this topical report and found it acceptable for reference.

The two recombiners located inside containment are seismic Category I and each is powered from a separate Class IE electric bus. The recombiners are designed to function in the post-accident containment environment. Two redundant hydrogen analyzers are provided to monitor the containment atmosphere following a LOCA to serve as a basis for actuating the hydrogen recombiners. The hydrogen analyzers are designed in accordance with seismic Category I requirements and powered from separate

Class 1E power sources. The hydrogen analyzers provide continuous indication and alarm in the control room if the containment atmosphere hydrogen concentration approaches the 4% level.

Mixing of the containment atmosphere to prevent localized buildup of combustible gases post-accident and to ensure that samples drawn by the hydrogen monitoring subsystem are representative is accomplished by three active systems; namely the containment spray system, the containment emergency fan cooler system, and the containment dome air circulation system, all of which are designed to engineered safety feature criteria.

The applicants have performed an analysis of the post-accident production and accumulation of hydrogen within the containment that is consistent with the guidelines of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," and Branch Technical Position CSB 6-2 of the same title. The applicants' analysis was performed assuming operation of one recombiner, actuated approximately 14 days after the LOCA when the hydrogen concentration was approximately 3.5 volume percent. The analysis demonstrated that the containment atmosphere was maintained below the lower flammability limit of four volume percent.

We have performed a confirmatory analysis of the hydrogen accumulation within the containment following a loss of coolant accident, which verified the analysis provided by the applicants.

We have reviewed the description of the combustible gas control system and find that it meets the recommendations of Regulatory Guide 1.7 and Branch Technical Position CSB 6-2 and Standard Review Plan Section 6.2.5. Our confirmatory analysis also verifies the hydrogen recombiners will maintain the hydrogen concentration within acceptable limits. Therefore, we conclude that the San Onofre 2 and 3 combustible gas control system is acceptable.

TMI-related hydrogen control issues will be discussed under items II.B.7 and II.B.8 in Section 22 of a supplement to this report.

6.2.6 Containment Leak Testing Program

We have reviewed the applicants' containment leak testing program for compliance with the containment leakage testing requirements specified in Appendix J to 10 CFR 50, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Such compliance provides adequate assurance that the containment leak-tight integrity can be verified throughout service lifetime and that the leakage rates will be periodically checked during service on a timely basis to maintain such leakage within the specified limits. Maintaining containment leakage within such limits provides reasonable assurance that, in the event of any radioactivity release within the containment, the loss of the containment atmosphere through leak paths will not be in excess of the limits specified for the site.

Specifically, we reviewed the leak testing program to assure that the containment penetrations and system isolation valve arrangements are designed to satisfy the containment integrated leak rate testing requirements and the local leak testing requirements of Appendix J.

Based on our review, we conclude that the proposed reactor containment leakage testing program, with the exception of the leak testing program for the containment airlocks, complies with the requirements of Appendix J to 10 CFR Part 50 and is acceptable. Leak testing of the containment airlocks is discussed below.

Section III.D.2 of Appendix J to 10 CFR 50 requires airlocks to be leak tested at 6-month intervals, and after each opening during the intervals. Section III.B.2 of Appendix J requires all penetrations to be leak tested at the calculated peak containment internal pressure, P_a , corresponding to the design basis accident.

Based on plant operating experience, requiring an airlock to be leak tested after each opening is an impractical requirement when frequent airlock usage is necessary over a short period of time. Furthermore, the San Onofre 2 and 3 airlock design incorporates dual seals on the airlock doors with the capability to pressurize the volume between the seals. Therefore, the applicants propose to leak test the airlock door seals within three days after opening an airlock. This will permit door seal integrity to be demonstrated without pressurizing the entire airlock. This is an acceptable test method for tests other than the six-month test. Testing of the door seals is more practical and still provides the desired confidence that the leak tightness of the airlock is within acceptable limits.

The airlock door seal tests will be performed at a pressure less than P_a . The acceptance criteria for the door seal tests is that no detectable seal leakage will occur when the volume between the seals is pressurized to 10 psig for at least 15 minutes. The lower test pressure of 10 psig is sufficient to verify that door seal integrity is being maintained and that the door seals are free of dirt and foreign objects. The lower test pressure is recommended by the airlock manufacturer and testing at the lower pressure is expected to extend the seal life. We, therefore, conclude that the use of a test pressure of 10 psig for the door seal tests is acceptable although it is lower than the test pressure P_a called for by Appendix J. This test pressure will be incorporated in the facility Technical Specifications. For the above reasons, we conclude that an exemption from the requirements of Section III.D.2 of Appendix J to 10 CFR Part 50 is warranted, and that such an exemption will not endanger life or property or the common defense and security and is otherwise in the public interest. Furthermore, we have determined that granting this exemption does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. We conclude that this exemption would be insignificant from the standpoint of environmental impact and, pursuant to 10 CFR 51.5(d)(4), that an environmental impact statement, or negative declaration and environmental appraisal, need not be prepared in connection with this action.

The applicants will retain the six-month leak test of the airlocks in accordance with Appendix J.

Additional staff effort on the subject of leak testing that will lead to a revision of Appendix J is being done in conjunction with generic item A-23, "Containment Leak Testing." The outcome of this task will be applicable to all plants, although implementation may vary, depending on their licensing status and design.

6.3 Emergency Core Cooling System

The San Onofre 2 and 3 emergency core cooling system (ECCS) is designed to provide core cooling as well as additional shutdown capability for accidents that result in significant depressurization of the reactor coolant system. These accidents include failure of the reactor coolant system piping up to and including the double-ended break of the largest pipe, rupture of a control rod drive, breaks in the steam piping, steam generator tube rupture, and loss of normal feedwater flow.

The design basis is to limit clad damage by precluding excessive temperatures and clad-water reactions. The applicants' analysis confirms that the requirements will be met even with minimum engineered safeguards available, such as the loss of one emergency power bus, with offsite power unavailable.

6.3.1 System Design

The emergency core cooling system consists of active and passive injection systems. The passive system (safety injection tanks) is actuated when the reactor coolant system (RCS) pressure drops below a preset value. The active components of the ECCS are the high pressure safety injections (HPSI) system and the low pressure safety injection (LPSI) system that are actuated by the safety injection actuation signal (SIAS).

The four safety injection tanks contain borated water covered by nitrogen pressurized to at least 600 psig. When the RCS pressure falls below the tank pressure, borated water is forced into the four cold legs.

The high pressure safety injection mode of operation, upon actuation of the SIAS, consists of the operation of two high head centrifugal pumps which provide high pressure injection of borated water from the refueling water storage tank (RWST) into the RCS. The charging pumps also align for injection following a SIAS, but no credit is given for any additional flow they may provide.

Low pressure injection consists of two LPSI pumps which take their suction from the RWST. The refueling water storage tanks (2 per unit) have a nominal volume of 245,000 ft³ of borated water per tank. A comparison between the ECCS equipment at San Onofre 2 and 3 and at ANO-2 is presented in table 6.3.

Table 6.3

Emergency Core Cooling System Equipment

	<u>ANO-2</u>	<u>SAN ONOFRE 2 & 3</u>
Low Pressure Safety Injection Pumps	2	2
Design Flow (gallons per minute)	3100	4150
Design Head (feet)	350	342
High Pressure Safety Injection Pumps	3	3
Design Flow (gallons per minute)	320	415
Design Head (feet)	2900	2830
Safety Injection Tanks	4	4
Design Pressure (psig)	700	700
Water Volume, Normal (cubic feet)	1480	1743
Refueling Water Storage Tank	1	2
Water Volume, Nominal (gallons per tank)	445,500	245,000

6.3.2 Evaluation

We have reviewed the system description and piping and instrumentation drawings to assure that abundant core cooling will be provided during the initial injection phase with and without offsite power and assuming a single failure. The cold leg safety injection tanks have normally open isolation valves in their discharge lines. These valves will have power removed from the motor operators to preclude inadvertent closure during the emergency core cooling system injection phase. There are two pumps in each of the two different active injection systems. In the HPSI system only two of the three available pumps are aligned for operation at any time. The pumps in each system are connected to separate power buses and would be powered from separate diesel generators in the event of loss of offsite power as required by General Design Criterion 17. Thus, at least one pump in each injection train would be actuated assuming a single power failure. The high and low head injection systems contain parallel valves in the suction and discharge lines, thus ensuring system function even if one valve fails to open. A failure modes and effects analysis is presented by the applicant covering mechanical equipment in the ECCS. This analysis indicates that no single active or passive failure could prevent the ECCS from fulfilling its short and long term functions. Passive failures in the ECCS are only considered to occur beginning 24 hours after initiation of an event and are limited to consideration of pump seal or valve stem leakage.

Electrically powered components of the ECCS, required for safety related operation, can operate off of on-site or offsite power in compliance with General Design Criterion 17. Components include pumps, valves, and instrumentation. Power must be removed from certain components during specific modes of operation to insure plant safety. We require the following valves to be locked in position and have their power removed under the stated conditions:

- (1) Valves 2HV9420 and 2HV9434 must be locked closed except when required for hotleg injection in order to prevent premature hotleg injection following a LOCA.
- (2) Safety injection tank isolation valves 2HV9340, 2HV9350, 2HV9360, and 2HV9370 must be locked open when RCS pressure exceeds 500 psig in order to preclude the loss of a safety injection tank during LOCA from a closed isolation valve.

In addition, we require that the refueling water storage tank isolation valve 10"-068-C-076 must be locked open since the closure of this valve before or during a small break LOCA might incapacitate the HPSI and LPSI pumps.

During our review, we questioned the possibility that manual valves 16"-022-C-173 and 16"-023-C-173, which isolate the refueling water storage tank from the shutdown cooling pumps, might inadvertently be left closed after the reactor is taken off the shutdown cooling system. The applicants responded by stating that these valves are administratively locked open during normal operation and that the failure modes and effects analysis for this system shows acceptable results if one valve is accidentally left in the closed position. In addition, the facility Technical Specifications

require low pressure safety injection pump operability inspections every thirty days. This inspection will confirm that these valves are open. We find that this meets all requirements of the standard review plan for manual valves in redundant trains, and is acceptable.

The large break LOCA analysis described in Section 15.3.5 of this report confirms that the ECCS satisfies the criteria in 10 CFR 50.46. The large break LOCA analysis was done with approved code models and had acceptable calculated results. We requested that additional small break LOCA calculations be performed using approved models to assure that the small breaks are not limiting. The results of our review of these analyses is also presented in Section 15.3.5 of this report.

Analysis of other events requiring actuation of the ECCS in Chapter 15 show that flows, temperatures, and pressures in the ECCS are satisfactory to mitigate consequences of these events. By providing redundant cooling and limiting fuel damage, the ECCS design meets General Design Criterion 35.

In response to our questions involving the capability of the HPSI pumps to operate for extended periods of time and the maintenance program provided for the HPSI pumps, the applicants, in amendment 15 to FSAR, stated that the HPSI pump design is similar to steam generator feedwater pumps manufactured by Ingersoll Rand. The applicants provided a list of feedwater pumps operating data which showed that those pumps could be operated without pump overhaul for more than 5 years. The applicants also stated that routine maintenance is provided to the HPSI pumps periodically, such as checks on the pump and motor assembly and auxiliary equipment, instrument calibrations, oil changes, alignment checks, etc., in accordance with plant procedures. The HPSI pumps are expected to have major maintenance performed at significantly longer time intervals than feedwater pumps. This is because the actual HPSI pump operation will be minimal. In addition, the routine inservice operational inspections defined in the Technical Specifications will continually confirm the HPSI pump operability. We conclude that the applicants have provided an adequate surveillance and maintenance program to insure proper HPSI pump operation.

During our review of the ECCS pump room leakage collection and water level detection system, we requested the applicants to verify that all three pump rooms are provided with appropriate leakage detection systems to prevent flooding of safety related pumps. In response, the applicants stated that there are 3 SIS pump rooms, two of which contain HPSI, LPSI and Containment Spray Pumps. All three SIS pump rooms have watertight doors to seal them. Any leakage from the ECCS pump seals in the three pump rooms is collected and directed to a cofferdam installed in the floor drain in the pump pit. The floor drain directs the leakage water directly to the ESF building sump. A Class IE level detector is mounted inside each pump room that will alarm in the control room on high water level. Any passive failures in the SIS pump rooms, other than pump seal leakage, will raise the water level in the pump room flood and actuate the Class IE level detector, thus identifying the affected train for operator action. The maximum flood levels identified in FSAR Table 3.4-2 for SIS pump rooms are based on flow rates that are in excess of 50 GPM. No credit was taken for

operator action for 30 minutes following an alarm indicating the presence of a flooding condition. Redundant safety-related components are located in separate compartments and are adequately protected from flooding by separation and watertight barriers. We find the above design acceptable based on the reasons given above.

The ECCS is designed with satisfactory high/low pressure isolation protection. The LPSI system is protected from RCS operating pressures by a closed motor-operated isolation valve and two check valves between LPSI pump discharge and the four vessel cold legs. The motor-operated isolation valve opens automatically on a SIAS. The HPSI system is a high pressure system, but is isolated from the RCS by a closed motor-operated isolation valve (open on SIAS) and 2 check valves in the lines to each of the 4 cold legs. Both the LPSI and HPSI systems have relief valves to provide pressure relief for water trapped between closed valves should there be a temperature rise.

The environmental qualification of equipment in the ECCS is discussed in Section 3.11 of this report. All motor-operated valves and all pumps in the ECCS required to operate following a LOCA are located outside containment, with the exception of the containment emergency sump isolation valves. Valve operators for the containment sump isolation valves are above the maximum post-LOCA flood level.

The recirculation actuation signal (RAS) automatically transfers suction of the HPSI and containment spray pumps from the RWST to the emergency sump and shuts off the LPSI pumps. The RAS meets our single failure requirements as discussed in Section 7.3 of this report and actuates on a low RWST level signal.

NPSH margins have been calculated for the ECCS pumps during injection and recirculation phases. Following preoperational testing of the ECCS, we require that the NPSH must be confirmed by the applicants using the as-built hydraulic resistances and pump flows.

The ECC system draws water from two refueling water storage tanks (RWST) during the injection phase following an SIAS. Because of the climate at the plant site, freezing of the tank contents or vent plugging caused by freezing is considered to be very unlikely.

The applicants have proposed a method of providing simultaneous hot and cold leg injection to begin several hours following a LOCA to preclude an unacceptable boron concentration buildup in the core which might cause boron precipitation and reduction in core cooling. We questioned the applicants as to whether enough time would be available to manually initiate the hot leg injection from the high pressure safety injection pumps before boron began to precipitate in the reactor core. The applicants supplied additional calculations which showed that with a four weight percent margin, precipitation will not occur for approximately seventeen hours. We agree that this is more than adequate time to make the valve realignment necessary to switch to simultaneous hot and cold leg high pressure safety injection.

All emergency core cooling system lines, including instrument lines, have suitable containment isolation features that meet the requirements of General Design Criterion 56 and Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Reactor Containment," as discussed in Section 6.2. The ECCS of San Onofre 2 and 3 have no shared components between units in compliance with General Design Criteria 5.

The applicants have committed to require, by administrative procedures, that ECCS lines will be maintained at or restored to a full water condition in order to minimize the possibility of water hammer. We conclude that procedures for maintaining lines in a full condition by use of vents, drains, or other methods are necessary, and find the applicants' commitment to be acceptable.

The ECCS is housed in a structure that is designed to withstand tornadoes, floods, and seismic phenomena in accordance with General Design Criterion 2. Flood protection is currently under staff review (see Section 2.4.3 and 3.4 of this report).

Missile protection and the protection against dynamic effects of pipe whip and discharging fluid is discussed in Section 3.5 and 3.6 of this report.

San Onofre 2 and 3 shutdown cooling system (SDCS) is designed to comply with Regulatory Guide 1.29, "Seismic Design Classification," Regulatory Guide 1.26, "Quality Group Classification and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and Regulatory Guide 1.48, "Design Limits and Loading Combinations for Seismic Category I Fluid System Components," as discussed in Section 3 of this report.

The instrumentation needed to monitor and control the emergency core cooling system equipment following a loss-of-coolant accident has been reviewed. This instrumentation provides sufficient information for the operator to maintain adequate core cooling following an assumed loss-of-coolant accident. Post-accident monitoring instrumentation includes pressurizer pressure and level, steam generator pressure and level, spray system pressure and temperature, LPSI header temperature, reactor coolant and containment temperature, containment pressure and RWST level.

In response to staff questions related to the potential for debris in containment to inhibit ECCS performance at San Onofre 2 and 3, and the effects of a postulated high energy line break in the vicinity of the sump, the applicants have provided additional information.

The applicants' response states that the portions of the shutdown cooling system piping upstream of the SDCS isolation valves are the only high energy line near the containment emergency sumps. Pipe breaks in this line have been analyzed by the applicants in accordance with the criteria presented in Section 3.6 of the FSAR and approved by the staff. The worst case is a double-ended break upstream of the isolation valves which will cause a jet directed toward and passing above the sump but will not impinge on the sump structure. A break in a line of this size

(16 inches diameter) will depressurize the reactor coolant system prior to the initiation of the recirculation mode. We have reviewed the applicants response and for the reasons stated, agree with the conclusions given above.

The applicants have committed to comply with the cleanliness and housekeeping guidelines of Regulatory Guide 1.39 as described in Subsection 3A.1.39 of the FSAR. Plant maintenance procedures will ensure that "as licensed" cleanliness is restored prior to each startup. An inspection program will be prepared according to the requirements of Regulatory Guide 1.82, item 14 for inspection of the containment sump components including screens and intake structures.

Significant blockage of the sump trash rack is precluded by insulation design. The encapsulated insulation and the reflective insulation used inside the secondary shield wall are installed in preformed plates ranging in size from 1 foot by 1 foot to 3 feet by 6 feet. These plates are designed to sink to the containment floor if they become removed from their installation. Thermal insulation used inside the containment consists primarily of metallic, reflective insulation for primary system components and encapsulated, non-metallic insulation for secondary system components. The reflective insulation does not contain material which could form particles small enough to pass through the fine screens in the pump suction lines. The encapsulated insulation is designed to insure that the non-metallic insulation remains inside the stainless steel jacket following an accident.

We have reviewed the adequacy of the information available to the control room operator to monitor the ECCS status during recirculation cooling. We conclude that sufficient information (e.g., RCS pressure and temperatures, margin to saturation, safety injection pressure and flow, and sump level) is available to the operator to detect ECCS performance degradation.

Periodic verification of ECCS performance during post-LOCA recirculation is currently required by the applicable Emergency Procedures. Specific guidance for inadequate core cooling due to ECCS degradation will be incorporated into the Emergency Procedures which will be used in operators training.

The applicants will provide individuals on the technical support center staff with appropriate training to identify and mitigate possible problems resulting from emergency sump vortexing. These individuals will have the responsibility of verifying system operation when in the recirculation mode and are in direct communication with the control room operators should mitigating action be necessary.

Based on procedures and operator training which address the potential for ECCS performance degradation, we find the above measures acceptable to monitor ECCS performance during the recirculation mode at San Onofre 2 and 3.

Based on the considerations noted above with respect to housekeeping requirements, the avoidance of materials likely to form small-size debris, the lack of an apparent mechanism for blockage of more than the previously tested value of fifty percent of

screen area of larger debris, and the ability to monitor an control ECCS status, we conclude that the present design of San Onofre 2 and 3 provides reasonable assurance that the post-LOCA recirculation of reactor coolant will not be impaired by debris, and is therefore acceptable.

ECCS electrical loads on the emergency diesels are satisfactory and are discussed in Section 8.3.1 of this report.

6.3.3 Testing

The applicants will demonstrate the operability of the emergency core cooling system by subjecting all components to preoperational and periodic testing, as required by Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," and 1.79, "Preoperational Testing of Emergency Core Cooling System for Pressurized Water Reactors," and General Design Criterion 37.

6.3.3.1 Preoperational Tests

One of the tests is to verify system actuation, namely the operability of all emergency core cooling system valves initiated by the safety injection actuation signal, the operability of all safeguard pump circuitry down through the pump breaker control circuits, and the proper operation of all valve interlocks.

Another test is to check the safety injection tank system and injection line to verify that the lines are free of obstructions and that the safety injection tank check valves and isolation valves operate correctly. The applicants will perform a blowdown of each safety injection tank to confirm the line is clear and check the operation of the check valves.

Operational tests of all the major pumps comprise the last category. These pumps consist of the high pressure safety injection pumps and low pressure safety injection pumps. The applicants will use the results of these tests to evaluate the hydraulic and mechanical performance of these pumps when delivering through the flow paths for emergency core cooling. We require that the pumps be operated under both miniflow (through test lines) and full flow (through the actual piping) conditions. The applicants have committed to perform these tests and have partially completed them.

By measuring the flow in each pipe, the applicants will make the adjustments necessary to assure that no one branch has an unacceptably low or high resistance. They will also check the systems to assure there is sufficient total line resistance to prevent excessive runout of the pumps.

The applicants must show that the maximum flow rate predicted from the test results confirms the maximum flow rate used in the net positive suction head calculations under the most limiting conditions. The applicants must show that the minimum acceptable flow used in the loss-of-coolant accident analysis is met by the measured total pump flow and a relative flow between the branch lines.

6.3.3.2 Sump Tests

The applicants have performed a test of the containment emergency sump hydraulic behavior to study intake head losses and vortex control using a full scale simulation. The test model includes a grating cage encapsulating the end of the intake pipe and a trash rack around the top of the sump opening, simulating the emergency containment sump features used at San Onofre 2 and 3 to prevent vortex formation. The simulation also includes a ring of vanes that can be positioned to create vortices. During the tests, heated water was circulated through the sump system at flow rates greater than the maximum value postulated for the worst recirculation case, and at water depths equal to the minimum postulated water level.

In the test, the direction of water flow was varied by adjusting the angles of the ring of vanes surrounding the simulated sump. The model trash rack was partially blocked to simulate the effects of an accumulation of debris. The tests demonstrated that the San Onofre 2 and 3 sump arrangement, including the trash rack and grating cage, prevents vortexing during post-LOCA recirculation.

We have reviewed the test report and observed videotapes of the tests, and conclude that for up to 50 percent blockage of the sump trash rack, the sump performance is not degraded and acceptable NPSH margins are maintained at the ECCS pump intake. Since significant (i.e., more than 50%) blockage of the sump is precluded by insulation design (see Section 6.3.2, above), we find the San Onofre 2 and 3 emergency containment sump design acceptable.

The applicants comply with the requirements of testing given in Regulatory Guide 1.79 which covers testing of the emergency core cooling system.

The ECCS will be accepted only after demonstration of power actuation of all components and after demonstration of flow delivery to all components within design requirements.

6.3.4 Conclusions, Emergency Core Cooling Systems

The emergency core cooling system proposed by the applicants is acceptable because it meets the General Design Criteria and Regulatory Guides noted above.

6.4 Control Room Habitability Systems

San Onofre 2 and 3 share a common control room. The following subsections describe the radiological and toxic gas protection aspects of the San Onofre 2 and 3 control room habitability systems.

6.4.1 Radiological Protection

The applicants propose to meet General Design Criterion 19 of Appendix A to 10 CFR Part 50 with respect to radiation by use of concrete shielding and by installing

redundant charcoal filters, both in the control room pressurization system (1,000 cfm capacity) and in the recirculation system (34,500 cfm capacity).

These systems will be activated automatically upon receipt of either a safety injection signal or a high radiation signal from the redundant radiation detectors located in the outside air intakes of the normal control room ventilation system. Additional details of the control room habitability systems are provided in Section 6.5.2.3 of this report. Independent calculations of the potential radiation doses to control room personnel following a LOCA show the resultant doses to be within the guidelines of Criterion 19. We conclude that the control room habitability systems provide adequate radiological protection for the control room operators in the event of a design basis accident.

6.4.2 Toxic Gas Protection

The applicants performed an analysis of toxic gas hazards with respect to control room habitability. The San Onofre Units 2 and 3 will use a sodium hypochlorite system for water treatment and thus storage of free chlorine on the San Onofre site is not planned. Carbon dioxide and aqueous ammonia will be stored on the site in quantities that could present a potential hazard. The applicants also identified hazardous substances being shipped regularly past the site on Interstate 5, which traverses the exclusion area as described in Section 2.2 of this report. Butane, chlorine and anhydrous ammonia have been estimated as being shipped at frequencies that are sufficiently high to warrant their specific consideration as toxic gas hazards with respect to control room habitability in accordance with Regulatory Guide 1.78.

We requested the applicants to provide protection features for the control room operators against the effects of a postulated onsite release or shipping accident involving chlorine or anhydrous ammonia. The applicants provided, as described in Amendment 11 of the FSAR, redundant toxic gas detectors in the normal control room air intake to detect chlorine and also butane, carbon dioxide and ammonia. The detectors will alarm the control room operators and will automatically isolate the control room should these chemicals be present in hazardous concentrations. In addition, self-contained breathing apparatus is provided for the control room operators. We have reviewed the control room habitability system in accordance with Regulatory Guides 1.78 and 1.95 and conclude that the system meets the guidelines of these Regulatory Guides, and is acceptable, subject to resolution of the toxic gas accident probability open issue discussed in Section 2.2.2 of this report.

6.5 Engineered Safety Feature Atmosphere Cleanup Systems

6.5.1 Summary Description

The engineered-safety-feature (ESF) atmosphere cleanup systems for San Onofre 2 and 3 consist of process equipment and instrumentation to control the releases of radioactive materials in gaseous effluents (radioactive iodine and particulate matter) following a design basis accident (DBA). In the San Onofre 2 and 3 application,

there are two filtration systems designed for this purpose: the fuel handling building post-accident cleanup filter system, and the main control room habitability system.

6.5.2 System Description and Evaluation

6.5.2.1 Fuel Handling Building Post-Accident Cleanup Filter System

The function of the fuel handling building post-accident cleanup filter system is to control offsite radiation exposures and exposures to operating personnel in the main control room resulting from postulated fuel handling accidents. The filter system is a redundant system. Each train has a design capacity of 13,000 cfm and consists of prefilters, high efficiency particulate air (HEPA) filters, charcoal adsorbers, and downstream HEPA filters. Fire detection temperature sensors, heating coils, water spray systems and axial fans are also provided. The equipment and components are designed to Quality Group C seismic Category I, and are located in a seismic Category I structure.

We have determined that the fuel handling building post-accident cleanup filter system is designed in accordance with the guidelines of Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Post-Accident ESF Atmosphere Cleanup System Air Filtration and Adsorption Units of LWR Power Plants," and will be capable of controlling the releases of radioactive materials in gaseous effluents in accordance with applicable regulations following a postulated DBA.

6.5.2.2 Containment Air Cleanup Systems

In addition to its heat removal and pressure suppression functions, the containment spray system also serves to reduce the fission product concentrations in the containment atmosphere following a postulated loss-of-coolant accident or a steam line break accident inside containment. The containment spray is actuated by an ESF actuation signal when the containment pressure reaches 12 psig or may be actuated by the operator from the control room.

The applicants have estimated that 80 percent of the containment free volume of 2.36 million cubic feet will be covered by the spray. Based on our experience with similar systems, we consider this to be a conservative estimate. Atmospheric mixing between the sprayed and unsprayed containment regions is promoted by the containment emergency fan cooler and dome air circulator systems. We have conservatively calculated that the air exchange rate between the sprayed and unsprayed regions will be 136,000 cfm.

The spray liquid will be borated water with a boron concentration of 2,150 ppm and will be drawn from the refueling water storage tanks during the injection phase of the ECCS operation. To enhance the iodine removal capability of the water, a sodium hydroxide solution of 40 weight percent will be added to the water using metering pumps to yield a solution with a pH value between 9 and 10 at the nozzles.

For the sprayed region we conservatively calculated a first order removal constant of 13.7 per hour for elemental iodine. However, for the offsite dose calculations in Section 15 of this report, we have limited the removal constant to a maximum of 10 per hour in order to be consistent with the assumptions of Regulatory Guide 1.4. The long-term sump water will be maintained at a pH value above 8 to preclude any significant re-evolution of iodine. A minimum pH value of 8 for the sump water is considered adequate to achieve and maintain an elemental iodine decontamination factor of 60. Table 6.4 lists additional assumptions and design parameters that were used in our evaluation of the effectiveness of the containment spray system for removing iodine from the containment atmosphere. We have evaluated the iodine removal effectiveness of the containment atmosphere cleanup spray as a dose mitigating system in the event of an accident and find the system effective for the removal of elemental and particulate iodine from the containment atmosphere. We conclude that the system meets the appropriate parts of the requirements of General Design Criterion 41.

6.5.2.3 Main Control Room Habitability System

The function of the main control room habitability system is to process potentially radioactive air in the control room after a DBA and to pressurize the control room. This system will permit operating personnel to remain in the control room following a DBA. The main control room habitability system is a redundant system, with each system having an intake design capacity of 1,000 cfm of air and recirculating design capacity of 35,000 cfm of air. Each system contains the following components: prefilter, HEPA filter, charcoal adsorber, downstream HEPA filter and fan. Cooling coils are also provided for relative humidity control. The equipment and components are designed to Quality Group C and seismic Category I and are located in a seismic Category I structure. We have reviewed the main control room habitability system in accordance with the guidelines of Regulatory Guide 1.52 and determined that the system is capable of maintaining a suitable control room environment following a DBA.

6.6 Inservice Inspection of Class 2 and 3 Components

General Design Criterion 36, "Inspection of Emergency Core Cooling Systems;" Criterion 39, "Inspection of Containment Heat Removal Systems;" Criterion 42, "Inspection of Containment Atmosphere Cleanup Systems;" and Criterion 45, "Inspection of Cooling Water System," Appendix A of 10 CFR Part 50, require, in part, that the subject systems be designed to permit appropriate periodic inspection of important component parts to assure system integrity and capability.

Section 50.55a(g), 10 CFR Part 50, defines the detailed requirements for the preservice and inservice inspection programs for light water cooled nuclear power facility components. Based upon a construction permit date of October 18, 1973, this section of the regulations requires that a preservice inspection program be developed for Class 2 components and be implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect six months prior to the date of issuance of the

Table 6.4

Parameters Used to Assess the Effectiveness of the
Containment Spray as an Iodine Removal Mechanism

Design Flow Rate (gpm)	1,750
Additive	NaOH 40 wt% solution
pH during injection	$9 \leq \text{pH} \leq 10$
pH during long-term recirculation	$8 \leq \text{pH} \leq 9$
Containment volume (cubic feet)	
sprayed	$1.91 (10)^6$
unsprayed	$4.5 (10)^5$
total	$2.36 (10)^6$
Atmospheric Exchange Rate Between Sprayed and Unsprayed Containment Regions (cfm)	$1.36 (10)^5$
Minimum Drop Fall Height (feet)	81.5
Elemental Iodine Partition Coefficient	
Injection Phase	5000
Recirculation Phase	1500
Maximum Decontamination Factor	
Elemental Iodine	60
Particulate Iodine	not limited
Elemental Iodine Removal Rate Constants	
for Sprayed Containment Region (hour^{-1}):	
calculated	13.7
value for dose calculation	10.0

construction permit. Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect twelve months prior to the date of issuance of the operating license, subject to the limitations and modifications listed in Section 50.55a(b) of 10 CFR Part 50.

Our evaluation of the San Onofre 2 and 3 preservice inspection program indicates that the program meets the requirements of 10 CFR Part 50, Paragraph 50.55a. As a result of our review of this program we have determined that certain preservice examination requirements are impractical and performing these examinations would result in hardships or unusual difficulties without a compensating increase in quality and safety. Our evaluation of the applicants' relief requests with a supporting technical justification are presented in Appendix H to this report. The inservice inspection program will be evaluated after the applicable ASME Code Edition and Addenda have been determined and before the initial inservice inspections have been performed.

We have also reviewed the augmented inservice inspection requirements for high energy fluid system piping between containment isolation valves, as described in Branch Technical Position APCSB 3-1 (SRP 3.6.1). Systems which must be subjected to augmented inservice inspection include main steam, main feedwater, auxiliary feedwater, high pressure safety injection, low pressure safety injection, charging and letdown. Relief may be granted from this requirement if requested by the applicants and approved by the Commission in accordance with 10 CFR 50.55a(g).

Compliance with the preservice and inservice inspections required by the ASME Code and 10 CFR Part 50 constitutes an acceptable basis for satisfying applicable requirements of General Design Criteria 36, 39, 42, and 45.

7.0 INSTRUMENTATION AND CONTROLS

7.1 Introduction

We have evaluated the San Onofre 2 and 3 instrumentation and control system using, as bases for our review, the Commission's General Design Criteria, the Institute of Electrical and Electronics Engineers (IEEE) Standards including IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations", the applicable regulatory guides for power reactors, and the applicable staff positions.

We have reviewed the information provided in section 7.1 of the Final Safety Analysis Report for the instrumentation and controls associated with the San Onofre 2 and 3 design. We conclude that the criteria, regulatory guides, and standards utilized in the design of the instrumentation and control systems are acceptable.

In addition we have reviewed the information provided in section 7.1 of the Final Safety Analysis Report which identifies the differences between San Onofre 2 and 3 and Arkansas Nuclear One Unit 2, which has been referenced by the applicants as a comparable design. Based on this information, we concentrated part of our review efforts on the major changes and modifications for San Onofre 2 and 3.

7.2 Reactor Protection System

The San Onofre 2 and 3 reactor protection system is, with some exceptions, identical to the system provided for the Arkansas Nuclear One Unit 2 plant. See sections 7.2.1, 7.2.2, 7.2.3 and 7.2.4, below, for discussion of these exceptions.

The reactor protection system is part of the overall plant protection system which is designed and built by Combustion Engineering. The engineered safeguards actuation system forms the rest of the plant protection system (See section 7.3, below).

Most of the reactor protection system is hard-wired, consisting of four independent sensor channels that monitor various parameters and trip bistables whenever the predetermined set points are exceeded. The parameters include:

- (1) High linear power level
- (2) High logarithmic power level
- (3) High pressurizer pressure
- (4) Low pressurizer pressure
- (5) Low steam generator number 1 water level
- (6) Low steam generator number 2 water level

- (7) High steam generator number 1 water level
- (8) High steam generator number 2 water level
- (9) Low steam generator number 1 pressure
- (10) Low steam generator number 2 pressure
- (11) High containment pressure
- (12) Loss of load

The remaining part of the reactor protection system is computer based. It is comprised of the core protection calculator which employs minicomputers to calculate the departure from nucleate boiling ratio and the local power density based on input from sensor channels. The core protection calculator generates a signal to the input of the reactor protection system whenever the calculated values exceed a predetermined setpoint.

Both portions of the reactor protection system feed the reactor trip logic matrices through a set of three bistable trip relays.

Each set of trip relay outputs are combined into three of six independent logic matrices representing all possible two-out-of-four trip combinations for the four protection channels. Each logic matrix contains four output relays. The output of the six logic matrices provide four redundant and independent trip paths to the undervoltage coils of the control element assembly power supply breakers. Thus, each logic matrix can interrupt the four trip paths, causing insertion of all control element assemblies. Each channel, logic matrix and trip path is completely testable during reactor operation.

The following sections address the major areas of our review.

7.2.1 "Loss of Load" Trip Input

The applicants have included a plant protection system input which causes a reactor scram on turbine trip above 55 percent power (loss of load). On similar applications, this trip input has been removed because it did not meet the requirements of IEEE Standard 279-1971. As justification for retaining the trip input for San Onofre 2 and 3, the applicants have analyzed the trip input (and its associated bypass circuitry) for conformance to the requirements of IEEE Standard 279-1971. The applicants have also stated that the trip input is for equipment protection only and is not required for safety. No credit is taken for this trip in the safety analysis described in Section 15 of the Final Safety Analysis Report.

The input consists of four independent pressure switches which monitor the hydraulic pressure in the four turbine stop valves. From these sensors, the circuitry is routed in four separated conduits to the reactor protection system cabinets in the control room. The bypass is implemented through the four ex-core nuclear instrumentation safety channels.

During our review we expressed concern over the sensors and the portion of the circuitry located in the non-Seismic Category I turbine building. It was not adequately demonstrated that there are no credible faults or failures, in this area of the plant, which could have adverse effects on the independent channels of the reactor protection system. The applicants have stated in the Final Safety Analysis Report that these circuits are treated as special circuits in the turbine building and that the protection afforded these circuits can preclude any failures in the turbine building from adversely affecting the reactor protection system.

During our review of the FSAR we determined that the implementation of these circuits is critical to the reactor protection system channel independence. Therefore, during our September 1980 site visit we inspected these circuits and verified the implementation of the criteria given in the FSAR and found acceptable by us, as discussed above. On this basis, we conclude that the loss of load trip is acceptable.

7.2.2 Computer Based Portion of the Reactor Protection System - Core Protection Calculator

A significant amount of staff review effort was expended on the core protection calculator portion of the reactor protection system as a part of the review of Arkansas Nuclear One Unit 2. Because of this previous review effort, we required the San Onofre 2 and 3 applicants to submit a summary of any modifications for their core protection calculator as compared to the Arkansas Nuclear One Unit 2 core protection calculator.

The applicants noted modifications in the following areas and for the following reasons:

- (1) Core protection calculator/control element assembly protection algorithms - these changes are a result of the change in the number of control element assemblies and control element assembly subgroups for San Onofre 2 and 3.
- (2) Core protection calculator/control element assembly data base constants - these changes are due to the specific core and coolant system characteristics.
- (3) Software changes related to thermal-hydraulic methods - the changes incorporate current Combustion Engineering methods.

Our review of these modifications is still in progress. We will report on the resolution of this issue in a supplement to this report.

The applicants have stated that all software changes will be in accordance with the procedure described in "Core Protection Calculator Protection Algorithm Software Change Procedure (CEN-39(a)-P)".

This procedure was reviewed and approved by the staff on the Arkansas Nuclear One Unit 2 docket. The San Onofre 2 and 3 applicants have committed to implement the

final approved "change procedure" in accordance with Appendix B provisions of 10 CFR Part 50 as well as to utilize the services of a qualified computer consultant to provide independent verification that approved changes in the software are properly made.

Based on the applicants' description and the proposed implementation of the changes in the core protection calculator, we conclude that the core protection calculator is acceptable for San Onofre 2 and 3 subject to satisfactory completion of our review of the three modifications listed above.

7.2.3 Plant Protection System Power Supply Independence

The plant protection system provides independent vital alternating current power supplies to various plant protection logic matrix circuits via voltage comparator circuits. This arrangement helps ensure that the loss of one vital power supply will not cause inadvertent reactor scram or inadvertent actuation of engineered safety features equipment. Therefore, to demonstrate that there is adequate isolation between the independent buses in this arrangement, we required analyses and/or tests to be performed. A similar concern existed at Arkansas Nuclear One Unit 2, and follow-up tests were required. In response to our requirement, the San Onofre 2 and 3 applicants have performed analyses supported by tests and reported the results reported in the Final Safety Analysis Report. The tests were similar to those conducted on Arkansas Nuclear One Unit 2 with appropriate considerations to account for the differences in the designs of the distribution systems for the two plants.

The San Onofre 2 and 3 analyses and tests demonstrated that the Arkansas Nuclear One Unit 2 tests results are applicable to San Onofre 2 and 3. Based on this demonstration, along with the previously accepted test results on Arkansas Nuclear One Unit 2, we conclude that this area of the design is acceptable for San Onofre 2 and 3.

7.2.4 Bypass of a Plant Protection System Trip Channel

The applicants have requested that the staff review the San Onofre 2 and 3 plant protection system (which includes the Combustion Engineering reactor protection system and engineered safety features actuation system) as a two-out-of-four system assuming one channel of all trip parameters in bypass for a prolonged period of time. The system as described by the applicants then would become equivalent to a two-out-of-three system. This type of operation has been requested during the reviews of other Combustion Engineering applications utilizing the same basic plant protection system. However, the staff has not previously approved prolonged bypass of a single plant protection system channel because it was concluded that various deficiencies existed in the design and implementation of the plant protection system of the other applications for prolonged operation on a three channel basis. The staff did approve operation of Arkansas Nuclear One Unit 2 for up to 48 hours with one channel in bypass.

To consider the type of operation requested by the San Onofre 2 and 3 applicants, we required that the applicants perform all plant analyses (such as the failure mode and effects analysis and single failure analyses required by IEEE-379 as endorsed by Regulatory Guide 1.53, "Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems") assuming that a channel is in bypass and only 3 channels are operable. This included the requirement to demonstrate the total independence of the four channels including physical and electrical independence.

The following are the areas of concern that required resolution before we could conclude 1) that the plant protection system as designed and installed has four totally independent channels and 2) that operation is acceptable for prolonged periods with bypass of a single channel.

- (1) Proposed use of the bypass capability
- (2) Interdependence of the plant protection system trip parameters (or functional units)
- (3) Verification of physical independence
- (4) Plant electrical power supply independence

These areas are discussed below.

- (1) Proposed use of the bypass capability.

During our review, we requested that the applicants describe the proposed use of the bypass, including the conditions and durations for which the bypass is proposed to be used, and the circumstances under which the bypassed channel would be restored to operability. In response to our request, the applicants described their proposed use of the bypass capability. The bypass is provided to remove a trip channel from service for a short period of time during routine maintenance or testing. In addition, the bypass can be used to remove a channel from service under extraordinary circumstances for an extended period.

To further define and document this proposed use of the bypass, we requested that the applicants address, in the facility Technical Specifications, the extraordinary situations during which prolonged channel bypass will be needed. In response, the applicants proposed a set of Technical Specification action statements to cover these situations. The proposed Technical Specifications state that for extraordinary cases of channel component failure where the component cannot readily be repaired or replaced, a channel may remain in bypass for up to 90 days. For failure of channel components that are inside containment and are not readily accessible, a channel may remain in bypass for up to 18 months.

- (2) Interdependence of the plant protection system trip parameters (or functional units).

The Combustion Engineering plant protection system is designed to allow a manual bypass (i.e., removal from service) to be implemented on a single parameter or functional unit within any one of the four plant protection system channels. The channel bypass is accomplished at the output contact of the bistable trip relays where the 2 out of 4 voting logic (through the six matrices) is performed. Bypass of more than 1 channel of any one parameter or functional unit is prevented by interchannel electrical interlocks backed up by procedures based on the Technical Specification requirements. With such capability, we are concerned that, because of interdependence among "other" parameters or functional units within the same plant protection system channel, it is possible that an operator might not be totally aware of all such interactions and that he might bypass a channel of one parameter and then bypass a corresponding "other" parameter or trip unit in another channel.

Therefore, we requested that the applicants define all the cases where such interdependence exists within a channel's functional units. In response to this requirement, the applicants identified, in the proposed Technical Specifications, a number of cases where such interdependence exists. In the proposed Technical Specifications, the applicants require that when bypassing a parameter of functional unit in a channel, the operator shall bypass all the "other" interdependent parameters or trip units in the same channel.

We have reviewed the proposed Technical Specification action statements and conclude that the specific cases of plant protection system trip parameter interdependence have been adequately identified, and that the inclusion of this information in the Technical Specifications resolves our concern about interdependence.

(3) Verification of physical independence.

To verify the physical independence of the four channels as installed, we reviewed the four channels which monitor the steam generator pressure of one steam generator. The applicants stated that this parameter was typical of all parameters for the plant protection system. Our review included the plant layout drawings for the cable trays, penetrations and conduits and included the circuits from the field transmitters (inside containment) to the plant protection system cabinets in the main control room. The instrument sensing lines from the process to the transmitter are field run using separation criteria consistent with the analyzed hazards in the areas. In addition, the actual routing of the conduits is also determined in the field to appropriate separation criteria. These portions of the design were reviewed during the September 1980 instrumentation and control system site visit. At that time we traced a number of circuits for plant protection system parameters and physically verified that the implementation of plant protection system physical independence criteria was acceptable because it meets the criteria of Regulatory Guide 1.75.

(4) Electrical power supply independence.

A major area of concern on earlier applications, where applicants requested approval to operate with one channel in prolonged bypass, was the number of independent vital instrument power supplies available to the four channel plant protection system. Typically, these other applicants could only demonstrate the existence of the two independent power supplies because their plants contained only two divisions of 125 volt direct current power sources.

The San Onofre 2 and 3 applicants have provided four 125 volt direct current sources and four corresponding Class 1E distribution systems. As discussed in Section 8.3.2 of this report, we conclude that the four power supply systems are completely independent, and this concern has been resolved for San Onofre 2 and 3.

Based on the resolution of our concerns as discussed above, we conclude that it is acceptable for San Onofre 2 or 3 to operate with a plant protection system trip channel in bypass under the conditions specified above, because during such operation the plant meets all the applicable acceptance criteria.

7.3 Engineered Safety Features Actuation System

7.3.1 General

The engineered safety features actuation system designed by Combustion Engineering is comprised of sensor monitoring channels and logic matrices similar to the reactor protection system. The system also includes two independent and redundant component actuation trains. Each channel, logic and actuated equipment train is testable during reactor operation. The design is identical to that of Arkansas Nuclear One Unit 2. The review of the San Onofre 2 and 3 application included the review of selected schematic drawings of the circuitry pertaining to the engineered safety features actuation system. Significant areas of this review are discussed below.

7.3.2 Engineered Safety Features Input and Basic Logic

Each logic subsystem is basically identical except for the trip input parameters used, and includes four redundant and independent channels per trip input. Each subsystem logic is configured in the same manner as the reactor trip system with the four trip path outputs arranged into two independent, selective, two-out-of-four coincidence logics. Each coincident logic actuates one of the two redundant groups of engineered safety features equipment.

System actuation subsystems and associated trip input parameters identified in the design are:

- (1) Containment isolation actuation subsystem - high containment pressure.

- (2) Safety injection actuation subsystem and containment cooling actuation subsystems - low pressurizer or high containment pressure.
- (3) Containment spray actuation subsystem - high-high containment pressure and safety injection actuation signal.
- (4) Recirculation spray actuation subsystem - low refueling water tank level.
- (5) Main steam line isolation subsystem - low pressure in either of two steam generators, or receipt of a containment isolation actuation signal.
- (6) Emergency feedwater actuation subsystem Number 1 (steam generator Number 1) -low steam generator Number 1 level coincident with no low pressure in steam generator Number 1 or low steam generator level coincident with a differential pressure between the two steam generators with the higher pressure in steam generator Number 1.
- (7) Emergency feedwater actuation subsystem Number 2 (steam generator Number 2); identical to above except the conditions are for steam generator Number 2 versus steam generator Number 1.

7.3.3 Inadvertent Actuation of Engineered Safety Features Equipment

During the review of San Onofre 2 and 3, the staff determined that significant safety impact could result if certain engineered safety features systems (or functions) were inadvertently actuated during postulated events. The systems identified as having such an impact were the recirculation actuation system and the emergency feedwater actuation system for steam generators Number 1 and Number 2.

The following paragraphs discuss the operation of each of these systems and our review of the instrumentation and control associated with these systems.

- (1) Recirculation actuation subsystem.

The recirculation actuation subsystem is designed to automatically initiate the changeover from the injection mode to the recirculation mode before the refueling water storage tank is emptied. The subsystem initiates opening of the reactor building sump valves. An inadvertent actuation of the system (both A and B trains) during the first few minutes of safety injection would be unacceptable because of the potential for the loss of the water source for the injection pumps.

- (2) Emergency feedwater actuation subsystem to steam generator 1 and to steam generator 2.

The emergency feedwater actuation subsystems to steam generator Number 1 and Number 2 are designed to automatically initiate the flow of emergency feedwater

to the steam generators upon conditions corresponding to a loss of main feed-water or main steam line break. The system opens the valves and starts the pumps to supply water to the steam generators and, in the case of the main steam line break, it opens only the valves to the unaffected steam generator. An inadvertent actuation of either train of the wrong emergency feedwater actuation subsystems (i.e. the one for the affected steam generator) could supply emergency feedwater to the ruptured steam generator.

This is unacceptable because it may cause additional water to be transferred to the reactor containment or it may cause an uncontrolled cooldown of the primary system which has not been analyzed.

Therefore, because of the potential for these unacceptable consequences if these inadvertent actuations should occur, we reviewed the associated instrumentation and control systems to determine if any credible single failure (as defined in IEEE Standard 379-1972) could cause the system to actuate inadvertently.

The Combustion Engineering portion of the engineered safety features actuation system, which includes the four input channels and the six logic matrices, is designed with separate power supplies to preclude the loss of a single power supply from causing an inadvertent actuation of these systems.

The staff noted that the bistable relay contact in the logic matrices is not specifically testable to determine if an open circuit exists. Therefore the staff believed that it is conceivable that open circuits could exist in the logics and that a concurrent single failure of the parallel contact could cause actuation of these systems.

The applicants have submitted detailed design information for the bistable relay contact to demonstrate the adequacy of the design. They believe that an open circuit failure mode for these contacts is not credible due to the design, manufacturing, and acceptance testing of these components. They have also provided the results of operating experience with these components which shows no such failures of this kind.

We have reviewed the information submitted to the staff and agree that such failures are highly unlikely. Therefore we find this area acceptable.

The output of the Combustion Engineering design is an input to the engineered safety features actuation system actuation trains which are in separated cabinets. Because of the separation and independence between the two trains, the inadvertent actuation of only one train is credible. The only systems where the inadvertent actuation of one train would result in operating of the system are the emergency feedwater actuation subsystems for steam generator No. 1 and No. 2. The inadvertent actuation of two valves in series in a single train can cause feedwater to be supplied to the affected steam generator. The applicants have provided design features to preclude a single failure from actuating both train A (or B) valves in series to each steam

generator. This is accomplished through the use of separated relays within the cabinet to actuate each of the valves.

We conclude that the design satisfies the criteria noted in Section 7.1, above, and is acceptable with respect to inadvertent actuation of these systems. In addition, during our site visit we reviewed the physical independence provided for these circuits and concluded that the implementation was acceptable.

7.3.4 Main Steam Isolation System

The actuation of the main steam isolation system automatically closes both main steam isolation valves, one in each steam line and, in addition, automatically closes the valves required to isolate feedwater flow to both steam generators, including those required for emergency feedwater supply. We reviewed selected schematic drawings for the emergency feedwater valves and determined that there are design provisions to override the main steam isolation system signal in order to supply the required emergency feedwater to the unaffected steam generator. We conclude that these design provisions are acceptable.

In the unlikely event that one main steam isolation valve fails to close, certain non-safety grade valves in the steam line are relied upon to provide back up protection for isolation of the unaffected steam generator. These valves include the turbine stop valves, turbine control valves and turbine bypass valves. These valves receive signals to close via non-Class 1E signals for these events.

The staff has completed the review of main steam isolation systems on a generic basis. Based on the staff's conclusions as published in NUREG-0138 (See Issue Number 1, "Treatment of Non-Safety Grade Equipment in Evaluation of Postulated Steam Line Break Accidents") and our review, we conclude that the San Onofre 2 and 3 design satisfies the staff's requirement as stated in the above referenced document and is acceptable.

7.4 Systems Required for Safe Shutdown

Our evaluation of the San Onofre 2 and 3 application included review of the selected schematic drawings of the circuitry pertaining to systems required for safe shutdown, including the circuitry used to initiate operation of individual components, for example, pumps and valves. In addition, we have reviewed the instrumentation and controls provided for effecting safe shutdown of the reactor from outside the control room.

7.4.1 Atmospheric Steam Dump System

The review of the atmospheric steam dump system included the review of the instrumentation and control of the atmospheric steam dump valves. The dump valves are required to close following a main steam line break. Subsequently, these valves must be available for opening for controlled cooldown of the plant. To meet these

requirements the applicants have stated that the instrumentation and control for these valves is Class 1E and that a main steam isolation system signal is used to ensure that these normally closed valves would stay closed for a main steam line break event. We conclude that this is acceptable.

7.4.2 Shutdown Outside the Control Room

The applicants have stated that if the operator is forced to abandon the control room, local instrumentation and controls are available outside the control room to maintain the unit in the hot shutdown condition. In addition, the capability for bringing the reactor to cold shutdown also exists outside the control room. We reviewed selected schematics which pertain to equipment with controls located on the remote shutdown panel. The circuits for the equipment with keylock switches in the control room are provided with transfer switches in order that the control room switch can be overridden, if necessary, at the shutdown panel. In addition, the equipment on the shutdown panel meets the single failure criterion in the sense that if one division of equipment fails, there is sufficient equipment from the other division to proceed to safe shutdown.

We conclude that the facility meets our requirements with respect to Criterion 19 and of the General Design Criteria and that this area is acceptable.

7.5 Safety-Related Display Instrumentation

We have reviewed the design of the instrumentation that provides information to the operator to enable him to perform safety actions and post accident monitoring. The review described below does not include TMI-related requirements, which are much more extensive, and which will be described in Section 22 of a supplement to this report.

7.5.1 Post-Accident Monitoring Instrumentation

The applicants have stated that the instrumentation required for postaccident monitoring is redundant with at least one channel recorded, qualified to the accident environment, and powered by Class 1E power source. This meets the requirements of Regulatory Guide 1.97, Revision 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident."

We conclude that this design, which is equivalent to designs previously licensed, satisfies our requirements as outlined in Section 7.5 of NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", and is acceptable.

7.5.2 Inoperable Status Indication

We have reviewed selected schematics for valves and pumps which are monitored for operable status. The San Onofre 2 and 3 design provides for automatic indication of the inoperable status of this equipment by monitoring the control power to the motor starters or motor breakers. In addition to the automatic feature, the design

includes a manual switch for each division of equipment. Indication is provided for the operator at the system level as well as at the component level.

We conclude that the design conforms to the recommendations of Regulatory Guide 1.47 "Bypass and Inoperable Status Indication for Nuclear Power Plant Safety Systems," and is acceptable.

7.6 Other Instrumentation Required for Safety

7.6.1 Shutdown Cooling System Low Pressure to High Pressure Isolation

Two motor-operated valves in series are provided for each of the two suction lines from the reactor coolant system to the shutdown cooling system. These valves are normally closed and are only opened by the operator for shutdown cooling after the reactor coolant system pressure is reduced below 361 pounds per square inch, gauge. This valving arrangement ensures that a single failure of an isolation valve will not preclude the availability of the system when required or preclude positive isolation of the system at the boundary of the reactor coolant system when required.

Consistent with the above stated single failure criteria, the applicants have provided four independent power supplies and instrument channels, one for each valve. In addition, for each line, each valve is interlocked with a pressure sensor manufactured by different vendors. The valve logic is implemented such that the valves are automatically closed if the reactor coolant system pressure rises above 500 pounds per square inch, gauge. Each valve is also interlocked to prevent opening whenever the reactor coolant system pressure is greater than 361 pounds per square inch, gauge.

Our review of the shutdown cooling system low pressure to high pressure isolation included the review of the schematic diagrams and specification data sheets to verify the implementation of the design. We conclude that the design meets the staff requirements stated in Branch Technical Position 3 of Appendix 7A of NUREG 75/087 (the Standard Review Plan) and is acceptable.

7.7 Control Systems Not Required for Safety

The following systems have been identified by the applicants as control systems not required for safety:

- (1) Reactor regulating system
- (2) Pressurizer control system
- (3) Feedwater control system
- (4) Steam bypass control system

The applicants have stated that none of these systems is required to mitigate the consequences of the transients analyzed in Section 15 of the Final Safety Analysis Report. In addition, the applicants have concluded that the consequences produced by

credible malfunctions of these control systems would be less severe than the transients analyzed in Chapter 15.

We have reviewed the applicants' analysis and conclude that the safety systems alone are capable of mitigating the consequences of any Chapter 15 event assuming the most adverse modes for the control system. Therefore we conclude that these systems are not required for safety and are acceptable.

7.8 Separation of Wiring Within the Main Control Board and Instrument Cabinets

Although the San Onofre 2 and 3 design preceded the issuance of Regulatory Guide 1.75, "Physical Independence of Electric Systems," the applicants have described their conformance to the recommendations of this guide.

The applicants have stated in the Final Safety Analysis Report that, in the main control board, six inch separation or a barrier is provided between redundant Class 1E wiring. In addition, the non-Class 1E wiring is run separate from the Class 1E wiring. The barriers to be utilized where necessary are metallic conduit, metallic gutter, and/or metal barriers.

We concluded that because the design meets the requirements of Regulatory Guide 1.75, this was an acceptable approach. During our site visit we reviewed the implementation of these requirements and observed that they had been acceptably implemented.

With respect to the other instrumentation cabinets, including the plant protection system cabinets, process instrumentation cabinets, auxiliary relay cabinets and reactor trip switchgear, the applicants have stated that six inch separation or a barrier is provided between redundant Class 1E wiring. However, they have identified that, within some instrument cabinets, the non-Class 1E wiring is bundled with the Class 1E wiring. This can be an acceptable alternate approach, if it can be demonstrated that the Class 1E circuits and equipment are not degraded by non-Class 1E circuits below an acceptable level. Therefore we required the applicants to justify this design through analyses or test.

In response, the applicants submitted an analysis describing their design, identified the maximum credible potential faults that can exist on these circuits, and identified the types of isolation devices and noise rejection capabilities of such devices and circuits. Based on our review of the analysis, we find that the applicants have provided sufficient justification to assure that faults imposed on the non-Class 1E circuits routed with Class 1E circuits inside the safety-related cabinets would not degrade the safety systems below an acceptable level. Therefore, we conclude that this design is acceptable. In addition, we reviewed the implementation of the separation criteria during our site visit and concluded that it was acceptable because it meets the requirements of Regulatory Guide 1.75.

8.0 ELECTRIC POWER SYSTEMS

8.1 General Considerations

The requirements in Criterion 17, "Electric Power Systems," and General Design Criterion 18, "Inspection and Testing of Electric Power Systems," of the General Design Criteria, Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," and the Institute of Electrical and Electronics Engineers (IEEE) Standard 308-1974 "Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations", served as the primary bases for evaluating the adequacy of the emergency power systems for San Onofre 2 and 3. The applicable sections of the Standard Review Plan, NUREG-75/087, provided guidance for conducting our review.

The following subsections provide our evaluation of the design criteria and design description in the Final Safety Analysis Report. In September 1980, we conducted a review of electrical drawings and visited the site to view the installation and arrangement of electrical equipment and cables for the purpose of verifying the proper implementation of the design criteria.

8.2 Offsite Power

San Onofre 2 and 3 share a common switchyard with Unit 1. The switchyard is a double bus-double breaker design with a nominal rating of 230 kilovolts. This is the only tie point between the bulk power systems of the Southern California Edison Company and the San Diego Gas and Electric Company. There is a circuit breaker approximately midway along each bus that can effect separation of the two power grids under adverse transient conditions. Such a split of the switchyard buses would leave Unit 3 and half the outgoing transmission lines connected to the San Diego Gas and Electric Company grid and Units 1 and 2 plus half the outgoing transmission lines connected to the Southern California Edison Company grid. Based upon the above and the configuration of the onsite distribution systems, we reviewed the possibility that the two grids might remain connected through the emergency buses, given a transient which caused disconnection at the switchyard. We conclude that the design precludes this event even when a single failure is assumed to occur.

There are eight transmission lines entering the switchyard from multiple rights of way. Each of the San Onofre 2 and 3 units has three reserve auxiliary transformers that provide a normal source of preferred power to the unit's emergency buses, an immediate alternate source of preferred power for the other unit's emergency buses,

and startup sources of power to both units. This configuration exceeds the requirements of Criterion 17 of the General Design Criteria and is acceptable.

The Southern California Edison Company and the San Diego Gas and Electric Company portions of the switchyard each has its own relay house with independent battery sources of control power. Each circuit breaker is equipped with primary and local breaker back-up relay protection that electrically isolates any circuit breaker which fails to operate or to effectively open, thus clearing the faulted circuit of all sources of power.

The switchyard components are testable during reactor power operation. The double bus configuration allows a circuit breaker to be racked out for testing without interrupting any power circuits. The protective relays can be individually bypassed for testing without sacrificing circuit protection. We find this capability to be in conformance with the requirements of Criterion 18 of the General Design Criteria and acceptable.

The applicants have provided two separate grid stability studies, one for each of the two power grids. This is appropriate because the only interconnection of these two grids occurs in the San Onofre switchyard. The Southern California Edison Company grid study provides documentation for the conclusions that steady state stability places no restriction on plant operation and that transient stability is maintained with the simultaneous loss of two transmission components. Twelve transient stability cases were presented as bounding events, all of which resulted in stable grid conditions. One of the 12 cases, a 3-phase fault affecting the Chino and Villa Park 230 kilovolt lines at San Onofre, was marginal. This case requires fault clearing between 4 and 5 cycles to maintain stability. Fault clearing is assumed in the analysis to take between 4 and 5 cycles to be accomplished. The above is acceptable because we consider the limiting case described to be a double contingency event, and our requirements for transient stability are satisfied by analyzing single contingency events.

The study further documents that for the loss of the largest generating unit (in this case San Onofre 2 or 3) the frequency would drop less than 0.1 Hertz. Load shedding programs are initiated at a drop of 0.9 Hertz and interconnection separations occur at a drop of 1.6 Hertz. Therefore, the loss of the largest generating unit results in acceptable grid conditions.

The San Diego Gas and Electric Company grid stability study also documents that transient stability is maintained for 3-phase faults at San Onofre resulting from the outage of two critical San Diego Gas and Electric Company grid transmission circuits.

We requested that the applicants investigate the possible effects on the rate of reactor coolant pump coastdown of power system "islanding" due to grid transients. The basis for this concern is documented in issue number 9 of NUREG-0138, "Staff

Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff." In response, the applicants provided a detailed analysis which concludes that there are two islands considered to be bounding.

The bases for judging bounding configurations were: (1) the smallest number of line outages required and (2) the highest frequency decay rates. For these two islands, initial frequency decay rates were calculated for the 1982 and 1983 transmission systems with various amounts of generation deficiency considered. The effect of system load dampening and automatic load shedding on the initial frequency decay rate were also analyzed. The results of the study demonstrate a very low probability of occurrence of islanding, and worst case decay rates of 1.99 Hertz per second in 1982 and 1.77 Hertz per second in 1983. The frequency decay rate equivalent to reactor coolant pump coastdown with stored flywheel energy is 3.2 Hertz per second. This event is therefore bounded by the total loss of forced reactor coolant flow accident presented in Section 15.3.2.1 of the Final Safety Analysis Report, and is acceptable.

During our review we asked the applicants a number of questions concerning the interaction of the onsite power system with the offsite power system. We compared the San Onofre 2 and 3 design to our established position on offsite/onsite power system interaction, and have reached the following conclusions. Our position is in four parts and each is separately addressed below.

Part 1 of the position requires undervoltage protection for low grid voltages. The undervoltage relays traditionally used to detect loss of offsite power at the emergency busses have had setpoints around 70-75 percent of nominal bus voltage. This protection alone does not protect the plant loads from damaging low voltages which are maintained above this setpoint. Our requirement has therefore been to require an additional protective trip at approximately 90 percent of nominal bus voltage with a time delay to avoid spurious trips due to short duration transients such as those occurring when starting larger motors. This protection can be accomplished by two relays with discrete settings typically of 70 percent and 90 percent (time delay) respectively or by one undervoltage relay with an inverse time-undervoltage characteristic. The applicants have provided the latter scheme and have submitted the appropriate settings and time delays for our review. The undervoltage relay settings and time delays are consistent with our position and the design is in conformance with the requirements of IEEE Standard 279-1971. We find this aspect of the design to be acceptable.

Part 2 of our position requires that the diesel generator bus load shedding feature be automatically bypassed once the diesel generator is supplying power to the bus. This is required so that the voltage drops encountered during load sequencing on the diesel generators will not interact with the load shedding

feature and negate the loading sequence. The applicants maintain that the use of inverse time undervoltage relays precludes the need for the above requirements. This is due to the fact that the time delay at 75 percent of nominal voltage envelopes the short term voltage drops associated with diesel generator loading. The applicants further state that should an insufficient voltage condition prevail on the emergency bus, the Class 1E motors will not start but will draw locked rotor current (which could result in damage to the motors) until tripped by protective relays. The undervoltage relays provided in the design are adjusted so as not to trip on the largest motor starting on a fully loaded bus. We find that the applicants' design provides an equivalent degree of protection to that required by our position and that it is acceptable.

Part 3 of our position deals with incorporating tests and test frequencies into the Technical Specifications to assure continued adherence to this position throughout the plant lifetime. These provisions have been incorporated into the Technical Specifications proposed by the applicants and this is acceptable.

Part 4 of our position requires that the tap settings on the plant transformers be optimized and verified at the preoperational testing stage by measurement. The applicants have provided documentation showing that analyses have been performed and that the tap settings have been adjusted accordingly. The most adverse case for one unit has been identified as the minimum expected voltage of the offsite power source with a fully loaded safety related bus, including the allowable loads for that bus from the other unit. Voltage profile verification is part of the preoperational testing program. The applicants have stated that the results of this verification program will be available for auditing. We find this acceptable, subject to the successful verification during preoperational testing.

For each unit at San Onofre 2 and 3, there are three reserve auxiliary transformers and two unit auxiliary transformers which supply normal power to the onsite system. All five transformers have two-voltage windings. One unit auxiliary transformer provides the normal source of power to the reactor coolant pumps in a two pumps per bus/one bus per winding configuration. One of the reserve auxiliary transformers is similarly configured to supply back-up power to the reactor coolant pump buses and, additionally, to supply a third source of power to the reactor coolant pump buses of the other unit at San Onofre 2 and 3.

The other unit auxiliary transformer supplies the remaining auxiliary loads, half from each low voltage winding. The remaining two reserve auxiliary transformers supply back-up sources of normal power to these same loads. Each reserve auxiliary transformer has one winding that supplies the auxiliary loads and one winding dedicated to an emergency bus for both normal and preferred sources of power to this bus.

The above configuration provides two immediate access circuits from the preferred power system to the onsite emergency buses. This exceeds the requirements of Criterion 17 of the General Design Criteria and is acceptable.

8.3 Onsite Power
8.3.1 Alternating Current Systems

The onsite power and distribution system is comprised of an emergency portion which is qualified as a Class 1E system and a normal portion which is non-Class 1E. Both units at San Onofre 2 and 3 are alike with some loads shared between them.

For the loads that are shared between units at San Onofre 2 and 3, we have reviewed the following areas: (1) status information provided to both unit operators, (2) control provisions for both unit operators, (3) coordination necessary between operators, and (4) single failure aspects of the design. The units at San Onofre 2 and 3 share a common control room area in the control building and the above indications and controls are located in a common section of this control area. Therefore the operators of both units have access to these features and the coordination required between operators is minimal. Under normal circumstances the loads will be connected to Unit 2 for power. The single failure provisions of the design are met by use of manual transfer switches, interlocked circuit breakers and Kirk key interlocking devices. Alternate feeder circuit breakers are racked out when not in use and the manual transfers are break-before-make.

The Class 1E portion of the onsite power system is a two-division split-bus configuration. The emergency buses receive normal and preferred power from the reserve auxiliary transformers as noted above. Failure of this source will initiate a fast transfer to the corresponding emergency bus on the other unit. This transfer will not take place if the bus in the other unit is not connected to offsite power or if a faulted conditions exists. This design provides two immediately available circuits to provide offsite power to each emergency bus. Total loss of offsite power initiates starting and loading of the diesel generators onto the emergency buses. A forth source of power to each emergency bus can be made available in approximately eight hours by disconnecting the generator links, providing a circuit breaker for the normally empty compartment at the emergency switchgear, and thus backfeeding power through the unit auxiliary transformer.

The applicants have provided certain installed spare emergency loads designated as "third-of-a-kind" loads. Power can be supplied for these loads from either redundant division of the emergency power system. These loads consist of a component cooling water pump, motor, a high pressure safety injection pump motor and a charging pump motor. These loads are normally not in use and both feeder breakers are normally open and in the racked out position. The manual transfer switch cannot be operated unless both feeder breakers are in the open position. We have reviewed the details of this design and conclude it is acceptable because the independence of the two emergency divisions cannot be compromised by a single failure, due to the following design features: the use of Kirk key interlocks, the spatial and electrical separation provided, the fact that all cables are in conduit, and the fact that multiple manual actions in a programmed sequence are required in order to energize the load.

The Class 1E portion of the emergency onsite power and distribution system is designed to permit the following testing and inspections:

- (1) During equipment shutdown the applicants will conduct periodic inspection and testing of wiring, insulation, connections, and relays to assess the continuity of the systems and the condition of components.
- (2) During normal plant operation the applicants will conduct periodic testing of the operability and functional performance of standby onsite power supplies circuit breakers and associated control circuits, relays, and buses.
- (3) During plant shutdown the applicants will conduct testing of the operability of the Class 1E system as a whole. Under conditions as close to design as practical, the full operational sequence that brings the system into operation, including operation of signals of the engineered safety features actuation system and the transfer of power between the offsite and the standby onsite power systems, will be tested.

We find that the above is in conformance with Criterion 18 of the General Design Criteria is acceptable.

We have reviewed the emergency onsite power system and have determined the following. There are no automatic transfers of loads or sources between redundant emergency buses, which is in accordance with Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems." There is no sharing of emergency power sources between units, which is in accordance with Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants". The two divisions of the emergency power and distribution system are independent, meet the requirements of Criteria 17 and 18 of the General Design Criteria and IEEE Standard 308-1974, and are acceptable.

The applicants have applied the following design criteria to the Class 1E equipment. Motor horsepower capability is equal to or greater than the maximum horse-power required by the driven load under normal running, runout, or discharge valve (or damper) closed conditions. The electrical system is designed such that the total voltage drop on the Class 1E motor circuits is less than 25 percent of the nominal motor voltage during starting, and the Class 1E motors are specified with accelerating capability at 75 percent nominal voltage at their terminals. The motor starting torque is capable of starting and accelerating the connected load to normal speed within sufficient time to perform its safety function for all expected operating conditions, including the design minimum terminal voltage. The minimum motor torque margin over pump torque through the accelerating period is determined by using the actual pump torque curve and calculated motor torque curve at 75 percent terminal voltage. The minimum torque margin (accelerating torque) is such that the pump-motor assembly reaches nominal speed in less than 8 seconds. Resistance-temperature detectors are provided in the motor slots for all large motors, 250-horsepower and over. For the same motors, one thermocouple bearing-temperature device is provided on each bearing which is not an antifriction type.

The above design criteria are in conformance with Section 8.3.1 of NUREG-75/087 (the Standard Review Plan) and are acceptable.

We requested that applicants perform a review of the electrical control circuits for all safety-related equipment to assure that disabling of one component will not, through incorporation in other interlocking or sequencing controls, render other components inoperable. The applicants documented that this is not a design practice and that the following criteria were used in their review.

- (1) Racking out the breaker, disconnecting the motor starter, or removing from service a valve electric operator assembly for safety-related equipment shall not render inoperable any equipment in the redundant system(s).
- (2) Racking out the breaker, disconnecting the motor starter, or removing from service a valve electric operator assembly for nonsafety-related equipment shall not render inoperable any safety-related equipment.
- (3) Interlocks in the starting circuitry that prevent redundant equipment from being run simultaneously (to the safety status/position) shall not be used.

Our review revealed no such interlocks.

The onsite emergency power sources are diesel generator units. These units are automatically started by either a safety injection actuation signal or emergency bus undervoltage. There is one generator per bus, driven by a 16 x 20 cylinder tandem diesel engine configuration with an electrical rating of 4700 kilowatts, continuous. The continuous rating is above the predicted operating loads. Analysis has shown that during the loading sequence, the frequency and voltage are maintained above a level which would degrade the performance of any load below minimum requirements. This meets the requirements of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies." We find this to be acceptable, subject to successful preoperational testing. We will request that our Office of Inspection and Enforcement provide followup at the plant site on this item.

Branch Technical Position ICSB 2 (PSB), found in Appendix 8A of NUREG-75/087 (the Standard Review Plan), requires that new and previously untried diesel generator designs to be used in nuclear power plant service undergo a prototype qualification program. This qualification program requirement is applicable to the tandem diesel configuration used at San Onofre 2 and 3. The applicants have referenced the program accomplished on a similar unit at Washington Public Power Supply System Nuclear Project No. 2 (Docket No. 50-397). We have reviewed the bases and rationale presented by the applicants for accepting the referenced diesel generator as an applicable prototype machine and concur with the applicants on its applicability.

Our review of the qualification program indicates it to be in conformance with our position. We notified the applicants that because the referenced test results had

not been provided on the referenced docket, the results should be submitted on the San Onofre 2 and 3 docket. We have subsequently received, reviewed and approved the results of the prototype qualification program. Therefore, we conclude that the diesel generator units have been acceptably qualified for nuclear power plant service.

Branch Technical Position ICSB 17 (PSB) also found in Appendix 8A of NUREG-75/087 (the Standard Review Plan) requires that diesel generator protective trips be bypassed when the diesel generator is required for a design basis event. All protective trips are allowed during periodic testing. The allowed exceptions to the above requirement for bypassing are diesel overspeed and generator differential. Any other trips retained must utilize coincident logic in order to avoid spurious trips. The applicants have provided the two trips mentioned above plus low lube oil pressure, the latter using a 2-out-of-3 coincidence logic. This is in full conformance with our position and is acceptable.

We have reviewed the diesel generator alarms and status information provided for the control room operator. The control room annunciation consists of single input alarms and multiple parallel or series alarms. The annunciator window engraving for the single input alarms identifies the specific nature of the problem. The window engraving for the multiple parallel or series input alarms is generalized and the operator requires the aid of the computer to interpret the alarm. The only condition that renders the diesel generator incapable of responding to an automatic emergency start signal with no control room alarm is the maintenance mode. For this mode, the following items assure operator awareness of diesel generator inoperability: (1) a key-locked switch on the mimic bus panel in the "maintenance mode" position, (2) red tags on the mimic bus panel and local panels that indicate the diesel generator is under maintenance, (3) involvement of the operator in the administrative procedure of placing the diesel generator in the maintenance mode and (4) light indication on the engineered safety features bypass status panel, which indicates that the diesel generator unit is in an inoperable status. We find this aspect of the design to be acceptable.

NUREG/CR-0660, "Enhancement of Onsite Emergency Diesel Generator Reliability," made specific recommendations on increasing the reliability of nuclear power plant emergency diesel generators. Information requests concerning these recommendations, and also concerning the design of the fuel oil storage and transfer system, were transmitted to the applicants in November 1980. The applicants responded in a letter dated November 26, 1980, stated how they meet or will meet the recommendations of NUREG/CR-0660 and our additional concerns.

We have reviewed these responses and have determined that conformance to recommendations is as follows:

<u>Recommendation</u>	<u>Conformance</u>
(1) Moisture in Air Start System	Yes
(2) Dust and Dirt in D/G Room	Yes
(3) Turbocharger Gear Drive	No
(4) Personnel Training	Yes
(5) Automatic Prelube	Yes
(6) Testing, Test Loading and Preventative Maintenance	Yes
(7) Improve Identification of Root Cause of Failures	Yes
(8) D/G Ventilation and Combustion Air Systems	Yes
(9) Fuel Storage and Handling	Yes
(10) High Temperature Insulation for Generator	*
(11) Engine Cooling Water Temperature Control	Yes
(12) Concrete Dust Control	Yes
(13) Vibration of Instruments and Controls	No

We have reviewed the above and conclude, for the reasons given below, that there is sufficient assurance of diesel generator reliability to warrant unrestricted plant operation through the first refueling period. However to assure long term reliability of the diesel generator installations we will condition the San Onofre 2** operating license to require that the following design and procedural modifications be implemented prior to plant startup following the first refueling.

- (1) Turbocharger Gear Drive: The diesel generators at San Onofre 2 and 3 have a turbocharger Mechanical Drive Gear Assembly whose gear ratio is 18:1. This drive gear assembly has not been designed to operate at no load or light load conditions and full rated speed for prolonged periods. To improve the reliability and availability of the diesel generators on demand we require the installation of a heavy duty turbocharger drive gear assembly as recommended by NUREG/CR-0660. The applicants state that the manufacturer (EMD) has developed another heavy duty turbocharger drive gear assembly and will be available in the near future.

* Explicit conformance is considered unnecessary by the staff in view of the equivalent reliability provided by the design, margin and qualification testing requirements that are normally applied to emergency standby diesel generators.

**We will require that the above design and procedural modifications will be made in San Onofre 3 prior to fuel loading.

The applicants have committed to install a heavy duty turbocharger gear drive assembly on the diesel generators during the first refueling or as soon thereafter as the assemblies are available. In the interim the applicants have stated that the following procedures will be incorporated into the plant operating procedures:

- (a) Plant test procedures will require that the diesel generator units be paralleled to the safeguard buses and loaded as quickly as possible during the periodic tests.
 - (b) Emergency operating procedures will limit the time of no load operation and require the operator to shutdown the unit if the diesel operates more than 30 minutes in a no load condition.
 - (c) The turbocharger mechanical drive gear assemblies will be replaced after 200 cumulative hours of no load operation or 1000 cumulative hours of operation under a combined no-load and moderate load operation whichever comes first as recommended by the manufacturer.
- (2) Vibration of Instruments and Controls: The applicants have stated that because of the plant design the diesel engine mounted controls and monitoring instruments cannot be separately floor mounted. To resolve the problem of diesel engine vibration induced damage to the engine instruments and controls, the applicants have stated that they will environmentally qualify for vibration service all engine mounted controls and instrumentation during the preoperational test period. Until the environmental qualification of the components is completed, the applicants have stated that they will perform an augmented inspection, test, and calibration program. This program will require that all instrumentation be tested and calibrated before and after the preoperational testing of the diesel generator units. Subsequently, the instrumentation will be tested and recalibrated as required every six months or 12 hours of engine operation, whichever comes first.

The present diesel generator design meets the requirements of Criteria 17, 18 and 21 of Appendix A of 10 CFR Part 50. Upon completion of the above changes and modifications, the design of the diesel generator and its auxiliary systems will also be in conformance with recommendations of NUREG/CR-0660 for enhancement of diesel generator reliability and the related NRC guidelines and criteria. We therefore conclude that this will provide reasonable assurance of diesel generator reliability through the design life of the plant.

The containment electrical penetrations are designed to withstand the maximum available fault current for times in excess of that required by the secondary circuit protection to function. Regulatory Guide 1.63, "Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants," recommends the provision of single failure protection for each penetration. Our review has shown that all penetrations with the exception of the 6.9 kilovolt reactor coolant pump

motor circuits meet this criterion. The problem identified with these 6.9 kilovolt circuits was that a single source of direct current control power was used for both the primary and backup protection schemes. We required that the applicants provide a different source of control power for one of the two protection schemes. The applicants have made the following design change to accommodate our requirement. The backup scheme control power for Unit 2 will now be provided by the Unit 3 non-Class 1E 125 volt battery and the Unit 3 backup scheme control power will be provided from the Unit 2 non-Class 1E 125 volt battery. We find that this modification meets our requirements and that the containment electrical penetration protection is acceptable.

The field cables inside the containment are connected to the containment electrical penetrations assemblies, utilizing electrical connector assemblies, terminal blocks and splices. The connections are made inside the electrical penetration assembly termination boxes.

The electrical connector assemblies are qualified to withstand a LOCA or MSLB environment. The splices used for Class 1E service inside the containment electrical penetration assembly termination boxes are made up of termination lugs and Raychem Thermfit Type WCSF-N and MCK-N heat-shrinkable sleeves. The termination lugs and Type WCSF-N and MCK-N heat-shrinkable sleeves are qualified to withstand a LOCA or MSLB environment. The supportive documentation for the qualification is included in revised FSAR Table 3.11A-1.

The applicants have listed 10 valves in section 16.4.5.2.1 of the proposed Technical Specifications that require power lockout in order to meet the single failure criterion in the fluid system. Branch Technical Position ICSB 18 (PSB) in Appendix 8A of NUREG-75/087 (the Standard Review Plan) requires that all such valves be listed in the Technical Specifications and that the position indication for these valves meet the single failure criterion. The applicants have stated that power lockout will be accomplished as follows. For motor operated valves, power is removed by padlocking the motor circuit breaker handle in the open position. Valve position indication is retained by providing a separate power supply to the valve status lights. For pneumatic solenoid valves, power is removed by removing the fuse from the power/control circuit. Valve position indication is retained by separately fusing the valve status lights. In order to meet our requirements that redundant valve status indication be provided to the control room operator, the applicants have provided the following designs. For the two reactor coolant loop hot leg safety injection valves, analog position indication is provided on the main control board and is independent of the valve status lights and the valve open/close circuitry. The second set of indications for the four safety injection tank isolation valves are provided on the bypassed and inoperable status indication panel. The applicants have proposed an alternative diverse method for identifying valve position on the four normally locked closed safety injection tank vent valves. Should a valve be inadvertently opened, the corresponding safety injection tank pressure will decrease and this will be alarmed and indicated in the control room. We find that the listing of the valves in the Technical Specifications, the methods of power lockout and the valve position indication are in accordance with our position and are acceptable.

Motor-operated valves with thermal overload protection devices for the valve motors are used in safety systems and their auxiliary supporting systems. Operating experience has shown that indiscriminate application of thermal overload protection devices to the motors associated with these valves could result in needless hindrance to successful completion of safety functions. Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves," (November 1975) addresses this subject. The guide recommends, in position C.1, bypassing during accident conditions or, in position C.2, properly selecting the setpoints for the thermal overloads in a manner that precludes spurious trips. This guide represents current staff practice and is the successor to branch technical position EICSB-27 "Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves." The applicants' documented criteria are in accordance with position C.2 of the guide and are acceptable.

In conclusion, we find the Class 1E alternating current power and distribution system has the required independence, redundancy, and capability to perform its safety function while degraded by a single failure. The system fulfills the requirements of Criteria 17 and 18 of the General Design Criteria, IEEE Standard 308-1974, and applicable regulatory guides. Therefore, we find the Class 1E alternating current power and distribution system at San Onofre 2 and 3 to be acceptable.

8.3.2 Direct Current Systems

Four Class 1E 125 volt direct current power subsystems (A through D) are provided for each unit at San Onofre 2 and 3. Each subsystem consists of a battery, battery charger, distribution switchboard and an engineered safety features distribution panel. Each battery is located in a separate room with separate ventilation within the control building. Subsystems A and B provide control power for 4.1 kilovolt and 480 volt loadcenter alternating current load groups A and B, diesel generator A and B control systems and channels A and B control systems, respectively. Also, these subsystems provide direct current power to the inverters for channels A and B, as well as to train A and B direct current actuators, respectively. Subsystems C and D provide only for nuclear steam supply system control power and direct current power to the inverters for channels C and D, respectively, as well as to the inverters for the two redundant shutdown cooling system suction isolation valves. No provisions exist for either manually or automatically transferring loads or sources between the redundant direct current subsystems in accordance with Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems." There are no provisions for any interunit connections. Based upon our review we find that the four direct current subsystems are independent.

There are four Class 1E 120 volt alternating current vital instrumentation and control subsystems (A through D) derived from the four direct current systems discussed above. These subsystems provide power to the four channels of the reactor trip and engineered safety features actuation system and are electrically and physically isolated from each other. Each vital instrumentation and control alternating current power supply consists of one inverter, one distribution panel,

and one manual transfer switch. Normally, the distribution panel is supplied from the inverter. Each inverter is supplied by a separate Class 1E 125 volt direct current subsystem. If an inverter is to be removed from service for maintenance or testing, a backup supply is provided from a Class 1E regulating-type transformer through a manual transfer switch. Provisions are made to prevent the backup power supply from being connected to more than one inverter at a time. Further, there are no provisions for either manually or automatically transferring loads or sources between the redundant subsystems, nor are there provisions for any interunit connections. Based upon our review we conclude that the four vital alternating current subsystems are independent.

There are also two non-Class 1E direct current power subsystems provided for each unit consisting of a 125 volt direct current and a 250 volt direct current subsystem. These two systems consist of a battery, battery charger and a distribution switchboard. Normal power is derived from the non-Class 1E alternating current system through the battery chargers. The 125 volt system supplies direct current power to non-Class 1E control, instrumentation, and power loads such as emergency lighting, valve actuators, and the inverter for the plant computer system. The 250 volt system supplies direct current power for the turbine emergency bearing oil pump, emergency hydrogen seal oil pump, and feedwater pump turbine emergency oil pump motors. Based upon our review we find that these non-Class 1E direct current subsystems are independent of the Class 1E direct current subsystems and are acceptable.

Each Class 1E battery has sufficient capacity to independently supply the required safety loads for 90 minutes. The capacity of each battery charger is based upon the largest combined demand of all the steady state loads and the charging current required to restore the battery from the design minimum charge state to the fully charged state within 12 hours. The battery chargers also have the capability to perform their required function if their associated battery is disconnected for any reason. This is in accordance with Regulatory Guide 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," and is acceptable.

The Class 1E direct current system is also designed to assure equipment protection from damaging overvoltages from the battery chargers that may occur due to faulty regulation or operator error. The battery chargers are equipped with built-in overvoltage shutdown protection circuitry to sense output voltages over a given setpoint and shut the battery charger down after an adjustable time delay. In addition, overvoltage relays are provided in both the battery chargers and the direct current switchboards which actuate an alarm in the main control room to alert the operator of an overvoltage condition. We find this aspect of the design to be acceptable.

In conclusion, the Class 1E direct current power subsystems (and their associated alternating current vital buses) have the required independence, redundancy, and capability to perform their safety functions while degraded by a single failure.

This fulfills the requirements of Criterion 17 of the General Design Criteria. We find the San Onofre 2 and 3 direct current systems to be acceptable.

8.3.3 Testability of the Onsite Power Systems

We have reviewed the provisions described in the Final Safety Analysis Report for testing the alternating current and direct current portions of the onsite power system. Our review was conducted to determine the capability to perform surveillance tests that are included in the Technical Specifications and the testing capability required by Criterion 18 of the General Design Criteria. On the basis of our review, we conclude that the design as presented will be capable of meeting these requirements. The integrated systems tests required by Criterion 18 can only be performed during shutdown conditions. The large majority of the component testing required can be done during power operation. We find this aspect of the design to be in accordance with Criterion 18 and acceptable.

8.3.4 Separation and Identification of Safety-Related Power Equipment and Systems

Although the San Onofre 2 and 3 design preceded the promulgation of Regulatory Guide 1.75, "Physical Independence of Electric Systems," we used this guide as a reference in determining the acceptability of the design. We identified three items during our review which we felt required either a design change or further information. The first item was our requirement that the low pressure emergency spray pump motor (a non-safety load powered from a safety bus) must be automatically tripped on receipt of an accident signal or must be removed from the safety bus and powered from a non-safety power supply. The applicants responded to this position by modifying the design to automatically trip this non-safety motor load on receipt of an accident signal. We find this aspect of the design to be acceptable.

The second item dealt with the control and instrumentation circuits for the essential lighting system. At our request, the applicants clarified the details of this aspect of the design. The only non-Class 1E circuit that is connected to Class 1E circuits without going through an isolation device is the annunciator circuit from the motor control center. This circuit is of such low energy that it does not provide a credible threat as a failure mechanism for the Class 1E circuits. We find this aspect of the design to be acceptable.

The third item was our requirement for further verification that when non-safety circuits leave a safety division or become non-associated with safety circuits, they are not routed in a manner as to become associated with redundant safety divisions. The applicants stated that electrical elementary diagrams are visually inspected to verify the routing, that the design review of the installation of circuits and raceway systems includes this consideration, and that the computerized circuit and raceway schedule further aids in this verification. We find that the above measures satisfy our concerns and are acceptable.

Physical identification of safety-related equipment is accomplished as follows. Four categories of safety and one category of non-safety circuits have been established. Each category has a color associated with it. Nameplates of appropriate color background are provided for all electrical equipment. Alphanumeric information on the nameplates uniquely identifies each component. Raceways are marked every 15 feet if safety-related and every 25 feet if non-safety related. The cables in these raceways are color coded throughout the entire cable length to verify initial installation. We find the above identification criteria to be acceptable.

9.0 AUXILIARY SYSTEMS

We have evaluated the design bases for the auxiliary systems, including their safety-related objectives, and the manner in which these objectives are achieved.

The auxiliary systems evaluated during our review which are necessary for safe plant shutdown include the saltwater cooling system, component cooling water system, ultimate heat sink, portions of the chemical and volume control system, and safety-related ventilation systems.

Our review of the San Onofre 2 and 3 systems necessary to assure safe handling of fuel and adequate cooling of the spent fuel include the new and spent fuel storage facilities, portions of the fuel pool cooling and purification system, portions of the fuel handling system, and portions of the fuel handling building ventilation system.

We have reviewed the sump and drain systems, whose failure would not prevent safe shutdown but could indirectly be a potential source of radiological release to the environment.

We have also reviewed certain auxiliary systems whose failure would neither prevent safe shutdown nor result in potential radioactive releases. These include the pressurizer relief tank, domestic water system, makeup demineralizer system, nuclear service water system, compressed air systems, and the nonsafety-related ventilation systems. The acceptability of these systems was based on our review which determined that: (a) where the system inter-faces or connects to a seismic Category I system or component, seismic Category I isolation valves will be provided to physically separate the non-essential portions from the essential system or components, and (b) the failure of non-seismic systems or portions of the systems will not preclude the operation of safety-related systems or components located in close proximity. We find that the above listed systems meet the above criteria and are acceptable.

9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

The new fuel storage racks provide dry storage for approximately one-third of the full core load. The racks are designed to maintain the fuel assemblies in an array which will limit the effective multiplication factor to 0.92 under the conditions of complete flooding by unborated water and 0.98 in the event that optimum moderating conditions occur. The outer structure of the rack design precludes the inadvertent placement of a fuel assembly in the rack closer than the design spacing. The new fuel storage racks are anchored to the new fuel storage floor. The new fuel racks and storage structure are designed to seismic Category I requirements.

We have reviewed the adequacy of the design of the new fuel storage facility with regard to its capability to maintain a subcritical array during normal, abnormal, and accident conditions. We conclude that the design is in conformance with Criterion 62 of the General Design Criteria and the positions of Regulatory Guide 1.13, "Fuel Storage Facility Design Basis," including the positions on seismic design and missile protection, and is acceptable.

9.1.2 Spent Fuel Storage

A separate fuel handling building and spent fuel storage pool is provided for each Unit at San Onofre 2 and 3. The storage pools and spent fuel racks are designed to seismic Category I requirements. Each fuel pool has a stainless steel liner and will be filled with borated water. The fuel handling buildings are seismic Category I and are protected against design and wind loadings and tornado-generated missiles. The fuel storage racks in each fuel pool are designed to provide storage for 800 fuel assemblies including some San Onofre Unit 1 fuel (see Section 9.1.3). The racks are designed to withstand crane uplift forces, and are also designed so that impact from accidental dropping or side swinging of a fuel assembly will not damage the stored assemblies. The fuel storage area is not exposed to overhead handling of the spent fuel cask or other heavy suspended loads.

The spent fuel pool racks are designed to accept Unit 2 and 3 fuel assemblies having enrichments up to 3.7 weight percent U-235. Unit 1 fuel assemblies having enrichment up to 4.0 weight percent are also to be stored. Each storage location consists of a stainless steel can of square cross-section having an outer dimension of 8.81 inches and a minimum wall thickness of 0.120 inch. These storage cans are arranged in a square array with center-to-center spacing of 12.75 inches.

For conservatism, calculations of reactivity are performed for the highest enrichment, no burnable poison, and fresh fuel assemblies. They were assumed to be in the most reactive locations in the cans in a pool filled with unborated water. No credit was taken for fuel assembly structural elements (spacers, etc.) nor for rack structure other than the stainless steel cans. The entire range of pool water temperatures from 32°F to boiling was covered. Calculations were performed by state-of-the-art diffusion theory and transport theory codes.

The value of the effective multiplication factor for the pool including all uncertainties was determined to be less than 0.946 for the Unit 2 and 3 fuel and less than 0.924 for the Unit 1 fuel. The stainless steel clad of Unit 1 fuel more than offsets its greater enrichment.

We find the analysis of spent fuel pool criticality to be acceptable for the following reasons:

- (1) Comparison of the quoted effective multiplication factor with calculations by other applicants using the same and other methods shows this calculation to be conservative,

- (2) The calculated effective multiplication factors meet our acceptance criterion of less than or equal to 0.95,
- (3) State-of-the-art calculation methods have been used,
- (4) Conservative conditions with respect to enrichment, assembly placement, presence of neutron poisons (including fission products) and pool water have been assumed.

We have reviewed the design of the spent fuel storage facility and conclude that it meets the requirements of Criterion 2 of the General Design Criteria with regard to protection against the effects of natural phenomena; the requirements of Criterion 61 of the General Design Criteria with regard to provision of suitable shielding, appropriate containment, confinement and filtering capability; and the requirements of Criterion 63 of the General Design Criteria with regard to prevention of criticality. The design meets the guidelines of Regulatory Guide 1.13 "Spent Fuel Storage Design Basis" and 1.29 "Seismic Design Classification" including the positions on seismic and tornado design requirements. We conclude that the design of the spent fuel storage facility is acceptable.

9.1.3 Spent Fuel Pool Cooling and Cleanup System

The spent fuel pool cooling and cleanup system is designed to maintain the quality and clarity of the spent fuel pool water and to remove the decay heat generated by the spent fuel assemblies stored in the fuel pool. The fuel pool cooling system is designed to Quality Group C and seismic Category I requirements. It consists of two trains, each of which includes a fuel pool cooling pump and a heat exchanger. The fuel pool cooling pumps are powered from the Class 1E electrical system. The safety-related component cooling water system provides cooling water to the fuel pool heat exchangers. The fuel pool cooling system piping is arranged so that the pool cannot be inadvertently drained to uncover the stored fuel.

Assured makeup water to the spent fuel pool is routed from the seismic Category I refueling water storage tanks (RWSTs). At our request the applicants, in FSAR Amendment 19, revised the system design to include Category I piping connecting the RWSTs with the spent fuel pool cooling pump suction side. Alternate sources include the nuclear service water and primary plant demineralized water.

The FSAR states that the system is designed to remove the heat from 800 assemblies (equivalent to about 2-1/3 Unit 2 or 3 cores, and 2 Unit 1 cores) including one full Unit 2 or 3 core that is placed in the pool 7 days after reactor shutdown, and one full Unit 1 core 90 days after the shutdown. FSAR Amendment 21 states that for this storage case, with both trains operating, the maximum fuel pool temperature would be 140°F. The shutdown cooling system can be used as backup cooling for the spent fuel pool cooling system when the fuel core is removed from the reactor vessel. The FSAR also presents a "normal" case, for which the system removes the decay heat produced by 583 assemblies, (equivalent to about 1-2/3 Unit 2 or 3 cores, and about 1-1/3 Unit 1 cores) including 1/3 of a Unit 2 or 3 core placed in the pool 7 days after

reactor shutdown. With one spent fuel pool cooling train in service, the spent fuel pool temperature would not exceed 140°F.

We have reviewed the design of the spent fuel cooling and cleanup system and conclude that it meets the requirements of Criterion 2 of the General Design Criteria regarding protection against the effects of natural phenomena, Criterion 44 regarding provision of suitable redundancy, and Criterion 61 as related to fuel storage systems design with provisions for containment of radioactive materials and decay heat removal. We further conclude that the system design meets the guidelines of Regulatory Guides 1.13, "Spent Fuel Storage Design Basis" regarding provision of a seismic Category I makeup system and prevention of excessive fuel pool water loss, 1.26 "Quality Group Classification and Design" regarding quality class, and 1.29 "Seismic Design Classification." The fuel pool temperatures are in conformance with the guidelines of Standard Review Plan Section 9.1.3. We conclude that the system design is acceptable.

9.1.4 Fuel Handling System

The fuel handling system is designed to provide safe means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the station after post-irradiation cooling.

The cask handling crane is designed to handle fuel casks up to 125 tons in weight. Both the crane and supports are designed to seismic Category I requirements. The spent fuel cask loading area is separated from the spent fuel pool by a 4-foot-thick reinforced concrete wall so that a spent fuel cask drop cannot damage the spent fuel pool. The loading area is connected to the spent fuel pool by a transfer canal. The travel of the spent fuel cask is limited to an area which contains no safety-related equipment or stored new or spent fuel, with the exception of the safety-related pool cooling system pumps and heat exchangers. The portions of the floor above the fuel pool cooling system components are designed to withstand cask drop loads without damage to the pumps and heat exchangers.

During cask handling operations, the fuel cask is not exposed to a drop of more than 30 feet onto an unyielding surface. The maximum possible drop height of 34 feet to plant grade occurs at a point above the open hatch to the rail car. Administrative controls will be employed to ensure that the 3-foot-high rail car is in place during cask handling operations to reduce drop height and provide a yielding surface. The cask handling system is designed to prevent cask travel over the spent fuel pool and the new fuel storage area. The cask crane travel is further restricted by limit switches. These switches limit horizontal cask travel and prevent the cask from being lifted more than six inches above the operating floor. We conclude that the cask handling system design makes it highly unlikely that the spent fuel or spent fuel pool structure will be damaged by a dropped cask.

We have reviewed the adequacy of the San Onofre 2 and 3 design to insure safe operation of the fuel handling system during normal, abnormal, and accident conditions. We conclude that the design is in conformance with the positions of Regulatory Guide 1.13, "Spent Fuel Storage Facility Design Basis," including the position regarding protection of the spent fuel storage facility from the impact of unacceptable heavy loads carried by overhead cranes, and is acceptable.

9.2 Water Systems

9.2.1 Saltwater Cooling System

The saltwater cooling system, an engineered safety feature support system, provides saltwater from the Pacific Ocean to the component cooling water heat exchangers for cooling during normal power generation, normal and emergency shutdown and cooldown of the reactor, and during the design basis loss-of-coolant accident. The saltwater cooling system for each unit consists of two 100 percent capacity critical trains, each of which may be supplied by either of two saltwater cooling pumps. Each train contains two pumps; one pump is located in the Unit 2 intake structure, and the other is located in the Unit 3 intake structure.

Any one of the four saltwater cooling pumps for each unit is capable of providing 100 percent of the cooling flow required after a postulated design basis accident. The saltwater discharge from the component cooling water heat exchangers is normally routed through the condenser circulating water return lines and it is backed up by an emergency discharge line which can overflow the discharge water outside the sea wall.

Essential portions of the system are designed to Quality Group C, seismic Category I requirements, and are protected to withstand adverse environmental occurrences, such as tornadoes and floods. Each train is powered from a separate essential alternating current bus. The Pacific Ocean in conjunction with the offshore intake and outfall conduits and the intake structures serves as the ultimate heat sink for the saltwater cooling system which is discussed in Section 9.2.3 of this report.

Based on our review, we conclude that the San Onofre 2 and 3 saltwater cooling system design is in conformance with the requirements of Criterion 44 of the General Design Criteria regarding the ability to transfer heat from safety-related components to the ultimate heat sink and regarding the single failure criterion. It is also in conformance with the requirements of Criteria 45 and 46 of the General Design Criteria regarding the system design for periodic tests and inspections, including functional testing and confirmation of heat transfer capabilities. We conclude that the system is acceptable.

9.2.2 Component Cooling Water System

The component cooling water system (CCWS) provides an intermediate cooling loop for removing heat from reactor plant auxiliary systems and transferring it to the saltwater cooling system. The CCWS consists of two independent closed loop flow paths. Each flow path contains one full capacity CCW pump which pumps water through

the CCW heat exchangers, where the system heat load is transferred to the saltwater cooling system. The cooled water then circulates to the plant components and returns to the pump suction. One of the two redundant flow paths is required during a design basis accident to meet the minimum engineered safety feature requirements. A third full CCW pump is provided and may be manually aligned to any one of the independent loops should one of the in service pumps fail.

Essential portions of the system are designed to Quality Group C, seismic Category I requirements, and are protected to withstand adverse environmental occurrences, such as tornadoes and floods. Each train is powered from a separate essential alternating current bus. The noncritical portions of the CCWS will be automatically isolated from the essential portions of the system during a design basis accident.

The CCWS provides a single supply and a single return line for all four reactor coolant pumps (RCPs). Each of these lines contains motor-operated valves for containment isolation. The motors, seals, and bearings of the reactor coolant pumps require continuous cooling. Inadvertent failure or closure of any one of the above motor-operated valves would terminate the cooling flow to all of the coolant pumps, thus potentially leading to fuel damage or breach of the primary system barrier resulting from multi-pump locked motor or pump seal failure.

During the course of our review, we notified the applicant that the component cooling water system design is to meet the following criteria:

- (1) A single failure in the CCWS shall not result in fuel damage or damage to the reactor coolant system pressure boundary caused by an extended loss of cooling to the RCPs. A single failure includes operator error, spurious actuation of motor-operated valves, and loss of CCW pumps.
- (2) A moderate energy leakage crack or an accident that is initiated from a failure in the CCWS piping shall not result in excessive fuel damage or a breach of the reactor coolant system pressure boundary when an extended loss of cooling to the reactor coolant pumps occurs. A single active failure shall be considered when evaluating the consequences of this accident. Moderate leakage cracks should be determined in accordance with the guidelines of Branch Technical Position APCS 3-1, "Protection Against Postulated Failure in a Fluid System Outside Containment."

To meet the two criteria above, that portion of the CCWS which supplies cooling water to the reactor coolant pump can be designed to non-seismic Category I requirements and Quality Group D if it can be demonstrated that the RCPs are capable of operating with loss of cooling for longer than 30 minutes without loss of function and without the need for operator protective action. Also, in this case, safety grade instrumentation to detect the loss of CCW to the RCPs and to alarm the operator in the control room must be provided. The entire instrumentation system, including audible and visible status indicators for loss of CCW must meet the requirements of IEEE Standard 279-1971/1974. Alternatively, it if cannot be demonstrated that the RCPs will

operate longer than 30 minutes without loss of function or operator corrective action, the CCWS design must meet one of the following requirements:

- (1) Safety grade instrumentation consistent with the criteria for the protection system shall be provided to initiate automatic protection of the plant. In this case, the CCW supply to the seal and bearing of the pumps may be designed to non-seismic Category I requirements and Quality Group D; or
- (2) The CCW supply to the pumps shall be capable of withstanding a single active failure or a moderate energy line crack as defined in Branch Technical Position APCSB 3-1 and shall be designed to seismic Category I, Quality Group C and ASME Section III, Class 3 requirements.

In Amendment 14 to the FSAR, the applicant responded, in part, that tests were performed involving operation of an RCP with no CCW flow for 30 minutes. In the first part of the test CCW flow was terminated to the RCP motor over a test period of 23.5 minutes. In the second part of the test, CCW flow was terminated to the pump seals over a test period of 30 minutes. The applicant stated that "the combined results of the two tests described above demonstrate that there is sufficient time available to allow the loss of CCW event to be terminated by operator action after 30 minutes to either restore CCW or turn off the RCP.

We requested the applicants to provide additional information to demonstrate that the RCP tests simulated the most severe condition of loss of CCW in view of the fact that they were performed separately for the motor bearings and pump seals. We also requested that the applicant provide information to demonstrate that the test simulated operating conditions with regard to operating pressure, pump speed, and motor load conditions, and that the pumps did not develop excessive vibration during the tests. In the applicant's response it was concluded that the tests as performed represent the integrated RCP and motor performance during a loss of the CCWS. With the CCW flow cut off to the pump motor, the increase in temperature in the motor oil reservoir would not accelerate shaft seal failure unless there was a gross failure of the motor bearings or other component. Conversely, with the CCW flow cut off to the pump seal, the increasing instability of the shaft seal controlled bleedoff flow experienced during the test would not affect the operation of the motor unless there was a gross failure of the pump shaft seals. The applicant also provided sufficient information to indicate that the tests were run at pump speeds, pressures and motor loads that simulated operating conditions, and that, while some increase in shaft vibration was noted during the test, this vibration decreased after CCW flow was restored, and a post-test examination did not indicate observable damage. We conclude that these tests adequately simulated loss of CCW flow to the RCP, and that the tests demonstrate that the RCPs are capable of operating with loss of cooling for a period of time compatible with corrective operator action.

We further requested that the applicants provide information to demonstrate that the operators will be provided with sufficient safety grade instrumentation to alert them to a CCW flow failure to the RCPs. The applicants provided sufficient information to

demonstrate that failure of common valves in the RCP CCW supply and return lines will be indicated in the control room by safety grade instrumentation. In addition, there are multiple, diverse alarms in the control room that alert the operators to off-normal RCP and motor parameters. While these instruments and annunciators are not safety grade, a failure of a non-IE signal would result in annunciation.

We have reviewed the CCWS design and conclude that it meets the requirements of Criterion 2 of the General Design Criteria regarding its capability of withstanding the effects of natural phenomena; Criterion 4 regarding capability of withstanding the effects of external and internal missiles and the effects associated with pipe breaks; Criterion 44 regarding the capability to transfer heat loads from safety related components to a heat sink under both normal operating and accident conditions, provision of suitable redundancy, and the capability to isolate subsystems if required so that the system safety functions will not be compromised; Regulatory Guide 1.26 "Quality Group Classification and Design" regarding quality class, and Regulatory Guide 1.29 "Seismic Design Classification." We conclude that system design is acceptable.

9.2.3 Ultimate Heat Sink

The ultimate heat sink provides cooling water from the Pacific Ocean for use in the saltwater cooling system during all modes of plant operation, including loss of offsite power or safe shutdown of the plant following an accident. The ultimate heat sink consists of the Pacific Ocean, with one intake conduit and one outfall conduit per unit, and includes the seismic Category I portion of the intake structures where the saltwater cooling pumps are located. The saltwater cooling pumps take suction from the intake structure to serve the component cooling water heat exchangers as described in Sections 9.2.1 and 9.2.2 of this report.

The intake and outfall conduit structures from the seawall landward are designed to seismic Category I requirements. The offshore intake conduits and structures from the seawall seaward were not originally designated seismic Category I structures. In response to our request, the applicants, in Amendment 12, to the FSAR provided a design modification of the system that provides a seismic Category I offshore intake conduit and a seismic Category I offshore intake structure downstream of the existing non-seismic Category I intake structure at the end of the offshore intake conduit.

Based on our review, we conclude that the design of the ultimate heat sink meets the guidelines in Regulatory Guide 1.27, "Ultimate Heat Sink For Nuclear Power Plants," and is acceptable.

9.2.4 Condensate Storage and Transfer System

The condensate storage and transfer system consists of two condensate storage tanks, a condensate transfer pump, and associated piping and valves. One of the condensate storage tanks, together with its associated piping and valves, is designed to seismic Category I requirements and serves as an assured water source to the

auxiliary feedwater system for plant safe shutdown. This tank has a capacity of 150,000 gallons and is located in a totally enclosed concrete structure which is protected from tornadoes, missiles, and flooding. A second condensate storage tank with a 500,000 gallon capacity provides makeup water to the seismic Category I tank. This tank is non-safety grade but is surrounded by a seismic Category I concrete wall.

We require that the applicants provide an assured condensate supply sufficient for maintaining the plant at hot standby for four hours followed by cooldown to 350°F with a failure of one power operated relief valve. During the course of our review, we informed the applicants that a total of 24 hours of assured water supply (approximately 350,000 gallons) would be acceptable. This requirement necessitates the use of approximately 200,000 gallons of the condensate contained in the non-seismic Category I tank. The applicants asserted that, in the event of the SSE, the condensate would be retained by the seismic Category I wall. We questioned the water retaining capability of the concrete wall surrounding the 500,000 gallon tank over a 24 hour period after the SSE, since cracks could form as a result of the earthquake. We also require demonstration that tornado generated missiles will not prevent utilization of the tank contents for safe cooldown. To show that San Onofre 2 and 3 meet our requirements, the applicants submitted a report titled "Watertight Reliability of Condensate Storage Tank and Its Concrete Enclosure Walls Under DBE and Tornado Effects," September 1980, followed by supplemental information transmitted in December 1980. Our review of the applicants' analyses is given below.

9.2.4.1 Introduction

In partial response to FSAR Question 010.65, the applicants provided an analysis to demonstrate that the condensate storage tank and its surrounding enclosure walls constitute a reliable storage facility to satisfy emergency cooling water requirements. The structural integrity, watertightness and water recovery aspects of the storage facility are verified with respect to the SSE and the tornado event postulated for San Onofre 2 and 3.

9.2.4.2 Structural Evaluation and Analytical Model

The structural analysis of the enclosure walls was performed with a finite element analytical model of the relevant portions of the structure. The wall which has the longest span was selected for the model since its long horizontal span makes it governing in terms of flexural response and crack formation. The boundary conditions were selected to obtain the most accurate evaluation of the displacement response undergone by the walls, since it was recognized that flexural deflection and curvature are of vital importance in the calculation of crack widths. The rotational boundary conditions at the vertical corners of the wall were represented by extending the model to include the connecting cross walls and introducing the fixed boundary at the end. The base boundary condition of the wall was also considered fixed. This assumption is substantiated by the 4 foot thick base mat and its overburden load from the heavy tank contents.

Consistent with the necessity to obtain an accurate and conservative evaluation of the wall deformations, a relatively fine mesh of finite elements with reduced effective moments of inertia was adopted for the model. The element moments of inertia were reduced to recognize the flexural section that results upon concrete cracking, and were calculated in accordance with ACI Code 318-71, Section 9.3.2.2. According to the Code formulation, the effective moment of inertia is a function of the actual flexural moment developed which in turn depends on the moment of inertia used. Therefore an interactive procedure was implemented and the ultimate results were deflections and curvatures which are conservatively higher than those initially obtained using the moment of inertia of the gross concrete section.

The loadings considered were hydrostatic, and seismic loads due to inertial response of walls and hydrodynamic effects due to convective and impulsive fluid pressures derived in "Nuclear Reactors and Earthquakes", TID7024, U.S. Atomic Energy Commission, August 1963. Three-component earthquake responses were considered, even though under the governing outward pressured loadings, there is no additive effect for the two horizontal components since the maximum out-of-plane displacement response of a single wall, at a given time, is the governing response. The hydrodynamic pressures from the earthquake components were combined by the square root of sum of squares, SRSS. The resultant hydrodynamic pressure was combined with the seismic response of the walls by absolute summation as a conservative recognition of the long-period, "sustained" type of response characteristic of seismic sloshing of liquids.

9.2.4.3 Determination of Crack Widths

The crack widths were evaluated using two different approaches, and the higher of the calculated values derived from the more rigorous approach was used in the leakage calculation.

In the first approach, the crack width is formulated as a function of the tensile stress in the reinforcing steel using an equation derived from experimental correlations. The formulation used is per ACI Committee 224, which in turn is an adaptation of the original research by Nawy (1972a and 1972b).

The total crack width as obtained from the dominant flexural and the lesser axial tension stresses was calculated. The flexural stresses were determined by linear elastic analysis of the reinforced concrete sections using working stress design (WSD) formulations. This provides an evaluation for sections subject to moments below the ultimate capacity, whereas for sections at or near the ultimate yielding moment, the appropriate ultimate strength design (USD) formulations were used. Axial stresses were found to be generally insignificant since the in-plane membrane tensions developed in this type of flat-wall flexural systems are normally low. The only locations with some axial tension were toward the top of the walls where horizontal tension related to a slight "hoop" actions results, and the stresses were simply calculated as the tension load divided over the total area of horizontal reinforcing (< 1 ksi).

The second approach for the calculation of crack widths is based on the curvature of rotational deformation undergone by the flexural elements. The basic postulation is that the rotational deformation, which is highly predictable and well defined by the flexural action undergone by the walls, is totally achieved through a concentrated rotation assigned to be effected at the postulated crack.

The crack width then follows from the product of the rotation times the radius to the center of rotation which corresponds to the neutral axis of the section. The resultant crack calculation is thus evaluated on the basis of the fulfillment of compatibility with the analytically defined flexural deformation of walls under pressure loading.

The crack widths calculated from rotational deformation are typically higher than those obtained per the stress-dependent formulation, and the final value is adjusted upwards by adding the axial tension component as previously calculated from the stress dependent formulation.

The most severe cracking develops at the base of the walls. At this location a single concentrated crack is a credible occurrence because of the pre-existing "cold" construction joint which, on the other hand, is safeguarded by a flexible waterstop. The applicant claims, and we concurred, that in the case under consideration, the watertight reliability of the waterstop is more decisively established upon considering the favorable confined and anchored conditions afforded to the waterstop by the reinforcing bars across the joint and the shear key provided.

9.2.4.4 Analysis of Leakage

The leakage calculation was based on theoretical expressions for flow through parallel plates extended to model flow through cracks in the reinforced concrete walls. The vertical cracks were modeled as equally dimensioned horizontal cracks located at the lowest elevation of each vertical segment. Using this approach the applicant simplified the analysis by maximizing the water pressure head and considering it as constant instead of variable due to depletion of water in the enclosure.

The analysis of leakage was based on the theoretical and experimental work performed by Huitt (1956), Iwai (1976) and Louis (1969). It was found that the laminar flow obeys Darcy's law for low Reynolds number and it can be applied to both smooth and rough walled plates. The applicants used a set of empirical equations produced by Louis to calculate the amount of leakage considering the conservative flow through smooth-walled cracks. Work performed by Iwai on basalt, granite and marble was used to develop the effect of crack aperture. Although no data are available for concrete, the applicants claim, and we concur, that granite and marble data approximate concrete because concrete is composed of granitic aggregate in a limestone matrix similar to marble.

9.2.4.5 Results of the Analysis

The condensate storage tank, designated as T-120, has a rated capacity of 500,000 gallons while the minimum contents is 280,000 gallons which is enforced by plant technical specifications. Accordingly, the analysis covered several cases which included its maximum rated capacity with and without the waterstop at the bottom of the wall as well as the minimum contents with and without waterstop. The analysis was also performed for the case of maximum rated capacity and neglecting the waterstop but with the worst combination of crack simultaneously. Other situations included study of leakage through sound concrete and the postulated localized aperture at the bottom of the wall to discharge the 260,000 gallons of excess water not required for cooling over the 24 hour period upon starting with the 500,000 gallons of initial volume.

The maximum crack width as resulting from the analysis was found to be 0.039 inches and less than 1500 gallons of water would leak through the condensate storage building walls in 24 hours under the worst loading conditions (i.e., high water due to 500,000 gallons of water with SSE loading.) By neglecting the effectiveness of the waterstop throughout the length of the base crack in the most critical wall the resulting leakage would still be less than 3000 gallons which is less than 2% of the excess 260,000 gallons of water available for cooling for that period.

Assuming the most critical combination of apertures (a condition that is not credible because the maximum aperture on the outside face neglects the hydrostatic head but represents an extreme limiting calculation) leakage would be less than 40,000 gallons in 24 hours. Further, the applicants calculate that a local aperture of a crack restrained in length by the reinforcing bar spacing could be almost two orders of magnitude greater than the conservative .001 inch opening at the outside face of the wall and still leave almost 100,000 gallons of excess water in the room after 24 hours.

9.2.4.6 Effect of Tornado on Condensate Tank

The existing thin shelled tank is vulnerable to tornado missile perforation at the locations not shielded by the concrete enclosure walls. However, the adequacy of the tank is maintained based on considerations of (1) the governing missile trajectory and the angle of incidence dictated by the geometry of the tank with respect to the enclosure walls, and (2) the aggregate thickness of steel plate and travel through water that the missile must undergo before impacting the rearmost plate. These considerations demonstrate that the lower level of the tank corresponding to 220,000 gallons is not susceptible to perforation. Therefore the minimum 200,000 gallons required plus the inside-tank unrecoverable allowance of 20,000 gallons are retained as debris-free water inside the tank, and there is no need to rely on water in the annulus between the tank and its enclosure.

The limited exposure of the steel tank above the enclosure walls renders the tank adequate for maximum positive wind pressure due to tornado event. The loading due to

transient depressurization under tornado event will be reduced to an acceptable limit by incorporating venting modifications into the tank, thus rendering it adequate for all tornado pressure loadings.

9.2.4.7 Conclusions

We reviewed the information provided by the applicants and we concur with the validity of the analyses contained therein including structural analysis, leakage analysis and tornado missile evaluation. We agree with the applicants that the analyses performed were conservative and incorporated the present state-of-the-art.

In summary, we conclude that the analyses performed by the applicants are conservative, and demonstrate that the condensate storage and transfer system will provide an assured water supply for the auxiliary system for at least 24 hours, thus meeting the requirements of Criterion 2 of the General Design Criteria regarding its capability of withstanding the effects of natural phenomena, and Criterion 4 regarding its capability of withstanding the effects of external and internal missiles. We conclude that the system design is acceptable.

9.3 Process Auxiliaries

9.3.1 Compressed Air System

A stored compressed air system provides both instrument air and service air for both units at San Onofre 2 and 3. The system consists of three identical 100 percent-capacity air compressing trains. The three air receivers are connected in parallel by a common header, which branches into the instrument air and service air subsystems.

The compressed air system is required for normal operation and startup of the plant; however, all pneumatically operated devices in the plant that are essential for safe shutdown are either (1) designed to move to the safe position upon loss of air pressure, or (2) provided with a seismic Category I backup bottled nitrogen system. Therefore, a supply of compressed air is not essential for safe shutdown of the plant and the compressed air system is, accordingly, not designed to meet seismic Category I requirements or the single failure criterion except between containment isolation valves. For this same reason, the sharing of the system by Units 2 and 3 does not compromise any safety features or safety-related functions.

The design basis and criteria for the compressed air system are in accordance with Regulatory Guides 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and 1.29, "Seismic Design Classification," with regards to Quality Group and seismic category of the safety-related portions of the system. The systems are designed to protect the safety function of plant safety-related systems and are, therefore, acceptable.

9.3.2 Sump and Drain Systems

The sump and drain systems accommodate drains from potentially radioactive sources and non-potentially radioactive sources through separate subsystems. The radioactive sump and drain systems collect potentially radioactive liquid waste from equipment and floor drainage of the containment, radwaste building, fuel handling building, penetration area, storage tank area, component cooling water area, and the safety injection area. These drains are discharged to the liquid radwaste system. Drains from non-potentially radioactive sources, such as the turbine building and diesel buildings, are discharged to the oily waste treatment system. The drain lines from the engineered safety features equipment rooms are separated into separate trains. Seismic Category I check valves are installed on each train to prevent back flow of drainage into rooms of the other engineered safety features train. All engineered safety features rooms are provided with watertight doors to prevent the spread of flooding damage should flooding occur in the building.

Based on our review, we conclude that the sump and drain systems are sufficient to protect safety-related areas and components from flooding and to prevent the inadvertent release of radioactive liquids to the environment due to piping or tank failure and are acceptable.

9.3.3 Chemical and Volume Control System

The chemical and volume control system is designed to control and maintain reactor coolant inventory and also to control the boron concentration in the reactor coolant through the process of makeup and letdown. The chemical and volume control system purifies the primary coolant by demineralization. Portions of this system also supply high pressure injection of borated water into the reactor coolant system for emergency boration. The positive displacement charging pumps serve as safety injection pumps when the emergency core cooling system is required to function. This latter function is evaluated in Section 6.3 of this report.

The chemical and volume control system also collects the controlled bleed-off from the reactor coolant pumps seals and provides a means of filling, draining, and pressure testing of the reactor coolant system. The portions of the chemical and volume control system required for safe shutdown of the reactor are designed to meet the seismic Category I requirements, the single failure criteria, and are powered from essential buses.

Based on our review, we conclude that the design of the chemical and volume control system is adequate for the system to meet the intended safety function and is acceptable.

9.4 Air Conditioning, Heating, Cooling, and Ventilation Systems

9.4.1 Auxiliary Building Ventilation Systems

The safety-related portions of the auxiliary building ventilation systems consist of (1) the air conditioning systems for the control room complex, engineered safety features switchgear rooms, and charging pump rooms and boric acid makeup pump rooms; (2) the ventilating systems for battery rooms and chiller rooms; and (3) emergency chilled water system. The systems are designed to seismic Category I requirements and powered from emergency power supplies.

The control room complex air conditioning system is designed to maintain the control room complex within the environmental limits required for operation of plant controls and uninterrupted safe occupancy of required manned areas during all operational modes including the design basis accident conditions. The system is designed to maintain the control room under positive pressure. If the radiation level rises above set limits, the radiation monitoring detector system generates the control room isolation signal which closes the isolation dampers and starts the redundant emergency air conditioning system. In addition, the control room isolation can be initiated by a manual switch inside the control room. There are two emergency fan-coil units for additional cooling in the cabinet areas of each unit. These fan-coil units are started by the same signal that starts the emergency air conditioning system for the control room complex. Control room habitability systems are also discussed in Section 6.4 of this report.

The emergency air conditioning system for the engineered safety feature switchgear rooms of each unit consists of two full capacity recirculation air conditioners. Both air conditioning units are started by safety injection actuation signals (SIAS). In the event of a loss-of-coolant accident these systems will maintain the required design temperature inside the switchgear rooms.

There are three charging pump rooms and two boric acid makeup pump rooms in each unit. The emergency air conditioning system for the charging pump rooms of each unit consists of four full capacity fan-coil units. One fan-coil unit is provided for each of two charging pump rooms and the third pump room is served by two full capacity fan-coil units. The boric acid makeup pump rooms emergency air conditioning system of each unit consists of two full capacity fan-coil units. One full capacity fan-coil unit is used in each pump room. All the above emergency fan-coil units are started automatically by the SIAS.

Each of the two chiller rooms, which house the emergency chillers, is serviced by an emergency ventilation system which consists of one supply fan and one exhaust fan. Outside air is filtered through a prefilter and supplied to the chiller rooms by the supply fans. The exhaust fans exhaust the air directly to the atmosphere and maintain a slightly negative pressure in the rooms.

There are four battery rooms and two emergency exhaust fans for each reactor unit. Each exhaust fan serves two battery rooms. The battery room exhaust system is

designed to prevent the hydrogen gas concentration from reaching dangerous levels. If the hydrogen concentration in any battery room becomes high, an alarm sounds in the control room. With the above battery room exhaust system design, a single active failure of one exhaust fan will cause loss of ventilation in two battery rooms. In FSAR Amendment 3, the applicants, in response to our request, provided results of an analysis which demonstrates that in the event of a single active failure of one exhaust fan, assuming uniform mixing of gas, it will take approximately 45 days to reach the hydrogen gas concentration of 3 volume percent in the two battery rooms. In FSAR Amendment 11, the applicants, in response to our inquiry, described the indicator lights in the control room which alert the plant operators if an emergency exhaust fan is lost. We conclude that the battery room exhaust system design, in conjunction with the indications of system malfunction provided to plant operators, to be adequate to prevent possible high localized concentrations of hydrogen gas in the battery rooms.

The emergency chilled water system is shared between Units 2 and 3. It consists of two 100 percent capacity water chillers. Each chiller supplies essential chilled water to one of the redundant emergency air conditioning units located in each unit. The seismic Category I CCWS provides cooling water to remove heat from the condensers of the chillers. The system is started by a safety injection activation signal from Unit 2 or from Unit 3.

We have reviewed the design of the auxiliary building ventilation systems and conclude that it meets the requirements set forth in Criterion 2 of the General Design Criteria with regard to system protection from the effects of natural phenomena, and General Design Criterion 19 of the General Design Criteria with regard to the capability to operate the plant from the control room during normal and accident conditions, and that it meets the single failure criterion. The emergency chilled water system is in conformance with Criterion 44 of the General Design Criteria regarding the ability to transfer heat from safety-related air conditioning units. The system design meets the guidelines of Regulatory Guide 1.29 "Seismic Design Classification" as related to seismic design classification. We conclude that the design of the auxiliary building ventilation systems is acceptable.

9.4.2 Support Building Ventilation Systems

The safety-related portions of the support building ventilation systems consists of the fuel handling building ventilation system, the safety equipment building ventilation system, the diesel generator building ventilation system, the intake structure ventilation system, and the auxiliary feedwater pump room ventilation system. The portions of the systems that are required for plant safety are designed to seismic Category I requirements and powered from emergency power supplies.

The function of the fuel handling building ventilation system is to maintain a suitable environment for equipment operation and to limit potential radioactive release to the atmosphere during normal operation and postulated fuel handling accident conditions. The nonsafety portion of the system provides normal fuel

handling building heating, ventilating, and air conditioning functions and consists of two half capacity air handling units and two half capacity exhaust fans. During a postulated fuel accident or high airborne radiation level within the fuel building, the redundant radiation monitors located in the exhaust ducts automatically start the redundant post-accident cleanup units and fuel pool pump room cooling units, and isolate the fuel handling building by closing redundant isolation dampers at the normal fuel handling building ventilation system air intake and exhaust and stop the normal ventilation system operation. Post-accident cleanup units operate with recirculation air after a fuel handling accident. Safety-related component cooling water is used as a cooling medium. The fuel pool pump room emergency cooling units maintain suitable temperature for safe operation of pumps. Emergency chilled water is used as the cooling medium.

The safety-related portions of the safety equipment building ventilation system consist of the safety injection pump rooms emergency cooling system and the component cooling water pump room emergency cooling system. The safety injection pump rooms emergency cooling system includes four 100 percent capacity cooling units, one in each of the first two pump rooms and two cooling units in the third pump room. The component cooling water pump room emergency cooling system has an arrangement that is similar to that of the safety injection pump rooms emergency cooling system. All the emergency cooling units are started automatically on a safety injection actuation signal. The safety injection actuation signal also starts the emergency chilled water system which provides cooling water to the cooling units.

The diesel generator building ventilation system maintains the room temperature during emergency conditions while the diesels are operating. The safety-related portions of the diesel generator building ventilation system consist of two redundant trains. Each train serves one of the two diesel generator rooms and includes four 25 percent capacity supply fans and one 100 percent capacity exhaust fan. The system is automatically placed in operation upon receiving a corresponding diesel engine start signal. The system may also be started and stopped manually from the local control panel. The fans and their associated motor operated dampers are connected to the Class 1E bus supplied by their respective diesel generator.

The intake structure ventilation system maintains the safety-related saltwater cooling system pump room temperature to permit continuous operation of the pumps. The safety-related portions of this system consist of four 100 percent capacity exhaust fans. There is one exhaust fan in each saltwater cooling pump room.

The auxiliary feedwater pump room ventilation system maintains the auxiliary feedwater pump room temperature to permit continuous operation of the pumps. The safety-related portions of this system consist of two 100 percent capacity exhaust fans. There is one exhaust fan in each auxiliary feedwater pump room.

Based on our review of the design of the support building ventilation systems, we conclude that they meet the single failure criterion and the guidelines of Regulatory

Guide 1.29, "Seismic Design Classification," and are acceptable, except for the fuel handling building ventilation system (see Section 15.4.4 of this report).

9.5 Other Auxiliary Systems

9.5.1 Fire Protection System

9.5.1.1 Introduction

We have reviewed the San Onofre 2 and 3 fire protection program reevaluation and fire hazards analysis submitted by the applicants by letter dated October 31, 1977, including Revisions 1 through 4. The San Onofre Nuclear Generating Station is a three unit site. San Onofre Unit 1 is operating and we have evaluated the fire protection program separately. However, we have discussed and evaluated areas that have interactions between the three Units.

The San Onofre 2 and 3 reevaluation was in response to our request to evaluate their fire protection program against the guidelines of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." As part of our review, we visited 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 system. The overall objective of our review was to ensure that in the event of a fire at San Onofre 2 and 3, personnel and the plant equipment would be adequate to safely shutdown the reactor, to maintain the plant in a safe shutdown condition, and to minimize any release of radioactivity to the environment.

Our 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.

Since Units 2 and 3 are of the same design except as noted, the comments made in this report apply to both Units.

Our conclusion, given in Section 9.5.1.12, is that the Fire Protection Program of San Onofre 2 and 3 with the proposed improvements, is adequate and meets General Design Criterion 3. We consider that the fire detection and suppression systems, the barriers between fire areas, administrative procedures for control of combustibles and ignition sources, and the trained onsite fire brigade with the capability to extinguish fires manually will provide adequate protection against a fire. Our consultants, Gage-Babcock and Associates, Inc., participated in the review of the fire protection program and in the preparation of this safety evaluation report, and concur with our findings.

9.5.1.2 Fire Protection Systems Description and Evaluation

(1) Water Supply Systems

The water supply system is common to both units. It consists of three fire pumps connected through a common header to a 12-inch cast-iron, cement-lined pipe yard main. Two electric motor driven fire pumps are rated at 1500 gpm at 128 psi head each and the diesel engine driven fire pump is rated at 2500 gpm at 126 psi head. The fire pumps and their controllers are UL listed. Their design and installation conforms to the requirements of NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps."

The pumps take suction from two 375,000 gallon water storage tanks, of which 300,000 gallons in each tank are reserved for fire protection, through a common header. The pumps discharge into a common header with two separate connections to the underground 12-inch yard main loop. The original design of both the suction and discharge headers was such that a single break could cause the loss of two of the three pumps. At our request, the applicants modified the suction and discharge headers so that a single break will not incapacitate more than one pump.

Two separate 60 gpm jockey pumps automatically maintain yard main pressure at 135 psi. The fire pumps start automatically on low header pressure. If the water supply system pressure falls to 105 psi, one of the electric fire pumps starts automatically. As the pressure falls to 100 psi and 95 psi, the second electric pump and the diesel engine driven pump start, respectively, after short time delays. The pumps can also be started manually from the control room and at the pumps. The pumps can be stopped only at the pump controller panels located adjacent to the pumps. Separate alarms are provided in the control room to monitor pump operation, prime mover availability, and failure of a fire pump to start.

The largest single fire suppression system water demand for areas that need to be protected is 1860 gpm. This occurs in two areas, namely, one section of the cable spreading room and in cable tunnel section 7. However, the two adjacent deluge systems being actuated simultaneously would raise the required water flow to 3450 gpm. Adding 500 gpm for hose streams creates a total water demand of 3950 gpm. The two electric motor driven fire pumps operating together, or one electric motor driven pump and the diesel engine driven pump operating together, can deliver the required water flow.

The San Onofre 2 and 3 water supply system is augmented by the Unit 1 system. The Unit 1 supply system consists of two 1,000 gpm at 120 psi electric motor driven fire pumps, which take suction from a 3 million gallon storage reservoir, with 300,000 gallons reserved for fire protection. The Unit 1 pumps are capable of being supplied from the emergency diesel generators at Unit 1.

A discussion of the fire protection water requirements following a seismic event is discussed in Section 9.5.1.4 of this report.

All valves in the fire protection water supply system are electrically supervised except for the post indicator valves, which are in the underground yard main system. The post indicator valves are locked open under administrative controls. The electrical supervision of valves alarms in the control room. The water supply valves meet the requirement of Appendix A, section C.3.b and are, therefore, acceptable.

We find that the water supply system, with the indicated modification, can deliver the required water demand with one pump out of service. We conclude that the water supply system is adequate, meets the guidelines of section C.2 of Appendix A, and is, therefore, acceptable.

(2) Sprinkler and Standpipe Systems

The wet pipe sprinkler systems, preaction sprinkler deluge systems, and water spray systems, are designed to the requirements of National Fire Protection Association (NFPA) Standard No. 13, "Standard for Installation of Sprinkler Systems," and NFPA 15, "Standard for Water Spray Fixed Systems." The areas that have been equipped with water suppression systems include the following:

Containment

- Charcoal Filter Area (EL 45)
- Combustible Oil Area

Cable Riser Galleries - Zone 5

Emergency A.C. Unit Room 308, Charcoal Filters - Zone 9

Emergency A.C. Unit Room 301, Charcoal Filters - Zone 9

Cable Riser Galleries - Zone 12

Emergency HVAC Unit Room 309A - Zone 13A*

ESF Switchgear Rooms 308A and B - Zone 15*

Diesel Generator Buildings - Train A & B - Zone 17

Auxiliary Feedwater Pump Room - Zone 22*

Spent Fuel Pool Heat Exchangers Room - Zone 23*

Low Radioactive Waste Storage Area - Zone 24

Piping Penetration Area (EL 30) Charcoal Filter - Zone 28

Cable Riser Galleries - Zone 29

Electrical Tunnel (EL 30'-6") - Zone 30

Control Room Complex - Zone 31*

- Turbine Lab, Room 230
- Instrument Repair Area, Room 248
- Storage, Rooms 249, 251, 252

* Sprinkler system installed at our request.

Fan Rooms 219 & 221, Charcoal Filter - Zone 32A
 Fan Rooms 233 & 234 - Zone 32B
 - Charcoal Filters
 - General Area*
 Spent Fuel Pool Pump Room - Zone 36*
 Cable Spreading Rooms - Zone 41
 Cable Riser Galleries - Zone 42
 Intake Structure - Zone 44*
 CCW Heat Exchangers and Piping Rooms - Zone 48*
 Electrical Tunnel - Zone 53 (EL 9'-6")
 Corridor, Elev. 50'-0", Auxiliary Building - Zone 63*
 Cable Riser Galleries - Zone 67
 Cable Riser Shaft - Zone 68
 Corridor 442, Elev. 70', Auxiliary Building - Zone 72*
 General Issue Room 425, Elev. 70'-0", Auxiliary Building*
 Corridor Room 105 - Zone 78*
 Salt Water Cooling Tunnel, Train A, Train B - Zone 83*
 Safety Equipment Building Elevation 8' A/C Room No. 017 - Zone 84*
 Turbine Building
 - Feedwater Pumps and Turbines
 - Hydrogen Seal Oil Unit
 - Hydrogen Gas Control Cubicle
 - Lube Oil Room
 - Main Lube Oil Tank Room - Zone 86

Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety related area in the plant except for the cable tunnels (Zones 30 and 53), the new and spent fuel storage areas (Zone 4), the electrical penetration area (Zone 10), and the piping penetration areas (Zones 28 and 45). At our request, the applicants have installed standpipe hose stations in five zones 4, 10, 28 and 45. The applicants have installed four 75 foot lengths of fire hose at each of two standpipe hose stations near the auxiliary building entrance to fire zone 30 to provide hose stream capability to the cable tunnels. In addition, hose streams from the yard hydrants can be used to suppress fires in the cable tunnels with access to the tunnels through five separate access hatches.

The water suppression systems and the standpipe hose stations are fed directly from the underground fire main or from interior water supply headers. The interior water supply headers are fed through a minimum of two separate supply connections to the looped yard system. However, the water supply headers are not provided with sufficient valves to prevent a single break from impairing both the fixed pipe water suppression systems and the standpipe hose systems in each of several buildings. The applicants have installed a back-up system, which

* Sprinkler system installed at our request.

can provide a source of fire suppression water following an SSE by a seismically qualifying standpipe system at strategic locations throughout the plant. These standpipe systems are provided with a manual shut off valve at the interface with the nonseismic fire protection header. A fire department connection is provided for each seismic standpipe system to enable a fire truck, located on site, to provide a minimum of two standpipe hose lines with 75 gpm each of water for a two hour period without interruption. The location of the seismic standpipe is such that at least one hose stream will be available for all areas of the plant which need protection. The seismic standpipe system risers are interconnected so that not more than one fire department pumper connection will be used to supply all the seismic standpipes in any one building.

The standpipe systems are consistent with the requirements of NFPA 14, "Standpipe and Hose Systems for Sizing, Spacing, and Pipe Support Requirements." Based on our review and the applicants' commitments, we conclude that the water suppression systems and standpipe systems meet the guidelines of Appendix A to BTP APCSB 9.5-1 and are, therefore, acceptable.

(3) Gas Fire Suppressions Systems

Total flooding halon systems are provided for the two Computer Rooms. The halon systems are actuated by heat detection systems. The halon systems are designed to achieve a 5% concentration for 10 minutes and are designed to the requirements of NFPA 12A, "Halogenated Fire Extinguishing Agent Systems - Halon 1301."

We have reviewed the design criteria and bases for the halon fire suppression systems. We conclude that these systems satisfy the provisions of Appendix A to BTP ASB 9.5-1 and are in accordance with the applicable portions of NFPA Standard No. 12A and are, therefore, acceptable.

(4) Fire Detection Systems

The fire detection systems consist of the detectors, associated electrical power supplies, and the annunciation panels. The types of detectors used are ionization (products of combustion), thermal, ultraviolet, and photoelectric. Fire detection systems give an audible and visual alarm which annunciates in the plant control room. Local audible and/or visual alarms are also provided. The fire detection systems are connected to the emergency power supply. Fire detection systems will be installed in all areas having safety related equipment. This includes the control room area, the new and spent fuel pool storage areas, and areas of cable concentration.

The fire detection systems are installed according to NFPA No. 72D, "Standard for the Installation, Maintenance, and Use of Proprietary Protection Signalling Systems." Those fire detection systems which are used to actuate suppression systems have been upgraded to a Class A system defined in NFPA 72D.

We have reviewed the fire detection systems to ensure that fire detectors are adequate to provide detection and alarm of fires that could occur. These systems are installed with due consideration for the use of detector spacings less than those recommended for smooth, unobstructed ceilings. We have also reviewed the fire detection system's design criteria to ensure that they conform to the applicable sections of NFPA No. 72D. We conclude that the design and the installation of the fire detection systems meet the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

9.5.1.3 Other Items Related to Fire Protection Program

(1) Fire Barriers and Fire Barrier Penetrations

Exterior walls and walls that separate buildings are three hour fire rated walls. The floor/ceiling assemblies separating areas in buildings containing safe shutdown systems are either two or three hour fire rated barriers. Interior walls are fire rated for two hours, with the exception of the walls between the electrical penetration area (Zone 2), the area outside of the personnel locks (Zone 3), and the wall between the control room proper and the peripheral rooms. For all fire areas not having a three hour fire rated assembly, we analyzed each individually with respect to its fuel load, fire suppression and detection systems, proximity to safe shutdown equipment, and concluded that two and one hour fire rated assemblies were adequate for the areas affected, meets sections D.1.d and D.1.j of Appendix "A" to BTP 9.5.1 and, therefore, is acceptable.

By referencing specific UL designs, the applicants have provided adequate documentation to substantiate the fire rating of both the fire rated barriers and the fire penetration seals used in the penetration cable trays, conduits, and piping. We have concluded that the fire barrier and fire seal ratings meet the guidelines of Appendix A to BTP ASB 9.5-1, and, therefore, are acceptable.

(2) Fire Doors and Dampers

We have reviewed the placement of fire doors and verified that all doorway openings to areas containing safe shutdown equipment or circuits are provided with fire doors with ratings commensurate with the fire rating of the wall, except for the following: the intake structure (Zone 44) and salt water cooling tunnel (Zone 83) are not provided with fire rated doors; the three charging pump rooms (Zone 50) are provided with non-rated watertight doors; and doorway between zones in the Safety Equipment Building are provided with non-rated watertight doors. For all areas not having a rated and labeled fire door, we reviewed the structure and composition of the doors and frame, the area fuel load, the fire protection features in the area, and concluded the existing unrated doors were adequate for the areas affected (based on the lack of fire loading and the substantial construction of the door) and, therefore, acceptable.

The applicants have provided 3-hour fire door dampers wherever ventilation ducts or openings penetrate 3-hour fire rated walls or ceiling/floor assemblies. All ventilation ducts or openings penetrating 2-hour fire rated walls or floor/ceiling assemblies, and all such penetrations of 1-hour rated assemblies for areas containing safe shutdown equipment or circuits, are provided with 1½-hour fire dampers. However, the ventilation ducts which penetrate the heavy concrete walls enclosing the charging pump rooms (Zone 50) were not provided with dampers. At our request, the applicants have committed to provide 1½-hour dampers for these duct penetrations.

Based on our review and the commitments, we conclude that the fire doors and dampers will be provided in accordance with the guidelines of Appendix A to BTP 9.5-1, Section D.1.j, and are, therefore, acceptable.

9.5.1.4 Seismically Induced Fires

Because the San Onofre Nuclear Generating Station is located in an area of high seismic activity, we considered the potential for fires caused by earthquakes as part of our defense-in-depth philosophy.

In the event of a fire after an earthquake, the applicants will rely on seismically qualified standpipe systems for fire suppression. The standpipe systems are supplied with water from mobile trailer tankers fitted with pumps. The seismic standpipe systems are designed to ensure adequate coverage of all areas of the plant containing safe shutdown equipment.

Since the fire detectors are non-seismic the applicants have agreed to have a Technical Specification that will require a plant visual inspection for fires within two hours following an earthquake. Since safe shutdown systems are protected by seismic Category I barriers rated at two and three hours, any fire after an earthquake should be detected by this inspection before safe shutdown systems would be affected. Based on our review and the Technical Specifications requirement, we find the detection of fires after an earthquake to be acceptable.

The reactor coolant pumps contain a lube oil that could be leaked out after a seismic activity. We were concerned that this oil could be ignited and create a fire inside the containment structure. To preclude this possibility, we required and the applicants agreed to provide an engineered oil collection system that will meet the requirements of Reg. Guide 1.29, paragraph C.2.

Based on our review and the applicants commitment, we find the seismic fire protection provisions to be adequate and, therefore, acceptable.

9.5.1.5 Alternate Shutdown

At our request, the applicants performed a five hazards analysis, which included consideration of the potential effects of a transient exposure fire on equipment and cables (within 20 feet of each other) required for safe shutdown. An alternate

shutdown system has been installed for the control room, cable spreading room, the ESF Switchgear Room (Zone 15), and one cable riser gallery (fire zone 5). Two alternate shutdown panels are provided, which are located in fire zone 66 in the Auxiliary Building. A fire in either the control room or spreading rooms would not jeopardize operation of the alternate shutdown panels nor would a fire in the panels cause functions in the control room or the cable spreading room. In a like manner, an instrumentation panel, which will provide RCS and steam generator parameters, will be provided. This instrumentation panel will be independent of and electrically separated from the cable riser gallery (fire zone 5). Therefore, a single fire event in any of the above areas will not impair mutually redundant safe shutdown systems of division I and II simultaneously.

Our review and acceptance of the San Onofre 2 and 3 alternate shutdown system is given in section 7.4.2 of this report.

We conclude that the installation of the alternate shutdown systems will preclude the possibility of a single fire event in the control room, cable spreading rooms, the fire zone 15 ESF Switchgear Room, and the fire zone 5 cable riser gallery from impairing mutually redundant safe shutdown systems simultaneously. Therefore, we find that the applicants' alternate safe shutdown system meets the requirements of Appendix A, and also meets section III.L of Appendix R to 10 CFR Part 50 and, therefore, is acceptable.

9.5.1.6 Plant Areas Containing Redundant Divisions

A number of plant areas have physical arrangements where redundant division of cable/conduits and equipment are in close proximity to each other and, therefore, could be vulnerable to a single, transient fire event. Originally, the applicants were relying solely on administrative controls to preclude a fire event from taking place in affected areas.

Based on our experience, administrative controls alone are not sufficient to prevent storage of combustibles, or presence of ignition sources. At our request, the applicants committed to meet the provisions of sections III.G.2 of Appendix R to 10 CFR Part 50. Therefore, when redundant division of cable or equipment are within 20 feet of each other and not separated by a two or three hour fire rated barrier (see section III), the applicants have provided a one hour fire rated enclosure for one of the redundant divisions. In addition, a fire suppression and detection system is provided for the area (see sections II.B and II.D).

Those areas that will have 1-hour fire rated barriers in addition to the automatic water suppression systems described in Section IIB include the following:

Cable River Galleries - Zones 12, 29, 42, 67
Emergency HVAC Unit Room 309A - Zone 13A
Auxiliary Feedwater Pump Room - Zone 22

Spent Fuel Pool Heat Exchangers Room - Zone 23
Electrical Tunnels - Zones 30, 53
Fan Rooms 233 & 234 - Zone 32B
Spent Fuel Pool Pump Room - Zone 36
CCW Heat Exchangers and Piping Rooms - Zone 48
Corridor, Elev. 50'-0", Auxiliary Building - Zone 63
Corridor 442, Elev. 70', Auxiliary Building - Zone 72
Corridor Room 105 - Zone 78
Salt Water Cooling Tunnel, Train A, Train B - Zone 83
Safety Equipment Building Elevation 8' A/C Room No. 017 - Zone 84

We have reviewed the plant areas containing redundant divisions of equipment and cable and conclude that, with the applicants' commitments, the fire protection meets the provisions of Appendix A and of section III.G.2 of Appendix R to 10 CFR Part 50, and is, therefore, acceptable.

9.5.1.7 Emergency Lighting

Eight-hour battery pack emergency lights are required for areas of the plant necessary for safe shutdown. At our request, the applicants installed self-contained 8-hour battery pack emergency lighting in all areas of the plant which could be manned to bring the plant to a safe cold shutdown and in access and egress routes to and from all fire areas.

Based on the applicants' commitment to install 8-hour battery emergency lights, we conclude that the emergency lighting meets the requirements of Appendix A and, also, the provisions of section III.J of Appendix R to 10 CFR Part 50 and is, therefore, acceptable.

9.5.1.8 Fire Protection for Specific Areas

(1) Control Room

The control room complex is separated from the radwaste building by a 3-hour rated wall and from other areas by 2-hour fire rated walls, and floor/ceiling assemblies. Support areas within the control room complex, including offices, storage rooms, and laboratory and instrument repair rooms, are separated from the control room by 1-hour fire rated walls and one 2-hour wall for the computer room.

Smoke detection has been provided for the entire control room fire area, in the ventilation system ducts, and in the main control board, and any other cabinet which contains redundant safe shutdown circuits. Standpipe hose stations and portable extinguishers are provided for manual fire suppression activities. At our request, the applicants have provided water type portable fire extinguishers.

There is no automatic fire suppression in the control room proper. However, at our request, the applicants have committed to providing automatic sprinkler systems to protect the adjacent turbine lab area, the instrument repair area, and the storage areas in the control room complex. These rooms are separated from the control room by a one hour fire rated barrier.

As discussed in Section V, the applicants have installed an emergency shutdown panel so that alternate shutdown capability exists independent of the control room.

Based on our review and the applicants' commitments, we conclude that the control room fire protection meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

(2) Cable Spreading Room

The cable spreading rooms (one for each unit) are separated from the balance of plant by adequate fire-rated walls and floor/ceiling assemblies.

Automatic fire suppression capability is provided by a zoned deluge system with directional spray nozzles designed to provide 0.15 gpm/sq. ft. based on the projected surface area of the cable trays. The water spray system hangers are designed to withstand a design basis earthquake. Manual fire suppression capability is provided by standpipe with hose stations and portable fire extinguishers. Portable fans are available for smoke venting. In addition, installed smoke detectors will initiate an early warning alarm in the control room prior to sprinkler system actuation.

We were initially concerned that a fire could affect redundant shutdown systems located in the cable spreading room. However, as discussed in Section 9.5.1.5 the applicants have installed an emergency shutdown panel so that alternate shutdown capability exists independent of the cable spreading rooms. The fire protection for both of the cable spreading rooms meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

(3) Containment

The fire hazard potential associated with the reactor coolant pumps is discussed in Section 9.5.1.4, above.

Containment fire protection features include: hose stations, fire detectors, and fire extinguishers. The applicants have committed to implement the provisions of III.G.2 of Appendix R to 10 CFR 50 for areas inside containment.

We have reviewed the applicants' Fire Hazards Analysis for the areas inside the containment building and conclude that the fire protection meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

(4) Other Plant Areas

The applicants' Fire Hazards Analysis addresses other plant areas not specifically discussed in this report. The applicants have committed to install additional detectors, portable extinguishers and hose stations, prior to fuel load. We find that the fire protection for these areas, with the commitment made by the applicants to be in accordance with the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

9.5.1.9 Administrative Controls and Fire Brigade

The administrative controls for fire protection consists of the fire protection organization, the fire brigade training, the controls over combustibles and ignition source, the prefire plans and procedures for fighting fires and quality assurance. The applicants have agreed to implement the fire protection program contained in the staff supplemental guidance "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated August 29, 1977, including (1) fire brigade training, (2) control of combustibles, (3) control of ignition sources, (4) fire fighting procedures, and (5) quality assurance. The applicants will implement the plant administrative controls and procedures before fuel loading.

The applicants will have a five-man fire brigade which meets our guidelines, and is, therefore, acceptable. Initially, the applicants had intended that their five man brigade would utilize self-contained air masks which would be placed at strategic locations throughout the plant. These units would not be reserved for fire brigade use. At our request, the applicants have placed five self-contained, positive pressure air masks, which will be reserved for fire brigade use, at each of two locations. Additional masks are available at the control room for general plant use.

We conclude that, with the above modifications and commitments, the five man fire brigade equipment and training will conform to the recommendations of the National Fire Protection Association, to Appendix A to BTP ASB 9.5-1, and to our supplemental staff guidelines identified above and, therefore, are acceptable.

9.5.1.10 Technical Specifications

The applicant has committed to follow our Standard Technical Specifications. We find this acceptable.

9.5.1.11 Appendix R Statement

On May 23, 1980, the Commission issued a Memorandum and Order (CLI-80-21) which states that: "The combination of the guidance contained in Appendix A to BTP 9.5-1 and the requirements set forth in this rule define the essential elements for an acceptable fire protection program at nuclear power plants docketed for Construction

Permit prior to July 1, 1976, for demonstration of compliance with General Design Criterion 3 of Appendix A to 10 CFR Part 50." On October 27, 1980, the Commission approved a rule concerning fire protection. The rule and its Appendix R were developed to establish the acceptable fire protection requirements necessary to resolve certain areas of concern in contest between the staff and licensees of plants operating prior to January 1, 1979.

Although this fire protection rule does not apply to the San Onofre Unit 2 and 3 nuclear facility, based on our review and evaluation of the San Onofre fire protection and the applicants' commitments, we conclude that the San Onofre fire protection program will meet the following three issues identified in Appendix R.

- (1) Section III.G., Fire Protection of Safe Shutdown Capability
- (2) Section III.J., Emergency Lighting
- (3) Section III.O., Oil Collection System for Reactor Coolant Pump.

The implementation schedule will be in accordance with the requirements of the rule.

Based on these commitments and our evaluation, we conclude that the San Onofre 2 and 3 fire protection program will meet all the requirements of Appendix R to 10 CFR Part 50 when the committed modifications have been completed, meets the requirements of GDC 3, and therefore is acceptable.

9.5.1.12 Conclusions

We conclude that a fire occurring in any area of the San Onofre Nuclear Plant, Unit 2 and 3, with all proposed modifications accomplished, will not prevent the units from being brought to a controlled safe cold shutdown. Further, such a fire would not cause the release of significant amounts of radiation.

We find that the Fire Protection Program for San Onofre 2 and 3, with the improvements and modifications committed by the applicants to be implemented prior to fuel loading, will meet the guidelines contained in Appendix A to BTP ASB 9.5-1, and meets the General Design Criterion 3 and is, therefore, acceptable.

9.5.2 Communications Systems

Diverse communications systems are provided at San Onofre 2 and 3 to ensure reliable communications for ease of operation, maintenance and plant safety. The communications systems have been designed to provide convenient and effective interunit and intraunit communication, and communication between the plant and locations external to the plant. These systems are designed to function under normal and emergency conditions and under maximum noise potential.

The communications systems provided are: (1) inplant communications systems, (2) public offsite communications systems, and (3) private offsite communications systems.

The inplant communications systems contain a private automatic exchange system for onsite and external Southern California Edison Company private automatic exchange system communications, a site public address system, a seismic Category 1, quality Class 2 emergency site evacuation alarm system, a site common battery telephone system, an inplant intercom system, and portable and fixed battery powered ultra high frequency two-way radios for onsite and offsite communications.

The public offsite communications system consists of commercial telephone services provided by the Pacific Telephone Company. This system provides direct dialing from onsite to offsite locations for both local and long distance communications, and also between extensions within the plant. This system is powered and maintained by the Pacific Telephone Company.

The private offsite communications system consists of a security force communications system using two communications channels (i.e., the public offsite communications system and U.S. Marine Corps private automatic exchange telephone dial line. A very high frequency radio link with U.S. Marine Corps is also available), and a power system communications system. The power system communications system provides for offsite communications with three Southern California Edison Company private automatic exchange dial trunk lines, a communications link with the San Diego Gas and Electric Company by means of multiplex and microwave channels, direct communications to U.S. Marine Headquarters Fire Station at Camp Pendleton, direct dialing from the watch engineer's office to all stations on the U.S. Marine Corps private automatic exchange system and a very high frequency radio communications (on a dedicated frequency) between the plant control room and the U.S. Marine Corps Headquarters Fire Station.

The scope of our review included assessment of the number and types of communications systems provided, assessment and adequacy of the power sources, and verification of functional capability of the communications system to provide effective communication under all conditions of operation and under maximum noise potential.

The basis for acceptance in our review was conformance of the design criteria and bases and design of the installed diverse communications systems to the acceptance criteria in Section 9.5.2 of NUREG-75/087 (the Standard Review Plan), industry standards, and the ability of the systems to provide effective communications from diverse means for interplant, intraplant, onsite and offsite locations during normal and emergency conditions, under maximum noise potentials.

We conclude that the communications systems provided at San Onofre 2 and 3 conform to the above cited standards and criteria and are acceptable, subject to completion of the review of the affect of earthquakes on implementation of the facility Emergency Plan, as discussed in Section 13.3.4 of this report.

9.5.3 Lighting Systems

The lighting systems installed at San Onofre 2 and 3 include all components necessary to provide adequate lighting throughout the plant and the plant site for all normal plant operation and emergency conditions.

The plant lighting systems consist of normal, emergency, and essential systems with required redundancy, isolation, and separation to provide lighting during normal station operation and for station operation during shutdown, accidents, or blackouts on loss of the preferred power sources.

The normal lighting system provides plant illumination for the two units and consists of 120 volt alternating current fixtures with incandescent lamps installed in containment structures, the safety equipment building, penetration rooms, the radwaste building, and the fuel handling building. Most of the normal lighting load is supplied from two double-ended load centers, each consisting of two 4160208Y/120 volt indoor, dry-type transformers and circuit breakers. The load centers are common to both units. Areas remote from the lighting load centers are fed by 480-208Y/120 volt dry-type transformers powered from non-Class 1E 480 volt, motor control centers.

The emergency lighting system is installed in all critical areas that are occupied by operating personnel, except where essential lighting is provided, and in exit corridors where lighting is required for safety. The emergency lighting system consists of strategically located self-contained battery powerpack units and light fixtures powered from either central battery powerpack units or non-Class 1E 125 volt direct current station batteries. These units are automatically energized on loss of normal alternating current power. The emergency light units are designed to provide direct current power for 90 minutes.

The essential lighting system provides the required minimum amount of direct current lighting in the areas used during reactor shutdown under normal and accident conditions. These areas include the main control room, the auxiliary control stations in the evacuation room, the engineered safety features switchgear rooms, and their access corridors. The essential lighting system consists of self-contained battery powerpacks and light fixtures energized from Class 1E alternating current buses during normal operation. The essential self-contained lighting units contain a battery, battery charger, and inverter ballast combination, and are designed to provide illumination for a minimum of 90 minutes. The essential lighting system is automatically energized in the event of loss of Class 1E alternating current power or disconnection of Class 1E alternating current power by a safety injection actuation signal.

All lighting subsystems serving the control room and auxiliary control stations are designed to seismic Category I requirements.

The scope of our review of the lighting systems included assessment of the number and types of lighting systems provided, assessment and adequacy of the power sources for

the normal, emergency, and essential systems, and verification of functional capability of the lighting system under all conditions of operation.

The basis for acceptance in our review was conformance of the design basis and criteria, and design of the lighting systems and necessary auxiliary supporting systems to the acceptance criteria in Section 9.5.3 of NUREG-75/087 (the Standard Review Plan), conformance to industry standards and the ability to provide effective lighting in all areas of the San Onofre 2 and 3 facility for all normal plant operations and emergency conditions.

We conclude that the various lighting systems provided at the San Onofre 2 and 3 facility conform to the above cited criteria and are acceptable.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

The emergency diesel engine fuel oil storage and transfer system is designed to provide an independent fuel oil supply train for each emergency diesel generator, and to permit operation of the diesel generator at rated load for a minimum of 7 days without replenishment of fuel.

Four emergency diesel generators are installed at San Onofre 2 and 3, two for each unit. Each diesel generator is independent and physically separated from the other and serves one train. A single failure in any one diesel generator system will affect only that diesel generator and not the others.

Each emergency diesel engine fuel oil storage and transfer system contains (1) a 55,000 gallon buried fuel oil storage tank which is enough to permit operation of the emergency diesel generator at a rated load for a minimum of seven days, (2) two motor driven fuel oil transfer pumps (one normally operating) powered from the emergency bus associated with the diesel generator, (3) a 550 gallon day tank (located in the diesel generator room) which is sufficient to operate the diesel generator at rated load for one hour, (4) instrumentation, controls and alarms, and (5) associated piping and valves to connect the equipment. Alarms annunciate locally and in the control room to alert the operator of any malfunction when the unit is in the ready standby mode, starting, or in operation.

To minimize material corrosion of the emergency diesel engine fuel oil storage and transfer system, the exterior surfaces of the buried fuel oil storage tanks are coated with coal tar epoxy and the interior surfaces with jet fuel epoxy. Underground piping and fittings are wrapped with protective coatings and all underground items are also provided with cathodic protection. The aboveground piping and component surfaces are painted and located inside the diesel generator room, which has a controlled environment.

The emergency diesel engine fuel oil storage and transfer system piping and components are designed to seismic Category 1, Class 3 requirements. All above-ground piping and components are located inside a seismic Category I structure which protects them

from tornadoes, tornado missiles, and other external environmental effects. This portion of the emergency diesel engine fuel oil storage and transfer system is also protected from pipe whip and jet impingement forces resulting from failure of a high or moderate energy line.

The scope of our review of the emergency diesel engine fuel oil storage and transfer system included layout drawings, piping and instrumentation diagrams, and descriptive information for the system and the auxiliary support systems essential to its operation.

The basis for acceptance in our review was conformance of the design criteria and bases and design of the emergency diesel engine fuel oil storage and transfer system to the acceptance criteria in Section 9.5.4 of NUREG-75/087 (the Standard Review Plan), industry standards, and the ability of the system to permit operation of the emergency diesel generator at rated load for seven days without replenishment of fuel.

We conclude that the emergency diesel engine fuel oil storage and transfer system for each emergency diesel generator conforms to the above cited criteria and can perform the design safety function and is acceptable.

9.5.5 Emergency Diesel Engine Cooling Water System

Four emergency diesel generators are installed to serve San Onofre 2 and 3, two for each unit. Each generator is driven by two diesel engines and each diesel engine has an independent cooling water system.

The emergency diesel engine cooling water system is an integral part of the diesel engine and is designed to maintain the temperature of the diesel engine within the safe operating range. The emergency diesel engine cooling water system is a closed loop cooling system with a combustion air turbocharger. Lubrication oil heat is rejected to the atmosphere, during operation, by the engine forced draft air radiator. When the engine is idle, an electric immersion heater will maintain engine jacket water at the manufacturer's recommended temperature to increase the first-try starting reliability. Water circulation on idle is by thermal convection.

The emergency diesel engine cooling water system for each engine contains a water expansion storage tank, a jacket water radiator, a three way temperature control valve, a lube oil cooler, an electric immersion heater, a temperature control manifold, a turbocharger aftercooler, engine driven water pumps (one for each bank of cylinders), the required instrumentation, controls, and alarms, and the associated piping and valves to connect the equipment. Alarms annunciate locally and in the control room to alert the operator of any malfunction when the unit is in the ready standby mode or in operation.

Two radiators and two expansion tanks for each diesel generator are located on the second floor of the seismic Category 1 diesel generator building. Each expansion

tank is designed to provide for system operation at maximum rated load for a period of seven days without makeup. Several sources of makeup water are available for the expansion tank, i.e., nuclear service water system and utility stations of the service and domestic water systems.

The emergency diesel engine cooling water system is designed to seismic Category 1 requirements and is protected from tornadoes, tornado missiles and flooding. This system is also protected from pipe whip and jet impingement forces resulting from failure of a high or moderate energy line.

To minimize material corrosion, the diesel engine cooling water is chemically treated with corrosion inhibitors as recommended by the engine manufacturer.

The scope of our review of the emergency diesel engine cooling water system included layout drawings, piping and instrumentation diagrams, and descriptive information for the system and the auxiliary support systems essential to its operation.

The basis for acceptance in our review was conformance to the design criteria and bases and design of the emergency diesel engine cooling water system to the acceptance criteria in Section 9.5.5 of NUREG-75/087 (the Standard Review Plan), industry standards and the ability of the system to maintain stable diesel engine cooling water temperature under all load conditions.

The staff concludes that the emergency diesel engine cooling water system for each engine conforms to the above cited criteria, and can perform the design safety function and is acceptable.

9.5.6 Emergency Diesel Engine Starting System

Four emergency diesel generators are installed to serve Units 2 and 3 at the San Onofre facility, two for each unit. Each emergency generator is driven by two diesel engines and each diesel generator unit has two independent and redundant air start systems.

The emergency diesel engine starting system is designed to provide a reliable method for starting each diesel engine such that within 10 seconds after receiving a start signal the diesel generator is operating at rated speed, frequency and voltage, and is ready to accept load.

Each redundant and independent emergency diesel engine starting system contains one air receiver of a size to provide for five engine starts without compressor assistance, an air dryer, an air compressor, a pressure regulator, two solenoid starting valves, four air starting motors, the instrumentation, control and alarms and associated piping and valves to connect the equipment. Alarms annunciate locally and in the control room to alert the operator of any malfunction when the unit is in the ready standby mode, starting, or in operation.

Each emergency diesel engine starting system is individually capable of starting the two diesel engines per generator but in normal operation, both redundant air start systems are used. The two air start systems are arranged so that each system provides starting air to two air motors for each engine. On receipt of a start signal, all four solenoid starting valves are normally energized, simultaneously activating all eight air starting motors and using air from both air starting systems independently. In the event of a failure in one of the redundant air start systems, the other will start the diesel generator. This arrangement improves the diesel generator first-try starting reliability.

With the exception of the air compressor and dryer, which will not be required during or after an earthquake, the emergency diesel engine starting system is designed to seismic Category 1 requirements and is protected from tornadoes, tornado missiles and flooding. The seismic Category 1 portions of this system are also protected from pipe whip and jet impingement forces resulting from failure of a high or moderate energy line.

The scope of our review of the emergency diesel engine starting system included layout drawings, piping and instrumentation diagrams, and descriptive information for the system and auxiliary support systems essential to its operation.

The basis for acceptance in our review was conformance to the design criteria and bases and design of the emergency diesel engine starting system to the acceptance criteria in Section 9.5.6 of NUREG-75/087 (the Standard Review Plan), industry standards, and the ability of the system to start the diesel generator within a specified time period.

We conclude that the emergency diesel engine starting system for each diesel engine conforms to the above cited criteria, and can perform the design safety function and is acceptable.

9.5.7 Emergency Diesel Engine Lubrication System

Four emergency diesel generators are installed to serve San Onofre 2 and 3, two for each unit. Each emergency generator is driven by two diesel engines and each engine has a separate lubrication oil system. The emergency diesel engine lubrication system is an integral part of the diesel engine and is designed to assure adequate lubrication of bearings and other wearing parts, and piston cooling.

Each emergency diesel engine lubrication system consists of four separate lube oil subsystems: the scavenging oil, main lubrication, piston cooling and the oil circulating and soak-pack subsystems. Lube oil is circulated through an oil cooler/heater for cooling when the engine is operating. Lube oil heat is rejected to the diesel engine cooling water system. On standby condition, engine lube oil is heated by circulating heated engine jacket water through the oil cooler/heater to improve starting reliability.

Each emergency diesel engine lubrication system contains three engine-driven lube pumps, a lube oil collection sump, a full-flow filter, a lube oil cooler/heater, a lube oil strainer, two electric oil circulating pumps (one alternating current normally operating pump and one direct current pump on stand-by), the instrumentation, controls, and alarms, and the associated piping and valves to connect the equipment. Alarms and protective devices are provided to enable the control room operator to monitor the diesel generator during standby, startup or in operation. The emergency diesel engine lubrication system piping and components are designed to seismic Category 1 requirements and the system is protected from tornadoes, tornado missiles, pipe whip, jet impingement forces and flooding.

The scope of our review of the emergency diesel engine lubrication system included piping and instrumentation diagrams, and descriptive information for the systems and auxiliary support systems essential to its operation.

The basis for acceptance in our review was conformance to the design criteria and bases and design of the emergency diesel engine lubrication system to the acceptance criteria in Section 9.5.7 of NUREG-75/087 (the Standard Review Plan), industry standards, and the ability of the system to provide necessary engine lubrication during periods of operation and maintain the engine lube oil at temperatures to improve first-try starting reliability.

We conclude that the emergency diesel engine lubrication system for each diesel engine conforms to the above cited criteria, and can perform the design safety function and is acceptable.

9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System

Four emergency diesel generators are installed to service Units 2 and 3 at the San Onofre facility, two for each unit. Each emergency diesel generator is driven by two diesel engines and each engine has its own completely separate and independent combustion air intake and exhaust system. The emergency diesel engine combustion air intake and exhaust system is designed to supply the required filtered air for combustion to the engine and to dispose of the resultant engine exhaust gases to the atmosphere without compromising diesel engine performance.

The combustion air intake system for each diesel engine contains an air filter/silencer assembly, piping from the air filter to the engine turbocharger, and an expansion joint. The two air filter/silencer assemblies, one for each diesel engine driving the emergency generator, are located in a separate enclosure on the second floor of the diesel generator building. The enclosure contains a missile proof combustion air intake louvre in the side wall.

The exhaust gas system for each diesel engine contains a muffler located on the second floor of the diesel generator building, connecting piping, and an expansion joint. The exhaust pipe from each muffler penetrates the roof of the diesel generator building and terminates above it.

The air intake and exhaust gas system is designed to minimize exhaust gas recirculation so that engine performance will not be degraded. The diesel generator building is located and oriented so that in the event of an accidental release of onsite stored gases, diesel generator performance is not degraded. The design and location of the emergency diesel engine combustion air intake and exhaust system are such that a single failure in any one of these systems will not disable both emergency diesel generators.

The air intake and exhaust system piping and components are designed to seismic Category 1 requirements. The systems are installed in the seismic Category 1 diesel generator building, which provides protection from the effects of tornado, tornado missiles and flood. This system is also protected from pipe whip and jet impingement forces resulting from failure of a high or moderate energy line.

The scope of our review of the emergency diesel engine combustion air intake and exhaust system included layout drawings, piping and instrumentation diagrams, and descriptive information for the system and auxiliary support systems essential to its operation.

The basis for acceptance in our review was conformance of the design criteria and bases and design of the emergency diesel engine combustion air intake and exhaust system to the acceptance criteria in Section 9.5.8 of NUREG-75/087 (the Standard Review Plan), industry standards, and the ability of the system to provide sufficient combustion air and release of exhaust gases to enable the emergency diesel generator to perform on demand.

We conclude that the emergency diesel engine combustion air intake and exhaust system for each diesel engine conforms to the above cited criteria, and can perform the design safety function and is acceptable.

10.0 STEAM AND POWER CONVERSION SYSTEM

10.1 Summary Description

The San Onofre 2 and 3 steam and power conversion system is of conventional design, similar to those of previously approved pressurized water reactor plants. The system is designed to remove heat energy from the reactor coolant by two steam generators and convert it to electrical energy by the steam-driven turbine-generator unit. Exhaust steam from the turbine is condensed and deaerated in the main condenser, and the resultant condensate is returned to the two steam generators as heated feedwater. The condenser transfers unusable heat to the circulating water system, which uses sea water to transfer rejected heat to the Pacific Ocean. The entire system is designed for the maximum expected power from the nuclear steam supply system.

Normally, the turbine and auxiliaries use all the steam generated. However, during transients or startup or shutdown conditions, up to 45 percent of rated steam flow may be discharged to the condenser by the automatically controlled turbine bypass system.

In the event of a turbine trip, or complete loss of load, steam is relieved to the condenser via the turbine bypass valves and/or to the atmosphere via the main steam safety valves and the atmospheric dump valves. With use of the turbine bypass system, the unit is capable of accommodating a loss of up to 55 percent of rated load without a reactor trip.

10.2 Turbine Generator

The turbine-generator for each unit is manufactured by the General Electric Company and is a tandem-compound type (single shaft), consisting of one double-flow high pressure turbine and three double-flow low pressure turbines. The rotational speed is 1800 revolutions per minute and the design net generator output is 1126 megawatts electric at 60 pounds per square inch gauge hydrogen pressure and 0.9 power factor.

10.2.1 Overspeed Protection

The turbine-generator is equipped with an electrohydraulic control overspeed protection system comprising two completely independent systems, i.e., an electronic-hydraulic governor speed control system and an emergency overspeed protection system. The redundancy in the turbine overspeed protection system provides assurance that destructive overspeed will not occur as a result of a single failure.

The electronic-hydraulic governor speed control system employs solid state control techniques in combination with unitized electrohydraulic actuated turbine steam

governing valves. This governor system is comprised of a three channel electronic speed sensing system with two out of three (2/3) logic feeding signals to amplifiers. These signals are input to the electronic governor system that controls each unitized actuator to modulate or close the turbine speed governing valves to maintain constant turbine speed for all conditions, or to shut down the turbine when rotor speed exceeds 106 percent of rated speed.

Each unitized actuator has its own self-contained hydraulic power unit comprised of a pump, a hydraulic oil tank and the associated equipment and controls. The unit requires only electric power for hydraulic pump operation and cooling water to maintain stable hydraulic oil temperature.

Turbine emergency overspeed protection is accomplished by two independent systems. The emergency overspeed protection system consists of two separate mechanical overspeed-sensing mechanisms and turbine trip channels arranged to accomplish tripping using one out of two (1/2) logic. Each mechanism is comprised of a mechanical, eccentric ring to mechanically actuate a trip switch if turbine speed should reach a preset overspeed of 111 percent of normal speed. The actuation of either of the two overspeed-trip channels will operate electric protective circuits that will shut down the turbine by deenergizing solenoid valves at all unitized actuator valves. This action dumps control oil pressure from the piston actuators causing fast closing of all governing valves, i.e., main turbine stop valves, control valves, reheat stop and intercept valves, and extraction steam valves.

The turbine is provided with an emergency trip system which will shut down the turbine on the following signals: (1) emergency trip pushbutton, (2) high moisture separator tank level, (3) low turbine exhaust vacuum, (4) low lubrication oil pressure, (5) high low-pressure turbine exhaust temperature, (6) electronic governor discrepancy, (7) reactor initiated turbine trip, (8) thrust bearing wear, (9) overspeed trip, (10) generator electric trips, and others. The turbine-generator protective trips are independent of the electrohydraulic speed governing and protection system.

The electronic-hydraulic governor and emergency overspeed protection systems include electrical control circuits for normal speed control, speed acceleration control, load control and overspeed protection.

Each turbine is provided with on-load testing capability for periodic testing of all turbine steam control valves and the associated electrohydraulic unitized actuators, with provisions for on-load testing of the normal overspeed and emergency overspeed protection channels.

An alarm module is provided for each turbine to monitor the operation of the electrohydraulic control system. Instrumentation is provided to continuously monitor and/or alarm the operation of each turbine-generator during startup, shutdown and in operation.

The scope of our review of the turbine-generator included descriptive information, system heat balance, layout drawings, and piping and instrumentation diagrams.

The basis for acceptance in our review was conformance of the design criteria and bases and design of the turbine-generator electrohydraulic overspeed protection system to the acceptance criteria in Section 10.2 of NUREG-75/087 (the Standard Review Plan) and industry standards.

Based on our review of the turbine-generator overspeed protection system design and conformance to the above cited criteria, we conclude that the system can perform its designed safety functions, and is acceptable.

10.2.2 Turbine Disc Integrity

During November, 1979, the NRC staff became aware of a problem of stress corrosion cracking in some low pressure turbine discs. Meetings were held with the two vendor suppliers (the Westinghouse and General Electric Companies) to ascertain the probable extent and severity of the problem. A recommendation was made for early inspection of turbines that had long operating times, particularly turbines with discs of marginal material properties or history of secondary water or steam chemistry problems. Since then, inspections have been performed on numerous Low Pressure Turbine units of both vendors with indications of cracking, some severe, found in some of them. Investigations are continuing.

The method used by the two suppliers of low pressure turbines and by the NRC staff to predict crack growth rates is based on evaluating all cracks found to date in low pressure turbines in this country, past history of similar turbine disc cracking and results of laboratory tests. This prediction method takes into account two main parameters; the yield strength of the disc, and the temperature of the disc at the bore area where the cracks of concern are occurring. The higher the yield strength of the material and the higher the temperature, the faster the crack growth rate will be.

The turbine units for San Onofre 2 and 3 were fabricated by General Electric Company of England (not associated with General Electric of the United States) to their own specifications and design. The San Onofre 2 and 3 applicants have submitted the minimum material properties of the low pressure turbine discs, as well as the calculation of the minimum critical crack size. Since the staff has no service experience with the design or with the turbine vendor, we utilized the most conservative approach in evaluating the submitted data. We have evaluated the data using the NRC criteria for Westinghouse low pressure turbines. Using this conservative criteria we have calculated that the low pressure turbines could operate in excess of ten years before inspection. However, since we do not have any service experience with this supplier's turbines, we have concluded that the bores of the low pressure turbine disc should be inspected for any ultrasonic indications after the second refueling outage. Unless the applicants commit to this inspection, we will condition the operating license to require it. We find that this requirement is acceptably

conservative, since the second refueling outage will occur before the turbine has operated three years.

10.3 Main Steam Supply System

10.3.1 System Design

For each unit at the San Onofre 2 and 3 facility, the steam produced in the two steam generators will be routed to the high pressure turbine by two main steam lines up to the common header. Each main steam line will contain one main steam isolation valve (MSIV). The portions of the main steam lines from the steam generators, through the containment, and up to and including the main steam isolation valves are Quality Group B and seismic Category I.

The main steam isolation valves are designed to close in five seconds upon receipt of a main steam isolation signal. The valves are designed to stop steam flow from either direction. Failure of one main steam isolation valve to close, coincident with a steam line break, will not result in the uncontrolled blowdown of more than one steam generator. In the event that the steam line break is upstream of a main steam isolation valve and there is a failure of a main steam isolation valve to close on the unaffected steam generator, blowdown of the unaffected steam generator is prevented by the closure of the non-seismic Category I turbine stop valves and turbine bypass valves which serve as an acceptable backup for this accident, based on the conclusions of NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR to NRR Staff," November, 1976.

Seismic Category I safety valves and power-operated atmospheric relief valves are provided for each steam generator immediately outside the containment structure upstream of the main steam isolation valves. The power-operated atmospheric relief valves are air operated, and backed up by seismic Category I bottled nitrogen system. They are powered from the Class 1E system, and can be manually controlled from the main control board or the evacuation shutdown panel. The nitrogen bottles supplying this system have the capacity to operate both atmospheric relief valves for 15 hours, or one valve for 30 hours. Hand wheels are also provided for local manual operation of these atmospheric relief valves.

We have reviewed the design of the main steam supply system and conclude that it meets the requirements of Criterion 2 of the General Design Criteria with regard to protection from the effects of natural phenomena, and the requirements of Criterion 34 of the General Design Criteria regarding capability for residual heat removal, including suitable redundancy. The system design meets the guidelines of Regulatory Guides 1.26, "Quality Group Classification and Standards," and 1.29, "Seismic Design Classification," regarding quality group and seismic design classification of components and piping. We conclude that the design of the main steam supply system is acceptable.

10.3.2 Steam and Feedwater System Materials

The applicants have stated that the mechanical properties of the materials selected for Class 2 and Class 3 components of the steam and feedwater systems will satisfy Appendix I of Section III of the ASME Boiler and Pressure Vessel Code, and Parts A, B or C of Section II of the Code. The applicants have also stated that the fracture toughness properties of ferritic materials satisfy the requirements of the Code that are applicable to these components. These fracture toughness tests and mechanical properties required by the code provide reasonable assurance that the ferritic materials will have adequate safety margins against the possibility of nonductile behavior or rapidly propagating failure.

The onsite cleaning and cleanliness controls during fabrication satisfy the positions given in Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the requirements of ANSI Standards N45.2-1973, "Fluid Systems and Associated Components during the Construction Phase of Nuclear Power Plants."

All welding conducted in limited access areas was performed by welders qualified in accordance with the requirements of Section IX of the Code. The completed welds are volumetrically inspected by either radiography or ultrasonic examination method. The precautions taken in controlling and monitoring the preheat and interpass temperatures during welding of carbon and low alloy steel components satisfy the recommendations given in Regulatory Guide 1.50, "Control of Preheat Temperature for Welding Low-Alloy Steel."

Tubular products are nondestructively examined in accordance with the code. Conformance with the codes, standards and regulatory guides mentioned constitutes an acceptable basis for assuring the integrity of steam and feedwater systems, and for meeting the applicable requirements of NRC General Design Criterion 1, Appendix A of 10 CFR Part 50.

10.4 Other Features of Steam and Power Conversion System

The non-seismic Category I condensate cleanup system, and condensate and feedwater systems were all reviewed to determine whether or not a failure would result in the loss of any essential equipment or would affect safe plant shutdown. These systems were also reviewed to ensure that adequate isolation is provided where they connect to seismic Category I systems.

The portion of the feedwater system extending from and including the feedwater isolation valves outside containment to the steam generator inlets is designed to seismic Category I requirements.

We have reviewed the design of these systems and conclude that a system failure will not affect safe plant shutdown and, therefore, are acceptable. The details of our

review of these and other non-seismic Category I systems and their potential interaction with seismic Category I systems will be discussed in Section 3.8.6 of a supplement to this report.

10.4.1 Main Condenser

Two main condensers are provided one for each unit. Each main condenser functions as a heat sink for the turbine exhaust steam, turbine bypass steam, and other turbine cycle flows, and to receive and collect condensate flows for return to the steam generators.

The main condenser is not required to effect or support safe shutdown of the plant or to perform in the operation of the engineered safety features. Therefore, it is designed to non-seismic requirements.

Each main condenser is designed for saltwater service and has three steam domes and two shells with divided circulating water boxes. The unit is designed to (1) accept full-load turbine exhaust steam, (2) accept turbine bypass steam flows up to 45 percent of full load main steam flow without exceeding turbine exhaust temperature limitations, (3) accept feedwater pump turbine exhaust, (4) accept miscellaneous other steam flows and drains, (5) deaerate the condensate to the required water quality, and (6) provide condenser hotwell storage capacity for approximately 5 minutes of operation at maximum load without makeup. Air leakages, non-condensable gases contained in the turbine exhaust steam, and hydrogen gas (normally not present) are collected in the condenser and removed by the main condenser evacuation system.

Each condenser is provided with alarms in the control room and instrumentation and controls for continuous monitoring of (1) condenser temperature, (2) backpressure, (3) condensate levels, (4) condensate makeup and draw-off, and (5) condensate sampling in each condenser section for high conductivity indicating saltwater leakage from condenser tubes. Should condensate become contaminated with sea water, the contaminated condensate in that section of the condenser is automatically pumped to the circulating water discharge line by the condensate overboard control system. High conductivity is annunciated in the control room for proper operator action.

The scope of our review of the main condensers included layout drawings, descriptive information, and piping and instrumentation diagrams.

The basis for acceptance in our review was conformance of the design criteria and bases and design of the condenser to the acceptance criteria in Section 10.4.1 of NUREG-75/087 (the Standard Review Plan) and industry standards.

Based on our review we conclude that the main condenser is in conformance with the above cited criteria and design bases, can perform its designed function, and is acceptable.

10.4.2 Main Condenser Evacuation System

There is a main condenser evacuation system at San Onofre 2 and 3. This system is designed to establish and maintain main condenser vacuum by removing noncondensable gases from the condenser and discharging the gases through a vent on top of the turbine deck. The system is designed to Quality Group D and to a nonseismic design classification. Each main condenser evacuation system consists of five primary and three secondary steam jet air ejectors, a moisture eliminator, an electrical heating coil, a demister, a high efficiency particulate air filter, a carbon adsorber and a downstream high efficiency particulate air filter. Air and noncondensables from the filtered vacuum pump exhaust are continuously monitored by a radiation monitor prior to release to the environment.

The scope of our review included the system capability to process radioactive gases and the design provisions incorporated to monitor and control releases of radioactive materials in gaseous effluents in accordance with Criteria 60 and 64 of the General Design Criteria. Based on our evaluation, we find the main condenser evacuation system to be acceptable. The basis for our acceptance is the conformance of the design, design criteria, and design bases for the main condenser evacuation system to the applicable regulations given above.

10.4.3 Turbine Gland Sealing System

The turbine gland sealing system is designed to control radioactive steam leakage from, and air inleakage into, the turbine. The components of the system are designed to Quality Group D and to a non-seismic design classification. The turbine gland sealing system consists of labyrinth seals, a steam supply system, a gland steam condenser, and an exhaust fan. Steam is supplied to the labyrinth seals from the auxiliary boiler system during startup and from the main steam system during load operations. The exhaust fan maintains a slight vacuum in the system and exhausts the noncondensables to a vent on the outside of the turbine area.

We have reviewed the system description and design criteria for the components of the turbine gland sealing system and find them consistent with the criteria given in Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and acceptable.

The basis for acceptance in our review is the conformance of the design, design criteria, and design bases for the turbine gland sealing system to the applicable Regulatory Guide listed above. Based on our evaluation, we find the proposed turbine gland sealing system to be acceptable.

10.4.4 Turbine Bypass System

The function of the turbine bypass system is to reduce the probability of reactor trips, thus maximizing plant availability. This is accomplished by providing a means

to absorb predetermined (by system design) load reductions on the turbine generator which occur more rapidly than the reactor power level can be reduced without actuation of the main steam safety valves or the atmospheric dump valves.

The turbine bypass system for each unit at San Onofre 2 and 3 consists of 8 air operated turbine bypass control valves (four for each condenser shell), instruments and controls, and associated interconnecting piping and miscellaneous other valves. The turbine bypass system connects to the main steam headers downstream of the main steam isolation valves. Operation of the bypass valves is controlled by the main steam dump and bypass control system. A design feature of this system is that no single equipment failure nor operator error will permit operation of more than one valve. Other features are: (1) the bypass valves are closed on loss of condenser vacuum, and (2) they fail closed on loss of actuation air pressure.

The turbine bypass system for each unit is designed to bypass up to 45 percent of nuclear steam supply system rated steam flow around the turbine to the main condenser. This capacity, combined with the 10 percent step-load change characteristics of the reactor, provides for a sudden generator load rejection of up to 55 percent without reactor trip and without operation of the main steam safety valves or the atmospheric dump valves. The turbine bypass system is used to (1) prevent overpressurization of the main steam supply system during all phases of operation, (2) control reactor pressure during heatup to rated pressure, (3) facilitate operation during turbine-generator startup, synchronization and limited loading, (4) control reactor pressure during power operation when the steam produced by the steam generator exceeds the transient turbine steam requirements, (5) maintain steam header pressure at the zero power level during hot standby conditions, and (6) remove stored heat, decay heat, and pump energy from the reactor cooling system during cooldown.

The turbine bypass system is not required to effect or support safe shutdown of the plant or to perform in the operation of engineered safety features. Therefore, it is designed to non-seismic requirements.

The turbine bypass system is provided with complete test capability. Individual control valves or group of control valves can be tested during power operation.

The scope of our review of the turbine bypass system included drawings, pipings and instrumentation diagrams, and descriptive information.

The basis for acceptance in our review was conformance of our design criteria and bases and design of the turbine bypass system to the acceptance criteria in Section 10.4.4 of NUREG-75/087 (the Standard Review Plan) and industry standards.

Based on our review we conclude that the turbine bypass system is in conformance with the above cited criteria and design bases, can perform its designed function, and is acceptable.

10.4.5 Circulating Water System

The circulating water system is designed to remove the heat rejected from the main condenser to the atmosphere via the Pacific Ocean. The circulating water system is not required to maintain the reactor in a safe shutdown condition or mitigate the consequences of accidents.

The applicants provided the results of an analysis for the effects of a possible flooding as a result of a postulated failure of the circulating water system at an expansion joint. Flooding in the turbine building and adjacent plant areas is detected by flood level sensors. The operation of each circulating water line is monitored by differential pressure indicators across each section of the condenser tubes, circulating water condenser inlet and outlet temperature indicators, and main condenser vacuum indicators. Remote indication is provided in the control room for each flood level alarm and the above monitoring instrumentation as a means of detecting a failure of an expansion joint at the condenser. Based on no operator action for 20 minutes after the expansion joint failure to effect corrective action, flooding of safety-related equipment will occur. The applicants have calculated that by 23 minutes after failure, the safety-related saltwater tunnel will be filled up with flooding water and the essential saltwater pump electrical power, instrumentation, and control cables will be submerged. All other safety-related systems and components are protected from flooding by watertight doors or hatches.

In response to our request to protect safety related electrical cables from flooding, the applicants, in Amendment 11, indicated that the safety related cable will begin to be submerged 16 minutes after a circulating water system expansion joint failure, assuming no operator action. The applicants further stated that the safety related electrical cables are qualified to the "Accelerated Water Absorption Tests of IPCEA Standard 5-19-81." In addition these cables are also qualified to the San Onofre Unit 2 and 3 "Long Term Moisture Absorption Test," in which a continuously energized cable was immersed in water for a period of 26 weeks. The applicants also indicated that there is no safety related electric equipment other than the cables in this area. We have evaluated this design and agree with the applicants' conclusion that a postulated circulating water system failure will not cause damage to any safety related equipment.

We have reviewed the adequacy of the design to assure safe operation of the circulating water system during normal, abnormal, and accident conditions. On the basis that a failure in the system will not cause damage of safety related systems or components, we conclude that the design of the circulating water system is acceptable. Additional system interaction studies will be discussed in Section 3.8.6 of a supplement to this report.

10.4.6 Auxiliary Feedwater System

The auxiliary feedwater system (AFWS) is designed to supply an assured source of water to the steam generators during normal plant startup and shutdown and in the

event of loss of main feedwater supply. During emergency conditions, the AFWS automatically supplies feedwater to the steam generators for reactor decay heat removal and cooldown. The auxiliary feedwater pumps take suction from the seismic Category I, tornado missile protected condensate storage tank, which is discussed in Section 9.2.4 of this report.

The original AFWS design included one 100 percent capacity steam turbine driven pump train and one 100 percent capacity motor driven pump train. In FSAR Amendment 21, the AFWS design was revised to include one 100 percent capacity steam turbine driven pump train and two 100 percent capacity motor driven pump trains. Each motor driven pump train, including the pump motor and associated motor operated valves, will be powered by a separate alternating current standby bus. The motor driven pump and associated valves and instrumentation can be powered from an emergency diesel generator in the event of loss of offsite power. The turbine driven pump receives steam from the main steam lines upstream of the main steam line isolation valves and exhausts to the atmosphere. The turbine driven pump train is available to supply auxiliary feedwater independently of onsite or offsite alternating current power supplies. The motor-operated valves at the steam supply lines and the auxiliary feedwater discharge lines of the turbine driven auxiliary feedwater train are powered from direct current power sources. The AFWS will start automatically on actuation of an emergency feedwater actuation signal (EFAS). In the event of a main steam line or main feedwater line break, the affected steam generator will be isolated automatically.

The AFWS is designed to seismic Category I. The AFWS components and piping are contained in enclosures protected from tornado missiles, with the exception of the steam supply line to the AFW turbine. This line is routed, along part of its length, in a trench covered by heavy grating. Along another part of its run, this pipe is not enclosed. Although this pipe run is potentially vulnerable to a tornado, the probability of tornado occurrence at the site is very low (see Section 2.3.1 of this report). Furthermore, the two electric-motor-driven AFW pump trains are designed to function in the event of the design basis tornado. Thus, one 100 percent capacity AFW train will be available even if the combination of the design basis tornado and a single failure is postulated. On this basis we conclude that the AFW system is adequately designed to meet the requirements of Criterion 2 of the General Design Criteria regarding protection from natural phenomena.

In order to minimize conditions leading to steam generator water hammer that could result from uncovering the feedwater sparger, followed by rapid reintroduction of water, the steam generator sprayers have been modified by inclusion of "J" tubes that discharge from the top of the feedring. The feedwater piping has been designed to minimize the drainable volume of the feedpipe. With regard to the ACRS generic issues regarding water hammer in the feedwater system, the applicants, at our request, have agreed to perform tests acceptable to us that verify the adequacy of the operating procedures for refilling the steam generator, assuming loss of offsite power, to prevent unacceptable feedwater hammer upon refill. These tests will be performed at Unit No. 2 prior to reaching 100 percent power.

We find the San Onofre 2 and 3 AFWS design acceptable because it meets the criteria of Branch Technical Position ASB 10-1 "Design Guidelines for AFWS Pump Drive and Power Supply Diversity for PWR Plants," including power diversity, redundancy, and capability to supply necessary emergency feedwater to the steam generators despite the postulated rupture of a high energy section of the system, assuming a concurrent single active failure.

11.0 RADIOACTIVE WASTE SYSTEM

11.1 Summary Description

The radioactive waste management systems are designed to provide for controlled handling and treatment of liquid, gaseous and solid wastes. The liquid radioactive waste system processes wastes from equipment and floor drains, sample wastes, decontamination and laboratory wastes, regenerant chemical wastes, and laundry and shower wastes. The gaseous radioactive waste system provides holdup capacity to allow decay of short lived noble gases stripped from the primary coolant and treatment of ventilation exhausts through high efficiency particulate air filters and charcoal adsorbers as necessary to reduce releases of radioactive materials to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 20 and 10 CFR Part 50.34a. The solid radioactive waste system provides the capability for the solidification, packaging and storage of radioactive wastes generated during station operation prior to shipment offsite to a licensed facility for burial.

In our evaluation of the liquid and gaseous radioactive waste systems, we considered: (1) the capability of the systems for keeping the levels of radioactivity in effluents "as low as is reasonably achievable" based on expected inputs over the life of the plant, (2) the capability of the systems to maintain releases below the limits of 10 CFR Part 20 during periods of fission product leakage from the fuel at design levels, (3) the capability of the systems 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 these systems, (5) the design features that will be incorporated to control the releases of radioactive materials in accordance with Criterion 60 of the General Design Criteria, and (6) the potential for gaseous release due to hydrogen explosions in the gaseous radwaste system.

In our evaluation of the solid radioactive waste treatment system, we considered: (1) system design objectives in terms of expected types, volumes and activities of waste processed for offsite shipment, (2) waste packaging and conformance to applicable Federal packaging regulations, and provisions for controlling potentially radioactive airborne dusts during baling operations, and (3) provisions for onsite storage prior to shipping.

In our evaluation of the process and effluent radiological monitoring and sampling systems we considered the system's capability: (1) to monitor all normal and potential pathways for release of radioactive materials to the environment, (2) to control the release of radioactive materials to the environment, and (3) to monitor the performance of process equipment and detect radioactive material leakage between systems.

In our evaluation, we have determined the quantities of radioactive materials that will be released in liquid and gaseous effluents and the quantity of radioactive waste that will be shipped offsite to a licensed burial facility. In making these determinations, we have considered waste flows, activity levels and equipment performance, consistent with expected normal plant operation, including anticipated operational occurrences, over the projected 30-year operating life of the plant.

The estimated releases of radioactive materials in liquid and gaseous effluents were calculated using the PWR GALE Code described in NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR GALE Code)," April 1976. The principal parameters used in these calculations are given in Table 11.1. The liquid and gaseous source terms are given in Tables 11.2 and 11.3, respectively. The source terms given in Tables 11.2 and 11.3 were used to calculate the individual and population doses in accordance with the mathematical models and guidance contained in Regulatory Guide 1.109, "Calculation of Annual Average Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I." Meteorologic factors in the dose calculations were determined using the guidance in Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents from Routine Releases from Light-Water-Cooled Reactors." The calculated individual doses are given in Table 11.4.

We evaluated potential radwaste system "augmentations" based on a study of the system designs, the doses to the population within 50 miles of the reactor, an interim value of \$1,000 per total body man-rem and \$1,000 per man-thyroid-rem for the reductions in dose by the application of "augmentations," and the cost of potential radwaste system augmentations as presented in Regulatory Guide 1.110, "Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors." The principal parameters used in the cost benefit analysis are given in Table 11.5.

Based on the following evaluation, we conclude that the liquid and gaseous radioactive waste treatment systems for San Onofre 2 and 3 are capable of maintaining releases of radioactive materials in liquid and gaseous effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a, and with Sections II.A, II.B, II.C, and II.D of Appendix I to 10 CFR Part 50.

Based on our evaluation, as described below, we find the proposed liquid, gaseous and solid radioactive waste systems and associated process and effluent radioactive waste systems and associated process and effluent radiological monitoring and sampling systems to be acceptable.

TABLE 11.1

PRINCIPAL PARAMETERS AND CONDITIONS USED IN CALCULATING RELEASES
OF RADIOACTIVE MATERIAL IN LIQUID AND GASEOUS EFFLUENTS FROM
SAN ONOFRE NUCLEAR GENERATING STATION
UNIT NOS. 2 AND 3

Reactor Power Level (megawatts thermal)	3600
Plant Capacity Factor	0.80
Failed Fuel	0.12% ^a
Primary System	
Mass of Coolant (pounds)	5.6×10^5
Letdown Rate (gallons per minute)	40
Shim Bleed Rate (gallons per day)	1×10^3
Leakage to Secondary System (pounds per day)	100
Leakage to Containment Building (pounds per day)	b
Leakage to Auxiliary Building (pounds per day)	160
Frequency of Degassing for Cold Shutdowns (per year)	2
Secondary System	
Steam Flow Rate (pounds per hour)	1.5×10^7
Mass of Liquid/Steam Generator (pounds)	1.7×10^5
Mass of Steam/Steam Generator (pounds)	1.2×10^4
Secondary Coolant Mass (pounds)	2.2×10^6
Rate of Steam Leakage to Turbine Area (pounds per hour)	1.7×10^3
Containment Building Volume (cubic feet)	2×10^6
Annual Frequency of Containment Purges (shutdown)	4
Containment Low Volume Purge Rate (CFM)	2000
Containment Atmosphere Cleanup Rate (CFM)	16,000
Pre-purge Cleanup Time Duration (hours)	16
Iodine Partition Factors (gas/liquid)	
Leakage to Auxiliary Building	0.0075
Leakage to Turbine Area	1.0
Main Condenser/Air Ejector (volatile species)	0.15

^aThis value is constant and corresponds to 0.12 percent of the operating power fission product source term as given in NUREG-0017 (April 1976).

^b1 percent per day of the primary coolant noble gas inventory and 0.001 percent per day of the primary coolant iodine inventory.

TABLE 11.1 (Continued)

Liquid Radwaste System Decontamination Factors

	Coolant Radwaste System	Miscellaneous Waste System	Chemical Waste System
Iodine	1×10^5	1×10^3	1×10^4
Cesium, Rubidium	2×10^5	2×10^1	1×10^5
Others	1×10^6	1×10^3	1×10^5

	All Nuclides Except Iodine	Iodine
Radwaste Evaporator Decontamination Factor	10^4	10^3
Coolant Radwaste System Evaporator Decontamination Factor	10^3	10^2

	Anions	Cesium, Rubidium	Other Nuclides
Boron Recycle Feed Demineralizer Decontamination Factor (H_3BO_3)	10	2	10
Primary Coolant Letdown Demineralizer Decontamination Factor (Li_3BO_3)	10	2	10
Evaporator Condensate Polishing Demineralizer (H^+OH^-)	10	10	10
Mixed Bed Radwaste Demineralizer	$10^2(10)$	$2(10)$	$10^2(10)$
Steam Generator Blowdown Demineralizer	$10^2(10)$	$10(10)$	$10^2(10)$
Containment Building Internal Recirculation System Charcoal Filter Decontamination Factor (Iodine Removal)			10
Main Condenser Air Removal System Charcoal Bed Decontamination Factor (Iodine Removal)			10
Containment Building Internal Recirculation System HEPA Filter Decontamination Factor (Particulate Removal)			100
Main Condenser Air Removal System HEPA Filter Decontamination Factor (Particulate Removal)			100

TABLE 11.2

CALCULATED RELEASES OF RADIOACTIVE MATERIALS
IN LIQUID EFFLUENTS FROM SAN ONOFRE NUCLEAR
GENERATING STATION, UNIT NOS. 2 AND 3

Nuclide	Curies per year per Unit	Nuclide	Curies per year per unit
Corrosion and Activation Products		Cs-136	1.7(-1)
		Cs-137	2/5(-1)
		Ba-137m	1.6(-1)
Cr-51	5.6(-4) ^a	Ba-140	6(-5)
Mn-54	9(-5)	La-140	4(-5)
Fe-55	4.9(-4)	Ce-141	2(-5)
Fe-59	3(-4)	Pr-143	1(-5)
Co-58	4.8(-3)		
Co-60	6.1(-4)	All others	5(-5)
Np-239	2.5(-5)		
Fission Products		Total, except H-3	1.1
Br-83	7(-5)	H-3	300
Rb-86	1.1(-3)		
Rb-88	1.4(-2)		
Sr-89	1(-4)		
Sr-91	4(-5)		
Y-91m	3(-5)		
Y-91	2(-5)		
Zr-95	2(-5)		
Nb-95	1(-5)		
Mo-99	1.9(-2)		
Tc-99m	1.5(-2)		
Ru-103	1(-5)		
Rh-103m	1(-5)		
Te-127m	8(-5)		
Te-127	1.1(-4)		
Te-129m	4.1(-4)		
Te-129	2.8(-4)		
I-130	1.9(-4)		
Te-131m	4(-4)		
Te-131	7(-5)		
I-131	8.1(-2)		
Te-132	6.2(-3)		
I-132	7.8(-3)		
I-133	5.3(-2)		
I-134	2.3(-4)		
Cs-134	3.5(-1)		
I-135	9.5(-3)		

a = Exponential Notation,
5.6(-4) = 5.6×10^{-4}

TABLE 11.3

CALCULATED RELEASES OF RADIOACTIVE MATERIALS IN GASEOUS EFFLUENTS FROM
SAN ONOFRE NUCLEAR GENERATING STATION UNIT NOS. 2 and 3
CURIES PER YEAR PER UNIT

Nuclide	Decay Tanks	Reactor Building	Auxiliary Building	Turbine Area	Air Ejector	Total
Kr-83m	a	2.0	a	a	a	2.0
Kr-85m	a	2.4(+1)	2.0	a	2.0	2.8(+1)
Kr-85	4.3(+2)	1.7(+2)	5.0	a	3.0	6.1(+2)
Kr-87	a	5.0	1.0	a	a	6.0
Kr-88	a	3.0(+1)	4.0	a	3.0	3.7(+1)
Kr-89	a	a	a	a	a	a
Xe-131m	a	9.0(+1)	3.0	a	2.0	9.5(+1)
Xe-133m	a	1.4(+2)	5.0	a	3.0	1.5(+2)
Xe-133	a	1.3(+4)	4.1 (+2)	a	2.6(+2)	1.4(+4)
Xe-135m	a	a	a	a	a	a
Xe-135	a	1.2(+2)	8.0	a	5.0	1.3(+2)
Xe-137	a	a	a	a	a	a
Xe-138	a	a	a	a	a	a
Total Noble Gases						1.5(+4)
I-131	a	3.5(-1)	8.0 (-2)	4.2 (-3)	5.0(3)	4.4 (-1)
I-133	a	2.7(-1)	9.0 (-2)	3.3 (-3)	5.6(-3)	3.7 (-1)
Mn-54	4.5(-3) ^b	2.2(-2)	1.8(-2)	c	c	4.4(-2)
Fe-59	1.5(-3)	7.4(-3)	6(-3)	c	c	1.5(-2)
Co-58	1.5(-2)	7.4(-2)	6(-2)	c	c	1.5(-1)
Co-60	7(-3)	3.3(-2)	2.7(-2)	c	c	6.7(-2)
Sr-89	3.3(-4)	1.7(-3)	1.3(-3)	c	c	3.3(-3)
Sr-90	6(-5)	2.9(-4)	2.4(-4)	c	c	5.9(-4)
Cs-134	4.5(-3)	2.2(-2)	1.8(-2)	c	c	4.4(-2)
Cs-137	7.5(-3)	3.7(-2)	3(-2)	c	c	7.4(-2)
Total Particulates						1.2
H-3	-	-	-	-	-	1.1(+3)
C-14	7.0	1.0	a	a	a	8.0
Ar-41	a	2.5(H)	a	a	a	2.5(+1)

a = Less than 1 curie per year for noble gases, and carbon-14, less than 10^{-4} curies per year for iodine.

b = Exponential Notation: $4.5(-3) = 4.5 \times 10^{-3}$.

c = Less than 1 percent of total for this nuclide.

TABLE 11.4

CALCULATED DOSES TO A MAXIMUM INDIVIDUAL AND THE 50-MILE
POPULATION FROM SAN ONOFRE 2 AND 3

Individual Doses

Liquid Effluents

Dose to total body from all pathways	0.064 millirem per year per unit
Dose to any organ from all pathways	0.15 millirem per year per unit

Noble Gas Effluents (at site boundary
0.36 miles NNW)

Gamma dose in air	4.6 millirad per year per unit
Beta dose in air	14 millirad per year per unit
Dose to total body of an individual	2.8 millirem per year per unit
Dose to skin of an individual	8.5 millirem per year per unit

Radioiodines and Particulates

Dose to any organ from all pathways (at a residence/garden, 1.3 miles NNW)	3.7 millirem per year per unit
---	--------------------------------

Population Doses

Liquid Effluents

Dose to total body from all pathways	0.17 person-rem per year per unit
Dose to thyroid from all pathways	0.14 person-rem per year per unit

Gaseous Effluents

Dose to total body from all pathways	21 person-rem per year per unit
Dose to thyroid from all pathways	46 person-rem per year per unit

TABLE 11.5

PRINCIPAL PARAMETERS USED IN THE COST-BENEFIT ANALYSIS

Labor Cost Correction Factor, Federal Power Commission Region VIII ^a	1.2
Indirect Cost Factor ^a	1.75
Cost of Money ^b	15 percent
Capital Recovery Factor ^{a, b}	0.0806

^aFrom Regulatory Guide 1.110, "Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors (March 1976).

^bFrom San Onofre 2 and 3 Environmental Report.

11.2 System Description and Evaluation

11.2.1 Liquid Waste Processing System

The liquid waste processing system for San Onofre 2 and 3 is shared between the two units. The liquid waste processing system consists of process equipment and instrumentation necessary to collect, process, monitor and recycle or dispose of radioactive liquid wastes. The liquid radwaste system is designed to collect and process wastes based on the origin of the waste in the plant and the expected levels of radioactivity. All liquid waste is processed on a batch basis to permit optimum control of releases. Prior to being released, samples are analyzed to determine the types and amounts of radioactivity present. Based on the results of the analyses, the waste is recycled for eventual reuse in the plant, retained for further processing, or released under controlled conditions to the environment.

A radiation monitor in the discharge line will automatically terminate liquid waste discharges if radiation measurements exceed a predetermined level. The liquid radioactive waste processing system consists of the coolant radwaste system, the miscellaneous waste subsystem and the chemical waste subsystem. In addition, the chemical and volume control system processes letdown from the primary system to control boron concentration and reactor water purity. In our evaluation model, we assumed that a portion of the chemical and volume control system flow will be released through the coolant radwaste system for tritium control. Steam generator blowdown is flashed to steam in a flash tank, with the liquid being cooled in a heat exchanger before passing through a filter and two demineralizers in series and then routed to the main condenser. The flashed steam is routed to the main condenser hotwell. In our evaluation, we assumed that all of the blowdown is recycled to the main condenser for reuse. Laundry, hot shower, and decontamination wastes are treated in the miscellaneous waste subsystem when radioactivity concentrations are in excess of pre-established limits.

11.2.1.1 Chemical and Volume Control System

A letdown stream of approximately 40 gallons per minute of primary coolant is removed from the primary reactor coolant system for processing through the chemical and volume control system (CVCS). The letdown stream is cooled through the letdown heat exchangers, reduced in pressure, filtered and processed through one of two mixed-bed demineralizers in the Li_3BO_3 form. At the end of core cycle life, this letdown stream is passed through an anion demineralizer to remove boron when the feed and bleed mode of operation is not practicable.

The processed letdown stream is collected in the volume control tank and reused in the primary coolant system. The chemical and volume control system is used to control the primary coolant boron concentration by diverting a portion of the treated letdown stream to the shared coolant radwaste system as shim bleed. We estimated the coolant radwaste system input from the chemical and volume control system letdown stream to be approximately 1,000 gallons per day per reactor.

Primary coolant-grade water from equipment drains, equipment leakage, and from relief valves inside containment is collected in the reactor drain tank and equipment drain tank. We estimated the coolant radwaste system input from the reactor and equipment drain tanks to be approximately 300 gallons per day per reactor.

The 1,000 gallons per day per reactor shim bleed and the 300 gallons per day per reactor input from the reactor and equipment drain tanks are processed through two mixed-bed demineralizers (Li_3BO_3 form) in series, through a gas stripper, and are collected in one of four 60,000 gallon radwaste primary holdup tanks. The streams form the inputs to the coolant radwaste system and are processed batchwise from the four radwaste primary holdup tanks.

11.2.1.2 Coolant Radwaste System

The wastes in the four radwaste primary holdup tanks are processed batchwise through the shared coolant radwaste system. The coolant radwaste system consists of two mixed-bed demineralizers (H_3BO_3 form) in series and two 120,000 gallon radwaste secondary holdup tanks. From the radwaste secondary holdup tanks, the processed liquid can be recycled to the reactor coolant makeup tank, can be discharged to the circulating water outfall if radioactivity concentrations are within established limits, or can be further processed through the coolant and boric acid recycle system. In our evaluation, we assumed that all inputs to the coolant radwaste system are further processed through the coolant and boric acid recycle system.

11.2.1.3 Coolant and Boric Acid Recycle System

The coolant and boric acid recycle system is used in series with the coolant radwaste system to enable reclaimed water and boric acid to be reused in the reactor coolant system. The coolant and boric acid recycle system is shared by Units 2 and 3, and consists of a boric acid evaporator and two mixed-bed deborating and polishing demineralizers in series. The boric acid recovered in the evaporate bottoms can be recycled. If the radioactivity is below a predetermined value, the treated stream may be pumped to the waste monitor release tank and discharged. In our evaluation, we assumed that 10 percent of the treated stream is discharged to the circulating water outfall and to the Pacific Ocean due to anticipated operational occurrences and for tritium inventory control, and that 90 percent of the treated stream is recycled to the primary coolant system.

11.2.1.4 Miscellaneous Liquid Waste System

The miscellaneous liquid waste system is shared by Units 2 and 3, and is designed to collect and treat non-reactor grade water for reuse within the plant or for discharge. Low conductivity non-reactor grade water from auxiliary building sumps, containment sumps, and other sources is collected in a shared 6,000 gallon waste holdup tank at an input flow rate of approximately 1,400 gallons per day per unit. High conductivity wastes from laboratory drains, decontamination area

drains, and demineralizer regenerant solutions are collected in a shared 25,000 gallon chemical waste tank at an input flow rate of approximately 400 gallons per day per unit.

The miscellaneous liquid waste system consists of two mixed-bed demineralizers in series, a miscellaneous waste evaporator, and two mixed-bed polishing demineralizers in series. In operation, certain of the listed components are bypassed, depending on the nature of the wastes to be processed. In our evaluation, we considered the miscellaneous liquid waste system to consist of two subsystems: a miscellaneous waste subsystem for the processing of low conductivity wastes, and a chemical waste subsystem for the processing of high conductivity wastes.

The miscellaneous waste subsystem processes low conductivity liquid wastes from the 6,000 gallon waste holdup tank. The miscellaneous waste subsystem consists of from two to four series-connected mixed-bed demineralizers and two 25,000 gallon test tanks. The test tanks are shared with the chemical waste system. If needed, the stream can be diverted to the miscellaneous liquid waste system evaporator for additional treatment. In our evaluation, we assumed that two demineralizers are used in series.

The chemical waste subsystem processes high conductivity wastes from the 25,000 gallon chemical waste tank. The chemical waste subsystem consists of a 50 gallons per minute evaporator package, two series-connected mixed-bed polishing demineralizers, and two 25,000 gallon test tanks.

The contents of the test tank for the miscellaneous waste subsystem and the chemical waste subsystem are sampled and analyzed batchwise, and the contents of the tanks are recycled for further treatment, recycled for inplant use, or discharged. The applicant's evaluation assumes that 100 percent of the treated streams from both subsystems of the miscellaneous liquid waste system are released to the Pacific Ocean with the circulating discharge stream. In our evaluation, we also assumed 100 percent release of the treated stream to the Pacific Ocean.

11.2.1.5 Laundry and Hot Shower Wastes

The plant does not have a separate laundry and hot shower system; this function is combined in the miscellaneous liquid waste system described above.

11.2.1.6 Turbine Area Drain

The turbine area drains are released through a radiation monitor to the Pacific Ocean via the circulating water outfall without treatment. A radioactivity monitor will automatically terminate liquid discharge if radioactivity exceeds a predetermined level. We assumed a release of 7,200 gallons per day per reactor and that the wastes are discharged without processing.

11.2.1.7 Steam Generator Blowdown System

The steam generator blowdown system for San Onofre 2 and 3 continuously processes steam generator blowdown at an average flow rate of 86,000 gallons per day per unit (design flow rate is 300 gallons per minute). The blowdown from the two steam generators for each unit is directed to a common flash tank. The liquid is cooled, filtered, and treated through two series connected demineralizers before being returned to the main condenser. The flashed steam is condensed in the main condenser hot well. We assumed that there would be no direct releases from this system to the environment.

11.2.1.8 Conformance with NRC Regulations and Staff Positions

The liquid radioactive waste treatment system is located in the auxiliary building which is designed to seismic Category I criteria. The proposed seismic design and quality group classification and capacities of principal components considered in the liquid radwaste system evaluation are listed in Table 11.6. We find the applicants' proposed liquid radioactive waste treatment system design to be acceptable in accordance with Branch Technical Position ETSB 11-1, "Design Guidance for Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Plants." The system design also includes measures intended to control the release of radioactive materials due to potential overflows from indoor and outdoor storage tanks. Tank levels are monitored either locally or in the control room and high level alarms will be activated should preset levels be exceeded. Overflow provisions such as sumps, dikes and overflow lines permit the collection and subsequent processing of tank overflow. We conclude that these provisions are capable of controlling the release of radioactive materials to the environment.

We have determined that during normal operation, the proposed liquid radioactive waste treatment system is capable of reducing the release of radioactive materials in liquid effluents to approximately 1.1 curies per year per reactor, excluding tritium and dissolved gases, and to 300 curies per year per reactor for tritium. The calculated annual releases of radionuclides in liquid effluents from each unit are given in Table 11.2.

Using the source terms given in Table 11.2, we calculate the total body dose to an individual in an unrestricted area to be less than 3 millirem per year per reactor, and any organ dose to be less than 10 millirem per year per reactor in accordance with Section II.A of Appendix I to 10 CFR Part 50. The calculated doses are given in Table 11.4.

The calculated doses from liquid effluent releases to the population within a 50 mile radius of each reactor, when multiplied by \$1,000 per total body man-rem or \$1,000 per man-thyroid-rem, resulted in a cost-assessment value of \$170 per year per unit for the total body man-rem dose and \$140 per year per unit for the man-thyroid-rem dose. Potential radwaste system "augmentations" were selected from

TABLE 11.6

DESIGN PARAMETERS OF PRINCIPAL COMPONENTS CONSIDERED IN THE
EVALUATION OF LIQUID AND GASEOUS RADIOACTIVE WASTE TREATMENT SYSTEMS

<u>Component</u>	<u>Number</u>	<u>Capacity Each</u>
<u>LIQUID SYSTEMS</u>		
Coolant Radwaste System Primary Demineralizers	2	280 gallons per minute
Coolant Radwaste System Gas Stripper	2	140 gallons per minute
Coolant Radwaste System Primary Holdup Tank	4	60,000 gallons per minute
Coolant Radwaste System Secondary Demineralizers	2	280 gallons per minute
Coolant Radwaste System Holdup Tanks	2	120,000 gallons per minute
<u>Coolant and Boric Acid Recycle Subsystem</u>		
Coolant and Boric Acid Recycle Subsystem Boric Acid Evaporator	1	50 gallons per minute
Coolant and Boric Acid Recycle Subsystem Demineralizers	2	160 gallons per minute
<u>Miscellaneous Waste System^a</u>		
Miscellaneous Waste System Waste Collection Tank	1	6,000 gallons per minute
Miscellaneous Waste System Demineralizers	2	65 gallons per minute
Miscellaneous Waste System Polishing Demineralizers	2	65 gallons per minute
Miscellaneous Waste System Test Tank	2	25,000 gallons per minute
<u>Chemical Waste Subsystem^a</u>		
Chemical Waste Subsystem Evaporator	1	50 gallons per minute
Chemical Waste Subsystem Polishing Demineralizer (also utilized as Miscellaneous Waste System polishing demineralizers)	2	65 gallons per minute
Chemical Waste Subsystem Test Tank (also utilized as Miscellaneous Waste System test tank)	2	25,000 gallons per minute
<u>GASEOUS SYSTEMS</u>		
<u>Gaseous Radwaste System^a</u>		
Gaseous Radwaste System Surge Tank	1	500 cubic feet
Gaseous Radwaste System Decay Tank	6	500 cubic feet

^aQuality Group and seismic design in accordance with, or exceeds, Branch Technical Position, ETSB 11-1 (Revision 1).

the list given in Regulatory Guide 1.110, "Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors." Our review of the miscellaneous liquid radwaste system shows that the equipment available for use in either the miscellaneous waste subsystem or the chemical waste subsystem consists of filters, four demineralizers, and an evaporator, with adequate interconnections to permit flexibility of operation. On the basis of the capacities and decontamination factors of the available equipment, we determined that there are no practicable "augmentations" which could be added to the system. To substantiate this determination, we note, for example, that an "augmentation" consisting of a fifth demineralizer would have a total annualized cost of \$37,000. However, our evaluation would not credit this augmentation with an effective decontamination factor due to the presence upstream of existing equipment. The calculated total annualized cost of \$37,000 for the "augmentation" would exceed the cost-assessment value of \$170 per year per unit to the total body man-rem dose and \$140 per year per unit to the man-thyroid-rem dose. We conclude, therefore, that there are no cost-effective "augmentations" to reduce the cumulative population dose at a favorable cost-benefit ratio, and that the proposed liquid radwaste treatment system meets the requirements of paragraph D of Section II of Appendix I to 10 CFR Part 50.

We conclude that the liquid radwaste treatment system will reduce liquid radioactive effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a and Appendix I to 10 CFR Part 50.

We have determined that the liquid radwaste treatment system is capable of reducing the release of radioactive materials in liquid effluents to concentrations below the limits in 10 CFR Part 20, during periods of fission product leakage from the fuel at design levels.

11.2.2 Gaseous Waste Processing Systems

The gaseous waste processing systems consist of the gaseous radioactive waste processing system, the vent gas collection system, and the plant ventilation system. These systems are designed to collect, store, process, monitor, recycle, and/or discharge potentially radioactive gaseous wastes which 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 vacuum pumps, and ventilation exhausts from the auxiliary building, reactor containment, and turbine area.

The gaseous radioactive waste processing system for the San Onofre 2 and 3 facility is shared between Units 2 and 3. The gaseous radioactive waste processing system collects and stores the hydrogenated fission product gases stripped from the primary coolant letdown, the volume control tanks, and the reactor drain tanks, by compressing into gas decay tanks. Releases from the gas decay tanks are mixed with plant ventilation air prior to release to the environment, through a common plant vent on top of the Unit 2 containment building. Ventilation exhaust air

from the containment building of each unit is released without treatment through separate vents located on the top of the Unit 2 and Unit 3 containment buildings; if radioactive concentration in containment air exceeds a predetermined concentration, the air will be circulated through an internal cleanup system consisting of high efficiency particulate air filters and charcoal adsorbers prior to release to the environment. Ventilation air from the auxiliary building and fuel building for Unit 2 and Unit 3 is released, without treatment, to the environment through a common vent located on the top of Unit 2 containment. The turbine area is an open structure and releases are directly to the atmosphere. Exhausts from the condenser air ejectors are processed through high efficiency particulate air filters and charcoal adsorbers before being released to the atmosphere through vents located on the turbine area structure.

11.2.2.1 Gaseous Radioactive Waste Processing System

The gaseous radioactive waste processing system is a shared system designed to collect and process gases stripped from the primary coolant and from the hydrogenated gases vented from the volume control tanks and the reactor drain tanks. The gases are compressed into pressurized storage tanks for decay. Redundant 5 standard cubic feet per minute capacity compressors are provided for this purpose. There are six storage tanks included in the gaseous radioactive waste processing system with a design pressure of 350 pounds per square inch, gauge and a 500 cubic foot volume in each.

In our evaluation, we assumed that the six tanks provided have the capacity to store the radioactive waste gases approximately 90 days for decay. We find the system capacity and design to be adequate for meeting the demands of the station during normal operation including anticipated operational occurrences.

11.2.2.2 Vent Gas Collection System

The vent gas collection system is a shared system designed to collect and discharge potentially radioactive gases from the vents of potentially radioactive liquid storage tanks and from the sampling system vent hoods. The gases are collected in the radwaste area vent header where they discharge into the continuous exhaust plenum of the plant ventilation system. Discharges from the vent gas collection system are not treated prior to release. All releases through the plant vent are continuously monitored for radioactivity concentration.

Our evaluation assumed that the fission product discharges from the vent gas collection system are less than 1 percent of the releases from the gaseous radioactive waste processing system.

11.2.2.3 Containment Ventilation System

Radioactive gases are released inside the containment when primary system components are opened or when primary system leakage occurs. In our evaluation we

assumed that the containment is purged continuously during power operation at 2000 CFM and in addition there will be 4 high volume shutdown purges per year at 40,000 CFM. Prior to purging, the containment atmosphere is recirculated through high efficiency particulate air filters and charcoal adsorbers. We assumed radionuclide removal during the recirculation phase to be based on a flow rate of 16,000 cubic feet per minute, a mixing efficiency of 70 percent, a particulate decontamination factor of 100 for high efficiency particulate air filters, and an iodine decontamination factor of 10 for charcoal adsorbers. The purge exhaust gases are released without filtration or other treatment. Containment purge exhaust radioactivity monitors will automatically isolate the purge system upon detection of a radioactivity concentration above a predetermined level.

11.2.2.4 Ventilation Releases from Other Buildings

Radioactive materials are introduced into the plant atmosphere as a result of leakage from equipment transporting or handling radioactive materials. We estimate that 160 pounds per day of primary coolant will leak to the auxiliary building, with an iodine partition factor of 0.0075. Small quantities of radionuclides are released to the turbine building atmosphere based on an estimated 1700 pounds per hour of steam leakage. The plant ventilation systems are designed to induce air flows from potentially less radioactively contaminated areas to areas having a greater potential for radioactive contamination. Our calculations assumed that effluents from the auxiliary building, from the fuel handling buildings, and from the turbine area are released directly to the environment without treatment.

11.2.2.5 Main Condenser Air Ejector Exhaust

Offgas from the main condenser air ejectors contains radioactive gases as a result of primary-to-secondary coolant system leakage. In our evaluation, we assumed a primary-to-secondary leak rate of 100 pounds per day. Noble gases and iodine are contained in the steam generator leakage and are released to the environment through the main condenser air ejectors in accordance with the partition factors listed in Table 11.1. The main condenser air ejector exhaust is released to the environment through high efficiency particulate air filters and charcoal adsorbers.

11.2.2.6 Conformance with NRC Regulations and Staff Positions

The proposed seismic design and quality group classification and capacities of the principal equipment in the gaseous radioactive waste processing system are listed in Table 11.6. We find that the San Onofre 2 and 3 gaseous radioactive waste processing system is in conformance with Branch Technical Position ETSB 11-1, "Design Guidance for Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Plants," and is acceptable. The gaseous radioactive waste processing system is located in the auxiliary building which is a seismic Category I structure.

We have compared the design, testing, and maintenance of HEPA filters and charcoal adsorbers installed in normal ventilation exhaust systems with the guidelines of Regulatory Guide 1.40 (October 1979), and we conclude that they are acceptable at San Onofre 2 and 3.

We have reviewed the design of the San Onofre 2 and 3 gaseous radioactive waste processing system for preventing a hydrogen explosion. The basis for our review is given in Section 11.3 (Revision 1) of NUREG-75/087, the Standard Review Plan (SRP), "Gaseous Waste Management Systems." The gaseous radioactive waste processing system is monitored by continuous hydrogen and oxygen gas analyzers and by periodic hydrogen and oxygen gas analyzers with high concentration alarms and provisions for automatic injection of nitrogen diluent upon alarm annunciation by the analyzers. These monitors are all located upstream of the two compressors. However, oxygen leakage into the compressors is prevented by a double-diaphragm arrangement with an additional leak detection spacer diaphragm located between the two diaphragms.

We find the gaseous radioactive waste processing system capacity and design criteria, along with the design provisions incorporated to reduce the potential of hydrogen explosions, discussed in the paragraph immediately above, to be acceptable.

We have determined that the proposed gaseous radwaste treatment and plant ventilation systems are capable of reducing the release of radioactive materials in gaseous effluents to approximately 8,800 curies per year per reactor for noble gases, 0.095 curies per year per reactor for iodine-131, 1,100 curies per year per reactor for tritium, 8 curies per year per reactor for carbon-14, and 0.34 curies per year per reactor for particulates.

The calculated annual releases of radionuclides in gaseous effluents from each unit are given in Table 11.3.

Using the source terms given in Table 11.3, we have determined the annual air dose per reactor in an unrestricted area to be less than 10 millirads for gamma radiation and 20 millirads for beta radiation. We have determined the annual individual external doses per reactor from gaseous effluents in an unrestricted area to be less than 5 millirems to the total body and 15 millirems to the skin. We have determined the annual dose per reactor in an unrestricted area from all pathways due to release of radioiodine and radioactive material in particulate form to be less than 15 millirem to any organ. The calculated doses are given in Table 11.4 and these meet the requirements of Section II.B and II.C of Appendix I to 10 CFR Part 50.

The calculated total body and thyroid doses from gaseous effluent releases to the population within a 50 mile radius of the station, when multiplied by \$1,000 per total body man-rem and \$1,000 per man-thyroid-rem resulted in cost-assessment values of \$21,000 per year per unit and \$40,000 per year per unit respectively. Potential radwaste system augments were selected from the list given in Regulatory

Guide 1.110. The most effective augment considered was the addition of a charcoal adsorber and high efficiency particulate air filter system on the containment mini-purge ventilation exhaust. The addition of this augment would result in a dose reduction of approximately 6.3 total body man-rem and 23.8 man-thyroid-rem, with corresponding cost-assessment values of \$6,300 and \$23,800, respectively. The calculated total annualized cost of \$26,500 for the augment exceeds the cost-assessment value of \$6,300 per year per unit for the total body man-rem dose and the reduction in cost-assessment value of \$23,800 per year per unit for the man-thyroid-rem dose. We conclude, therefore, that there are no cost-effective augments to reduce the cumulative population dose at a favorable cost-benefit ratio, and that the proposed gaseous waste treatment and ventilation systems meet the requirements of Section II.D of Appendix I to 10 CFR Part 50.

We conclude that the gaseous waste treatment and ventilation systems are capable of reducing releases of radioactive materials in gaseous effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a and Appendix I to 10 CFR Part 50. We find that the proposed gaseous radwaste treatment system and plant ventilation systems are capable of reducing the release of radioactive materials in gaseous effluents to concentrations below the limits of 10 CFR Part 50 during periods of fission product leakage from the fuel at design levels.

11.2.3 Solid Radioactive Waste Treatment System

The solid waste system is shared between the two units and is designed to process two general types of solid wastes: "wet" solid wastes which require solidification prior to shipment, and "dry" solid wastes which require packaging and, in some cases, compaction prior to shipment to a licensed burial facility. "Wet" solid wastes consist mainly of spent filter cartridges, demineralizer resins, and evaporator bottoms which contain radioactive materials removed from liquid streams during processing. "Wet" solid wastes are combined with urea formaldehyde solidification agent and catalyst in containers (50 cubic foot containers and 55-gallon drums) to form a solid matrix. The containers are subsequently sealed and placed in a shield, as required, for offsite shipment.

"Dry" solid wastes, consisting mainly of ventilation air filtering medium (charcoal), contaminated clothing, paper, rags, laboratory glassware, and tools, are packaged in 55-gallon drums.

11.2.3.1 Wet Solid Wastes

The principal sources of spent resins are ten 50 cubic foot liquid radwaste system demineralizers, two 50 cubic foot deborating demineralizers, six 36 cubic foot purification and deborating demineralizers, four steam generator blowdown purification demineralizers, and two spent fuel pool purification demineralizers. Spent resins from the demineralizers are collected in one of two spent resin storage tanks. When the resin is to be packaged, it is sluiced to a disposable liner and dewatered before solidification. The resin beads are solidified by

filling the void spaces with urea formaldehyde and catalyst. A disposable paddle is used to agitate the mixture in the liner during the solidification process. Concentrated evaporator waste is collected in an evaporator bottoms tank, and then pumped batchwise through an inline mixer where it is blended with a urea formaldehyde solution. From the inline mixer, the mixture is sprayed into a disposal liner while a liquid catalyst is simultaneously sprayed into the liner by a separate nozzle to assure intimate mixing of the waste-urea formaldehyde solution and the catalyst.

On the basis of our evaluation and on recent data from operating plants, we have determined that approximately 11,000 cubic feet per unit of "wet" solid wastes, containing approximately 2,000 curies of activity, will be shipped offsite annually. The principal radionuclides in the solid wastes will be long-lived fission and corrosion products, mainly cesium-134, cesium-137, cobalt-58, cobalt-60 and iron-55.

11.2.3.2 Dry Solid Wastes

Dry solid wastes are packaged in 55-gallon drums. Compressible wastes such as clothing, paper, and rags are compressed prior to packaging.

During the baling operation, the air flow in the vicinity of the baler is exhausted by a fan through a high efficiency particulate air filter to the auxiliary area exhaust system to reduce the potential for airborne radioactive dusts. We estimate the dry solid wastes will total 4,100 cubic feet per year per reactor with a total activity content of 5 curies.

11.2.3.3 Conformance with Federal Regulations and NRC Staff Positions

The solid radwaste system is housed in the auxiliary building and conforms to the design, construction, and testing criteria of Branch Technical Position ETSB 11-1 (Rev. 1), "Design Guidance for Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Plants." The auxiliary building is designed to seismic Category I criteria. In addition, the solid radwaste system incorporates a process control program and provides for waste storage in accordance with Branch Technical Position ETSB 11-3, "Design Guidance for Solid Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Reactor Plants." Storage facilities include an area in the auxiliary building for approximately 20 shipping containers (50 cubic feet each) of high level waste and 75 55-gallon drums of low level waste. We find the storage capacity adequate for meeting the demands of the station for normal operation.

On the basis of our evaluation of the solid waste system, we conclude that the system design will accommodate the wastes expected during normal operations, including anticipated operational occurrences.

The packaging and shipping of all wastes will be in accordance with the applicable requirements of 10 CFR Parts 20 and 71 and 49 CFR Parts 170-178.

From these findings, we conclude that the solid waste system is acceptable.

11.3 Process and Effluent Radiological Monitoring Systems

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 11.7 provides the proposed locations of continuous monitors. Monitors on certain effluent release lines will automatically terminate discharges should radiation levels exceed a predetermined value. Systems which are not amenable to continuous monitoring, or for which detailed isotopic analyses are required, are periodically sampled and analyzed in the plant laboratory.

We have reviewed the locations and types of effluent and process monitors provided. Based on the plant design and on continuous monitoring locations and intermittent sampling locations, we have concluded that all normal and potential release pathways will be monitored. We have also determined that the sampling and monitoring provisions are adequate for detecting radioactive material leakage to normally uncontaminated systems and for monitoring plant processes which affect radioactivity releases. On this basis we find that the monitoring and sampling provisions meet the requirements of Criteria 60, 63 and 64 of the General Design Criteria and the guidelines of Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants."

11.4 Conclusions

In our evaluation, we have calculated releases of radioactive materials in liquid and gaseous effluents for normal operation including anticipated operational occurrences based on expected radwaste inputs over the life of the plant.

In our evaluation we determined that the applicant's proposed design of the liquid and gaseous waste treatment systems satisfies the design objectives of Appendix I to 10 CFR Part 50.

We conclude that the liquid and gaseous radwaste treatment systems will reduce radioactive materials in effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a and, therefore, are acceptable.

We have considered the potential consequences resulting from reactor operation with a 1 percent operating power fission product source term and determined that under these conditions, the concentrations of radioactive materials in liquid and gaseous effluents in unrestricted areas will be a small fraction of the limits specified in 10 CFR Part 20.

TABLE 11.7
PROCESS AND EFFLUENT MONITORS

<u>Stream Monitored</u>	<u>Type Detector</u>	<u>Range</u>
<u>GASES</u>		
Waste Gas Header**	Gas, Low Range β Scintillator Gas, High Range β Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter 10^{-3} to 10^2 microcuries per cubic centimeter
Containment Purge**	Gas, β Scintillator Particulate, β Scintillator	10^{-3} to 10^2 microcuries per cubic centimeter 10^{-9} to 10^{-4} microcuries per cubic centimeter
Plant Vent**	Gas, β Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter
Radwaste Area Vent Header	Gas, β Scintillator Particulate, iodine, γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter 10^{-9} to 10^{-4} microcuries per cubic centimeter
Fuel Handling** Vent Header	Gas, β Scintillator Particulate, iodine γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter 10^{-9} to 10^{-4} microcuries per cubic centimeter
Condenser Air Ejector Vent	Gas, β Scintillator, Low Range Gas, γ Scintillator, High Range	10^{-6} to 10^{-1} microcuries per cubic centimeter 10^{-3} to 10^2 microcuries per cubic centimeter
<u>LIQUIDS</u>		
Component Cooling Water	γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter
Radwaste Discharge Line	γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter
Turbine Area Sumps	γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter
Radwaste Condensate Return	γ Scintillator	10^{-6} to 10^{-1} microcuries per cubic centimeter

*All liquid and gaseous effluent streams will be monitored in accordance with the guidelines of Regulatory Guide 1.21.

**These monitors will alarm and automatically terminate the release when the radioactivity level exceeds a predetermined value.

We have considered the capabilities of the radwaste systems to meet the anticipated demands of the plant due to anticipated operational occurrences and have concluded that the liquid, gaseous, and solid waste system capacities and design flexibilities are adequate to meet the anticipated needs of the plant.

We have reviewed the applicants' quality assurance provisions for the radwaste systems, the quality group classification used for system components, the seismic design applied to the design of the gaseous waste processing system, and the seismic design applied to the design of structures housing the radwaste systems. The design of the radwaste systems and structures housing these systems meet the acceptance criteria as set forth in Branch Technical Position ETSB 11-1 (Rev. 1) "Design Guidance for Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Plants," presently incorporated in revised form in Regulatory Guide 1.143 (July 1978).

We have reviewed the provisions incorporated in the applicants' design to control the releases of radioactive materials in liquids due to inadvertent tank overflows and conclude that the measures proposed by the applicant are consistent with our acceptance criteria as set forth in Branch Technical Position ETSB 11-1 (Rev. 1).

Our review of the radiological process and effluent monitoring system included the provisions for sampling and monitoring all normal and potential effluent discharge paths in conformance with Criterion 64 of the General Design Criteria, for providing automatic termination of effluent releases and assuring control over releases of radioactive materials in effluents in conformance with Criterion 60 of the General Design Criteria and Regulatory Guide 1.21, for sampling and monitoring plant waste process streams for process control in conformance with Criterion 63 of the General Design Criteria, for conducting initial test programs in conformance with the guidelines of Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," for conducting sampling and analytical programs in conformance with the guidelines of Regulatory Guide 1.21, and for monitoring process and effluent streams during postulated accidents. The review included piping and instrument diagrams and process flow diagrams for the liquid, gaseous, and solid radwaste systems and ventilation systems, and the location of monitoring points relative to effluent release points. We conclude that the applicants' radiological process and effluent monitoring systems are acceptable. The basis for acceptance has been conformance of the applicants' designs, design criteria, and design bases for the radwaste treatment and monitoring systems to the applicable regulations and guides referenced above, as well as to staff technical positions and industry standards.

12.0 RADIATION PROTECTION

We have evaluated the proposed radiation protection program presented in Section 12 of the San Onofre 2 and 3 Final Safety Analysis Report. The radiation protection measures incorporated at San Onofre 2 and 3 are intended to "ensure that internal and external radiation exposures to station personnel, contractors, and the general population due to station conditions, including anticipated operational occurrences, will be within all applicable limits, and furthermore, will be as low as is reasonably achievable."

The criterion used to determine the acceptability of the radiation protection program is that doses to personnel will be maintained within the limits of 10 CFR Part 20, "Standards for Protection Against Radiation." The radiation protection design and program features must also be consistent with the guidelines of Regulatory Guide 8.8, "Information Relevant to Maintaining Occupational Radiation Exposures as Low as is Reasonably Achievable." Some of the radiation protection measures which the applicants will use at San Onofre 2 and 3 include: location of radioactive components in separately shielded cubicles; use of remotely operated valves or handwheel extensions; proper ventilation of areas to minimize inhalation doses; use of permanent radiation monitoring systems; and training of personnel in radiation protection. The applicants' use of these and other radiation protection features will help ensure that occupational radiation exposures are maintained as low as is reasonably achievable, both during plant operation and during decommissioning.

On the basis of our review of the San Onofre 2 and 3 Final Safety Analysis Report, we conclude that the radiation protection measures incorporated in the design will provide reasonable assurance that occupational radiation doses will be maintained as low as is reasonably achievable and below the limits of 10 CFR Part 20. These radiation design features are consistent with the guidelines of Regulatory Guide 8.8. We find the San Onofre 2 and 3 radiation protection to be acceptable. The details of our finding are discussed in the following sections.

12.1 Assuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable

The applicants provide a management commitment to assure that San Onofre 2 and 3 will be designed, constructed, and operated in a manner consistent with Regulatory Guides 8.8, 8.10, "Operating Philosophy for Maintaining Occupational Radiation Exposures As Low As Is Reasonably Achievable," and 1.8, "Personnel Selection and Training." The "as low as is reasonably achievable" philosophy was applied during the design of the plant. Since then, the applicants have continued to review,

update, and modify the plant design during the ensuing design and construction phases. Onsite inspections are conducted to check the shielding and piping layout design. The objective of these design reviews and inspections is to ensure that the personnel exposures at San Onofre 2 and 3 will be maintained as low as is reasonably achievable.

The plant chemical and radiation protection engineer has the responsibility to ensure that radiation exposures are maintained as low as is reasonably achievable. The engineer is responsible for the radiation protection program at San Onofre 2 and 3, which includes responsibility for the appropriation of radiation protection devices and protective clothing and the maintenance of radiation records. The engineer is also responsible for training of employees and contractors in radiation protection techniques. Prior to startup, the chemical and radiation protection engineer reviews the station maintenance and operating procedures. After startup, these procedures are reviewed on a 2-year cycle by the plant onsite review committee.

The objectives of the plant radiation design are to: (1) minimize the personnel time spent in radiation areas; and (2) minimize radiation levels in routinely occupied plant areas. By meeting the design objectives, the applicants intend to maintain occupational radiation exposures at San Onofre 2 and 3 as low as is reasonably achievable.

In order to satisfy the design objectives and minimize radiation exposures, the applicants have incorporated the following facility and equipment design considerations at San Onofre 2 and 3. Components requiring frequent maintenance are modularized for ease of disassembly and removal to a lower radiation zone for repair. The applicants have provided redundancy of equipment or components to reduce the need for immediate repair when radiation levels may be high. Equipment, instruments, and sampling stations requiring routine access or maintenance will be located for ease of access. The applicants have designed equipment, piping, and valves to minimize crud traps. Radioactive equipment is located in separate cubicles with labyrinth entrances. Pumps and valves for this equipment is located outside of these cubicles in lower radiation areas. These design considerations conform with the guidelines of Regulatory Guide 8.8 and are acceptable.

Operating and maintenance personnel will follow specific procedures in order to assure that "as low as is reasonably achievable" goals are achieved in the operation of the plant. Procedures for routine jobs are based on experience gained from operation of San Onofre 1 and from other operating reactors. Procedures written for unusual or first time jobs involving significant radiation exposure will be reviewed and approved by the plant onsite review committee (the chemical and radiation protection engineer is a member of this committee) and the station superintendent. Some of the exposure reduction design features which have been incorporated as a result of modifying Unit 1 procedures for use with Units 2 and 3 include provision for: (1) sufficient clearance for personnel to perform inservice inspections; (2) permanent platforms for ease of entry into steam generator channel hoods; (3) numerous decontamination areas throughout the facility; and (4) refueling cavity drains to allow more thorough drainage and minimize hot spots.

The applicants have incorporated several "as low as is reasonably achievable" techniques to reduce the exposures associated with maintenance and inspection activities during plant outages. Careful preplanning and the use of "dry runs" and mockups will precede high exposure jobs. Access to and from work areas will be controlled and radiation zones will be posted. The applicants will minimize doses to workers by the use of temporary shielding and by draining and flushing radioactive tanks in the work area prior to performing maintenance work. In addition to these generalized work procedures, the applicants have formulated specific "as low as is reasonably achievable" considerations for steam generator repair, reactor head removal and installation, and inservice inspections. These practices are in accordance with the guidelines contained in Regulatory Guides 8.8 and 8.10 and are acceptable.

12.2 Radiation Sources

Section 12.2 of the Final Safety Analysis Report contains a description of 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 applicants in arriving at quantitative values for these contained and airborne source terms.

The reactor core is the primary source of radiation in the containment, emitting neutrons and gamma rays. The reactor coolant system is the next highest source of radiation in the containment. The reactor coolant contains fission products from fuel clad defects and activation and corrosion products. Of these radiation sources, nitrogen-16 is the predominant activity in the reactor coolant pumps, steam generators, and the reactor coolant piping. In buildings other than the containment, the primary sources of personnel exposure are fission products, activation and corrosion products, and spent fuel assemblies (in the fuel building). The shielding used to protect personnel from these sources is based on fission source terms for full-power operation with one percent fuel cladding defects. Other parameters used, as well as a complete description of source term development, are contained in Section 11 of the Final Safety Analysis Report. The source terms presented are comparable to estimates by other applicants with similar designs and are acceptable.

The applicants have provided a tabulation of the normal expected radioactive concentrations in all the applicable regions due to equipment leakage. The bases for these leakage calculations are in accordance with Regulatory Guide 1.112, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors."

The ventilation system will route air from areas of low potential contamination to areas of increasing potential airborne contamination. The amount of uncontrolled exfiltration from an area will be minimized by exhausting a greater volumetric flow than is supplied to an area. The resulting expected airborne isotopic concentrations in all applicable regions will be well below the maximum permissible concentrations for the critical organ for occupational workers.

12.3 Radiation Protection Design Features

The radiation protection design features at San Onofre 2 and 3 are intended to help maintain occupational radiation exposures as low as is reasonably achievable. Many of these design features have been incorporated as a result of the applicants' "as low as is reasonably achievable" design efforts, based in part on the radiation exposure experience gained during the operation of San Onofre 1, and other nuclear power plants. Plant equipment and components will be designed to minimize exposure to personnel and the possibility of inadvertent radioactive releases to the environment. Evaporators have chemical addition connections to permit the use of chemicals for descaling operations. Pumps and tanks have drain connections for draining prior to maintenance work. Pumps servicing radioactive equipment are located in separate cubicles with adequate space for access to the pumps for servicing. Heat exchangers are provided with corrosion-resistant tubes of stainless steel or other suitable materials. Instrument devices are located in low-radiation zones, where practical, for safe readout. Those primary instrument devices located in high-radiation zones are designed for easy removal to a lower radiation zone. Valves are located in shielded valve galleries. Manually operated valves located in high radiation zones are provided with remote-manual operators or reach rods. In order to minimize maintenance, piping located in pipe chases is designed for the lifetime of the unit.

In addition to designing the plant equipment to comply with "as low as is reasonably achievable" guidelines, the applicants designed the equipment and facility layout to minimize personnel exposure. Concrete floors and walls of cubicles which contain equipment handling radioactive liquids are covered with a smooth-surfaced coating to facilitate decontamination. Pipes carrying radioactive materials are separated from non-radioactive piping and are located in shielded pipe chases. Penetrations are designed to minimize streaming. Major components in radioactive systems are isolated in separate shielded cubicles. These cubicles are sized to permit adequate space and ease of motion for maintenance purposes. Inservice inspection points are located in properly shielded low radiation zones to reduce inspector exposure. Adequate lighting is provided in all areas for personnel safety and convenience. These features conform with those contained in Regulatory Guide 8.8 and are acceptable.

Several features have been incorporated in the design to minimize the buildup, transport, and deposition of activated corrosion products in the reactor coolant and auxiliary systems at San Onofre 2 and 3. Limitations on nickel concentration and cobalt impurity in reactor coolant system component specifications will minimize the formation of cobalt-58 and cobalt-60 in the reactor coolant system. Crud traps in welds are minimized through the use of butt welds in lieu of socket welds. Piping is designed to minimize low points and dead legs. Horizontally run pipes carrying resin slurries or evaporator bottoms will be sloped and will have large radius bends to maintain normal flows. Equipment and piping containing radioactive materials will have provisions for draining and flushing. These crud

reduction methods are based on those guidelines contained in Regulatory Guide 8.8 and are acceptable.

Areas within the restricted area are divided into five radiation zones. The dose rate criterion for each of these zones is derived from the zone's expected occupancy and access restrictions. These criteria are then used as for the radiation shielding design. This allows for arrangements of radioactive equipment that are in accordance with the requirements of 10 CFR Part 20 and the guidelines of Regulatory Guide 8.8. During plant operation and refueling conditions, chemical radiation protection personnel will perform routine radiation and contamination surveys of all accessible areas of the units. As a result of these surveys, measured radiation levels and the locations of radiation sources will be posted at the entry of any radiation or high radiation area.

The radiation shielding has been designed to reduce personnel and population exposures to levels that are within the dose regulations of 10 CFR Part 50 and are as low as is reasonably achievable within the dose regulations of 10 CFR Part 20. The applicants have also provided shielding where required to reduce potential equipment neutron activation and mitigate the possibility of radiation damage to materials. Radioactive components and piping are located in separate shielded cubicles to minimize exposure during maintenance and inspection activities. Potentially high radiation components are totally enclosed in shielded compartments with hatch openings or removable concrete block walls. Readouts and controls for radioactive equipment are remotely located to reduce personnel exposures. Design features to minimize radiation streaming through penetrations include: (1) providing offsets between the radiation source and accessible areas; (2) locating penetrations as far above the floor elevation as possible; and (3) using baffle shield walls or grouting the area around the penetration. The applicants have installed an annular reactor cavity shield of reinforced concrete in the annular gap around the reactor vessel below the reactor vessel nozzles. This is intended to minimize neutron streaming through the annular gap to the upper levels of the containment. These shielding techniques are intended to maintain personnel radiation exposures as low as is reasonably achievable and are acceptable.

The shielding thicknesses at San Onofre 2 and 3 were selected to ensure compliance with the plant radiation zoning and to minimize plant personnel exposure. The applicants' dose rate calculations were based on equations contained in Rockwell's "Reactor Shielding Design Manual." The shielding analysis was performed using the following acceptable computer codes; ANISN, QAD, and SDC. The applicants used Monte Carlo calculations for shielding problems involving more complex geometries. All concrete radiation shielding in the plant is designed following the recommendations of Regulatory Guide 1.69, "Concrete Radiation Shields for Nuclear Power Plants."

The ventilation system at San Onofre 2 and 3 is designed to protect personnel and equipment from extreme thermal environmental conditions and ensure that plant

personnel and the general public are not inadvertently exposed to airborne contaminant concentrations exceeding those given in 10 CFR Parts 20 and 50. The applicants intend to maintain personnel exposures as low as is reasonably achievable by: (1) maintaining air flow 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) piping equipment vents and lines directly to collection devices, thereby minimizing airborne contamination. These design criteria are in accordance with those contained in Regulatory Guide 8.8 and are acceptable. The San Onofre 2 and 3 ventilation system is designed in accordance with the guidelines of Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Engineered-Safety-Feature Atmosphere Cleaning System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants." The applicants will replace filter elements before the radioactivity level is great enough to create a personnel hazard. The active elements of the atmosphere cleanup systems are designed to permit ready removal and are accessible directly from working platforms.

The area radiation monitoring system is designed to: (1) alert personnel in non-radiation or low-radiation areas of increasing radiation levels; (2) monitor fuel and waste storage and handling areas; (3) sense a loss-of-coolant accident condition or fuel handling accident during containment purge and initiate containment purge isolation; and (4) provide a continuous record of radiation levels at key locations throughout the plant. In order to meet these objectives, 20 area monitors are located in areas where personnel may be present and where radiation levels could become significant. The area radiation monitoring system is equipped with local and remote audio and visual alarms and a facility for central recording. The applicants will calibrate all area monitors on a quarterly basis. Each containment building contains three emergency radiation monitoring system radiation monitors which provide post accident containment monitoring.

The design objectives of the airborne radioactivity monitoring system include: (1) measuring and controlling quantities of radionuclides in plant systems; (2) measuring and controlling radioactivity in effluents before and/or during their release to the environment; and (3) determining the levels of radioactivity in in-plant areas. Fixed constant air monitors will be installed on all effluent paths and in areas where airborne activity is expected to occur or where it had to be determined in an emergency. The applicants will use portable constant air monitors when needed to monitor air in areas not provided with fixed airborne radioactivity monitors. All airborne radioactivity monitors will be calibrated at least semiannually. The objectives and location criteria of the San Onofre 2 and 3 area and airborne radiation monitoring systems are in conformance with 10 CFR Parts 20 and 50 and Regulatory Guides 8.2 and 8.8.

12.4 Dose Assessment

The applicants have based the estimate of annual man-rem exposure at San Onofre 2 and 3 on plant specific projections as to occupancy and dose rates, and on experience from currently operating pressurized water reactors, including San Onofre 1. Equipment and equipment layout has been designed to minimize time spent by employees in high radiation fields. The amount of circulating crud in systems will be reduced by careful material selection. The shielding at San Onofre 2 and 3 has been conservatively designed and the actual anticipated dose rates within the shielded cells are expected to be less than the design dose rates.

The applicants have performed an assessment of the doses that will be received by plant and contractor personnel. This dose assessment is based upon occupancy factors, expected dose rates, expected airborne radioactivity concentrations, and estimates of the time and manpower necessary to perform the various tasks involved in plant operation. The dose assessment includes a breakdown of the annual man-rem doses associated with major functions; operations; maintenance (including special maintenance), refueling, security, radwaste handling, and inservice inspection. Also included is a listing of the percentage of time spent by each member of the plant staff in each of the five radiation zones. In arriving at total man-rem estimates, the applicants used personnel exposure estimates to evaluate alternative system designs, plant layouts, and shielding arrangements. The applicants estimate the total annual collective dose to plant personnel and contractors to be 411 man-rem per unit (822 man-rem for the two-unit site). This estimate is based on experience from pressurized water reactors operating between the years 1970 and 1974. It is also based on information presented in NUREG-75/032, "Occupational Radiation Exposure at Light Water Cooled Power Reactors 1969-1974," and the National Environmental Studies Project, "Compilation and Analysis of Data on Occupational Radiation Exposure Experienced at Operating Nuclear Power Plants." Currently operating light water reactors average 500 man-rem annually. We find the bases for the San Onofre 2 and 3 exposure estimates acceptable and consistent with the acceptance criteria in Section 12.4 of NUREG-75/087 (the Standard Review Plan).

The peak airborne radionuclide concentrations for most areas of the plant will be within the limits specified in 10 CFR Part 20. The applicants will make use of occupancy time limits and/or respiratory equipment to protect personnel required to enter plant areas where these radionuclide limits are exceeded. Section 12.4 of the Final Safety Analysis Report includes a tabulation of expected annual doses to plant personnel from airborne radioactivity for each building in the plant. These dose rates were calculated using the airborne radioactivity in Technical Information Document 14844 and Regulatory Guides 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors," 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," 1.24, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water

Reactor Radioactive Gas Storage Tank Failure," and 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors." The applicants' assumptions and models upon which the internal dose estimates are based for occupational exposures are acceptable.

12.5 Health Physics Program

The objectives of the radiation protection program are: (1) to ensure that radiation exposure to personnel on site is maintained within the guidelines of 10 CFR Part 20; and (2) to ensure that station effluent releases are maintained below 10 CFR Part 20 values and that they do not exceed the values given in the station Environmental Technical Specifications.

The chemical and radiation protection engineer will be in charge of the radiation protection program at San Onofre 2 and 3. This program encompasses the handling and monitoring of radioactive materials, including special nuclear, source, and byproduct materials. The chemical and radiation protection engineer will also be responsible for assuring that the station operation meets the radiation protection requirements of 10 CFR Part 19, 10 CFR Part 20, 10 CFR Part 50 Appendix I, and applicable Regulatory Guides. Other duties include maintaining "as low as is reasonably achievable" radiation exposures, providing radiation protection training for company employees and contractors and reviewing station maintenance and operating procedures. The qualifications of the health physics personnel, the objectives of the radiation protection program, and the ways in which it will be implemented are in accordance with the guidelines of Regulatory Guides 1.8, 8.2, 8.8, and 8.10, and are acceptable.

The radiation protection facilities at San Onofre 2 and 3 will include a radiation protection laboratory and offices, access control area, decontamination areas, calibration area, and radiochemistry laboratory and counting room. The radiochemistry laboratory contains a shielded sampling room which has sample line outlets running from various radioactive process streams in Units 2 and 3. A commercial, offsite firm will be responsible for the laundering of contaminated protective clothing and equipment. These facilities and the use of a commercial laundering firm are sufficient to maintain occupational radiation exposures as low as is reasonably achievable and are consistent with the provisions of Regulatory Guide 8.8.

Equipment to be used for radiation protection purposes includes fixed radiation detection instrumentation, portable radiation survey instruments, personnel monitoring instruments, fixed and portable area and airborne radioactivity monitors, air samplers, respiratory equipment, and protective clothing. The number and types of equipment to be used is adequate and provides reasonable assurance that the applicant will be able to maintain occupational exposures as low as is reasonably achievable.

All station employees, contractors, support personnel, and visitors are required to wear a self-reading dosimeter and/or a beta-gamma sensitive film badge when in a

controlled area. The self-reading dosimeters will be read and recorded daily. These will be used to keep a running total of an individual's dose prior to film badge processing. Film badges will be processed by a contractor at least monthly, or more frequently if significant exposures are suspected. Workers involved in high-exposure jobs will be issued thermoluminescent dosimeters. In addition, neutron sensitive film badges will be issued to individuals subject to significant neutron exposure. Each member of the permanent station organization who works in the exclusion area will receive a whole-body count and/or bioassay at least once each year. These wholebody counts and/or bioassays will be performed in accordance with the recommendations of Regulatory Guide 8.9, "Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program."

Personnel radiation exposures will be maintained as low as is reasonably achievable and within the limits of 10 CFR Part 20 by strictly adhering to the plant's radiation protection procedures. These procedures deal with such topics as radiation and contamination surveys, procedures and methods to maintain exposures as low as is reasonably achievable, controlling access and stay time, contamination control, airborne activity control, personnel monitoring, radioactive materials safety program, and radiation protection training.

Based on the information presented in the Final Safety Analysis Report and the applicants' responses to our questions, we conclude that the applicants intend to implement a radiation protection program that will maintain in-plant radiation exposures within the applicable limits of 10 CFR Parts 20 and 50 and will maintain exposures as low as is reasonably achievable.

13.0 CONDUCT OF OPERATIONS

The Southern California Edison Company, one of the applicants, will be the Project Manager and Operating Agent for San Onofre Units 2 and 3. All organizational elements and operational activities discussed in this section refer to the Southern California Edison Company organization, since it will be responsible for plant operation.

13.1 Organizational Structure and Qualifications

During our review we evaluated the corporate management and technical support provided for operations including the educational background and experience of individuals holding management and supervisory positions; the structure, functions, and responsibilities of the onsite organization established to operate and maintain the plant including shift manning requirements; and the qualifications of the applicants' plant personnel. The applicants' organization is currently being revised to reflect the recommendations of NUREG-0660, "NRC Action Plan Developed as a result of the TMI-2 Accident," and NUREG-0737, "Clarification of TMI Action Plan Requirements." Consequently, our review of the above areas will be addressed in Section 22.0 of this report or its supplement(s), under items I.A.1.3 and I.B.1.2.

13.2 Training Program

The San Onofre Units 2 and 3 Superintendent has overall responsibility for the conduct and administration of the training programs for all personnel. The program has been formulated to provide the required training based upon individual employee experience and intended position. The program conforms to the requirements set forth in American Nuclear Standards Institute (ANSI) N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel," and 10 CFR Part 55.

The nuclear training program provides a flexible, effective means of preparing personnel for station operations and license examinations. The Southern California Edison Company will conduct or contract for the teaching of each segment of the training program. Certain segments are conducted by Nuclear Utility Service, Inc., and/or Combustion Engineering, Inc.

All of the initial operator license candidates for San Onofre 2 and 3 will have been previously licensed on Unit 1 and have at least one year of experience on that unit. In addition, the training provided for personnel who will be licensed consists of the following segments: Nuclear Power Preparatory; Nuclear Steam Supply System Lecture Series; Reactor Simulator Training; Onsite Training; and NRC Examination Preparation.

A comprehensive on-the-job training program is conducted at Unit 1 for professional technical personnel, technicians and repairmen to meet the requirements of the

facility license. All station personnel receive training in the following areas: first aid practices, noise control, radiation protection, use of safety equipment, evacuation procedures, handling of chemicals, and safe work practices.

Plans for requalification training and replacement training conform to the requirements of 10 CFR Part 50, 10 CFR Part 55, Appendix A, and follow the guidance given in ANSI N18.1-1971. Complete records of all training administered will be maintained.

On the basis of our review, we conclude that the training programs and schedules for all staff members are acceptable for the preoperational test program, for operator licensing examinations, and for fuel loading.

13.3 Emergency Preparedness Evaluation

13.3.1 Introduction

The applicants have filed with the Nuclear Regulatory Commission a revision to the San Onofre Nuclear Generating Station Units 2 and 3 Emergency Plan, as amended (hereinafter referred to as the Plan). The NRC staff conducted a review of this Plan. Our review also included site visits to the facility and a public meeting on September 27, 1979.

The Plan was reviewed against the criteria of the sixteen licensee planning standards in Appendix E to 10 CFR 50, and Part II of the "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," NUREG-0654, Rev. 1, November 1980. In addition, we have requested all licensees and applicants of nuclear plants in California to provide analyses of the effects of an earthquake on their emergency plans. We specifically requested these utilities to discuss their capability to insure the availability of personnel and equipment to the plant sites after an earthquake.

This section of this report lists each objective of NUREG-0654 in order, followed by a summary of the applicable portions of the facility emergency plan as they apply to the planning standards.

The findings and determinations of the Federal Emergency Management Agency (FEMA) on the Federal, State and local emergency plans are not available at this time, but will be discussed in a supplement to this report.

13.3.2 Evaluation of Applicants' Emergency Plan

(1) Assignment of Responsibility (Organization Control)

Planning Standard

Primary responsibilities for emergency response by the nuclear facility licensee (applicants), State and local organizations within the Emergency Planning Zones

have been assigned, the emergency responsibilities of the various supporting organizations have been specifically established, and each principal response organization has staff to respond and to augment its initial response on a continuous basis.

Applicants' Emergency Plan Evaluation

The Watch Engineer is initially designated as the Site Emergency Coordinator. When an abnormal condition arises it is the engineer's responsibility to determine if the abnormality meets any of the emergency classifications specified in the Plan and to implement the Plan, if necessary. There is continuous (24-hour) communication capability between San Onofre and Federal, State, and local response organizations to ensure rapid transmittal of accurate notification information and emergency assessment data.

Responsibility for the overall direction of the onsite emergency response organization is vested in the Site Emergency Coordinator. Qualified members of the station staff who report directly to the coordinator have been assigned specific responsibilities for the major elements of emergency response.

Written agreements have been executed with the agencies and organizations that will provide support. These include the State of California, Orange County, San Diego County, the City of San Clemente, Tri-City Hospital, South Coast Community Hospital, Superior Ambulance Company, Scudders Ambulance Company and several physicians. Additional arrangements have been made with the UCLA School of Medicine to provide consultation services in the treatment of radiation exposures or injuries complicated by radioactive contamination.

(2) Onsite Emergency Organization

Planning Standard

On-shift responsibilities for emergency response are unambiguously defined, adequate staffing to provide initial facility accident response in key functional areas is maintained at all times, timely augmentation of response capabilities is available, and the interfaces among various onsite response activities and offsite support and response activities are specified.

Applicants' Emergency Plan Evaluation

The Watch Engineer on duty is designated as the Site Emergency Coordinator until relieved by the Plant Manager or a designated alternate. The authorities and responsibilities of the Emergency Coordinator have been clearly specified. The Emergency Coordinator can immediately and unilaterally declare an emergency and make the necessary notifications and recommendations to the authorities responsible for implementing offsite emergency measures.

Station staff emergency assignments have been made and the relationship between the emergency organization and normal staff complement is shown in the Plan. Positions or titles of shift and plant staff personnel, both on and offsite, who are assigned major emergency functional duties are listed. The shift staffing for two-unit operation satisfies the functional objectives identified in Table B-1 of NUREG-0654 for nuclear power plant emergencies. However, the applicants have not yet provided information on their capability to augment staffing during an emergency. We will review this capability and report our findings in a supplement to this report. This deficiency must be corrected according to the schedule in NUREG-0654, Revision 1.

The duties and responsibilities of corporate management personnel who will augment the plant staff have been established. Upon request from the Emergency Coordinator, the Corporate Radiological Emergency Support Organization will be activated. The Vice-President of Nuclear Engineering and Operations will be dispatched to the Primary Emergency Operations Center to head a public relations team. A framework for a long-term recovery organization has been established to perform post-accident recovery functions. Interfaces between and among the corporate staff, station staff, governmental and private sector organizations, and technical contractor groups have been specified along with services to be provided.

(3) Emergency Response Support and Resources

Planning Standard

Arrangements for requesting and effectively using assistance resources have been made, arrangements to accommodate State and local staff at the applicants' Emergency Operations Facility (EOF) have been made, and organizations capable of augmenting the planned response have been identified.

Applicants' Emergency Plan Evaluation

Arrangements for requesting and using outside resources have been made, including authority to request implementation of the Federal Radiological Monitoring and Assessment Plan by the Emergency Coordinator. Also, assistance is available from Combustion Engineering, Bechtel Power Corporation, and the Institute for Nuclear Power Operations.

The Primary Emergency Operations Center (PEOC, interim Emergency Operations Facility) will be activated for the more serious emergency classifications, i.e., Alert, Site Emergency, General Emergency. The facility can accommodate representatives from Federal, State and local government agencies, as well as representatives from contractor and other support groups. It will be the central point for providing information needed by primary response agencies for implementation of protective actions, and the central point for media contact.

(4) Emergency Classification System

Planning Standard

A standard emergency classification and action level scheme is in use by the nuclear facility licensee, including facility system and effluent parameters; State and local response organizations will rely on information provided by the licensee for determinations of minimum initial offsite response measures.

Applicant's Emergency Plan Evaluation

The applicants have established four standard emergency classes - Notification of Unusual Event, Alert, Site Emergency and General Emergency. The initiating conditions used for recognizing and declaring the emergency class are based on specific measurable parameters or observable conditions defined as Emergency Action Levels (EAL). The applicants have incorporated the various initiating conditions as set forth in NUREG-0654 for each class of emergency.

The California State and the City of San Clemente plans are still under revision. All other Federal, State, and local plans have recently been submitted for review. We are awaiting a FEMA finding of adequacy in order to determine the consistency of the Federal, State, and local emergency classification scheme with that of the applicants. We will provide FEMA's finding in a supplement to this report.

(5) Notification Methods and Procedures

Planning Standard

Procedures have been established for notification of State and local response organizations and for notification of emergency personnel by all response organizations; the content of initial and followup messages to response organizations and the public have been established; and means to provide early warning and clear instruction to the populace within the plume exposure pathway Emergency Planning Zone have been established.

Applicants' Emergency Plan Evaluation

Procedures have been established for notification of State and local response organizations in case of emergency. The Emergency Coordinator has been given the authority and responsibility to initiate prompt notification to these agencies. Initial notification is made directly to the Camp Pendleton Marine Corps Base, Orange County Health Department, California Department of Parks and Recreation, City of San Clemente, and the California State Office of Emergency Services (OES) for immediate action to protect the public within the plume exposure EPZ. Initial notification will also be made to the San Diego County Office of Disaster Preparedness, but during off-hours the call will be received by an answering service (see subsection (6), below).

The information to be reported to the offsite agencies in the event of an emergency has been predetermined in accordance with the recommendations in NUREG-0654. Such information is contained in four notification forms, one for each emergency class. These forms provide blanks and preworded information on the class of emergency, whether a release is/has taken place, potentially affected areas and appropriate protective action recommendations.

The applicants are installing an early warning system within the 10-mile emergency planning zone. In the pre-accident public information program, the populace will be instructed that the sirens are simply alerting devices and that the people should turn on radios to pre-designated stations for further instructions. Installation of the system is scheduled to be completed by July 1, 1981, in accordance with 10 CFR 50, Appendix E.

SCE is currently developing a public information program, to be implemented about April 1, 1981. This program aims to provide the resident and transient populations within the 10-mile EPZ with information on emergency classes and protective measures. This program will be coordinated with local government agencies.

(6) Emergency Communications

Planning Standard

Provisions exist for prompt communications among principal response organizations, to emergency personnel and to the public.

Applicants' Emergency Plan Evaluation

The station communication system is designed to provide secure, redundant and diverse communications to all essential onsite and offsite locations during normal and accident conditions. Onsite systems are comprised of a public address system, an intercom system, two-way radio systems, and a direct dial telephone system. Offsite systems are comprised of both commercial and leased telephone lines, two-way radio systems, and a direct dial telephone system which provides communication to other SCE facilities. A direct commercial telephone line is dedicated to NRC communications.

These telephones plus other systems are located in plant areas manned 24 hours a day. The Emergency Coordinator or the coordinator's designee will, in emergency situations, communicate directly with the City of San Clemente, State OES, State of California Department of Parks and Recreation, Camp Pendleton Marine Corps Base, Orange County Department of Health, and the NRC duty officer. These offices are manned 24 hours a day and have means to contact key personnel at all times. The San Diego Office of Disaster Preparedness will also be notified, but it is manned only during regular office hours. During non-office hours, a

professional answering service will relay messages to a duty officer. This arrangement does not comply with the NUREG-0654 requirement for 24-hour manning of communication links. We will require the applicants to provide initial notification to other county agencies that are manned around-the-clock. We will await the FEMA finding of adequacy of such an arrangement, and will provide our evaluation in a supplement to this report.

The Control Room, the Technical Support Center, Operations Support Center and Primary Emergency Response Center will be able to communicate with each other via the above mentioned onsite and offsite communications systems. Some systems (such as the commercial telephone lines) are routinely used and are therefore constantly kept in working order; systems that are not routinely used are tested periodically.

(7) Public Information

Planning Standard

Information is available to the public on a periodic basis on how they will be notified and what their initial actions should be during an emergency; the principal points of contact with the news media for dissemination of information (including physical location) are established in advance; and procedures for coordinated dissemination of information to the public are established.

Applicants' Emergency Plan Evaluation

The applicants' public information program will consist of general information on nuclear energy, radiation, and emergency planning. This information will be provided to the public in various forms such as pamphlets, advertisements, or bill inserts such that all of the topic areas will be covered annually. The program is being developed (see Section E above) and will be implemented about April 1, 1981.

During a site or general emergency, the Vice President, Nuclear Engineering and Operations, will serve as the principal point of contact with the news media. He and the SCE public relations team will be stationed in the PEOC. Formal press release will be prepared by the corporate Emergency Support Center, but press briefings will be conducted at the PEOC. Working space is available for the news media, when necessary, at the Boy's and Girl's Club of San Clemente.

In an unusual event or alert, press releases and other media relations will be handled by the SCE Public Relations staff at the Corporate Headquarters.

(8) Emergency Facilities and Equipment

Planning Standard

Adequate emergency facilities and equipment to support the emergency response are provided and maintained.

Applicants' Emergency Plan Evaluation

The applicants have committed to provide emergency support facilities including a Technical Support Center (TSC), Emergency Operations Facility (EOF), and an Operations Support Center. Each will be activated for an Alert or higher emergency classification.

The Technical Support Center is being constructed adjacent to the Control Room. It will be used as the assembly point for utility, vendor, NRC, and other personnel who would be directly involved in assessment of onsite accident response and mitigation. It has the capability to display plant status conditions, and will be habitable to the same degree as the control room. At present, an interim TSC has been set up adjacent to the control room. It is furnished with telephone lines for onsite and offsite communications.

An interim Emergency Operation Facility is located in the San Clemente City Hall. SCE has committed to build a permanent Emergency Operations Facility (EOF) at 1.0 km from SONGS in the north-northeast direction. Design of the EOF will be completed about May, 1981 and construction will be completed by July, 1982. We require that the design, instrumentation and function of the EOF be in substantial agreement with criteria in NUREG-0696. The EOF will be used to evaluate and coordinate emergency and reentry/recovery operations on a continuing basis by SCE, Federal, local, and State officials. It will also be the location where a public relations team will be stationed as mentioned above in Section (7).

The Onsite Operations Support Center is located in the Administration and Warehouse Building and will be the assembly point for unassigned personnel. It is provided with telephone facilities for communication with the Control Room, the TSC, and other locations.

The Plan provides a listing of the emergency equipment stored at various strategic locations around the facility. Stored emergency equipment will be inventoried and surveyed periodically. Equipment resources are provided to replace those that may be removed for servicing and calibration. Onsite monitoring systems and instrumentation used to initiate emergency measures or provide continuing assessment have been identified. These include meteorological and seismic instrumentation, radiological monitors, process monitors, fire detection systems, and portable dose rate and radiation detection instruments.

The meteorology program at the site does not meet the criteria of Appendix 2 of NUREG-0654. However, the applicants have committed to a completion schedule for an upgraded program that meets the NUREG-0654 requirements. In addition, offsite meteorologic data can be obtained from several non-SCE facilities.

The applicants are making provisions for offsite monitoring including a thermoluminescence dosimeter (TLD) network, fixed air-sampling stations, and portable radiation monitoring instruments for use by the offsite field assessment teams. The monitoring system meets the criteria in the NRC Radiological Assessment Branch Technical Position for Environmental Radiological Monitoring Programs.

(9) Accident Assessment

Planning Standard

Adequate methods, systems and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use.

Applicants' Emergency Plan Evaluation

The applicants have identified the instruments that will be used to identify and assess an accident at San Onofre. In addition, the applicants have committed to provide methods to project actual or potential offsite consequences using plant parameters and process radiological monitor indications. A high range containment monitor will be available for assessing the gross activity within containment. This information, together with the predetermined activity levels resulting from various nuclide releases from the coolant and the fuel, will aid the operators in assessing the status and extent of core degradation in the event of a serious accident. We require that the applicants provided portable detectors capable of sensing a radioactivity level of 10^{-7} $\mu\text{Ci/cc}$ in the plant vent for use in predicting offsite doses in the event of an actual release following a serious accident. However, the capability currently exists to detect radioiodine levels as low as 10^{-12} $\mu\text{Ci/cc}$ in air samples taken to the onsite laboratory.

In addition to projecting offsite consequences from measured in-plant parameters, the applicants have also established a field monitoring capability. Field monitoring teams will be employed whenever a site or general emergency is declared. These teams will have use of portable radiation monitors, air samplers, two-way radios and company vehicles.

(10) Protective Response

Planning Standard

A range of protective actions has been developed for the plume exposure pathway for emergency workers and the public. Guidelines for the choice of protective actions during an emergency, consistent with Federal guidance, are developed and

in place, and protective actions for the ingestion exposure pathway appropriate to the locale have been developed.

Applicants' Emergency Plan Evaluation

The applicants have established an onsite protective response for employees, contractor personnel, and members of the general public who may be within the exclusion area at the time of an emergency. This response consists of warning and notification, relocation and accountability, and protective actions. Onsite warning and notification will be by means of various alarm systems, station public address system, or by members of the security force depending on the location of the individuals within the exclusion area. In the case of a Site or General Emergency, personnel within the protected area will be relocated and an initial accountability completed. The Emergency Coordinator will authorize the site evacuation when necessary. Evacuation can take place on the plant access road via the security gates. Additional onsite protective measures include the use of individual respiratory protection, protective clothing, and radioprotective drugs.

The Plan provides for recommending offsite protective measures using protective action guides established by the State of California (these PAGs are more restrictive than those established by the U.S. Environmental Protection Agency). The particular recommendation may be sheltering or evacuation depending on the magnitude of the projected dose, the meteorological conditions, the nature of the release, and the predetermined evacuation time estimates for the affected sector(s).

(11) Radiological Exposure Control

Planning Standard

The means for controlling radiological exposure are established for emergency workers. The means for controlling radiological exposures shall include exposure guidelines consistent with EPA Emergency Worker and Lifesaving Activity Protective Action guides.

Applicants' Emergency Plan Evaluation

The applicants are developing a radiation protection program for controlling radiological exposures in the event of an emergency. Emergency exposure guidelines have been provided for the various categories of radiation workers. These guidelines are consistent with the EPA Emergency Worker and Life Saving Activity Protective Action Guides. The Plan clearly states that the Supervisor of Chemistry and Radiation or a designated alternate is authorized to permit emergency exposures in excess of 10 CFR Part 20 limits.

The capability has been established for 24-hour-per-day dose determination for emergency personnel. Dose records will be maintained to ensure that the exposure history is current.

Onsite contamination control measures for personnel, equipment, and access control are provided. The criteria for decontamination of personnel and equipment are specified in the Plan, together with the criteria for permitting return of areas and items to normal use.

Provisions have been established for decontaminating onsite personnel including provisions for extra clothing and decontaminants suitable for the type of contamination expected. Reserve supplies of clothing and decontaminants are stored onsite.

(12) Medical and Public Health Support

Planning Standard

Arrangements are made for medical services for contaminated injured individuals.

Applicants' Emergency Plan Evaluation

The applicants have made arrangements with South Coast Community Hospital and the Tri-City Community Hospital to provide medical assistance to site personnel injured in accidents involving radioactive contamination. Additional arrangements have been made with the UCLA School of Medicine to provide consultation services and assistance in the treatment of radiation overexposures or injuries complicated by radioactive contamination.

The plant has first aid facilities for providing medical assistance to all site personnel. The facilities can provide first aid treatment for minor injuries and emergency aid for more serious injuries. Agreements have been made with several physicians who would provide medical services during normal operation and emergencies.

Written agreements have been made with the Scudder Ambulance Company and the Superior Ambulance Company for transporting injured and contaminated personnel.

(13) Recovery and Reentry Planning and Postaccident Operations

Planning Standard

General plans for recovery and reentry are developed.

Applicants' Emergency Plan Evaluation

The Emergency Coordinator has the responsibility for determining and declaring when an emergency situation is stable and has entered the recovery phase. General guidelines have been set by which decisions to relax protective measures are to be made. The general structure of a long-term recovery organization has been proposed. This organization will handle all recovery efforts that may be complicated or extend over a long period of time.

The applicants have established a method to periodically estimate total population exposure during the recovery phase. The method is described in the SONGS Environmental Technical Specifications as it relates to compliance with 10 CFR 50, Appendix I requirements.

(14) Exercises and Drills

Planning Standard

Periodic exercises will be conducted to evaluate major portions of emergency response capabilities, periodic drills will be conducted to develop and maintain key skills, and deficiencies identified as a result of exercises or drills will be corrected.

Applicants' Emergency Plan Evaluation

Annual exercises will be held involving the onsite response organizations. Local government agencies will participate. Although the State plan will be exercised annually, it may be done separate from the licensee in some years due to the existence of other nuclear power reactor facilities within the State's jurisdiction. At least once every six years the annual exercise will be conducted between 6 p.m. and midnight, and another between midnight and 6 a.m. The scenario used for the various exercises will contain at least the essential elements as set forth in NUREG-0654. Arrangements will be made for official observers and a critique will be held after the exercise. Station management will review and resolve any identified deficiencies, and ascertain that appropriate actions have been taken to correct the deficiencies.

In addition to the exercises, various drills will be conducted covering communications, fires, medical emergencies, health physics and radiological monitoring. Depending on the particular drill, the frequency varies from quarterly to annually. Minimum requirements have been established for each of the drills. Deficiencies resulting from evaluation of the drills will be handled by station management as discussed above for exercises.

(15) Radiological Emergency Response Training

Planning Standard

Radiological emergency response training is provided to those who may be called on to assist in an emergency.

Applicants' Emergency Plan Evaluation

The applicants will provide training in the Emergency Plan and procedures to all permanent plant personnel. This includes assignment of duties and responsibilities, location and use of assembly areas, and familiarization with alarms and communications systems. In addition, those personnel having specific response roles as part of the onsite emergency organization are given specialized training in accordance with their expected duties. These areas include emergency response coordination and direction, accident assessment, radiological monitoring, repair and damage control, rescue, and first aid.

Training is also provided for those offsite organizations whose services may be required in an emergency, such as medical support personnel and the local fire department.

(16) Responsibility for the Planning Effort: Development, Periodic Review and Distribution of Emergency Plans

Planning Objective Standard

Responsibilities for emergency plan development, review and distribution are established and that planners are properly trained.

Applicants' Emergency Plan Evaluation

The Vice President, Nuclear Engineering and Operations, has the overall authority and responsibility for radiological emergency response planning at the corporate level. The staff Health Physicist is the Emergency Planning Coordinator, responsible for maintenance of the emergency plan.

Provisions exist for annual review and revision of the emergency plan and its implementing procedures. In addition, the critiques of drills and exercises will be used as bases for changes and revisions. Any changes to these documents will be provided to the organizations and individuals having a responsibility for implementing the emergency plan.

An independent audit (as defined in NUREG-0654) of the overall emergency preparedness program will be performed at least biennially. The audit will include the emergency plan and procedures, training, readiness training and emergency equipment

13.3.3 Evaluation of State and Local Plans

Revised emergency plans have recently been submitted by Orange County, San Diego County, the City of San Juan Capistrano, the State of California Department of Parks and Recreation, and the U.S. Marine Corps at Camp Pendleton. Revised emergency plans are currently being prepared by the State of California Office of Emergency Services (OES) and the City of San Clemente. When all the revised plans are available, they will be reviewed by the Federal Emergency Management Agency (FEMA). The FEMA determinations and findings concerning Federal, State, and local emergency plans will be presented in a supplement to this report.

13.3.4 Conclusions

We reviewed the applicants' emergency plan against the criteria in NUREG-0654, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," November 1980. Based on our review, we conclude that the San Onofre onsite emergency plan, when revised in accordance with the applicants' commitments, will provide an adequate planning basis for an acceptable state of emergency preparedness, and will meet the requirements of 10 CFR 50 and Appendix E thereto. However, the San Onofre emergency plan must be revised to address the final criteria and implementation schedule for the emergency centers and their functions, emergency manpower levels, and meteorological program as stated above.

The applicants have been requested to explicitly address protective action determination and implementation after an earthquake in the revised site plan. In addition, FEMA has been requested as part of their review of Federal, State, and local emergency plans to review the planning efforts for the areas around the site to assure that protective actions to be recommended by the applicants after earthquakes could be implemented and are adequate.

After receiving the findings and determinations made by FEMA on Federal, State, and local emergency response plans, and after reviewing the applicants' revised site plan, a supplement to this report will provide the staff's overall conclusions on the status of emergency preparedness for San Onofre and related Emergency Planning Zones.

The final NRC staff approval of the state of emergency preparedness for the San Onofre site will be made following implementation of the emergency plans to include development of procedures, training and qualifying of personnel, installation of equipment and facilities, and a joint exercise of all the plans (site, Federal, State, and local).

13.4 Review and Audit

The Southern California Edison Company has described proposed provisions for the review and audit of plant operations. They include the Onsite Review Committee that will provide a continuing review of plant operations, and the Offsite Nuclear Audit

and Review Committee that will provide an independent review and audit of plant operations. The applicants have described, in Section 16.6.5 of the FSAR, acceptable provisions for the independent review of certain procedures and safety evaluations for changes to procedures, as described in 10 CFR 50.59 and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." We have reviewed the provisions for the review and audit of plant operations and find that the applicants' program for the review of plant operations conforms to the staff positions described in Regulatory Guide 1.33, "Quality Assurance Requirements (Operation)," Revision 1, 1977, which endorses ANSI N18.7-1976, and is acceptable.

13.5 Station Procedures

The Final Safety Analysis Report states that safety-related activities at San Onofre Units 2 and 3 will be conducted in accordance with detailed written and approved procedures meeting the requirements of Regulatory Guide 1.33 and ANSI N18.7-1972, "Standard for Administrative Controls for Nuclear Power Plants." Areas covered include general station operating procedures, system operating procedures, emergency operating procedures (including responses to significant alarms), procedures performed by nonlicensed personnel including maintenance, radiological control, and testing activities, and administrative control procedures. The applicants' provisions meet the requirements of 10 CFR Parts 50.54(i), (j), (k), (l) and (m). All written procedures and administrative policies are reviewed by the Onsite Review Committee and approved by the Superintendent prior to implementation.

We have reviewed the provisions for preparation, review, approval and use of written procedures, and conclude that they are acceptable because they meet the criteria specified above.

13.6 Industrial Security

The applicants submitted a Modified Amended Security Plan as required by 10 CFR Part 73.55 encompassing protection of the San Onofre Nuclear Generating Station Units 1, 2, and 3. The implementation of this plan at Units 2 and 3 is currently undergoing a review prior to the issuance of operating licenses for these units and will be reviewed throughout the plants' operating life to assure continuing compliance with the requirements of Part 73.55 of 10 CFR 73.

The identification of vital areas and measures used to control access to these areas, as described in the plan, may be subject to future amendments based upon a confirmatory evaluation of Units 2 and 3 to determine those areas where acts of sabotage might cause a release of radionuclides in sufficient quantities to result in dose rates equal to or exceeding 10 CFR Part 100 limits. We will report on the conclusions reached during our review in a supplement to this report.

14.0 INITIAL TEST PROGRAM

The applicants' initial test program consists of prerequisite tests, preoperational tests, and startup tests. The prerequisite component tests are performed upon completion of construction on systems or portions of systems to verify that individual components are properly installed and adjusted. Preoperational tests generally are system level tests that are conducted prior to fuel loading to demonstrate the structures, systems, and components meet performance requirements. Preoperational tests on nonsafety-related systems are termed acceptance tests for administrative purposes. The startup test program, which consists of fuel loading and the following activities (precritical tests, initial criticality low power tests, and power ascension tests), will demonstrate that the plant will operate in accordance with design and is capable of responding as designed to anticipated transients and postulated accidents as described in the FSAR. Our review concentrated on the preoperational and startup tests.

The applicants' organization and staff for performing the initial test program were reviewed. An adequate number of appropriately qualified personnel are assigned to develop test procedures, conduct the tests, and review the results of the tests. Plant staff personnel are utilized to maximize the training benefits of the test program.

The applicants have stated that the test procedures were developed using input from the NSSS vendor, the architect-engineer, the applicants' engineering staff, and other equipment suppliers and contractors as needed. The applicants state that their review of operating experiences at similar plants was also factored into the development of the test procedures.

The tests are being conducted using approved test procedures. Administrative controls cover (1) the completion of test prerequisites, (2) the completion of necessary data sheets and other documentation, and (3) the review and approval of modifications to the test procedures. Administrative procedures also cover implementation of modifications or repair requirements identified as being required by the tests and any necessary retesting.

The results of each test are reviewed for technical adequacy and completeness by qualified personnel including the NSSS vendor and architect-engineer as appropriate. Preoperational test results are reviewed prior to fuel loading and the startup test results from each activity or power level will be reviewed prior to proceeding to the next activity or power level.

Normal plant operating and emergency procedures are used in performing the initial test program, thereby verifying the correctness of the procedures to the extent practical.

In planning for the initial test program, the applicants scheduled adequate time to conduct all preoperational tests and startup tests. The sequence for performing the startup tests are scheduled such that systems required to prevent, limit or mitigate the

consequences of postulated accidents will be tested prior to exceeding 25% of rated power and that the safety of the plant will not be totally dependent on the performance of untested systems, structures, and components. Preoperational test procedures will be available for IE review at least 30 days prior to the expected performance of the test and startup test procedures will be available at least 90 days prior to fuel loading.

We reviewed the abstract of each test procedure presented in Chapter 14 of the FSAR. We verified that there are test abstracts for those structures, systems, components, and design features that:

- (1) Will be used for shutdown and cooldown of the reactor under normal plant conditions and for maintaining the reactor in a safe condition for an extended shutdown period;
- (2) Will be used for shutdown and cooldown of the reactor under transient (infrequent or moderately frequent events) conditions and postulated accident conditions and for maintaining the reactor in a safe condition for an extended shutdown period following such conditions;
- (3) Will be used for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications;
- (4) Are classified as engineered safety features or will be relied on to support or ensure the operations of engineered safety features within design limits;
- (5) Are assumed to function or for which credit is taken in the accident analysis of the facility, as described in the FSAR; and
- (6) Will be used to process, store, control, or limit the release of radioactive materials.

We also reviewed the test objectives, prerequisites, test methods, and acceptance criteria for each test abstract in sufficient detail to establish that the functional adequacy of the structures systems, components and design features will be demonstrated. A number of test abstracts were modified in response to staff comments.

We reviewed the initial test program's conformance with applicable Regulatory Guides including 1.20 (June 1975), "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," 1.41 (March 1973), "Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments," 1.52 (June 1973), "Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System, Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," 1.68 (November 1973), "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," 1.68.2 (July 1978), "Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants," 1.79 (September 1975), "Preoperational Testing of Emergency Core Cooling Systems for Pressurizer Water Reactors," 1.80 (June 1974), "Preoperational Testing of Instrument Air Systems," and 1.108 (August 1977), "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants."

Based on the above, we conclude that the initial test program described in the application meets the acceptance criteria of Section 14.2 of the Standard Review Plan and will demonstrate the functional adequacy of plant structures, systems, and components. We also conclude that the initial test program described meets the test requirements of General Design Criterion 1 of 10 CFR 50 Appendix A and Section XI of 10 CFR 50 Appendix B and is acceptable.

Additional low-power tests will be conducted during the startup phase to demonstrate the following plant characteristics: length of time required to stabilize natural circulation, core flow distribution, ability to establish and maintain natural circulation with or without onsite and offsite power, and the ability to uniformly borate and cool down to hot shutdown conditions using natural circulation. The latter demonstration may be performed using decay heat following power ascension and vendor acceptance tests, and need only be performed at those plants for which the test has not been demonstrated at a comparable prototype plant. Our evaluation of these tests will be included in Section 22 of a supplement to this report.

15.0 ACCIDENT ANALYSIS

15.1 General Discussion

15.1.1 Introduction

We have evaluated the response of the San Onofre 2 and 3 plant to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. The potential consequences of each event are examined to determine their effect on the plant, to determine whether plant protection systems are adequate to limit consequences of such occurrences, and to insure that the design criteria of NUREG-75/087 (the Standard Review Plan or SRP) are met.

Initial plant conditions for the safety analyses are given in Table 15.1. This range of initial conditions corresponds to a range compatible with the monitoring functions of the core operating limit supervisory system (COLSS) which is a non-safety related instrumentation system that aids the operator in maintaining the plant within the limiting conditions of operation (LCO). COLSS monitoring and calculational functions include peak linear heat rate, margin to departure from nucleate boiling (DNB), total core power, and azimuthal tilt. COLSS compares these parameters to their LCOs and provides an alarm to the operator via the plant computer if an LCO is approached or exceeded. In determining the range of interest for initial conditions used in the safety analyses, sensitivity studies of COLSS' parameters were made for selected transients and accidents in order to provide a conservative approach to system safety limits.

A range of fuel parameters based on first-core values are used for the safety analyses. These include Doppler weighting factors from 0.85 to 1.15, moderator temperature coefficients from $+0.5 \times 10^{-4} \Delta\rho/^{\circ}\text{F}$ to $-3.3 \times 10^{-4} \Delta\rho/^{\circ}\text{F}$, shutdown control element assembly (CEA) reactivity worth available at full power and zero power at $-8.85\% \Delta\rho$ and $-4.45\% \Delta\rho$ respectively, and decay heat generation rate based upon an infinite reactor operating period at full power. The decay heat curve used in the analyses is that required by 10 CFR 50, Appendix K. The reactivity insertion curve, used to represent the control assembly insertion, accounts for a stuck rod, in accordance with General Design Criteria 27.

CE-1 is the DNB correlation used to determine thermal margins in the transient analyses. The applicability of CE-1 is discussed in Section 4.4 of this report. The effect of rod bow on the departure from nucleate boiling heat flux is not included in the safety analysis. As provided in the technical specifications, a departure from nucleate boiling ratio (DNBR) penalty will be applied to assure that the minimum departure from nucleate boiling ratio values for the anticipated transients do not violate the fuel design limit of 1.19.

TABLE 15.1
CHAPTER 15 GENERAL INITIAL CONDITIONS

Parameter	Units	Range
Core Power, B	% of 3,410 MWt	$B \leq 102$
Radial 1-pin peaking factor, F_R (with uncertainty)	--	$F_R \leq 1.7$
Axial shape index, ASI ^(a)	--	$-0.6 \leq ASI \leq +0.6$
Core inlet coolant flowrate, G	% of 143×10^6 lbm/h	$100 \leq G \leq 120$
Core inlet coolant Temperature, T	°F	$520 \leq T \leq 560$ (100% power) $520 \leq T \leq 540$ (0 power)
System pressure, P	lb/in. ² a	$2,000 \leq P \leq 2,300$

(a)
$$ASI = \frac{\text{area under axial shape in lower half of core} - \text{area under axial shape in upper half of core}}{\text{total area under axial shape}}$$

The reactor protection system trips considered in the analyses in accordance with General Design Criteria 20 are:

- (1) High logarithmic power level
- (2) High linear power level
- (3) Low DNBR (Core Protection Calculator)
- (4) High local power density (Core Protection Calculator)
- (5) High pressurizer pressure
- (6) Low pressurizer pressure
- (7) Low steam generator water level
- (8) Low steam generator pressure

Time delays to trip and uncertainties in trip times are included in the analyses.

The core protection calculator (CPC) system consists of 4 digital calculators (one in each reactor protection system protection channel) which calculate DNBR and local power density. These values are compared with trip setpoints for initiation of a low DNBR trip and high local power density trip.

The low DNBR trip is provided to trip the reactor core when the calculated DNBR approaches a preset value. The algorithms which calculate the minimum departure from nucleate boiling ratio (MDNBR) include allowances for sensor and processing time delays and uncertainties. Many events as analyzed in Chapter 15 of the San Onofre 2 and 3 FSAR have their MDNBR reach exactly 1.19 as calculated by the CE-1 correlation.

Inputs to the CPC include core inlet and outlet temperature, pressurizer pressure, reactor coolant pump speed, excore flux power, selected CEA positions, and CEA subgroup deviation. Calculations performed by the CPC include reactor coolant system (RCS) flowrate, ΔT power, axial power distribution, fuel rod radial peaking factors, DNBR, local power density, core average power, CEA group deviation alarm and calibrated excore power. Outputs from CPC available to the operator on a display and control panel include DNBR margin and calibrated neutron flux. The operator can also monitor all calculators, including specific inputs or calculated functions.

There are differences between the CPC proposed for San Onofre 2 and 3 and that approved for Arkansas Nuclear One - Unit 2 (ANO-2). The applicants have addressed our concerns and we have their submittal under review. We will report on this issue in a supplement to this report.

15.1.2 Analytical Techniques

The analysis methods used for postulated transients and accidents are normally reviewed on a generic basis. In this regard, we have received submittals from Combustion Engineering for the loss-of-coolant accident, the rod ejection accident, and the computer codes and methods used in the analysis of reactor transients as shown in Table 15.2. The mathematical model used in steam line break accident and the feedwater line break analyses is described in the CESSAR application, as discussed below. The Combustion Engineering topical reports associated with the thermal-hydraulic design of the San Onofre 2 and 3 reactor cores are discussed in Section 4.4 of this report.

The loss-of-coolant accident and rod ejection accident reviews have been completed and the analysis methods were found acceptable. The staff safety evaluation is documented in four letters from the NRC staff to Combustion Engineering, Inc. (Kniel, 1976; Parr, 1974; Parr, 1975a; Parr, 1975b).

Generic topical reports on methods of analysis of steam and feed line breaks have been submitted for staff approval by Combustion Engineering in appendices to the CESSAR Final Design Report. Information specific to San Onofre 2 and 3 steam and feed line break analysis has been submitted by the applicants. Our review of this information is not yet complete. However, the results of our review to date indicates that there is reasonable assurance that the conclusions based on these analyses will not be appreciably altered by completion of the analytical review. If the final approval of the methods indicates that any revisions to the analyses are required, the applicants will be required to implement the results of such changes at San Onofre 2 and 3.

The topical reports on the methods used in the analysis of reactor transients are under review by the staff. The topical report on the COAST code (CENPD-98) used to compute coolant flow transient behavior during a loss-of-flow transient has been approved by the staff (Reference 5). The status of the code reviews is discussed below:

(1) CENPD-107 CESEC - Digital Simulation of A Combustion Engineering Nuclear Steam Supply System, April 1974

The CESEC computer program is used for the analysis of various system transients and is currently under review by the staff. Our review of CENPD-107 will be completed on a time schedule consistent with issuance of the San Onofre 2 and 3 operating license. If final approval of CENPD-107 indicates that any revisions to the analyses are required, this information shall be included in the San Onofre 2 and 3 review.

The applicants have stated their intent to perform a verification of the CESEC code based on the results of the startup test program to be conducted on Arkansas Nuclear One Unit 2. We are presently reviewing the ANO-2 startup test

TABLE 15.2

TOPICAL REPORTS FOR CODES USED IN SAFETY ANALYSES

<u>Topical Report</u>	<u>Status</u>
1. <u>Large Break LOCA Code</u>	
CENPD-132	Approved
CENPD-132, Supplement 1	Approved
CENPD-132, Supplement 2	Approved
2. <u>LOCA Blowdown Code</u>	
CENPD-133	Approved
CENPD-133, Supplement 2	Approved
3. <u>LOCA Refill/Reflood Code</u>	
CENPD-134	Approved
CENPD-134, Supplement 1	Approved
4. <u>Fuel Rod Heat Transfer Code</u>	
CENPD-135	Approved
CENPD-135, Supplement 2	Approved
CENPD-135, Supplement 4	Approved
5. <u>Reflood Code When Reflood at Less than 1 Inch per Second</u>	
CENPD-138	Approved
CENPD-138, Supplement 1	Approved
6. <u>Heat Transfer Coefficients for 16 x 16 Fuel Bundles Code</u>	
CENPD-123	Approved
7. <u>Small Break LOCA Evaluation Model Code</u>	
CENPD-137	Approved
CENPD-137, Supplement 1	Approved
8. <u>Reactor Coolant Code for Flow During Coastdown Transient</u>	
CENPD-98	Approved
9. <u>CEA Ejection Analysis Code</u>	
CENPD-190	Approved
10. <u>Code used to Simulate NSSS</u>	
CENPD-107	Approved
CENPD-107, Supplement 1	Approved
CENPD-107, Supplement 2	Approved
CENPD-107, Supplement 3	Approved
CENPD-107, Supplement 4-P	Approved
11. <u>ATWS Analysis for CE Plants</u>	
CENPD-158	Approved
12. <u>Loss of Flow Analysis Method</u>	
CENPD-183	Under Review
13. <u>Core Thermo-hydraulics Code</u>	
CENPD-161	Approved
CENPD-206	Approved
CENPD-207	Under Review

data. Based on the results of our review to date, we find the CESEC analysis acceptable. If the completion of our review changes this conclusion, revised analysis may be required, and if necessary, will be obtained from the applicants.

(2) CENPD-183 Methods for Loss of Flow Analysis, July 1975

The analysis method used for loss-of-flow transients is described in CENPD-183. This report originally was dependent on the approval of CENPD-177, but CENPD-177 was withdrawn from review at the request of Combustion Engineering (Scherer, 1980a). Therefore, the staff review of CENPD-183 was deferred. Subsequently, Combustion Engineering amended CENPD-183 and removed the dependence on CENPD-177 (Scherer, 1980b). We are currently in the process of rescheduling our review of CENPD-183. We will report on the resolution of this issue in a supplement to this report.

The staff is currently reviewing the analysis methods for steam generator tube rupture and the various transients analyzed as Condition II and III events in Chapter 15. These reviews will be pursued as part of the review for CESSAR final design approval evaluation. Our review at this time indicates that there is reasonable assurance that the conclusions based on these analyses will not be appreciably altered by completion of the analytical review. If the final approval of the methods indicates that any revisions to the analyses are required, San Onofre 2 and 3 will be required to implement the results of such changes.

Based on previous acceptable analyses for Combustion Engineering plants, on a comparison with other industry models, on independent staff audits calculations, and on previous startup testing experience, we conclude that, with the exceptions noted above, the analytical methods used are acceptable for the safety analyses performed for San Onofre 2 and 3.

15.2 Normal Operation and Anticipated Operational Transients

The applicants have analyzed several events expected to occur once or more times during the lifetime of the plant. It is demonstrated that all the transients are terminated without exceeding specified fuel design limits (departure from nucleate boiling ratio remains at or above 1.19 using the CE-1 correlation) and that the reactor coolant pressure stays below the 110 percent of design. For transients plus single failure events (transients in combination with any single failure), core geometry is maintained such that there is no loss of core cooling capability. Radiological consequences for various postulated events are given in Section 15.4.

15.2.1 Increase in Heat Removal by the Secondary System

The applicants have analyzed the following events which produce increased primary system cooling:

- (1) Decrease in feedwater temperature,
- (2) Increase in feedwater flow,
- (3) Increased main steam flow,
- (4) Inadvertent opening of steam generator atmospheric dump valve.

The inadvertent opening of all the turbine bypass valves at full power is the most severe of the postulated increased steam flow transients. The low DNBR trip limits the minimum DNBR to slightly above 1.19, the minimum DNBR limit. The auxiliary feedwater system automatically starts up following a low steam generator water level trip and maintains adequate steam generator water inventory. RCS pressure is reduced to below 2250 psig throughout most of the transient, and pressures never approach limiting conditions, i.e., 100% of design pressure. None of these events progress to a more serious plant condition unless additional faults occur. Therefore, we find the results of these events acceptable.

For transients coupled with a concurrent single failure, the most limiting event with respect to DNBR is the increase in main steam flow with loss of all AC power. Other single failures considered include loss of condenser cooling flow. Based on the minimum calculated DNBR of 1.06, the applicants originally calculated that approximately 0.1% of the fuel pins experienced DNB. We believe that this approach amounts to the use of a statistical convolution to calculate the number of failed pins. We consider any pin which has a DNBR below 1.19 to be failed. In response to our request, the applicants recalculated the amount of failed pins to be 0.6% using our criterion.

Reactor coolant system pressure for increase in heat removal plus a single failure is maintained below 110% of design pressure. We find the results of the applicants' analysis for the events which result in an increase in heat removal by the secondary system with a single failure acceptable.

15.2.2 Decrease in Heat Removal by the Secondary System

The applicants analyzed the following events which cause a decrease in secondary side heat removal:

- (1) Loss of external load,
- (2) Turbine trip,
- (3) Loss of condenser vacuum,
- (4) Loss of normal AC power,
- (5) Loss of normal feedwater flow.

The most limiting transient with respect to departure from nucleate boiling ratio (DNBR) is the loss of condenser vacuum where the calculated minimum DNBR is 1.95. Credit is not taken for reactor trip due to turbine trip in this transient. The reactor is assumed to trip on high-pressurizer pressure, the second trip signal. Offsite power is assumed available to provide AC power to the auxiliaries. The maximum calculated pressure for these events is also achieved by the loss of condenser vacuum transient where peak RCS pressure reaches 2582 psia. We find these results acceptable because the system pressure and fuel limits are not violated.

For transients coupled with a single failure, the most limiting event with respect to DNBR is the loss of all normal AC power with a concurrent single failure. The minimum DNBR in this transient is bounded by increased main steam flow with a concurrent single failure. The maximum calculated RCS pressure for these events is 2612 psia for the loss of condenser vacuum with failure of a primary safety valve to open. Other single failures considered for the loss of condenser vacuum are loss of all AC power on reactor trip and failure of one steam generator safety valve to open.

The applicants' calculations show that for transient events leading to decrease in heat removal by the secondary system (with and without single failure), at most a small fraction of the fuel rods in the reactor fail for transients with a single failure, core geometry is maintained with no loss of core cooling capability, and maximum RCS pressure remains below 110 percent of design. We find the results of these analyses acceptable.

15.2.3 Decrease in Reactor Coolant Flow Rate

The applicants analyzed the following events which lead to a decrease in reactor coolant flow.

- (1) Partial loss of forced reactor coolant flow
- (2) Total loss of forced reactor coolant flow.

The partial loss of forced reactor coolant flow is bounded by the total loss of forced reactor coolant flow. Total loss of forced reactor coolant flow (TLFRCF) analysis uses an initial RCS pressure of 2400 psia which is outside of the COLSS range. We are concerned that this initial condition is not conservative because a high initial pressure causes an immediate trip.

The total loss of forced reactor coolant flow is the design base transient which determines coefficients for the low flow portion of the minimum DNBR algorithm incorporated in the core protection calculators (CPC). We will review the acceptability of the TLFRCF based on simulator tests of the CPC to show that it protects the core from exceeding the critical heat flux and local overpower. Our review of the CPC is discussed in Sections 4.4, 7.2.2, and 15.1.1 of this report. We will report on the resolution of this issue in a supplement to this report.

15.2.4 Reactivity and Power Distribution Anomalies

The applicants analyzed the following events which affect reactivity and power distribution.

- (1) Uncontrolled CEA withdrawal from a subcritical or low power condition,
- (2) Uncontrolled CEA withdrawal at power,
- (3) Control element assembly misoperation,
- (4) Inadvertent boron dilution,
- (5) Startup of an inactive reactor coolant system pump.

15.2.4.1 Uncontrolled CEA Withdrawal at Low Power

For those transients classified under the category of reactivity and power distribution anomalies, the uncontrolled control element assembly (CEA) withdrawal at a subcritical or low power conditions is the most limiting transient with respect to maximum reactor coolant system pressure. The core inlet temperature is assumed at a minimum value of 520°F, which is inconsistent with the review procedure provided in Section 15.4.1 of the Standard Review Plan. However, Combustion Engineering analyses show that minimizing the inlet temperature keeps the steam generator safety valves from opening, thereby maximizing primary system pressures. A hot pin radial peaking factor including uncertainties of 2.38 is used. This is the highest radial peaking factor expected for any CEA configuration anticipated during the core lifetime. In addition, no credit is taken for the turbine bypass system, thereby increasing the peak RCS pressure reached during the transient. The reactor trips on low DNBR.

The calculated minimum DNBR of 1.19 and the maximum calculated pressure of 2559 psi do not violate the specified fuel design limits and 110% of system design pressure respectively. By not violating these limits and since the RPS initiates a reactor trip automatically, the criteria of General Design Criteria 20 and 25 are met. Fuel centerline temperature is maintained below the projected melting point of the fuel for any expected burnup. We find the results of this event acceptable because they meet applicable criteria.

15.2.4.2 Uncontrolled CEA Withdrawal at Power

This event as analyzed is less severe than that of uncontrolled CEA withdrawal from low power. An initial power level of 78.4% of full power is used to maximize the approach to the fuel design limits. Since the transient is automatically terminated by a low DNBR trip, the calculated maximum RCS pressure is 2518 psia (below 110% of design pressure), and since the calculated minimum DNBR is 1.19, the criteria of General Design Criteria 25 and 20 are met. As in the low power uncontrolled CEA withdrawal event, the maximum fuel centerline temperature is well below that

required to melt the fuel. We find these results acceptable because they meet the applicable acceptance criteria.

15.2.4.3 CEA Misoperation

The control element assembly (CEA) misoperation events analyzed by the applicants include individual full- or part-length control element assembly drops and dropping of part-length control element assembly subgroups. A subgroup is defined as any one set of four symmetrical control element assemblies, which is controlled by the same control element drive mechanism control system.

The effect of any individually misoperated control element assembly on core power distributions will be evaluated by the control element assembly calculators, and an appropriate power distribution penalty factor will be transmitted to the core protection calculators (CPCs). The CPCs will, themselves, assess other changes in core conditions (e.g., changes in coolant temperature, axial power distribution, power level) and initiate a low departure from nucleate boiling ratio or high local power density trip if required. However, there are trip delay times associated with the CPC-generated departure from nucleate boiling ratio and high local power density trips, and time is required to insert control element assemblies following scram. To ensure that the CPCs can accommodate all misoperation events, it must be demonstrated that the elapsed time between initiation of the event and the time the core approaches either the departure from nucleate boiling ratio or local power density limit is sufficient to allow for CPC scram initiation and control element assembly insertion. Therefore, the misoperating events of most interest are those that result in a rapid decrease in margin to safety limit.

The worst full-length CEA drop incident is caused by the dropped CEA that produces the maximum increase in the radial peaking factor and the least negative reactivity insertion.

The drop of a single part-length CEA or subgroup results in either a negative or positive reactivity change depending on the initial part-length CEA position and the axial distribution of thermal neutron flux. The appropriate (most negative) Doppler and moderator temperature coefficients were used by the applicants in the San Onofre 2 and 3 accident analyses.

The analyses of the nuclear steam supply system response (total power, coolant temperature, system pressure) was performed using the CESEC code. The detailed response of the core (hot channel; power, heat flux, fuel and cladding temperatures, etc.) were calculated using the STRIKIN code. The thermal margin on DNBR in the core was calculated using the TORC computer program with the CE-1 critical heat flux (CHF) correlation. Since the consequences of a single control element assembly or bank drop are strongly dependent upon the axial power distribution that exists at the start of the transient, the analyses were performed using several different

axial power distributions as initial conditions with each distribution characterized by an axial shape index.*

The results of these analyses show that the most rapid approach to the DNB specified acceptable fuel design limits for a CEA misoperation is caused by either the single full-length CEA drop or the part-length CEA subgroup drop. The single part-length drop causes the most rapid approach to the centerline melt specified acceptable fuel design limits. For each case studied, the departure from nucleate boiling ratio assumed as an initial condition was varied until the minimum departure from nucleate boiling ratio reached during the transient was equal to 1.19.

We have reviewed the analysis of the misoperation events and find acceptable the approach used to establish that, during the most limiting events, no violations occur of the specified acceptable fuel design limits on DNBR, centerline fuel temperature, and RCS pressure.

15.2.4.4 Inadvertent Boron Dilution

The applicants' analysis of an inadvertent boron dilution event concentrates on operation during cold shutdown. Various indications to an operator (e.g., charging pump on, pressurizer level rising, or diverter valve open) concerning the occurrence of a boron dilution event are discussed.

After reviewing the boron dilution analysis, we requested that the applicants provide additional alarms to alert the operator of an unplanned dilution event during all modes of operation. The applicants agreed to install alarms on the source range nuclear instrumentation. The setpoint of these alarms is to be adjusted periodically as the shutdown flux decays so that the alarm will sound at least 15 minutes before criticality is reached (30 minutes during refueling) for the worst credible accident and with all uncertainties conservatively accounted for. We conclude that with these modifications, San Onofre 2 and 3 meets the requirements of the Standard Review Plan, Section 15.4.6, and is acceptable.

15.2.4.5 Inadvertent Fuel Loading Errors

We have evaluated the consequences of the postulated fuel loading errors. The two errors considered were (1) the erroneous loading of fuel pellets or fuel rods of different enrichment in a fuel assembly, and (2) the erroneous placement or orientation of fuel assemblies. We conclude that the analyses provided by the applicants show that, for each case considered, either the error is detectable by the available instrumentation (and hence remediable) or the error is undetectable, but the offsite consequences of any core damage are only a small fraction of the 10 CFR Part 100 dose guidelines.

*Axial shape index (ASI) =

$$\frac{\text{Power in the bottom half of the core} - \text{power in the top half of the core}}{\text{total core power}}$$

15.2.4.6 CEA Ejection

The mechanical failure of a control rod mechanism pressure housing would result in the ejection of a control element assembly. For CEAs that are 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 have been made to make this accident extremely unlikely, the applicants have analyzed the consequences of such an event.

Methods used in the analysis are reported in CENPD-190-A (Ref. 1), which has been reviewed and accepted by us. This report demonstrates that the model used in the accident analysis is conservative relative to a three-dimensional kinetics calculation.

Four cases were analyzed: beginning-of-cycle at 102 percent and at zero power, and end-of-cycle at 102 percent and at zero power. The calculated total average enthalpy of the hottest fuel pellet was well below the Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," acceptance criterion of 280 cal/gm. Analyses have been performed to show that the pressure pulse produced by the rod ejection will not stress the RCS boundary beyond faulted limits. Further analyses have shown that a cascade effect is not credible.

The ejected rod worths and reactivity coefficients used in the analysis have been reviewed and have been judged to be conservative. The assumptions and methods of analysis used by the applicants are also in accordance with those recommended in Regulatory Guide 1.77. Therefore, we conclude that this analysis is acceptable.

15.2.5 Increase in Reactor Coolant System Inventory

This transient and its associated infrequent event (i.e., with a concurrent single active failure) are described by the applicant in terms of a chemical and volume control system (CVCS) malfunction or inadvertent operation of the emergency core cooling system (ECCS) during power operation. The maximum RCS pressure due to a CVCS malfunction is limited by the high pressurizer pressure reactor trip and the steam generator safety valves to 110 percent of design pressure. The steam generator safety valves limit the main steam system pressure to within 110 percent of design.

The inadvertent operation of the ECCS during power operation is not a concern since the RCS pressure (2250 psia) exceeds the shutoff head of the safety injection pumps or the opening pressure of the safety injection tanks. The plant design is such that these incidents leading to excessive RCS inventory do not generate more serious plant conditions unless other faults occur independently.

We find that the increase in reactor coolant system inventory event results meet the acceptance criteria and are acceptable.

Increase in reactor coolant system inventory transients with a single failure do not result in violation of DNBR or RCS pressure limits. Single failures considered are startup of the third charging pump and failure of the letdown system. Operation of the third charging pump is most limiting. We find the results of these events acceptable.

15.2.6 Conclusions

The applicants present results for various anticipated operational occurrences (with and without assumed single failures) which meet our acceptance criteria with respect to fuel and primary system performance. We conclude, therefore, that the applicants have provided adequate protection systems for anticipated operational occurrences in compliance with General Design Criterion 20, except as noted in previous sections of this report.

15.3 Limiting Accidents

The applicants analyze events which, though not postulated to occur during the lifetime of the plant, could have serious radiological consequences if the event is not effectively mitigated. Since each limiting event has separate acceptance criteria as defined by the Standard Review Plan, the criteria for each event will be discussed under its pertinent section. Radiological consequences are discussed in detail in Section 15.4 of this report.

15.3.1 Steam Line Breaks

During a steam line break (SLB) accident, the reactor coolant system pressure must remain below 110 percent of design pressure. Fuel failures are calculated based on violating the minimum DNBR criteria using appropriate design correlations. Radiological consequences of the steam line break event are discussed in Section 15.4.

Three SLB accidents are analyzed by the applicants - (1) a full power, double-ended steam line break (inside containment) with concurrent loss of ac power; (2) a full power, double-ended steam line break (inside containment) with no loss of offsite ac power; and (3) a hot zero power, double-ended steam line break (outside containment) with concurrent loss of offsite ac power. These events are analyzed assuming various conservative parameter inputs including steam quality, Doppler reactivity, moderator reactivity, void reactivity feedback, core mixing, CEA worth and feedwater flow.

No credit for moisture carryover is allowed during steam generator blowdown, moderator reactivity is chosen as a function of the lowest cold leg temperature, and there is no assumed mixing in the core lower plenum. A study of single failures was performed to determine which is most limiting. Failures considered included failure of main feedwater isolation valve to close after a main steam isolation signal (MSIS), failure of one main steam isolation valve to close after MSIS, failure of turbine stop valves to close after reactor trip, failure of one diesel generator to start after loss of ac power and failure of one high pressure safety injection (HPSI) pump to start after

a safety injection actuation signal (SIAS). This study shows loss of one HPSI pump has the most adverse effect. Various assumptions regarding time of loss of offsite ac power and the location and size of the SLB inside and outside containment are analyzed. The worst break with respect to fuel damage is a loss of ac power coincident with the complete severance of a main steam line inside containment. For the limiting case (loss of offsite power with the break inside containment), a low DNBR trip scrams the reactor and a low steam generator pressure trip initiates MSIS. Low primary system pressure initiates SIAS.

Auxiliary feedwater is not initiated during the first 30 minutes for the SLB cases presented in the San Onofre 2 and 3 FSAR. This is due to (1) the differential pressure between the two steam generators inhibits automatic auxiliary feedwater flow to the ruptured steam generator, and (2) a low water level setpoint is not reached in the intact steam generator.

For all three SLB events analyzed, the minimum DNBR never drops below 1.19 and the maximum RCS pressure does not exceed 110% of design pressure. Core geometry is maintained such that there is no loss in core cooling capability. Containment analysis is discussed in SER Section 6.2.

The applicants have submitted analyses which show that vessel integrity is preserved in the event of repressurization of the primary system following a steam line break or a small break LOCA. Analyses included SLBs at 102% power and hot zero power. The LOCA evaluation provided by the applicants only analyzed very small breaks where the RCS became water solid a short time after actuation of the safety injection system. No operator action was credited for 30 minutes. We find the results acceptable because vessel integrity is preserved.

We have reviewed the consequences of an SLB outside of containment when the SIAS is manually bypassed during shutdown operations. Such a break would not require an automatic SIAS to mitigate the event since the total positive reactivity added would be approximately 3.9% $\Delta\rho$ while the shutdown margin by technical specification would be at least 5.15% $\Delta\rho$. The staff finds the San Onofre 2 and 3 design acceptable to mitigate such an SLB when SIS is bypassed.

The steam flow restrictor venturis which mitigate the consequences of an SLB are designed in accordance with Seismic Category I, ASME Section III Class 2, and Quality Class 2 requirements. We find them acceptable for mitigating an SLB. The applicants have indicated that the minimum shutdown margin during a steam line break will occur about 180 seconds into the accident. We have requested additional analyses during this time period to assure that the resultant power distribution under reduced flow and pressure conditions will not result in unacceptable amounts of fuel damage.

In response to our request, the applicants, in amendment 16, provided analysis results which are based on the minimum allowable (by technical specification)

shutdown margin and a stuck control rod. The results indicated that for the steam line break cases with and without loss of offsite power, DNB does not occur at any time after reactor trip. However, the applicants did not perform an analysis for a main steam line break case with a manual RCP trip on HPI actuation. We believe that the results of this analysis will be bounded by the doses analyzed in the FSAR, namely the main steam line break with or without loss of offsite power. To verify our judgement that the results of this analysis are acceptable, we have requested that the applicants demonstrate by analysis that a main steam line break with manually tripping RCPs (after a time delay) on HPI actuation will not cause DNB at any time after a reactor trip. If the results of this analysis do not confirm our expectations, we will require that appropriate changes be made, if necessary, to prevent unacceptable fuel failures.

15.3.2 Feedwater System Pipe Breaks

Feedwater system pipe break acceptance criteria require that the peak RCS and main steam pressures during the analyzed accident be less than 110% of design. Fuel damage due to the pipe break may be such that the calculated doses at the site boundary are a fraction of 10 CFR Part 100. The full spectrum of break areas is analyzed by the applicants with the largest break being with most limiting. System parameters are chosen for input in order to maximize the RCS pressure and to maximize the mismatch between core power and steam generator heat removal capacity. Failure of the pressurizer or steam generator safety valves to open or the feed line check valves to close are considered sufficiently unlikely such that they not be considered credible single active failures. Loss of normal offsite and onsite power is assumed to occur at that time during the accident which causes several trip signals to be set almost simultaneously. High pressurizer pressure initiates the reactor trip. The low water level in the steam generators actuates the emergency feedwater system. The emergency feedwater flow reaches the steam generator with the intact feedwater line at 96 seconds after the pipe break. The maximum RCS pressure during the accident is 2870 psia (110% of design is 2750 psia), the maximum steam generator pressure is 1136 psia (110% of design is 1210 psia), and the minimum DNBR is 1.21. The core geometry is maintained such that core cooling capacity is not impaired. The maximum RCS pressure during the accident is 2870 psia (approximately 115% of design pressure) which exceeds the limit of the acceptance criteria in the Standard Review Plan. However, the ASME Boiler and Pressure Vessel Code Section III, Division 1 has a provision which permits, under emergency conditions, the stress in the RCS components to reach 120% of design pressure. Since the feedwater pipe break accident does not cause the stress value in RCS components to exceed the above code limit, we find the above justification acceptable because the plant meets the Code. Based on our review of the above, we conclude that the result of the feedwater line analysis is acceptable.

15.3.3 Single Reactor Coolant Pump Shaft Seizure

During a reactor coolant pump shaft seizure accident, the following criteria must be met. Offsite doses at the exclusion boundary should be a fraction of 10 CFR Part 100

guidelines, while only a small fraction of fuel rods in the reactor should fail. Core geometry should remain intact so that there is no loss of core cooling capability. If the DNBR falls below the 1.19 minimum DNBR limit, fuel damage should be assumed. Reactor coolant pressure should be maintained below 110% of design pressure and a rotor seizure, by itself, should not degenerate into a more serious condition or result in the loss of function of the reactor coolant system or containment barriers.

Following shaft seizure, the reactor is tripped by a low DNBR trip signal which also automatically trips the turbine. Following turbine trip, offsite power is available to provide ac power to the auxiliaries. The initial conditions and system parameters are chosen to maximize calculated fuel damage. The steam bypass control system is assumed to be in the manual mode. During this transient, the maximum calculated RCS pressure is 2302 psia which is below 110% of design, and the calculated minimum DNBR is 0.83 which violates the single active failure design limit value of 1.19. The applicants indicate that less than 1.7% of the fuel rods failed. We consider the method used by the applicants to determine the number of failed fuel rods to be inconsistent with the SRP and standard licensing practice. We required that fuel failures be recalculated using the criteria that any rod which has a DNBR less than 1.19 fails. In response to our request, the applicants, in amendment 14, indicated that for the locked rotor accident, the percent of fuel pins with CE-1 DNBR less than 1.19 is 4.2%. Our evaluation of the radiological consequences (assuming 4.2% of the fuel pins are failed) for the locked rotor accident is addressed in Section 15.4.13 of this report.

The capability to provide cooling to the core can be impaired if cladding temperatures are sustained at a level such that significant clad ballooning occurs. Clad temperature calculations for the locked rotor accident are carried out past the point of clad temperature turnaround. The magnitude of the temperatures and the duration of the higher temperatures for this accident are such that no significant core geometry changes are predicted to occur. Since the core cooling capability is not compromised, and the RCS pressure remains below 110% of design pressure, we find the results of this accident to be acceptable.

15.3.4 Single Reactor Coolant Pump, Sheared Shaft

During a reactor coolant pump sheared shaft accident, the acceptance criteria are the same as the criteria stated in Section 15.3.3, above, for the reactor coolant pump shaft seizure accident.

Following the postulated shearing of a reactor coolant pump shaft, a reactor trip occurs due to low reactor coolant flow cross the affected loop steam generator. The reactor trip produces an automatic turbine trip. Following turbine trip, if offsite power is available to provide ac power to the auxiliaries, the turbine bypass valves would be open. If the steam bypass control system is in the manual mode and no credit for operator action is taken for 30 minutes following first indication of the event, the steam release to the atmosphere through the steam generator safety valves would be no more than that following a loss of all normal ac power. The initial

conditions and system parameters are chosen to maximize calculated fuel damage. The applicants' analysis was based on an initial system pressure of 2000 psia. However, the applicants also indicated that even if the accident is initiated from the highest allowable operating pressure of 2300 psia, the maximum RCS pressure is still not calculated to reach the primary safety valve setpoint. Thus the maximum pressure is below 110% of the design pressure. The calculated minimum DNBR is 0.65 which violates DNBR limit value of 1.19. The applicants stated that the percentage of fuel pins with minimum CE-1 DNBR less than 1.19 is 6.9%.

Our evaluation of the radiological consequences (assuming 6.9% of the fuel pins are failed) for the RCP sheared shaft accident is addressed in Section 15.4.10 of this report. Since the core cooling capability is not compromised, and the RCS pressure remains below 110% of the design pressure, we find the results of this accident acceptable.

15.3.5 Loss-of-Coolant Accident (LOCA)

The acceptance criteria for a LOCA as required by 10 CFR 50.46 are:

- (1) The calculated maximum fuel element cladding temperature shall not exceed 2200°F;
- (2) The calculated total oxidation of the cladding shall not exceed 17% of the total cladding thickness before oxidation;
- (3) The calculated total amount of H₂ generated from the chemical reaction of the cladding with water or steam shall not exceed 1% of the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;
- (4) Calculated changes in core geometry are such that the core shall remain amenable to cooling;
- (5) After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptable low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity.

Details of the ECCS mitigating and long-term cooling systems for a LOCA are given in Section 6.3 of this report. The applicants analyzed a complete break spectrum for large breaks (1.0, 0.8, 0.6 double-ended slot and guillotine). These calculations are made using approved code models which meet Appendix K requirements (see Table 15.1-2, items 1 thru 6).

During the LOCA calculation, offsite power is assumed lost. The time of ECCS flow delivery to the core includes delay time for the start up of the diesel generators. In addition, all ECCS flow delivered to the broken cold leg is assumed to spill directly to containment. Studies show that the worst single failure for the large

break spectrum is failure of one low pressure safety injection pump to start. Containment parameters are chosen to minimize containment pressure so that core reflood calculations are conservative (See Section 6.3). Fuel rod initial conditions are chosen to maximize clad temperature and oxidation. The applicants performed clad ballooning calculations which show that none of the LOCAs analyzed had core geometry changes of a magnitude large enough to significantly reduce core cooling capability. Calculations of core geometry are carried out past the point where temperatures are decreasing. The most limiting break with respect to peak clad temperature is the 1.0 x double-ended guillotine break in the pump discharge leg. The peak clad temperature is 2183°F, which is below the 2200°F limit. The limiting local and core-wide clad oxidation values calculated by the applicants were 16.45% local for the 0.8 DEG/PD and 0.68% core-wide for the 1.0 DEG/PD.

In the initial FSAR submittal, small-break loss-of-coolant accidents were not explicitly calculated for San Onofre 2 and 3. The applicants submitted a table comparing Arkansas Nuclear One Unit 2, CESSAR and Calvert Cliffs Unit 1 small and large break calculations. This table indicated that small breaks were not limiting. We determined that this comparison was not sufficient and requested that the applicants perform a small break LOCA analysis for San Onofre 2 and 3 for postulated breaks sizes of .01 ft², 0.1 ft² and 1.0 ft². The applicants performed these calculations using high pressure safety injection pump data recently received from the pump manufacturer. Although the pump performance specifications were met, the as-built pump flowrates were less than the previously assumed rates. After reviewing the results of the above calculations, the applicants performed an additional calculation for a 0.05 ft² break. For this calculation, peak cladding temperatures exceeded the acceptance criteria of 10 CFR 50.46. To correct this the applicants reevaluated certain conservative assumptions used in the original analysis. Additional analyses were performed taking credit for the charging and borating portion of the chemical and volume control system. This is a safety grade system and is part of the safety injection system. In the revised analysis the maximum peak cladding temperature reached was 1732 degrees F for the 0.05 ft² break. We have reviewed these calculations and find that they meet the requirements of 10 CFR 50.46. We find the results of this analysis acceptable provided that pre-operational tests and subsequent monthly performance tests will confirm that the high pressure safety injection pump flow rates meet or exceed the values used in the small-break loss-of-coolant accident analysis. This will be accomplished by the use of appropriate Technical Specifications. We conclude that the LOCA calculations submitted for San Onofre 2 and 3 are in conformance with 10 CFR 50.46 and are acceptable.

15.3.6 Inadvertent Opening of a Pressurizer Safety Valve

The design of the RCS for San Onofre 2 and 3 does not include any power operated relief valves, only safety valves. The inadvertent opening of a safety valve requires a mechanical failure plus a transient to increase pressure. We are not aware of any inadvertent pressurizer safety valve openings on commercial pressurized water reactors. Therefore, this event is classified as an accident. The applicants analyze this event using their small break LOCA model. There is no core uncover and the maximum peak clad temperature is 748°F. We find these results acceptable.

15.3.7 Anticipated Transients Without Scram

A number of plant transients can be affected by a failure of the scram system to function. For a pressurized water reactor, the most important transients affected include loss of normal feedwater, loss of electrical load, inadvertent control rod withdrawal, and loss of normal electrical power. In September 1973, we issued WASH-1270, "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors," establishing acceptance criteria for anticipated transients without scram. In conformance with the requirements of Appendix A to WASH-1270, Combustion Engineering submitted an evaluation of anticipated transients without scram in Topical Report CENPD-158, "Topical Report Anticipated Transients Without Scram." On December 9, 1975, we issued our "Status Report on Anticipated Transients Without Scram for Combustion Engineering Reactors." In response, Combustion Engineering issued Revision 1 to CENPD-158 in May 1976. A reevaluation of the potential risks from anticipated transients without scram (ATWS) has been published in NUREG-0460, Volumes 1 through 4. The status of NUREG-0460 is described below:

- (1) In March 1980 the 4th Volume of NUREG-0460 was issued by the NRC staff. The recommendations included design criteria for plants such as San Onofre 2 and 3, and recommended rule making to establish such criteria.
- (2) The NRC staff presented its recommendations on ATWS to the Commission, including the recommendation for rulemaking, in September, 1980.
- (3) After deliberation, the Commission will act on the matter. Whether it will agree to rule making is speculative at this time. If rule making is initiated by the Commission, we would expect that any rule adopted would include an implementation plan for all classes of plants.

San Onofre 2 and 3 would be required to provide plant modifications in conformance with ATWS criteria and scheduler requirements provided in the rule or as adopted by the Commission. The following discussion presents the bases for operation of San Onofre 2 and 3 prior to the adoption of a rule.

In NUREG-0460, Volume 3, we state: "The staff has maintained since 1973 (for example, see pages 69 and 70 of WASH-1270) and reaffirms today that the present likelihood of severe consequences arising from an ATWS event is acceptably small and presently there is no undue risk to the public from ATWS. This conclusion is based on engineering judgment in view of: (a) the estimated arrival rate of anticipated transients with potentially severe consequences in the event of scram failure; (b) the favorable operating experience with current scram systems; and (c) the limited number of operator reactors." In view of these considerations and our expectation that the necessary plant modifications will be implemented in one to four years following a Commission decision on anticipated transients without scram, we have generally concluded that pressurized water plants can continue to operate because the risk from anticipated transient without scram events in this time period

is acceptably small. As a prudent course, in order to further reduce the risk from anticipated transient without scram events during the interim period before completing the plant modifications determined by the Commission to be necessary, we have required that the following steps be taken:

- (1) Develop emergency procedures to train operators to recognize anticipated transient without scram event, including consideration of scram indicators, rod position indicators, flux monitors, pressurizer level and pressure indicators, pressurizer relief valve and safety valve indicators, and any other alarms annunciated in the control room with emphasis on alarms not processed through the electrical portion of the reactor scram system.
- (2) Train operators to take actions in the event of an anticipated transients without scram, including consideration of manually scrambling the reactor by using the manual scram button, prompt actuation of the auxiliary feedwater system to assure delivery to the full capacity of this system, and initiation of turbine trip. The operator should also be trained to initiate boration by actuation of the high pressure safety injection system to bring the facility to a safe shutdown condition.

We consider these procedural requirements an acceptable basis for interim operation of the facility based on our understanding of the plant response to postulated anticipated transients without scram events.

15.3.8 Conclusions

The applicants have presented results for various accidents which meet our acceptance criteria as detailed Section 15 in the Standard Review Plan. We conclude, therefore, that the applicants have provided adequate protection systems to mitigate accidents in compliance with General Design Criteria 20, except as noted in the previous sections on accidents.

15.4 Radiological Consequences of Accidents

The applicants have calculated the potential offsite radiological consequences from various postulated design basis accidents. These accidents are the same as those analyzed for previously licensed pressurized water reactor plants. We performed independently similar calculations for the following accidents:

- loss-of-coolant accident, including post-LOCA recirculation leakage,
- fuel handling accident inside containment,
- fuel handling accident in fuel building,
- spent fuel cask drop,
- rupture of radioactive gas storage tank,
- steam line break accident,
- steam generator tube rupture accident,
- control element assembly ejection accident,

TABLE 15.3
RADIOLOGICAL CONSEQUENCES OF DESIGN BASIS ACCIDENTS (REM)

<u>ACCIDENT</u>	<u>EXCLUSION AREA</u> <u>600 METERS (1)</u>		<u>LOW POPULATION ZONE</u> <u>3140 METERS (2)</u>	
	<u>THYROID</u>	<u>WHOLE BODY</u>	<u>THYROID</u>	<u>WHOLE BODY</u>
Loss of Coolant Accident	110	3	33	1
ESF post-LOCA Leakage:				
Continuous leakage	7	1	7	1
Pump seal failure	43	1	42	1
Fuel Handling Accident in Fuel Building	41	7	3	1
Steam Line Break:				
Mode 1*	6	-	2	-
Mode 2**	10	-	3	-
Steam Generator Tube Failure:				
Mode 1*	3	-	1	-
Mode 2**	21	-	2	-
Control Element Assembly Ejection Accident:				
Containment leakage	12	1	8	1
SG tube leakge	56	-	7	-
Letdown Line Break	9	1	1	1

* Mode 1: without iodine spike

** Mode 2: with iodine spike

(1) Dose to a hypothetical individual for the first two hours following the accident.

(2) Dose to a hypothetical individual for the course of the accident, assumed to be 30 days.

reactor coolant pump shaft break, and
letdown line rupture outside of containment.

Our evaluation of these accidents is presented in the following subsections. The offsite doses we calculated are presented in Table 15.3 for all accidents and the assumptions we used are presented in Table 15.4 through 15.11 for specific accidents. These calculated doses are within the exposure guidelines of 10 CFR Part 100 in all cases.

15.4.1 Loss-of-Coolant Accident, Containment Direct Leakage

The assumptions which we used in the analysis of the radiological consequences of the design basis loss-of-coolant accident (LOCA) due to direct containment leakage are listed in Table 15.4. Although we calculated a value of 13.7 per hour for the elemental iodine removal rate constant, we conservatively used a value of 10 per hour in our analysis to assure compatibility with the assumptions given in Regulatory Guide 1.4 as discussed in Section 6.5.2 of this report. We have calculated an overall two-hour thyroid dose reduction factor of 6.3 for the mitigating action of the containment spray system. The calculated doses, listed in Table 15.3, are within the dose guidelines of 10 CFR Part 100.

15.4.2 Engineered Safety Features Post-LOCA Leakage

As part of the loss-of-coolant accident evaluation, the applicants evaluated the potential radiological consequences of the leakage from equipment of engineered safety feature (ESF) systems located outside the containment. We reviewed the applicants' evaluation and performed an independent analysis. These ESF systems are the high and low pressure safety injection systems (HPSI and LPSI respectively) and the containment spray system (CS) all of which are fully redundant. The HPSI and CS systems will circulate spilled water from the containment sump to outside the containment during the recirculation mode following a large break LOCA. The LPSI system will circulate sump water outside containment during the long term cooling following a small break LOCA. The equipment is located below grade level in the ESF equipment building in three pump rooms with watertight doors and a liquid level detection system as described in Section 6.3.2 of this report. Valve stem leakage is collected in the pump pit of each room from where it drains to the ESF building sump. This sump is located in an enclosed area and is connected via a sump pump to the liquid rad waste system. The sump is approximately 9 feet deep and maintained with at least 1.5 feet of water (800 gallons) to provide for dilution of the leakage. Pump seal leakage drains to the sump directly via a piped leak-off collection system. Each pump room has an independent normal and emergency air cooling system. An ESF grade air filtration system is not provided. The applicants have identified, at our request, the potential sources of leakage from the ESF pump seals and valve stems of redundant systems.

The maximum combined leakage from all sources is estimated to be approximately 1250 cubic centimeter per (or approximately 0.7 gallons per hour) based on a leakage

TABLE 15.4

INPUT PARAMETERS AND ASSUMPTIONS TO DETERMINE RADIOLOGICAL
CONSEQUENCES DUE TO A POSTULATED LOSS-OF-COOLANT ACCIDENT

Power Level (megawatts thermal)	3,560
Containment free volume (cubic feet)	2.36×10^6
Containment Leak Rate (percent per day)	
0 hours - 24 hour	0.1
24 hour - 30 days	0.05
Core activity inventory available for leakage from containment (percent)	
noble gases	100
iodine	25
Iodine form (percent)	
elemental	91
particulate	5
organic	4
Total two-hour iodine dose reduction factor due to containment spray	6.3
Iodine removal rate constants for spray containment region (per hour)	
elemental	10.0
particulate	0.22
organic	0.0
Distance (meter)	
Exclusion area boundary (EAB)	600
Low population zone (LPZ)	3,140
Atmospheric dispersion factors, X/Q (seconds per cubic meter)	
0 - 2 hours (EAB)	$4.0(10)^{-4}$
0 - 8 hours LPZ	$2.7(10)^{-5}$
8 - 24 hours	$1.9(10)^{-5}$
24 - 96 hours	$8.2(10)^{-6}$
96 - 720 hours	$2.5(10)^{-6}$

of 50 cubic centimeter per hour for each pump seal and 10 cubic centimeter per hour per inch of valve stem diameter. This also includes the leakage from the LPSI system which is not used during the recirculation mode following a large break LOCA. The applicants also considered a gross failure of a pump seal that could result in a leakage of 500 cubic centimeter per minute (or approximately 8 gallons per hour). This value is based on field experience and tests conducted by the seal manufacturer, Durametallic Corporation. At our request the applicants have committed to propose technical specifications that will limit the combined ESF leakage and surveillance requirements to verify these limits.

We have evaluated the radiological consequences of the potential ESF leakage, both from continuous operational leakage and from the gross failure of a pump seal. We assumed the containment sump water contains a mixture of iodine fission products in accordance with Regulatory Guide 1.4. Other assumptions were made in accordance with Appendix B of Standard Review Plan 15.6.5 and are summarized as appropriate LOCA assumptions in Table 15.4 and for both ESF leakage conditions in Table 15.5. The iodine partition factor of 0.1 for the iodine release in the ESF pump rooms is based on pH value of about 8 and a temperature of less than 212° F for the recirculating sump water. We conservatively assumed no dilution of leakage in the ESF building sump, no plate-out, and direct and immediate release of the airborne activity to the environment. Our calculated offsite doses resulting from the continuous pump seal and valve stem leakage and from the gross failure of a pump seal are listed in Table 15.3.

We will include a requirement in the plant technical specification for San Onofre 2 and 3 that will limit the potential post-LOCA leakage from ESF system outside containment. In addition, the applicant has committed, in response to NUREG 0694, Item III.D.1.1, "Primary Coolant Sources Outside Containment," to institute a leak reduction program for all potential leakage sources of primary coolant outside containment to keep this leakage to levels as low as practicable.

Based on our review of the San Onofre 2 and 3 design and proposed operation of the ESF systems that will circulate radioactively contaminated water outside containment following a postulated LOCA and based on our requirement for Technical Specifications on the leakage from these ESF systems we conclude (1) that the doses from the postulated leakage of post-LOCA recirculation water, when added to the direct containment leakage dose, will result in a dose that is within the guidelines of 10 CFR Part 100; and (2) that the provisions taken by the applicant for mitigating the doses are acceptable.

15.4.3 Fuel Handling Accident In Containment

The applicants have provided systems to mitigate the consequences of a fuel handling accident inside containment. Redundant radiation monitors will detect within two seconds the radioactive gases released from the surface of the refueling pool inside containment and will initiate closure of the containment purge valves. Valve closure time will not exceed ten seconds in accordance with technical specifications,

TABLE 15.5

ASSUMPTIONS FOR EVALUATION OF LOCA DOSES DUE TO ESF

LEAKAGE OUTSIDE CONTAINMENT

<u>Case 1</u>	Operational leakage from pump seals and valve stems - maximum combined leak rate from all seal and valves, taken as twice the estimated leak rate in accordance with SRP 15.6.5, Appendix B (cubic centimeters per hour)	2,540
<u>Case 2</u>	Gross pump seal failure leak rate (cubic centimeters per hour)	30,000
<u>Case 1 and Case 2</u>		
	Start of leakage after LOCA (i.e, initiation of HPSI and CS systems recirculation mode) (hours)	0.5
	Duration of leakage (days)	30
	Iodine partition factor for release in ESF building	0.1
	Other appropriate information, see Table 15.4	

resulting in a total response time of 12 seconds from the time the radioactive gas bubble breaks the surface of the pool until the isolation valves fully close. The vertical distance between the surface of the pool and the inlets to the air exhaust ducts is 20 feet. Using standard ventilation equations, the applicants calculated a minimum travel time of 20 seconds from the surface of the pool to the inlets of the exhaust duct. The slant distance due to fuel handling operations away from the edge of the pool wall will increase travel time. The travel time from the inlet of the exhaust duct to the inboard isolation valve is an additional 3.5 seconds. This total travel time of 23.5 seconds, compared with an isolation time of 12 seconds, will assure that the isolation valves will close before any activity will be released to the environment. We have reviewed the analysis provided by the applicants and conclude that there will be no significant offsite consequences from a fuel handling accident in containment. We therefore conclude that the design and operation of the containment isolation system is acceptable with respect to fuel handling operations inside containment.

15.4.4 Fuel Handling Accident in the Fuel Building

The applicants have provided an analysis of the radiological consequences of a fuel handling accident in the spent fuel pool area. The Units 2 and 3 at San Onofre have separate fuel buildings. Each building is of poured reinforced concrete construction, including the roof. There are three openings to the area at the operating floor: the new fuel delivery hatch, the spent fuel casket loading hatch and a personnel access door from the adjacent penetration room. The fuel hatches, which are closed during fuel handling operations in the spent fuel pool, are equipped with neoprene gaskets and are self-sealing if the outside pressure should drop below the building internal pressure. Electrical, pipe, and duct penetrations will be sealed with a fire resistant silicone foam.

The fuel handling area is provided with a normal ventilation system and a post-accident cleanup system (see also Section 9.4.2 of this report.) The normal ventilation system maintains a slight negative pressure in the area during normal operations by means of an air flow imbalance between the supply and exhaust fans. In case of a fuel handling accident, radiation monitors in the exhaust ducts of the normal ventilation system will detect the radioactivity released and will automatically isolate the system and start the post-accident cleanup system. This is an internal recirculation system with ESF grade HEPA and activated charcoal filters. The system will not discharge to the atmosphere and will not maintain the negative pressure in the building. Each train of the system has a capacity of approximately 13,000 cfm, of which 9,250 cfm will be circulated to the fuel handling area. The remainder will be directed to equipment areas in the basement of the building.

During our review we requested additional information and analyses about two aspects of the design and operation of the fuel handling building and its ventilation system. These related to the assumptions used in the calculation of the radiological consequences of a fuel handling accident, specifically, the mixing of the fuel handling building atmosphere and potential exfiltration to the outside environment.

In this evaluation of the radiological consequences of a fuel handling building accident, the applicants assumed that the activity released from the fuel pool surface following the accident is mixed instantaneously with the fuel handling building atmosphere. The released activity was thus assumed to occupy the entire volume of the building. However, in the air intake and outlet ducts of the system, the openings are located close to the roof of the building, approximately 50 feet above the surface of the spent fuel pool. The outlet duct openings are located as close as seven feet from the intake openings. We determined that the design and operation of the system potentially could short-circuit the intended airflow and mixing of the atmosphere and therefore would not provide for an effective air cleanup, i.e., removal of radioiodine released from the pool surface during the accident.

To enhance mixing, the applicants replaced the original, four-way outlet diffuser with a high-throw air supply outlet which will discharge the air 50 feet straight downward to the pool surface. This will improve air circulation and will provide an air sweep action over the pool. In addition, the applicants have committed, at our request, to conduct a test of the post-accident cleanup system that will qualitatively verify the air circulating and mixing capabilities of the system. The test will be performed on the Unit 3 fuel handling building prior to the storage of spent fuel in either the Unit 2 or Unit 3 spent fuel pool.

The second staff concern related to the potential exfiltration to the outside environment following a fuel handling building accident. The applicants analytically modelled the post-accident cleanup system as a one-through ventilation and filtration system discharging directly to the environment. In this model the potential for unfiltered leakage was not taken into account. Such exfiltration could occur as a result of a sudden atmospheric pressure drop, which could create a pressure difference between the building internal pressure and the outside barometric pressure. Although the staff concluded that the fuel handling building, in comparison with such buildings at other facilities had been designed and constructed to greatly reduce such leakage we were unable to conclude that it is a zero leakage building.

At our request the applicants committed to perform a positive pressure test of the fuel handling building. The test will demonstrate whether or not the actual, measured exfiltration is consistent with the assumptions used in the fuel handling building accident analysis. The acceptance criteria for the test will be that the exfiltration shall not exceed 1300 scfm, as measured in the building supply air flow, when the building pressure is increased to 0.1 inches, positive water gauge. The test will be performed on the Unit 3 fuel handling building prior to the storage of spent fuel in either the Unit 2 or the Unit 3 spent fuel pool.

We have independently evaluated the potential radiological consequences from a postulated fuel handling accident. Our assumptions for the release of the radioactivity to the fuel building atmosphere are listed in Table 15.6. We assumed that the radioactivity from the fuel handling building accident would be instantaneously released into the building volume and would mix uniformly with the building atmosphere. We modelled the post-accident cleanup system as a recirculation system according to

TABLE 15.6
ASSUMPTIONS USED IN ANALYSIS OF A FUEL HANDLING
ACCIDENT IN FUEL BUILDING

Power Level (megawatt thermal)	3560
Number of Fuel Rods Damaged	236
Total Number of Fuel Rods in Core	51,212
Radial Peaking Factor of Damaged Rods	1.65
Shutdown Time (hours)	72
Inventory Released from Damaged Rods, Iodines and Noble Gase percent	10
Fuel pool reduction factor	
Iodines	100
Noble Gases	1
Iodine Release from Pool (percent)	
Elemental	75
Organic	25
Filter Efficiency for Iodine Removal (percent)	
Elemental	90
Organic	30
Atmospheric diffusion factors, X/Q (sec/m ³)	
2 hour - exclusion area boundary	4.0×10^{-4}
8 hours - low population zone	2.7×10^{-5}

its design and intended operation. We evaluated the offsite doses by assuming an exfiltration of 1300 scfm from the building atmosphere to the outside environment. The resultant two-hour thyroid dose at the exclusion area boundary is 41 rem, as listed in Table 15.3. This value is well within the guidelines of 10 CFR Part 100.

We conclude, based on our above-described review and independent analysis of the San Onofre 2 and 3 fuel handling building, and based on the applicants' commitment to demonstrate by test the mixing and exfiltration characteristics of the building, that the design and operation of the fuel handling building and the post-accident cleanup ventilation system are acceptable.

15.4.5 Spent Fuel Cask Drop Accident

The potential height for dropping a fuel cask during operations in the fuel building is physically limited to less than 30 feet to assure the structural integrity of the cask, as discussed in Section 9.1 of this report. Therefore, in accordance with Standard Review Plan Section 15.7.5, no loss of cask integrity is postulated to occur in the event of a drop and we conclude there will be no significant radiation releases to the environment. The radiological consequences will be less than a small fraction of the dose guideline values in 10 CFR Part 100.

15.4.6 Gas Decay Tank Failure

The applicants have evaluated the potential radiological consequences associated with the failure of a radioactive gas decay tank in accordance with the guidelines of Regulatory Guide 1.24. The gas decay tanks and associated equipment have been designed and constructed as Seismic Category I equipment. Technical Specifications will be established to limit the inventory of activity of a gas decay tank to a level such that the potential doses from a postulated tank failure will be a small fraction of the 10 CFR Part 100 exposure guidelines.

15.4.7 Main Steam Line Failure Outside Containment

We have reviewed the sequence of events and the radiological consequence analysis performed by the applicants for a main steam line failure outside the containment. We have evaluated the radioactivity release, both with and without a pre-accident iodine spike. Our assumptions are listed in Tables 15.7 and 15.8 and our calculated doses are listed in Table 15.1. Technical Specifications on primary and secondary coolant activities will limit potential doses to a small fraction of the 10 CFR Part 100 exposure guidelines, even if the accident should occur with an iodine spike.

15.4.8 Steam Generator Tube Failure

We have evaluated a steam generator tube failure accident with and without a coincident loss of offsite power. The assumptions used in our analysis are listed in Table 15.9. The primary and secondary coolant activities will limit potential doses to small fractions of the 10 CFR Part 100 exposure guidelines even if the accident were to occur with a pre-accident iodine spike.

15.4.9 Control Element Assembly Ejection Accident

We have evaluated the control rod assembly ejection accident and determined that the design of the plant will assure that the recovery from the accident is sufficiently rapid and effective to limit the radioactivity releases. The evaluation of the radiological consequences was performed using the recommendations of Regulatory Guide 1.77 and was based on a conservative plant response to the accident. We evaluated the doses assuming direct containment leakage and leakage through postulated defective steam generator tubes. Our assumptions for the accident evaluation are listed in Tables 15.7 and 15.10. Our calculated doses are listed in Table 15.3 and are well within the guideline values of 10 CFR Part 100.

15.4.10 Reactor Coolant Pump Shaft Break

We have evaluated the potential radiological consequences of a postulated break of a reactor coolant pump shaft. We assumed that 6.0 percent of the fuel rods would fail as a result of a departure from nucleate boiling (see Section 15.3.4) and that the primary coolant system remains intact. Other assumptions were the same as for the control element assembly ejection (CEAE) accident as appropriate (see Section 15.4.9). We conservatively assumed that the initial steam release from the secondary system is via the steam generator safety valves directly to the atmosphere and at 30 minutes the operator will use the steam dump valves to cool down the plant. Based on a comparison of the failed fuel fraction and the steam releases with the assumptions for the CEAE accident, we conclude that the potential radiological consequences from the postulated pump shaft break accident are a small fraction of the guidelines of 10 CFR Part 100.

15.4.11 Letdown Line Break

The applicants have performed an analysis of the failure of a two-inch diameter letdown line as the accident with the most severe potential radiological consequences of any failure of a small diameter pipe carrying primary coolant outside the containment. The applicants have stated that there are no instrument sensing lines that connect to the reactor coolant system and penetrate the containment. The letdown line meets the requirements of General Design Criteria 55 of 10 CFR Part 50 Appendix A in that it is equipped with an inboard and outboard isolation valve. We have independently performed an analysis of the radiological consequences of such an event using assumptions in accordance with Standard Review Plan 15.6.2, Revision 2. The letdown line was postulated to rupture outside the containment resulting in a rapid loss of primary coolant inventory and pressure. Although the isolation valves will close due to either a high letdown line temperature or a safety injection actuation signal, we assumed conservatively that these automatic functions failed and that the isolation is accomplished manually by the operator at 30 minutes after the failure occurred. We assumed that the primary coolant concentration was at the equilibrium technical specification limit of 1.0 μCi I-131 equivalent per gram as given in NUREG-0212, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors." The iodine release rate from the fuel was assumed to increase, (i.e., iodine spiking) by a factor of 500 at the time of the letdown line

TABLE 15.7

ASSUMPTIONS USED IN THE ANALYSIS OF:

MAIN STEAM LINE FAILURE OUTSIDE CONTAINMENT
STEAM GENERATOR TUBE FAILURE
CONTROL ELEMENT ASSEMBLY EJECTION ACCIDENT
LETDOWN LINE BREAK ACCIDENT

- (1) Power level prior to accident is 3560 Mwt.
- (2) Primary and secondary coolant equilibrium iodine concentrations are as limited by Technical Specifications:

primary coolant: 0.1 μCi of dose equivalent I-131 per gram
secondary coolant: 0.1 μCi of dose equivalent I-131 per gram
- (3) For accidents with a pre-existing iodine spike, primary coolant iodine concentration is the maximum allowed by Technical Specifications for 48 hour periods (i.e., 60 μCi dose equivalent I-131 per gram).
- (4) At the time of accident iodine release rate to the primary coolant is assumed to increase by a spiking factor of 500 over the equilibrium release rate.
- (5) Loss of offsite power occurs at time of reactor trip.
- (6) Atmospheric diffusion factors, X/Q (sec/m^3):
2 hour exclusion area boundary 4.0×10^{-4}
8 hour low population zone 2.7×10^{-5}

TABLE 15.8

STEAM GENERATOR TUBE RUPTURE ACCIDENT ASSUMPTIONS

- (1) Steam line break occurs outside containment and upstream of main steam isolation valve.
- (2) Reactor is at hot zero power conditions at time accident occurs.
- (3) Entire secondary side coolant inventory of affected steam generator is released to atmosphere following steam line break.
- (4) Primary to secondary leakage into affected steam generator continues at the Technical Specification value of 1 gallon per minute for duration of accident and is released directly to atmosphere.
- (5) Decontamination factor of 1.0 is assumed for iodine released through affected steam generator and of 10 between water and steam phases in unaffected steam generator.
- (6) Accident recovery occurs at 6.6 hours following accident (i.e., leakage from primary to secondary system terminates).

TABLE 15.9

STEAM GENERATOR TUBE FAILURE ACCIDENT ASSUMPTIONS

- (1) Reactor is operating at full power at time of accident occurrence.
- (2) Initial primary to secondary leak rate is 55 pounds per second in affected steam generator.
- (3) Affected steam generator is isolated from atmosphere and primary system cooldown begins 30 minutes after accident occurrence using unaffected steam generator.
- (4) Accident recovery is complete at 3.2 hours (i.e., time when the RCS shutdown heat removal system commences operation).
- (5) Iodine decontamination factor between water and steam phases in secondary side of steam generators is assumed to be 10.
- (6) Primary to secondary leak rate is 1 gallon per minute in unaffected steam generator.

TABLE 15.10

CONTROL ELEMENT ASSEMBLY EJECTION ACCIDENT ASSUMPTION

- (1) Reactor is operating at full power at the time of accident occurrence.
- (2) As a result of the core transient, 7.9 percent of the fuel rods in the core are assumed to experience cladding failure and 0.5 percent of fuel rods are assumed to experience fuel melting.
- (3) 10 percent of iodine activity in fuel rods which experience cladding failure and 50 percent of iodine activity in the rods which experience melting is assumed to be released into primary coolant.
- (4) Primary to secondary leakage continues at a rate of 1 gallon per minute for duration of accident.
- (5) Accident recovery occurs at 3.2 hours after accident occurs (i.e., primary system shutdown cooling system is activated).

break. Other assumptions are listed in Table 15.11. The resulting doses are listed in Table 15.3 and are small fractions of the 10 CFR Part 100 exposure guidelines.

15.4.12 Postulated Radioactive Releases due to Liquid Tank Failures

The consequences of component failures for components located outside the reactor containment, which could result in releases of liquids containing radioactive materials to the environs, were evaluated. Considered in our evaluation were (1) the radionuclide inventory in each component assuming a 1% operating power fission product source term, (2) a component liquid inventory equal to 80% of its design capacity, (3) the mitigating effects of plant design including overflow lines and the location of storage tanks in curbed areas designed to retain spillage, and (4) the effects of site geology and hydrology.

The applicants have incorporated provisions in the design to retain releases from liquid overflows as discussed in Section 11.2.1 of this report.

We determined that there are no ground water users down gradient from potential liquid releases due to liquid tank failures.

Therefore, we did not calculate ground water radioactivity concentrations for potential receptors.

Based on the foregoing evaluation, we conclude that the provisions incorporated in the applicants' design to mitigate the effects of component failures involving contaminated liquids are acceptable.

TABLE 15.11
LETDOWN LINE BREAK ACCIDENT ASSUMPTIONS

- (1) Reactor is operating at full power at time of accident occurrence.
- (2) Isolation valves fail to close automatically.
- (3) Manual isolation of letdown line at 30 minutes.
- (4) Total primary reactor coolant released into auxiliary building is to 94,510 pounds.
- (5) Flash fraction of coolant is 40 percent.
- (6) Fraction of iodine released to atmosphere is 40 percent.
- (7) No holdup, filtration, or plateout of airborne iodine in auxiliary building.

16.0 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 Commission. The finally approved technical specifications will be made a part of the operating license. Included will be sections covering safety limits, limiting safety system settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls.

The applicants have proposed that the technical specifications given in Section 16.0 of the San Onofre Units 2 and 3 Final Safety Analysis Report be used. These technical specifications are based upon NUREG-0212, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors."

We are currently working with the applicant to finalize the technical specifications for San Onofre Units 2 and 3. On the basis of our review to date, we conclude that normal plant operation within the limits of the technical specifications will not result in potential offsite exposures in excess of the 10 CFR Part 20 limits. Furthermore, the limiting conditions for operation and surveillance requirements will assure that necessary engineered safety features will be available in the event of malfunctions within the plant.

17.0 QUALITY ASSURANCE

17.1 General

The description of the San Onofre Units 2 and 3 quality assurance program for the operations phase is contained in Section 17.2 of Southern California Edison Company's Topical Report SCE-1-A, Amendment 3, "Quality Assurance Program," dated March 1980. Our evaluation of this quality assurance program is based upon a detailed review of this information and discussions with representatives of Southern California Edison Company and the NRC Office of Inspection and Enforcement. We assessed Southern California Edison Company's quality assurance program for the operations phase to see if it complies with the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and the applicable regulatory guidance listed in Table 17.1, "Regulatory Guidance for Quality Assurance."

17.2 Organization

The structure of the organizational units responsible for the operation of San Onofre Units 2 and 3 and for the establishment and execution of the operations phase quality assurance program is shown in Figure 17-1. The Vice President, Advanced Engineering, who reports to the Senior Vice President, has the responsibility for establishing corporate quality assurance policies, goals and objectives and for executing the quality assurance program. The Manager, Quality Assurance, reports directly to the Vice President, Advanced Engineering, and has the responsibility for establishment, maintenance and surveillance of the quality assurance program.

Reporting to the Manager, Quality Assurance, are the offsite and onsite Project Quality Assurance Supervisors who are responsible for directing and managing the activities of both the offsite and onsite quality assurance engineers, respectively. Representative activities of the quality assurance engineers include the following: (1) reviewing and approving design and procurement documents for inclusion of quality assurance requirements; (2) performing inspection activities; (3) performing preaward evaluation of suppliers; and (4) conducting internal audits of station operations and external audits of contractors and suppliers.

The quality assurance organization has the authority to: (1) identify quality problems; (2) initiate, recommend or provide solutions through designated channels; (3) verify implementation of solutions; and (4) stop unsatisfactory work and to control further processing, delivery and installation of nonconforming items.

TABLE 17.1
REGULATORY GUIDANCE FOR QUALITY ASSURANCE

1. Regulatory Guide 1.8, Revision 1-R, "Personnel Selection and Training" (9/75).
2. Regulatory Guide 1.28, "Quality Assurance Program Requirements (Design and Construction)" (6/7/72).
3. Regulatory Guide 1.30, "Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electrical Equipment" (8/11/72).
4. Regulatory Guide 1.33, Revision 1, "Quality Assurance Program Requirements (Operation)" (1/77).
5. Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants" (3/16/73).
6. Regulatory Guide 1.38, Revision 1, "Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants" (10/76).
7. Regulatory Guide 1.39, Revision 1, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants" (10/76).
8. Regulatory Guide 1.58, "Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel" (8/73).
9. Regulatory Guide 1.64, Revision 2, "Quality Assurance Requirements for the Design of Nuclear Power Plants" (6/76).
10. Regulatory Guide 1.74, "Quality Assurance Terms and Definitions" (2/74).
11. Regulatory Guide 1.88, Revision 2, "Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records" (10/76).
12. Regulatory Guide 1.94, Revision 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).
13. Regulatory Guide 1.116, "Quality Assurance Requirements for Installation, Inspection and Testing of Mechanical Equipment and Systems" (6/76).
14. Regulatory Guide 1.123, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants" (10/76).
15. ANSI Standard N45.2.12, "Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants," Draft 3, Revision 4 (2/74).

The quality assurance organization, which verifies the effective implementation of the quality assurance program, is assigned responsibility for: (1) assisting in the development and implementation of indoctrination and training programs for personnel performing quality-affecting activities; (2) reviewing and approving quality assurance procedures and instructions; (3) assuring that personnel qualifications are current and applicable to the work being performed; (4) assuring that design and procurement documents include applicable quality assurance requirements; (5) performing preaward evaluation of suppliers and surveillance and inspection at the suppliers' facilities; (6) approving the disposition of nonconforming items; (7) assuring corrective actions are effective and accomplished in a timely manner; and (8) conducting internal audits of station operations and external audits of suppliers.

The Nuclear Engineering and Operations Department, under the direction of the Vice President, Nuclear Engineering and Operations, is responsible for the operation, maintenance and safety of the station. The Plant Manager, within the Nuclear Engineering and Operations Department, is responsible for the routine administration and implementation of the quality assurance program at the station. The resolution of disputes on quality assurance program requirements arising between quality assurance personnel and other department personnel are escalated to appropriate levels of management designated in Figure 11-1 culminating with the Senior Vice President for resolution.

17.3

Quality Assurance Program

Southern California Edison Company has committed that its quality assurance program for the operations phase is to be in compliance with the provisions of the regulatory guidance provided by the NRC in Table 17-1.

Procedures and instructions for implementing the quality assurance program are contained in quality assurance manuals which are established and maintained by the Manager, Quality Assurance. In compliance with applicable regulations, codes and standards. The quality assurance organization is responsible for assuring that procedures and instructions provide for complete and adequate quality assurance requirements with sufficient reviews, inspections and audits by quality assurance personnel to verify the effective implementation of the entire quality assurance program.

Southern California Edison Company's quality assurance program requires that implementing documentation encompasses detailed controls for: (1) translating codes, standards, regulatory requirements, technical specifications, and engineering and process requirements into drawings, specifications, procedures, and instructions; (2) developing, reviewing and approving procurement documents, including changes; (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 and inspecting and/or testing materials, equipment, processes or services; (8) calibrating and

maintaining measuring and test equipment; (9) handling, storing and shipping items; (10) identifying the inspection, test and operating status of items; (11) identifying and dispositioning nonconforming items; (12) correcting conditions adverse to quality; (13) preparing and maintaining quality assurance records; and (14) auditing activities which affect quality. We have not yet completed our review of the list of structures, systems, and components to which the quality assurance program applies (the Q-List). We will report the resolution of this issue in a supplement to this report.

Quality is verified through checking, review, surveillance, inspection, testing and audit of quality-related activities. The quality assurance program requires that quality verification be performed by individuals who are not directly responsible for performing the quality-related activities. Inspections are performed by qualified personnel in accordance with procedures, instructions and checklists approved by the quality assurance organization.

The quality assurance organization is responsible for the establishment and implementation of the audit program. Audits are performed in accordance with preestablished written checklists by appropriately trained personnel not having direct responsibilities in the areas being audited. The audit function, which is conducted at scheduled intervals and/or on a random unscheduled basis, includes an objective evaluation of the adequacy of and compliance with quality assurance policies, practices, procedures and instructions; the adequacy of work areas, activities, processes, items and records; the effectiveness of implementation of the quality assurance program; and product compliance with applicable engineering drawings and specifications. The quality assurance program requires documentation of audit results and review by management having responsibility in the area audited to determine and take corrective action needed, if any.

Followup audits are performed to determine that nonconformances are effectively corrected and that the corrective action precludes repetitive occurrences. Audit reports, which indicate performance trends and the effectiveness of the quality assurance program, are prepared and issued to responsible management for review and assessment.

17.4 Conclusions

Our review of Southern California Edison Company's quality assurance program description for the operations phase of San Onofre Units 2 and 3 has verified that, subject to favorable completion of the staff's review of the Q-List discussed above, the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Southern California Edison Company's quality assurance program.

Based upon our detailed review and evaluation of the quality assurance program description contained in Section 17.2 of the quality assurance topical report, SCE-1-A, Amendment 3, dated March 1980 for San Onofre Units 2 and 3, we conclude that:

- (1) The quality assurance organization of Southern California Edison Company is sufficiently independent of cost and schedule (when opposed to safety considerations), has sufficient authority to effectively carry out Southern California Edison Company's quality assurance program, and has sufficient access to management at a level necessary to perform its quality assurance functions.
- (2) The quality assurance program description contains adequate quality assurance requirements and a comprehensive system of planned and systematic controls which satisfy each of the criteria of Appendix B to 10 CFR Part 50 in an acceptable manner.

As is discussed in Section 17.3, above, we will report on the results of our review of the San Onofre 2 and 3 Q-List in a supplement to this report.

18.0 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The San Onofre Nuclear Generating Station, Units 2 and 3 application for operating licenses is being reviewed by the Advisory Committee on Reactor Safeguards. We intend to issue a supplement to this safety evaluation report after the Committee's report to the Commission relative to its review is available. The supplement will append a copy of the Committee's report and will address comments made by the Committee, and will also describe steps taken by us to resolve any issues raised as a result of the Committee's review.

19.0 COMMON DEFENSE AND SECURITY

The application reflects that the activities to be conducted will be within the jurisdiction of the United States and that all of the directors and principal officers of the applicants* are United States citizens. The applicants are not owned, dominated, or controlled by an alien, a foreign corporation, or a foreign government. The activities to be conducted do not involve any restricted data, but the applicants agreed to safeguard any such data which might become involved in accordance with the requirements of 10 CFR, Part 50. The applicants will rely upon obtaining fuel as it is needed from sources of supply available for civilian purposes, so that no diversion of special nuclear material for military purposes will be involved. For these reasons and in the absence of any information to the contrary, we find that the activities to be performed will not be inimical to the common defense and security.

* Southern California Edison Company
San Diego Gas and Electric Company
City of Anaheim, California
City of Riverside, California

20.0 FINANCIAL QUALIFICATIONS

The Commission's regulations which relate to financial data and information required to establish financial qualifications for an applicant for a facility operating license are Section 50.33(f) of 10 CFR Part 50 and Appendix C to 10 CFR Part 50. To assure that we have the latest information to make a determination of the financial qualifications of an applicant, it is our current practice to review this information during the later stages of our review of an application. We are continuing our review of the financial qualifications of the San Onofre 2 and 3 applicants and will report the results of our evaluations in a supplement to this report.

21.0 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

21.1 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 to 10 CFR Part 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 Part 50.

21.2 Preoperational Storage of Nuclear Fuel

The Commission's regulations in 10 CFR Part 140 require that each holder of a construction permit under 10 CFR Part 50, who is also the holder of a license under 10 CFR Part 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 issuance of an operating license under 10 CFR Part 50), shall, during the interim storage period prior to 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 Part 70 license. Payment of an annual indemnity fee is required.

The applicants 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 No. NF-226). Further, the applicants will execute an Indemnity Agreement with the Commission effective as of the date of its preoperational fuel storage license. The applicants will pay the annual indemnity fee applicable to preoperational fuel storage.

21.3 Operating Licenses

Under the Commission's regulations, 10 CFR Part 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 which must be maintained for San Onofre Nuclear Generating Station, Units 2 and 3 (which have a rated capacity in excess of 100,000 electrical kilowatts), is the maximum amount available from private sources, i.e., the combined capacity of the two nuclear liability insurance pools, which amount is currently \$140 million.

Accordingly, licenses authorizing operation of San Onofre 2 and 3 will not be issued until proof of financial protection in the requisite amount has been received and the requisite indemnity agreement executed.

We expect that, in accordance with the usual procedure, the nuclear liability insurance pools will provide, several days in advance of anticipated issuance of the operating license document, evidence in writing, on behalf of the applicants, that the present coverage has been appropriately amended so that the policy limits have been increased to meet the requirements of the Commissioner'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 applicants will be required to pay an annual fee for operating license indemnity as provided in our regulations.

On the basis of the above considerations, we conclude that the presently applicable requirements of 10 CFR Part 140 have been satisfied and that, prior to issuance of the operating licenses, the applicants will be required to comply with the provisions of 10 CFR Part 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.

22.0 TMI-2 REQUIREMENTS

22.1 Introduction

The accident at Three Mile Island (TMI) Unit 2 resulted in requirements which were developed from the recommendations of several groups established to investigate the accident. These groups include the Congress, the General Accounting Office, the President's Commission on the Accident at Three Mile Island, the NRC Special Inquiry Group, the NRC Advisory Committee on Reactor Safeguards, the Lessons-Learned Task Force and the Bulletins and Orders Task Force of the NRC Office of Nuclear Reactor Regulation, the Special Review Group of the NRC Office of Inspection and Enforcement, the NRC Staff Siting Task Force and Emergency Preparedness Task Force, and the NRC Offices of Standards Development and Nuclear Regulatory Research. The report NUREG-0660 entitled "NRC Action Plan Developed as a Result of the TMI-2 Accident" (Action Plan) was developed to provide a comprehensive and integrated plan for the actions now judged necessary by the NRC to correct or improve the regulation and operation of nuclear facilities. The Action Plan was based on the experience from the TMI-2 accident and the recommendations of the investigating groups.

The development of the Action Plan (NUREG-0660), the NRC has transformed the recommendations of the investigating groups into discrete scheduled tasks that specify changes in its regulatory requirements, organization, or procedures. Some actions to improve the safety of operating plants were judged to be necessary before an action plan could be developed, although they were subsequently included in the Action Plan. Such actions came from the Bulletins and Orders issued by the Commission immediately after the accident, the first report of the Lessons Learned Task Force, and the recommendations of the Emergency Preparedness Task Force. Before these immediate actions were applied to operating plans they were approved by the Commission.

In June 1980, we issued NUREG-0694, "TMI-Related Requirements for Operating Licenses," which identified a discrete set of TMI-related licensing requirements in the Action Plan for plants that are scheduled to receive an operating license in the near future. This was followed in November 1980 by NUREG-0737, "Clarification of TMI Action Plan Requirement." NUREG-0737 incorporates, in one document, all TMI-related items approved for implementation by the Commission for operating reactors as well as plants scheduled to receive operating licenses in the future. NUREG-0737 also includes information about schedules, applicability, method of implementation review, submittal dates, and clarification of technical positions. Section 22 of this Safety Evaluation Report summarizes the NRC staff review of San Onofre 2 and 3 against the criteria of NUREG-0660, as clarified by NUREG-0737.

22.2 Discussion of Requirements

At this time the applicants have submitted their response to the requirements of NUREG-0737 and the staff review is in progress. We will report on the resolution of these issues in a supplement to this report.

23.0 CONCLUSIONS

Based on our evaluation of the application as set forth above, it is our position that, subject to favorable resolution of the outstanding matters described herein, we will be able to conclude that:

1. The application for facility licenses filed by the applicants* dated March 21, 1977, as amended, complies with the requirements of the Atomic Energy Act of 1954, as amended (Act), and the Commissioner's regulations set forth in 10 CFR Chapter 1; and
2. Construction of San Onofre Nuclear Generating Station, Units 2 and 3, has proceeded and there is reasonable assurance that it will be substantially completed, in conformity with Construction Permits No.s CPPR-97 and CPPR-98, the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and
3. The facilities will operate in conformity with the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and
4. 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 the regulations of the Commission set forth in 10 CFR Chapter 1; and
5. The applicants are technically and financially qualified to engage in the activities authorized by these licenses, in accordance with the regulations of the Commission set forth in 10 CFR Chapter 1; and
6. 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 will be issued to the applicants for operation of San Onofre Nuclear Generating Station, Units 2 and 3, the units must be completed in conformity with the provisional construction permits, the application, the Act,

* Southern California Edison Company
San Diego Gas and Electric Company
City of Anaheim, California
City of Riverside, California

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 Commission's Office of Inspection and Enforcement prior to issuance of the licenses.

Further, before operating licenses are issued, the applicants will be required to satisfy the applicable provisions of 10 CFR Part 140.

APPENDIX A

CHRONOLOGY OF RADIOLOGICAL REVIEW

November 30, 1976	Letter from applicants submitting operating licenses application for acceptance review
December 9, 1976	Letter to applicant advising of receipt of application and advising that acceptance review has begun
December 17, 1976	Letter to applicants transmitting sample technical specifications and errata sheet relative to fire protection reevaluation
December 17, 1976	Letter to applicants requesting information concerning reactor vessel supports
December 22, 1976	Letter from applicants concerning anticipated transients without scram
January 5-6, 1977	Site visit to review onshore tracer program
January 24, 1977	Letter to applicants requesting submittal dates for certain information in connection with acceptance review
February 10-11, 1977	Meeting with applicants to obtain information necessary to complete reactor vessel support analysis
February 18, 1977	Letter from applicants in response to January 24 letter, providing schedule for submitting certain information
February 25, 1977	Letter to applicants advising that application is acceptable for docketing and transmitting request for additional information
February 25, 1977	Letter to applicants regarding new regulation concerning industrial sabotage
March 21, 1977	Letter to applicants concerning request for withholding from public disclosure information on reactor vessel supports which was transferred at February 10 meeting
March 21, 1977	Letter from applicants transmitting application for docketing
March 23, 1977	Application docketed
March 30, 1977	Letter from applicants transmitting drawings of the San Onofre reactor vessel support system to be used as a model Combustion Engineering design for the North Anna audit analysis (includes certain proprietary data)

April 11, 1977	Letter to applicants requesting information concerning instrument trip setpoint values
April 18, 1977	Letter to applicants advising that information on reactor internals submitted on March 30, 1977, in connection with North Anna audit analysis, will be withheld from public disclosure
April 22, 1977	Letter to applicants concerning standard format for meteorological data on magnetic tape
April 26, 1977	Submittal of Amendment No. 1, response to NRC letter of February 25, 1978, consisting of enlarged containment drawings and revised information for the Final Safety Analysis Report
May 4, 1977	Letter to applicants transmitting Intrusion Detection Systems - Handbook
May 4-5, 1977	Site visit to discuss seismic and structural audit of Category I structures and to inspect such structures
May 9, 1977	Letter from applicants transmitting annual reports
May 12, 1977	Transmittal to applicants of "Steam Generator Supports Installation," CE Drawing E-1370-320-007, Rev. 2, which were inadvertently submitted with Amendment No. 1
May 12, 1977	Letter from applicants advising that instrument trip setpoint data will be submitted in April 1979
May 18, 1977	Meeting with applicants to discuss meteorological tracer tests
May 25, 1977	Letter from applicants transmitting revised Security Plan
May 25-26, 1977	Site visit to inspect apparent faulting in vicinity of site
June 16, 1977	Letter from Department of Army Corps of Engineers transmitting comments as a result of review
June 24, 1977	Letter to applicants transmitting first round questions and staff positions
July 7, 1977	Submittal of Amendment No. 2, consisting of revised information to satisfy several commitments
July 26, 1977	Letter to applicants regarding documentation of deviations from the Standard Review Plan
July 26, 1977	Meeting with applicants to compare reactor vessel support loads calculated by Combustion Engineering and by Idaho Nuclear Engineering Laboratory

August 5, 1977	Letter to applicants transmitting additional first round questions and positions
August 19, 1977	Letter to applicants concerning program for upgrading bases of Standard Technical Specifications
August 19, 1977	Submittal of Amendment No. 3, consisting of responses to letters dated March 30 and June 24, 1977, and other revised information
August 29, 1977	Letter to applicants transmitting "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance
September 9, 1977	Letter to applicants transmitting schedule for review of Final Safety Analysis Report
September 19, 1977	Letter to applicants transmitting petition regarding physical searches and proposed regulation concerning security clearances
September 27, 1977	Letter to applicants transmitting final set of first round questions
September 30, 1977	Letter to applicants advising that information on fuel assembly loss coefficients submitted August 19, 1977, will be withheld from public disclosure
September 30, 1977	Submittal of Amendment No. 4, consisting of responses to letter dated August 5, 1977, and revised information
October 12, 1977	Letter from applicants advising that applicants do not plan to participate in generic program for upgrading Standard Technical Specifications
October 25, 1977	Letter to applicants regarding physical security assessment models
October 31, 1977	Letter from applicants transmitting report, "Geotechnical Studies, Northern San Diego County," dated October 1977
October 31, 1977	Letter from applicants transmitting report, "Fire Hazards Analysis and Comparison with Appendix A of NRC Branch Technical Position 9.5-1," October 1977
November 21, 1977	Letter from applicants advising of recent microseismic activity in the area of San Juan Capistrano, California
November 22, 1977	Letter to applicants transmitting revised schedule for safety review
November 22, 1977	Letter from applicants transmitting "Supplemental Report of Geological Investigations, Trail Six Landslide (Area 1), Southeast of San Onofre Nuclear Generating Station"

November 28, 1977	Letter to applicants advising that implementation of physical search regulations is to be delayed
November 29, 1977	Meeting with applicants to discuss dewatering well voids
December 2, 1977	Submittal of Amendment No. 5, consisting of responses to letter dated September 27, 1977, and revised information
December 9, 1977	Meeting with applicants to discuss staff evaluation of tracer tests
December 23, 1977	Letter to applicants transmitting additional second round questions and positions
December 23, 1977	Letter from applicants transmitting "Status Report on the Investigation of Dewatering System, San Onofre Nuclear Generating Station, Units 2 and 3"
January 25, 1978	Submittal of Amendment No. 6, consisting of responses to letter dated November 21, 1977, structural drawings and report on mechanical matters, and other revised information
February 2, 1978	Letter to applicants concerning review of inservice testing program for pumps and valves
February 13, 1978	Submittal of Amendment No. 7, consisting of responses to letter dated December 23, 1977, and other revised information
February 14-17, 1978	Meeting with applicants to discuss and observe (1) dewatering well cavities, (2) geologic features in vicinity of site, and (3) reactor coolant system and emergency core cooling system
March 1, 1978	Letter from applicants transmitting "Modified Amended Security Plan, Revision 1"
March 10, 1978	Letter to applicants transmitting additional second round questions
March 10, 1978	Meeting with applicants to discuss proposed changes to intake conduit and dewatering well cavities
March 13, 1978	Letter from applicants transmitting "Status Report on the Investigation of Dewatering System, San Onofre Nuclear Generating Station, Units 2 and 3," February 14, 1978
March 16, 1978	Letter from applicants transmitting "Interim Report on the Investigation of Dewatering System, San Onofre Nuclear Generating Station, Units 2 and 3," March 10, 1978

March 31, 1978	Letter from applicants requesting extension of completion dates of construction permits
April 5, 1978	Submittal of Amendment No. 8, consisting of partial response to letter dated March 10, 1978, proposed technical specifications for fire protection systems, certain design and construction drawings, and other revised information
April 10, 1978	Letter to applicants concerning safeguards meeting to be held May 11-12, 1978, in Albuquerque, New Mexico
April 11, 1978	Letter from applicants transmitting "Report on Settlement Observation Program, San Onofre Nuclear Generating Stations, Units 2 and 3," March 22, 1978
April 11, 1978	Letter from applicants transmitting "Offshore Circulating Water System/ Ultimate Heat Sink, San Onofre Nuclear Generating Station, Units 2 and 3"
April 19, 1978	Letter from applicants transmitting additional copies of soil engineering construction control data, geophysical and boring log data base
April 19, 1978	Letter to applicants transmitting revised safeguards handbooks
April 26, 1978	Letter from applicants transmitting annual financial reports
April 27, 1978	Letter from applicants transmitting information on grouting of the open cavity at dewatering well No. 6
Undated letter (Received 4/28/78)	Letter from applicants transmitting "Status Report on Investigation of Dewatering Well System, San Onofre Nuclear Generating Station, Units 2 and 3." March 24, 1978
May 5, 1978	Letter to applicants transmitting for comment, "Nuclear Security Personnel for Power Plants, Review Plan and Acceptance Criteria for a Security Training Program," NUREG-0219, Draft 2
May 9, 1978	Letter from applicants transmitting "Status Report on the Investigation of Dewatering System, San Onofre Nuclear Generating Station, Units 2 and 3," April 28, 1978, and structure drawings
May 16, 1978	Submittal of Amendmenet No. 9, consisting of responses to letter dated March 10, 1978, a discussion of status of questions for which commitments are outstanding, and revised information
May 22, 1978	Letter from applicants transmitting "Geologic Investigation of Fault E, Southeast of the San Onofre Nuclear Generating Station, San Onofre, California," dated May 12, 1978

May 23, 1978	Meeting with applicants to discuss transportation of hazardous materials
June 1, 1978	Meeting with applicants to discuss startup testing
June 12, 1978	Letter from applicants transmitting "Status Report on Investigation of Dewatering System, San Onofre Nuclear Generating Station, Units 2 and 3," May 26, 1978
June 12, 1978	Letter to applicants transmitting Sandia reports on physical security protection
June 15, 1978	Meeting with applicants to discuss Reactor Systems Branch questions and inspect Unit 2 containment pump
June 16, 1978	Site visit and meeting with applicants to discuss their responses to second round questions from the Reactor Systems Branch and to hear presentation and tour the emergency containment sump and safety injection pump rooms
June 22, 1978	Meeting with applicants to observe progress to date in construction of 3-D model of dewatering well cavities
June 29, 1978	Submittal of Amendment No. 10, which provides information to satisfy several commitments, and consists of revised information
July 10, 1978	Letter from applicants transmitting "Evaluation of the Impact of Tack Welding, San Onofre Nuclear Generating Station, Units 2 and 3"
July 18, 1978	Letter to applicants transmitting "Barrier Penetration Database," NUREG/CR-0181
July 24-26, 1978	Meeting with applicants to discuss outstanding safety concerns in the area of instrumentation and control
July 26, 1978	Letter to applicants transmitting additional questions and positions
July 28, 1978	Letter from applicants transmitting "Final Report of the Onshore Tracer Tests Conducted December 1976 Through March 1977 at the San Onofre Nuclear Generating Station," Volumes 1 and 2 dated June 1977, and a tape of meteorological data collected December 20, 1976 through March 29, 1977
August 1, 1978	Letter to applicants transmitting 10 CFR Part 50, Appendix I model technical specifications
August 2, 1978	Letter to applicants transmitting, "Nuclear Security Personnel for Power Plants, Content and Review Procedures for a Security Training and Qualification Program," NUREG-0219, July 1978

August 3, 1978	Letter to applicants concerning fire brigade manpower requirements
August 11, 1978	Letter from applicants transmitting pages inadvertently omitted from July 28, 1978 submittal
August 11, 1978	Letter to applicants concerning standard format for meteorological data on magnetic tape
August 15, 1978	Letter to applicants advising of pressurized water reactor steam generator workshop to be held September 7-8, 1978
August 18, 1978	Meeting with applicants to discuss seismology and geology
August 18, 1978	Letter to applicants transmitting final set of second round questions
August 25, 1978	Letter from applicants transmitting "Report on the Results of Analyses Performed on Well 8 at the SONGS Units 2 and 3," "Report on Deep Exploration Drilling Program, Dewatering Well No. 8," and "Report on Shallow Exploration/Grouting Program"
August 28, 1978	Letter to applicants advising of regional meetings to discuss upgraded guard qualification and training requirements
August 31, 1978	Meeting with applicants to discuss CEDM snubber design and other concerns of the Mechanical Engineering Branch
September 1, 1978	Meeting with applicants to discuss transportation accident hazards
September 8, 1978	Submittal of Amendment No. 11, consisting of responses to letters dated July 26 and August 18, 1978, information to satisfy several commitments, and other revised information
September 11, 1978	Letter to applicants advising of revised date for meeting on upgraded guard qualification and training requirements
September 19, 1978	Letter to applicants transmitting comments on Modified Amended Security Plan
September 20, 1978	Letter to applicants transmitting additional questions and positions
September 21, 1978	Letter to applicants advising of guidelines for audit of seismic and structural design calculations
September 28, 1978	Letter to applicants transmitting page inadvertently omitted from September 20 letter
September 29-30, 1978	Meeting with applicants to discuss seismology and geology

October 5, 1978	Letter from applicants transmitting "Status Report on the Investigation of the Dewatering System," September 21, 1978
October 18, 1978	Submittal of Amendment No. 12, consisting of responses to letters dated July 26 and August 18, 1978, information to satisfy several commitments, and other revised information
October 24-26, 1978	Meeting with Bechtel Power Corporation to initiate staff audit of seismic and structural analysis of San Onofre 2 and 3
Undated letter (Received 11/8/78)	Letter from applicants advising that the revised security plan is to be submitted by November 20, 1978
November 14, 1978	Letter from applicants transmitting "Status Report on the Investigation of the Dewatering System," October 27, 1978
November 16, 1978	Letter to applicants transmitting Revision 1 of Draft Radiological Effluent Technical Specifications and "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants," NUREG-0133
November 20, 1978	Letter to applicants advising that security pamphlet (TRADOC Pamphlet 350-30) is available without charge
November 29, 1978	Letter from applicants advising that security plans will be submitted December 15, 1978
November 29, 1978	Caseload Forecast Panel visit to site
December 1, 1978	Site visit to discuss dewatering well cavities
December 4-8, 1978	Meeting with Bechtel Power Corporation to conduct staff audit of seismic and structural calculations and the bases therefor
December 12, 1978	Submittal of Amendment No. 13, consisting of responses to requests for information
December 14, 1978	Meeting with applicants to discuss fuel design
December 15, 1978	Meeting with applicants to discuss seismology and geology of site
December 15, 1978	Notice of proposed ACRS Subcommittee Meeting to be held March 21-22, 1979
December 19, 1978	Letter from applicants transmitting revised Security Plans
December 26, 1978	Letter from applicants transmitting "Status Report on the Investigation of the Dewatering System," November 30, 1978

December 27, 1978	Letter from applicants transmitting proprietary data regarding structural design analysis and testing of fuel for San Onofre 2 and 3
December 28, 1978	Letter to applicant authorizing extension of construction completion dates to June 1, 1980 (Unit 2) and June 1, 1981 (Unit 3)
January 3, 1979	Letter from applicants transmitting completed forms for seismic and structural design analysis audit
January 11, 1979	Letter to applicants requesting information that will assist the seismic qualification review team in its site visit
February 2, 1979	Letter from applicants transmitting Amendment 1 to "Fire Hazards Analysis and Comparison with Appendix A of NRC BTP 9.5-1, 10/77"
February 13, 1979	Meeting with applicants to discuss fuel design
February 14, 1979	Meeting with applicants to discuss concerns of Auxiliary Systems Branch and Reactor Systems Branch
February 15, 1979	Letter to applicants transmitting guidance for Offsite Dose Calculation Manual
February 16, 1979	Letter from applicants transmitting "Report on Deep Exploration Drilling Program, Dewatering Well No. 6" and "Report on Exploration/Grouting Program, Dewatering Well No. 6"
February 22, 1979	Notice of cancellation of ACRS Subcommittee meeting scheduled for March 21 - March 22, 1979
February 28, 1979	Letter from applicants transmitting information requested following seismic and structural design analysis audit conducted December 4-8, 1978
March 2, 1979	Letter to applicants transmitting "Summary of Operating Experience with Recirculating Steam Generators," NUREG-0525
March 7-9, 1979	Meeting with applicants to discuss seismic/structural audit open items
March 9, 1979	Letter to Combustion Engineering granting withholding of proprietary information submitted by applicants on December 27, 1978
March 13, 1979	Submittal of Amendment No. 14, consisting of responses to requests for information and requesting exemptions from 10 CFR 50 Appendices G, H, and J
March 15, 1979	Letter to applicants transmitting Safety Evaluation Report open items list and transmitting additional questions and positions

March 16, 1979	Letter from applicants transmitting seismic and geologic information
March 20, 1979	Meeting with applicants to discuss Safety Evaluation Report open items
March 23, 1979	Letter from applicants transmitting Safeguards Contingency Plan
March 23, 1979	Letter from applicants transmitting revised pages for "Physical Security Plan, San Onofre Nuclear Generating Station, Units 1, 2 and 3," December, 1978
March 30, 1979	Letter from applicants transmitting "Status Report on the Investigation of the Dewatering System," March 1979.
April 3-5, 1979	Site visit to discuss and observe site geology
April 26, 1979	Meeting with applicants to discuss fuel design and analysis
April 27, 1979	Meetings with applicants to discuss core protection calculator and fire protection requirements
May 4, 1979	Meeting with applicants to discuss geology
May 8, 1979	Letter from applicants transmitting 1978 Annual Reports for Southern California Edison Company and San Diego Gas & Electric Company
May 16, 1979	Letter from applicants transmitting equipment seismic qualification summary information
May 29, 1979	Letter from applicants transmitting proprietary and nonproprietary fuel design information
June 12, 1979	Meeting with applicants to discuss probability analysis at San Onofre from offsite hazards such as gas pipelines and hazardous transportation
June 13, 1979	Meeting with utilities that have applications pending to discuss (1) staff policies regarding the review of current applications and (2) the criteria for establishing priorities for the review of these applications
June 18, 1979	Submittal of Amendment No. 15, consisting of responses to requests for information and reports entitled "Final Report on Hydraulic Model Studies of Containment Emergency Sump Recirculation Intakes" and "Report on Evaluation of Maximum Earthquake and Site Ground Motion Parameters"
June 28, 1979	Letter from applicants transmitting proprietary and nonproprietary slides of fuel design presented at April 26, 1979 meeting

July 6, 1979	Letter from applicants transmitting proprietary and nonproprietary information and calculations related to the structural design analysis audit
July 11, 1979	Letter from applicants transmitting final reports: (1) "Report on the Exploration/Demobilization of Wells 4 and 5" (2) "Report on Deep Exploration Drilling Program, Dewatering Well No. 7" (3) "Report on Exploration/Grouting Program, Dewatering Well No. 7" and errata sheet
July 12-13, 1979	Meeting with applicants to complete seismic/structural audit
July 17, 1979	Letter from applicants transmitting application to permit partial ownership transfer to City of Anaheim and City of Riverside
July 17, 1979	Letter from applicants transmitting proprietary information regarding drop tests of fuel assembly
July 19, 1979	Meeting with applicants to discuss addition of Cities of Anaheim and Riverside as applicants
July 24-25, 1979	Tour of facility and meeting with applicants to discuss fire protection issues
August 7, 1979	Letter to Combustion Engineering advising that May 29 submittal will be withheld from public disclosure
August 10, 1979	Meeting with applicants to discuss dewatering well demobilization
August 15, 1979	Letter from applicants transmitting "Summary Report of the Investigation/Demobilization of Construction Dewatering Wells"
August 20, 1979	Letter from applicants transmitting information regarding their management and technical capabilities to cope with events like the TMI-2 accident
August 23, 1979	Letter from applicants transmitting security officer training and qualification plan
August 24, 1979	Letter from applicants transmitting additional copies of "Evaluation and Action Plan for San Onofre Nuclear Generating Station Units 2 and 3 Relative to the Three Mile Island Incident," dated August 1979.
August 24, 1979	Letter to applicants concerning secondary water chemistry control
August 27, 1979	Transmittal of affidavit for proprietary slides presented in April 26 meeting

August 29, 1979	Letter from applicants transmitting correspondence regarding small break LOCA report
September 4, 1979	Letter from Southern California Edison Company requesting that SER open items be resolved and that licensing activities for San Onofre 2 be placed back on schedule consistent with issuance of operating license in November 1980
September 12, 1979	Letter from applicants transmitting annotated geophysical lines
September 13, 1979	Meeting with applicants to discuss maximum earthquake associated with offshore zone of deformation
September 18, 1979	Letter from San Diego Gas & Electric Company requesting that Safety Evaluation Report open items be resolved and that licensing activities be placed back on schedule consistent with issuance of an operating license for Unit 2 in November 1980
September 26-27, 1979	Meeting and site visit to observe control room and discuss initial staff review of emergency plan
September 27, 1979	Letter to applicants concerning followup actions resulting from review of TMI-2 accident
October 16, 1979	Submittal of Amendment No. 16, consisting of responses to several open items and information to satisfy several commitments
October 17, 1979	Letter to applicants concerning anticipated transients without scram
October 29, 1979	Letter to applicants transmitting fire protection questions and positions
October 31, 1979	Letter to applicant transmitting emergency planning questions and positions
October 31, 1979	Meeting with applicants to discuss fire protection analysis
November 9, 1979	Letter to applicants providing clarification of lessons-learned short term requirements
November 16, 1979	Meeting with applicants concerning their response to seismological concerns discussed at September 13, 1979 meeting
November 19, 1979	Visit by Caseload Forcecast Panel to review bases for estimate of date of completion of construction of Unit 2
November 20, 1979	Memorandum from applicants transmitting "Report on the Evaluation of Maximum Earthquake and Site Ground Motion Parameters Associated with the Offshore Zone of Deformation"

November 21, 1979	Letter to applicants concerning upgraded Emergency Plan
November 23, 1979	Letter to applicants concerning proposed Revision 2 to Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Condition During and Following an Accident"
November 28, 1979	Letter to applicants transmitting "Cladding Swelling and Rupture Models for LOCA Analysis," NUREG-0630 (draft)
December 5, 1979	Letter to Combustion Engineering advising that information submitted June 28 and August 27 will be withheld from disclosure
December 10, 1979	Letter from applicants transmitting information on emergency planning
December 11, 1979	Letter to applicants transmitting request for additional information regarding safeguards contingency plan
December 13, 1979	Meeting with applicants to discuss Regulatory Guide 1.97
December 19, 1979	Letter from applicants transmitting "Status Report on Followup Actions Resulting from the NRC Staff Reviews Regarding the Three Mile Island Unit 2 Incident," December 1979
December 21, 1979	Letter to applicants transmitting request for additional information
December 21, 1979	Letter to applicants concerning environmental monitoring for direct radiation
December 21, 1979	Letter to applicants advising of regional meetings to be held to discuss proposed change to regulation concerning emergency response plans
December 24, 1979	Submittal of Amendment No. 17, consisting of responses to open items and "Fire Hazards Analysis and Comparison with Appendix A of NRC Branch Technical Position 9.5-1, Amendment 2," October, 1977
December 26, 1979	Letter to applicants transmitting request for information regarding evacuation times
December 28, 1979	Letter from applicants advising of realignment of organizational responsibilities for design, construction and operation of nuclear units
January 21, 1980	Letter from applicants transmitting "Calculations for Reanalysis of Electrical Cable Tunnel Structure" (proprietary) and "Reanalysis of Electrical Cable Tunnels (non-proprietary)
January 21, 1980	Letter from applicants transmitting comments on impact of backfitting proposed Revision 2 to Regulatory Guide 1.97

January 21, 1980	Letter from applicants transmitting information on their environmental qualification program
February 5, 1980	Letter to applicants concerning "Interim Staff Position on Equipment Qualification of Safety-Related Electrical Equipment," NUREG-0588
February 13, 1980	Letter from applicants transmitting generic position developed by group of utilities concerning proposed Revision 2 to Regulatory Guide 1.97
February 13, 1980	Letter to Combustion Engineering advising that documents submitted by applicants on July 17, 1979 will be withheld from public disclosure
February 14, 1980	Letter to Bechtel Power Corporation advising that documents submitted by applicants on January 21, 1980 will be withheld from public disclosure
February 15, 1980	Letter from applicants transmitting responses to questions from Geosciences Branch
February 20-21, 1980	Meeting with applicants to discuss fire protection, auxiliary feedwater system, and post-accident monitoring instruments
February 21, 1980	Letter to applicants concerning qualification of safety-related electrical equipment
February 29, 1980	Letter from applicants transmitting "Simulation of Strong Ground Motions" in response to Geosciences Branch questions
March 4, 1980	Meeting with applicants to discuss responses to staff questions on seismology
March 5, 1980	Meeting with applicants to discuss seismic issues
March 7, 1980	Meeting with Friends of the Earth to discuss emergency preparedness
March 10, 1980	Letter to applicants advising of actions required from operating license applicants of nuclear steam supply systems designed by Westinghouse and Combustion Engineering resulting from Bulletins and Orders Task Force review of TMI-2 accident
March 10, 1980	Letter to applicants transmitting "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants (For Interim Use and Comment)" NUREG-0654/FEMA-REP-1
March 11, 1980	Letter to applicants advising of change of submittal date for evacuation time estimates
March 20, 1980	Letter to applicants transmitting request for additional information

March 28, 1980	Letter to applicants regarding qualifications of reactor operators
April 1, 1980	Letter from applicants transmitting information to be used in confirmatory piping analysis
April 18, 1980	Letter from applicants transmitting photographs of LANDSAT photos of southern California
April 18, 1980	Letter from applicants transmitting data on which review will be based regarding seismic reflection profiles within 25 km of San Onofre
April 21, 1980	Letter to applicants requesting information on Category 1 masonry walls
April 23, 1980	Letter from applicants requesting extension of Construction Permit completion dates to April 15, 1981 and June 15, 1982 for Units 2 and 3, respectively
April 25, 1980	Letter to applicants providing clarification of NRC requirements for emergency response facilities
April 25, 1980	Letter to applicants requesting response to staff comments on Guard Training and Qualification Plan
May 12, 1980	Submittal of Amendment No. 18, consisting of responses to open items and Amendment No. 3 to "Fire Hazards Analysis and Comparison with Appendix A of NRC Branch Technical Position 9.5-1, October, 1977"
May 12, 1980	Letter from applicants transmitting "Offshore Geophysical Maps"
May 15, 1980	Meeting with applicants to discuss condensate storage tank, auxiliary feedwater reliability, and third auxiliary feedwater pump
May 20, 1980	Meeting with applicants and USGS to discuss need for additional offshore seismic profiles near site
May 20, 1980	Letter to applicants forwarding additional guidance on "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," NUREG-0577
May 21, 1980	Meeting with applicants and USGS to discuss need for additional offshore exploration in vicinity of site
May 22, 1980	Letter from applicants transmitting Annual Financial Reports
May 23, 1980	Letter to applicant transmitting request for additional information
May 28, 1980	Letter to Bechtel Power Corporation advising that information submitted by applicants on July 6, 1979 will be withheld from public disclosure

May 28-29, 1980	Meeting with applicants to discuss open items relating to (1) analysis of reactor internals, (2) load combination methods, (3) confirmatory piping analysis, and (4) implementation of design criteria for shutdown systems
May 30, 1980	Letter from applicants regarding recent meeting and reiterating need for Unit 2 to begin loading fuel on April 15, 1981
June 6, 1980 (received)	Letter from applicants regarding staff requests for offshore geophysical data
June 11, 1980	Letter from applicants transmitting geological information, including Oceanographic Services geophysical data
June 13, 1980	Letter to applicants concerning reorganization of NRR
June 16, 1980	Letter to applicants transmitting request for additional information
June 16, 1980	Letter from applicants transmitting financial information
June 18, 1980	Letter from applicants transmitting piping design information to be used in connection with audit of confirmatory piping analysis
June 20, 1980	Letter from applicants transmitting additional geophysical data offshore from San Onofre
June 24, 1980 (received)	Letter from applicants advising that there are no masonry walls in Seismic Category I plant structures for San Onofre
June 24, 1980	Letter to applicants concerning underclad cracking in reactor vessel nozzles
June 26, 1980	Letter to applicants providing further Commission guidance for power reactor operating licenses (re NUREG-0694)
June 27, 1980	Letter from applicants transmitting additional information relative to their submittal of May 12, 1980, and logs of two onshore borings
June 30, 1980	Letter to applicants transmitting <u>Federal Register</u> Notice regarding regional meetings to be held to discuss requirements for environmental qualification of electrical equipment
July 1, 1980	Letter from applicants transmitting information in response to a question in geosciences area and transmitting logs from six vibratory core holes taken offshore of the site
July 2, 1980	Meeting with applicants to discuss condensate storage water capacity following a Safe Shutdown Earthquake

July 2, 1980	Meeting with applicants to discuss control room design review program
July 2, 1980	Letter to applicants transmitting request for information regarding evacuation times
July 11, 1980	Letter to applicants requesting best estimate of construction completion date and fuel load target date
July 16, 1980	Letter from applicants transmitting response to questions concerning design calculations of Unit 3 electrical tunnel
July 22, 1980	Letter from applicants forwarding information on potential for underclad cracking in reactor vessel nozzles
July 24, 1980	Meeting with applicants to discuss results of analysis of October 1979 Imperial Valley earthquake using Unit 1 analytical modeling technique
July 28, 1980	Letter to applicants transmitting request for additional information
July 29, 1980	Letter from applicants transmitting "Interpretative Results, High Resolution Geophysical Survey In Selected Areas Between Dana Point and Oceanside, Offshore California," July 28, 1980
July 31, 1980	Letter to applicants concerning interim criteria for shift staffing
August 1, 1980	Letter to applicants providing information on and transmitting copy of "Functional Criteria for Emergency Response Facilities," NUREG-0696
August 1, 1980	Letter from applicants transmitting response to requests for information, "Summary Report on Basic Data From Two Onshore and Six Offshore Geologic Borings," and supplemental information to June 27 submittal
August 4, 1980	Letter from applicants transitting "QA Program," SCE-1-A, Amendment 3
August 4-8, 1980	Meeting with applicants to conduct on-site review of control room design and operation
August 5, 1980	Letter from applicants transmitting response to question concerning design calculations for Unit 3 electrical tunnel
August 5, 1980	Letter to applicants transmitting Order extending construction completion dates to April 15, 1981 and June 15, 1982 for Units 3 and 3, respectively
August 5, 1980	Issuance of Amendment No. 2 to Construction Permits CPPR-97 and CPPR-98 to permit transfer of partial ownership to Cities of Riverside and Anaheim
August 12-15, 1980	Meetings with applicant to discuss non-TMI related open items

August 13, 1980	Submittal of Amendment No. 19, consisting of responses to several open items, responses to additional questions, and other information
August 13, 1980	Letter from U.S. Geological Survey transmitting "Review of Offshore Seismic Reflection Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California
August 13, 1980	Letter from applicants transmitting input data used in CESEC and TORC computer codes for analysis of several steam line and feedline breaks, CEN-127(S)-P (proprietary and nonproprietary versions)
August 14, 1980	Meeting with applicants to discuss results of recent offshore investigations near site
August 14, 1980	Letter from applicants transmitting "Simulation of Earthquake Ground Motions for San Onofre Nuclear Generating Station, Unit 1, Final Report," May 1978 and Supplements I, II & III, dated July, 1979, August, 1980 and August, 1980
August 15, 1980	Letter to applicants transmitting letters from California Division of Mines and Geology dated August 11 and August 12, 1980 and letter from U.S. Geological Survey dated August 13, 1980
August 18, 1980	Letter from applicants forwarding revised emergency plan
August 19, 1980	Letter from applicants advising that estimated construction completion date (and fuel load target date) for Unit 2 is April 15, 1981
August 21, 1980	Letter from applicants transmitting "Evaluation of Peak Horizontal Ground Acceleration Associated With the Offshore Zone of Deformation at San Onofre Nuclear Generating Station"
August 22, 1980	Letter from applicants transmitting information concerning origin of folds and faults found offshore and south of site
August 28, 1980	Letter from applicants transmitting revised Safeguards Contingency Plan
September 3, 1980	Letter from applicants transmitting "CPC/CEAC Software Modifications for San Onofre Unit 2" (proprietary and nonproprietary versions)
September 3, 1980	Letter from applicants transmitting "Security Force Training and Qualification Plan, San Onofre Nuclear Generating Station, Units 1, 2, and 3, August 1979, Revision 1, September 1980"
September 5, 1980	Letter to applicants providing preliminary clarification of TMI-2 Action Plan requirements

September 9, 1980	Meeting with Combustion Engineering and applicants to discuss audit of CENPD-178 analysis methods
September 9-10, 1980	Caseload Forecast Panel site visit to update NRC estimate of date of construction completion
September 9-11, 1980	Meeting with applicants to conduct electrical site visit
September 10, 1980	Meeting with applicants and Combustion Engineering to discuss questions on CENPD-178
September 12, 1980	Submittal of Amendment No. 20, consisting of responses to "TMI-Related Requirements for New Operating Licenses," NUREG-0694
September 19, 1980	Letter to applicants transmitting errata sheets and corrected table for September 5 letter
September 23, 1980	Meeting with applicants to discuss seismology and geology
September 25-26, 1980	Site tour and meeting with applicants to discuss resolution of certain open items
September 29, 1980	Letter from applicants forwarding responses to questions
September 30-October 2, 1980	Meeting with applicants to review seismic qualifications of electrical and mechanical equipment
October 1, 1980	Letter to applicants concerning environmental qualification of safety-related equipment
October 6, 1980	Letter from applicants transmitting responses to questions related to preservice and inservice inspection and testing
October 6, 1980	Letter to applicants regarding implementation of guidance from Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports"
October 8, 1980	Letter from applicants transmitting geological information
October 8, 1980	Letter from applicants transmitting magnetic tape of hourly meteorological data and other meteorological data
October 20, 1980	Meeting with applicants to discuss completion dates and review matters for state and local emergency plans for site and vicinity

October 29, 1980	Letter from applicants transmitting applicants' responses to audit findings as a result of audit performed by NRC's Human Factors Engineering Branch
October 31, 1980	Letter to applicants forwarding "Clarification of TMI Action Plan Requirements," NUREG-0737
November 5, 1980	Letter from D. B. Slemmons (consulting geologist) reporting on his review of seismic design parameters
November 7, 1980	Letter to applicants transmitting request for additional information
November 12, 1980	Letter from applicants transmitting emergency operating instructions
November 13, 1980	Letter to applicants regarding final regulations on emergency planning
November 14, 1980	Letter from applicants transmitting conformed copies of Participation Agreement for ownership of facility
November 14, 1980	Letter to applicants providing clarification of TMI-related requirements for new operating licenses-requirements for training during low power testing
November 14, 1980	Submittal of Amendment No. 21, consisting of responses to open items and requests for information to satisfy commitments
November 18, 1980	Letter from applicants forwarding "Data Transmittal for SCE Fuel Audit Analysis," CEN-140(S) (proprietary and nonproprietary versions)
November 18, 1980	Letter from applicants transmitting insert pages for fuel handling building calculations submitted July 6
November 24, 1980	Letter from applicants forwarding "Auxiliary Feedwater System Design Review and Reliability Evaluation for San Onofre Nuclear Generating Station, Units 2 & 3, October 1980"
November 25, 1980	Letter from applicants transmitting "Secondary Water Chemistry Monitoring Program for San Onofre Nuclear Generating Station, Units 2 & 3"
November 25, 1980	Letter to applicants regarding Commission Memorandum and Order of May 23, concerning safety-related electrical equipment qualification
November 26, 1980	Letter from applicants transmitting responses to several questions forwarded November 7, 1980
November 26, 1980	Letter from San Diego Gas & Electric Company advising that (1) Southern California Edison will provide description of revised organization and (2) addressee has new title

November 26, 1980	Letter from U.S. Geological Survey forwarding results of review of San Onofre 2 & 3 geologic and seismologic data
November 26, 1980	Letter from applicants transmitting proposed Appendix A Technical Specifications
November 26, 1980	Letter to applicants providing clarification of Orders on environmental qualification of safety-related electrical equipment
December 1, 1980	Letter from applicants providing information on environmental qualification tests under consideration for performance within next two years
December 4, 1980	Letter from D. B. Slemmons providing corrections for November 5 letter
December 8, 1980	Letter from applicants transmitting (1) responses to questions and schedule commitments for remaining questions and (2) "Southern California Pressurizer-Brittle Fracture Evaluation," Calc. No. PRS-705
December 9, 1980	Letter from applicants transmitting revised Section 4.0 of "Water Tight Reliability of Condensate Storage Tank and Its Concrete Enclosure Walls Under DBE and Tornado Event"
December 9, 1980	Letter to applicants forwarding "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," NUREG-0654/ FEMA-REP-1, November 1980, and other related information
December 15-18, 1980	Meeting with applicants to discuss TMI and non-TMI open items
December 18, 1980	Letter from XYZYX Information Corporation forwarding preliminary report on emergency procedures
December 22, 1980	Letter to applicants transmitting "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, related staff position, and request for additional information on control of heavy loads
December 23, 1980	Letter from applicants transmitting listing of open items, identifying actions to be taken by applicants and NRC staff
December 31, 1980	Issuance of Safety Evaluation Report on seismological and geological matters
December 31, 1980	Letter to Combustion Engineering advising that proprietary information on fuel audit analysis submitted November 18 will be withheld from public disclosure

December 31, 1980	Letter to Combustion Engineering advising the proprietary information on CPC/CEAC Software Modifications submitted September 3 will be withheld from public disclosure
January 6, 1981	Letter to Combustion Engineering advising that proprietary information on CESEC and TORC computer codes related to steam line and feedwater breaks submitted August 13 will be withheld from public disclosure
January 9, 1981	Letter from applicants transmitting response to several open items and questions
January 12, 1981	Letter from applicants transmitting Revision 1 to December 23 letter, updating the list to reflect open items which have been resolved as of January 12
January 14, 1981	Letter from applicants transmitting response to several open items and questions
January 15, 1981	Meeting with applicants to discuss explosion probabilities
January 19, 1981	Letter from applicants transmitting "Functional Design Specification for a Control Element Assembly Calculator," CEN-148(S)-P (proprietary)

APPENDIX B

BIBLIOGRAPHY

Section 2.4 - Hydrology

U.S. Department of Commerce, NOAA, "Tide Tables 1978 West Coast of North America."

U.S. Army Coastal Engineering Research Center, "Shore Protection Manual", 1977.

Chow, Ven Te, "Open Channel Hydraulics", McGraw-Hill Book, Co., 1959.

Daily, J. W., Harleman, D. R. F., "Fluid Dynamics" 1966.

Loomis, H. G., "Report on the Propagation of a Tsunami to the Shoreline at San Onofre, California" NOAA, June 1973.

Hydrometeorological Branch, National Weather Service, "Probable Maximum Thunderstorm Precipitation Estimates - Southwest States" August 1972, Revised March 30, 1973.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants."

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants."

ANSI N170, "Standards for Determining Design Basis Flooding at Power Reactor Sites."

U.S. Nuclear Regulatory Commission, "Standard Review plan for the Review of Safety Analysis Reports for Nuclear Power Plants," USNRC Report NUREG-75/087, Section 2.4.

Sections 2.5 - Geology, Seismology, and Geotechnical Engineering

Abbott, P. L. and Gastil, R. G. 1979, Baja California Geology - Field Guide and Papers, Department of Geological Sciences in San Diego State University, San Diego, California.

Anderson, J. G., 1979, Estimating the Seismicity from Geologic Structure for Seismic-Risk Studies: Bulletin of the Seismological Society of America, V. 69, p.135-158.

Angstman, B. G., Spudis, P. F. K, and Fletcher, J., 1979, The Coyote Lake Earthquake: 0.42g Acceleration from an S-P Converted Phase: EOS, Transactions, American Geophysical Union, V.60, p. 890.

Archuleta, R. J., 1980, 3-D Near Field Modeling and Strong Motion Prediction in a Layered Medium, in U.S. Geological Survey. Program Statement for Fiscal Year 1980: Geologic and Seismologic Research Related to Environmental Safety of Nuclear Facilities Sites for Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, p. 4-6.

- Barrows, Allan G., 1974, A Review of the Geology and Earthquake History of the Newport-Inglewood Structural Zone, Southern California, CDMG Special Report 114.
- Biehler, S., 1975, Seimologic Investigations of the San Juan Capistrano Area, Orange County California, in Recent Geotechnical Studies Southern Orange County, California, Volume 2, Southern California Edison Company and San Diego Gas and Electric Company, February 1976.
- Bonilla, M. G., 1980, Comment on 'Estimating Maximum Expectable Magnitudes of Earthquakes from Fault Dimensions:' Geology V. 8, pp. 162-163.
- Boore, D. M., Joyner, W. B., Oliver, A. A., and Page, R. A., 1978, Estimation of Ground Motion Parameters, U.S. Geological Survey Circular 795, 43 pages.
- Boore, D. M. and Fletcher, J. B., 1980, A Preliminary Study of Selected Aftershocks of the 1979 Imperial Valley Earthquake from Digital Acceleration and Velocity Recordings, in Selected Papers on the Imperial Valley, California, Earthquake of October 15, 1979, U.S. Geological Survey Open-File Report 80-1094 pp. 43-67.
- Crouch, James K., 1979, Neogene Tectonic Evolution of the California Continental Borderland and Western Transverse Ranges, GSA Bull., Part 1, V. 90, p. 338-345.
- Day, S.M., 1979, Three Dimensional Finite Difference Simulation of Fault Dynamics: Systems, Science, and Software, SSS-R-80-4295, Final Report Sponsored by: National Aeronautics and Space Administration, Ames Research Center, December, 1979.
- Del Mar Technical Associates, 1978, Simulation of Earthquake Ground Motions for the San Onofre Nuclear Generating Station -- Unit 1, May 1978, Final Report.
- Del Mar Technical Associates, 1979a, Simulation of Earthquake Ground Motions for San Onofre Nuclear Generating Station -- Unit 1, Supplement 1, July 1979.
- Del Mar Technical Associates, 1979b, Earthquake Ground Motion Simulations for San Onofre -- Unit 1 Response to Proposed Task 4, September 1979.
- Del Mar Technical Associates, 1980a, Simulation of Earthquake Ground Motion for San Onofre Nuclear Generating Station Unit 1, Supplement II, August 1980.
- Del Mar Technical Associates, 1980b, Simulation of Earthquake Ground Motions for San Onofre Unit 1 Supplement III, August 1980.
- Ehlig, P.L., 1977, Geologic Report on the Area Adjacent to the San Onofre Nuclear Generating Station, Northwestern San Diego County, California.
- Esteve, L., 1970, Seismic Risk and Seismic Design Decisions; in Hansen, R. J., eds., Seismic Design for Nuclear Power Plants, MIT Press, Cambridge, Mass., pp. 142-182.
- Fife, D. I., 1974, Geology of the South Half of the El Toro Quadrangle Orange County, California. California Division of Mines and Geology. Special Report 110.

Fugro, Inc., 1977, Supplemental Report of Geologic Investigations, Trail Six Landslide (Area 1), Southeast of San Onofre Nuclear Generating Station, prepared for Southern California Edison Company;

_____, 1976, Final Report on Geologic Features at the San Onofre Nuclear Generating Station, Units 2 & 3;

_____, 1975, Geologic Investigations of the Bulldozer Excavation at the Proposed Viejo Substation Site;

_____, July 5, 1974, Analysis of Geologic Features at the San Onofre Nuclear Generating Station;

_____, November 1, 1974, Analysis of C and D Type Features at the San Onofre Nuclear Generating Station.

Gastil, R. G., Kies, R., and Melius, D. J., 1979, Active and Potentially Active Faults; San Diego County and north-western-most Baja California, *in* Abbott, P. L., and Elliott, W. J., eds., Earthquakes and Other Perils, San Diego region: San Diego Association of Geologists for Geological Society of America, Field Trip Guidebook, pp. 47-60.

Greene, H. G., Bailey, K. A., Clarke, S. H., Ziony, J. I., and Kennedy, M. P., November 1979, Implications of Fault Patterns of the Inner California Continental Borderland Between San Pedro and San Diego, *in* Abbott, P. L., and Elliot, W. J, eds., Earthquakes and Other Perils, San Diego Region: San Diego Association of Geologists for Geological Society of America, Field Trip Guidebook.

Gutenberg, B. and Richter, C., 1942, Earthquake Magnitude, Intensity, Energy and Acceleration. Bulletin of the Seismological Society of America, V. 32, pp. 163-192.

Hadley, D. M., and Helmberger, D. V., 1980, Simulation of Strong Ground Motions: Bulletin of the Seismological Society of America, V. 70, pp. 617-630.

Hanks, T. C., Hileman, J. A., and Thatcher, W., 1975, Seismic Moments of the Larger Earthquakes of the Southern California Region: Geological Society of America Bulletin, V. 86, pp. 1131-1139.

Harding, T. P. 1973, Newport-Inglewood Trend, California - An Example of Wrenching Style of Deformation, AAPG Bull, V. 57, No. 1, pp. 97-116.

Hartzell S., 1980, Faulting Process of the May 17, 1976 Gazli, USSR, Earthquake: Bulletin of the Seismological Society of America, V. 70, pp. 1715-1736.

Jennings, P. C., and Kanamori, H. 1979, Determination of Local Magnitude, M_L , from Seismoscope Records: Bulletin of the Seismological Society of America, V. 69, pp. 1645-1670.

Kanamori, H., 1978, Qualification of Earthquakes, Nature, V. 271, pp. 411-414.

Kanamori, H., 1979, A Semi-empirical Approach to Prediction of Long Period Motions from Great Earthquakes: Bulletin of the Seismological Society of America, V. 69, pp. 1645-1670.

Kanamori, H., and Jennings, P. C., 1978, Determination of Local Magnitude M_L , from Strong-Motion Accelerograms. Bulletin of the Seismological Society of America, V. 68, pp. 471-485. Rams.

Krinitzky, E. L., and Chang, F. K., 1975, Earthquake Intensity and the Selection of Ground Motions for Earthquake Design; Report 4, State-of-the-Art for Assessing Earthquake Hazards in the United States, Miscellaneous Paper S-73-1, U.S. Army Engineer Waterways Experiment Station, Vicksburg, Miss.

Legg, Mark R., and Kennedy, Michael, P., November 1979, Faulting Offshore San Diego and Northern Baja California, in Abbott, P. L., and Elliot, W. J., eds., Earthquakes and Other Perils, San Diego Region: San Diego Association of Geologists for Geological Society of America, Field Trip Guidebook.

Morton, P. K., Edgington, William J., and Fife, Donald L., 1974, Geology and Engineering Geologic Aspects of the San Juan Capistrano Quadrangle, Orange County, California, California Division of Mines and Geology, Special Report 112.

Nason, R., 1978, Seismic Intensities in the 1906 Earthquake Fault Zone: Earthquake Notes, V. 49, No. 1, p. 1.

Nuttli, O., 1979, The Relation of Sustained Maximum Ground Acceleration and Velocity to Earthquake Intensity and Magnitude: Report 16, State-of-the-Art for Assessing Earthquake Hazards in the United States, Miscellaneous Paper S-73-1, U.S. Army Engineer Waterways Experiment Station, Vicksburg, Miss.

Richter, C., 1958, Elementary Seismology, W. H. Freeman and Company San Francisco, California.

Shlemon, Roy J. 1978, Late Quaternary Evolution of the Camp Pendleton-San Onofre State Beach Coastal Area, Northwestern San Diego County, California;
_____, 1978, Late Quaternary Rates of Deformation, Laguna Beach - San Onofre State Beach, Orange and San Diego Counties, California.

Slemmons, D. B., 1977, Faults and Earthquake Magnitude: Report 6, State-of-the-Art for Assessing Earthquake Hazards in the United States, Miscellaneous Paper S-73-1, U.S. Army Engineer Waterways Experiment Station, Vicksburg, Miss.

Southern California Edison Company, 1976, Recent Geotechnical Studies, Southern Orange County, California, Vol. 1.

Swanger, H. J., Murphy, J. R., Bennett, T. J., and Guzman, R., 1980, State-of-the-Art Concerning Near-Field Earthquake Ground Motion; Annual Report September 1978 - September 1979, NUREG/CR-1340.

TERA Corporation, 1980, Evaluation of Peak Horizontal Ground Acceleration Associated with the Offshore Zone of Deformation at San Onofre Nuclear Generating Station: Submitted to Southern California Edison Co. August 1980.

Tocher, D., and Hobgood, J., 1978, Landslides and Other Disturbances Associated with Earthquakes and the Modified Mercalli Intensity Scale of 1931; Earthquake Notes, V. 49, No. 1, p. 20.

Topozada, T. R., 1975, Earthquake Magnitude as a Function of Intensity Data in California and Western Nevada; Bulletin of the Seismological Society of America, V. 65, pp. 1223-1238.

Topozada, T. R., Real, C. R., Bezore, S. P., and Parke, D. L., 1979, Compilation of Pre-1900 California Earthquake History; Annual Technical Report - Fiscal Year 1978-79, Open File Report 79-6 SAC (Abridged Version) California Division of Mines and Geology.

U. S. Nuclear Regulatory Commission, 1975, Safety Evaluation of the Geologic Features at the Site of the San Onofre Nuclear Generating Station.

U. S. Atomic Energy Commission, 1972, Safety Evaluation of the San Onofre Nuclear Generating Station Units No. 2 & 3, Docket Nos. 50-361, 50-362.

West, Jack C., 1975, Generalized Sub-surface Geological and Geophysical Study, Capistrano Area, Orange County, California.

West, Jack C., 1979, Supplement to the Generalized Sub-surface Geological and Geophysical Study Capistrano Area, Orange County, California.

Whitcomb, J. H., 1979, Seismic Mapping and Monitoring of Earthquake Hazard in the Vicinity of San Onofre, California; Final Report October 1, 1974 - December 31, 1977, NUREG/CR0502.

Woodward-Clyde Consultants, 1979, Report of the Evaluation of Maximum Earthquake and Site Ground Motion Parameters Associated with the Offshore Zone of Deformation, San Onofre Nuclear Generating Station: Report for Southern California Edison Company, June 1979.

Wyss, M., 1979, Estimating Maximum Expectable Magnitude of Earthquakes from Fault Dimensions: Geology, V.7, pp. 336-340.

Section 3.3 - Wind and Tornado Loadings

"Wind Forces on Structures", Final Report of the Task Committee on Wind Forces of the Committee on Load and Stresses of the Structural Division, Transactions of the American Society of Civil Engineers, 345 East 47th Street, New York, N.Y., 10017, Paper No. 3269, Vol. 126, Part II, 1961, P. 1124-1198.

Section 3.5 - Missile Protection

A. Amirikian, "Design of Protective Structures," Bureau of Yards and Docks, Publication No. NAVDOCKS P.-51, Department of the Navy, Washington, D.C., August 1950.

Williamson, R. A., and Alvy, R. R., "Impact Effect of Fragments Striking Structural Elements", Holmes and Narver, Revised Edition, 1973.

Section 3.7 - Seismic Design

USAEC Regulatory Guide 1.60, "Design Response Spectra for Nuclear Power Plants".

USAEC Regulatory Guide 1.61, "Damping Values for Seismic Analysis of Nuclear Power Plants".

USAEC Regulatory Guide 1.12, "Instrumentation for Earthquakes".

Section 3.8 - Design of Category I Structures

American Institute of Steel Construction, "Specification for Design, Fabrication & Erection of Structural Steel for Buildings, 101 Park Avenue, New York N.Y. 10017, Sixth Edition, 1969.

American Concrete Institute, "Building Code Requirements for Reinforced Concrete" (ACI 318-1971), P.O. Box 4754, Redford Station, Detroit, Michigan 48219.

American Society of Mechanical Engineers, "ASME Boiler and Pressure Vessel Code," Section III, and Addenda. United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.

Letter from Burton L. Lex of Bechtel Power Corp. to Robert B. Minogue with attachments, dated May 6, 1976.

Letter from Robert B. Minogue of NRC to Burton Lex dated July 27, 1976.

Section 4.2 - Fuel System Design

"Safety Evaluation Report Related to Operation of Arkansas Nuclear One, Unit 2," USNRC Report NUREG-0308, November 1977. Available from the NRC Division of Technical Information and Docket Control.

M. G. Andrews, "Densification of Combustion Engineering Fuel," Combustion Engineering Report CENPD-118, June 1974.

R.O. Meyer, "The Analysis of Fuel Densification," USNRC Report NUREG-0085, July 1976. Available from the NRC Division of Technical Information and Docket Control.

"Fuel Evaluation Model," Combustion Engineering Report CENPD-139-A, July 1974.

R. O. Meyer, C. E. Beyer, and J. C. Voglewede, "Fission Gas Release from Fuel at High Burnup," USNRC Report NUREG-0418, March 1978. Available from the NRC Division of Technical Information and Docket Control.

"CEPAN Method of Analyzing Creep Collapse of Oval Cladding," Combustion Engineering Report CENPD-187-A, March 1976.

"16x16 Fuel Assembly Flow Test," Combustion Engineering Report, PED-76-003-NP, December 1976.

Letter from D. H. Williams, Arkansas Power and Light Company, to J. F. Stolz, NRC, Subject: Fuel Assembly Flow Tests, April 25, 1977.

Memorandum from D. Ross, NRC, to D. B. Vassallo, "SER Supplement--Arkansas Nuclear One, Unit 2," June 20, 1977.

Letter from A. E. Scherer, Combustion Engineering to V. Stello, NRC, LD-77-122, December 23, 1977.

Letter from W. P. Johnson, Maine Yankee Atomic Power Company, to V. Stello, NRC, February 14, 1978.

Letter from A. E. Lundvall, Baltimore Gas and Electric Company, to V. Stello, NRC, February 17, 1978.

B. L. Siegel, "Evaluation of the Behavior of Waterlogged Fuel Rod Failures in LWRs," USNRC Report NUREG-0303, March 1978. Available from the NRC Division of Technical Information and Docket Control.

"C-E Burnable Poison Irradiation Test Program," Combustion Engineering Report CEN-50, March 1977.

N. Fuhrman and D. B. Scott, "Cladding Damage Analysis of Maine Yankee Core II Burnable Poison Rods," Combustion Engineering Report CEN-77 (M)-P, January 1978.

"Safety Evaluation Report Related to Operation of Arkansas Nuclear One, Unit 2," Supplement 2, USNRC Report NUREG-0308, September 1978. Available from the NRC Division of Technical Information and Docket Control.

"Fuel and Poison Rod Bowing," Combustion Engineering Report CENPD-225, October 1976.

Memorandum from D. F. Ross and D. G. Eisenhut, NRC, to D. B. Vassallo and K. R. Goller, "Interim Safety Evaluation Report on the Effects of Fuel Rod Bowing in Thermal Margin Calculations for Light Water Reactors," December 8, 1976. Available in NRC PDR for inspection and copying for a fee.

Memorandum from D. F. Ross and D. G. Eisenhut, NRC, to D. B. Vassallo and K. R. Goller, "Revised Interim Safety Evaluation Report on the Effects of Fuel Rod Bowing in Thermal Margin Calculations for Light Water Reactors," February 16, 1977. Available in NRC PDR for inspection and copying for a fee.

"Structural Analysis of Fuel Assemblies for Combined Seismic and Loss-of-Coolant Accident Loading," Combustion Engineering Report CENPD-178, August 1976.

"Zircaloy Growth In-Reactor Dimensional Changes In Zircaloy-4 Fuel Assemblies," Combustion Engineering Report CENPD-198, December 1975.

Letter from K. Kniel, NRC, to A. E. Scherer, Combustion Engineering, June 22, 1976.
Available in NRC PDR for inspection and copying for a fee.

"Zircaloy Growth Application of Zircaloy Irradiation Growth Correlations for the Calculation of Fuel Assembly and Fuel Rod Growth Allowances," Combustion Engineering Report CENPD-198, Supplement 1, December 1977.

Letter from R. L. Baer, NRC, to A. E. Scherer, Combustion Engineering, Subject: Request for Additional Information on Topical Report CENPD-198-P Supplement No. 1, August 28, 1978.
Available in NRC PDR for inspection and copying for a fee.

"Response to Request for Additional Information on CENPD-198-P, Supplement 1," Combustion Engineering Report CENPD-198, Supplement 2-P, November 1, 1978.

Letter from R. L. Baer, NRC, to A. E. Scherer, Combustion Engineering, August 21, 1979.
Available in NRC PDR for inspection and copying for a fee.

Arkansas Power and Light Company, "Arkansas Nuclear One, Unit 2 Final Safety Analysis Report," p. 4.2-7a, Docket 50-368, May 25, 1977. Available in NRC PDR for inspection and copying for a fee.

Memorandum from R. P. Denise, NRC, to R. J. Mattson, "Summary Minutes of Meeting on Cladding Rupture Temperature, Cladding Strain, and Assembly Flow Blockage," November 20, 1979.
Available in NRC PDR for inspection and copying for a fee.

D. A. Powers and R. O. Meyer, "Cladding Swelling and Rupture Models for LOCA Analysis," NRC Report NUREG-0630, April 1980. Available from the NRC Division of Technical Information and Docket Control.

Letter from D. G. Eisenhut, NRC, to all Operating Light Water Reactors, dated November 9, 1979. Available in NRC PDR for inspection and copying for a fee.

Memorandum from H. R. Denton, NRC, to Commissioners, "Potential Deficiencies in ECCS Evaluation Models," November 26, 1979. Available in NRC PDR for inspection and copying for a fee.

U.S. Nuclear Regulatory Commission, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - LWR Edition," USNRC Report NUREG-75/087, Section 4.2, "Fuel System Design," Rev. 1. Available for purchase from National Technical Information Service, Springfield, Virginia 22161.

U.S. Government Printing Office, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors," Part 50.46, Title 10 Energy, Code of Federal Regulations, January 1, 1979. Available from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.

U.S. Government Printing Office, "General Design Criteria for Nuclear Power Plants," Part 50, Appendix A, Title 10 Energy, Code of Federal Regulations, January 1, 1979. Available from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.

U.S. Government Printing Office, "ECCS Evaluation Models," Part 50, Appendix K, Title 10 Energy, Code of Federal Regulations, January 1, 1979. Available from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors." Copies are available from U.S. Government Printing Office, Washington, D.C. 20402. ATTN: Regulatory Guide Account.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors." Copies are available from U.S. Government Printing Office, Washington, D.C. 20402. ATTN: Regulatory Guide Account.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors." Copies are available from U.S. Government Printing Office, Washington, D.C. 20402. ATTN: Regulatory Guide Account.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." Copies are available from U.S. Government Printing Office, Washington, D.C. 20402. ATTN: Regulatory Guide Account.

U.S. Nuclear Regulatory Commission, Regulatory Guide 1.126, "An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification," Rev. 1. Copies are available from U.S. Government Printing Office, Washington, D.C. 20402. ATTN: Regulatory Guide Account.

Section 4.4 - Thermal and Hydraulic Design

Letter: O. D. Parr to A. E. Scherer, Topical Report Evaluation, CENPD-162, "Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids; Part 1, Uniform Axial Power Distribution, Supplement No. 1, May 1976.

Letter: O. D. Parr to A. E. Scherer, Review of CENPD-190, CEA Ejection, CE Method for Control Element Assembly Ejection Analysis, June 10, 1976.

Letter: D. B. Vassall to A. E. Scherer, June 12, 1978 (Rod Bow)

CENPD-207, "Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Spacer Grids, Part 2, Non-Uniform Axial Power Distributions," June 1976.

Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

Federal Register 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Plants," July 7, 1971.

Federal Register 10 CFR Part 50 § 50.55a, "NRC Codes and Standard Rules - Applicable Codes, Addenda, and Code Cases 'In Effect' for Components that are Part of the Reactor Coolant Pressure Boundary." June 12, 1971.

"Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 2, September 1975.

Section 5.2.3 - Reactor Coolant Pressure Boundary Materials

ASME Boiler and Pressure Vessel Code, Section III, 1971, Edition, including Summer Addenda 1974:

- a. Paragraph NB-2121: Permitted Material Specifications
- b. Paragraph NB-2122: Special Requirements Conflicting with Permitted Material Specifications
- c. Specifications for Materials Listed in Tables 1-1.1, 1-1.2, and 1-1.3.

ASME Boiler and Pressure Code, Section II, 1971 Edition, including Summer Addenda 1974.

NRC Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," May 1973.

10 CFR Part 50 - Appendix G, "Fracture Toughness Requirements," June 1, 1973.

ASME Boiler and Pressure Vessel Code, Section III, through 1974 Summer Addenda including Appendix G, "Protection Against Non-Ductile Failure."

ASME Specification, SA 370-71b, "Methods and Definitions for Mechanical Testing of Steel Products," ASME Boiler and Pressure Code, Section II, Part A - Ferrous, 1971 Edition, including Summer, 1974 Addenda.

ASTM E 23-73, "Notched Bar Impact Testing of Metallic Materials," Annual Book of ASTM Standards, Part 31, July 1973.

ASTM E 208-69, "Standard Method for Conducting Dropweight Test to Determine Nilductility Transition Temperature of Ferritic Steels," Annual Book of ASTM Standards, Part 31, July 1973.

NRC Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low Alloy Steel," May 1973.

NRC Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants," March 16, 1973.

NRC Technical Position MTEB 5-1, "Interim Position on Regulatory Guide 1.31. "Control of Ferrite Content of Stainless Steel Weld Metal."

NRC Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel," February 23, 1973.

NRC Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants", March 16, 1973.

NRC Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel," May 1973.

NRC Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," May 8, 1973.

NRC Regulatory Guide 1.71, "Welder Qualification for Limited Accessibility Areas," December 1973.

NRC Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," March 10, 1971.

ASTM A 262-70, Practice E, "Copper-Copper Sulfate-Sulfuric Acid Test for Detecting Intergranular Attack in Austenitic Stainless Steel," Annual Book of ASTM Standards, Part 3, April 1973.

ASTM A 393-63, "Recommended Practice for Conducting Acidified Copper Sulfate Test for Intergranular Attack in Austenitic Stainless Steel," Annual Book of ASTM Standards, Part 3, April 1973.

ANSI N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components during the Construction Phase of Nuclear Power Plants," Draft 2, Revision 0, November 15, 1973, American National Standards Institute.

Section 9.0 Auxiliary Systems

10 CFR Part 50, Appendix A, General Design Criterion 1, "Quality Standards and Records."

10 CFR Part 50, Appendix A, General Design Criterion 2, "Design Bases for Protection Against Natural Phenomena."

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

10 CFR Part 100, Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants."

Regulatory Guide 1.26, "Quality Group Classification and Standards."

Regulatory Guide 1.29, "Seismic Design Classification."

Regulatory Guide 1.84, "Code Case Acceptability ASME Section III Design and Fabrication."

Regulatory Guide 1.85, "Code Case Acceptability ASME Section III Materials."

ASME Boiler and Pressure Vessel Code, 1971 and 1974 Editions, Section III, "Nuclear Power Plant Components," American Society of Mechanical Engineers.

ASME Boiler Pressure Vessel Code, 1971 and 1974 Editions, Section VIII, Division 1 or Division 2, "Pressure Vessels," American Society of Mechanical Engineers.

ANSI B31.1-1974, "Power Piping," American National Standards Institute.

API Standard 620, Fifth Edition, "Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks," American Petroleum Institute, (1973).

API Standard 650, Fifth Edition, "Welded Steel Tanks for Oil Storage," American Petroleum Institute (1973).

AWWA D100-73, "AWW Standard for Steel Tanks-Standpipes, Reservoirs, and Elevated Tanks for Water Storage," American Water Works Association.

ANSI B96.1-1973, "Specification for Welded Aluminum-Alloy Field-Erected Storage Tanks," American National Standards Institute (1973).

Huitt, J. L. "Fluid flow in simulated fractures," AIChE Journal, V. 2, p. 259, 1956.

Iwai, K., "Fundamental studies of fluid flow through a single fracture," Ph. D. thesis, University of California, Berkeley, 208, P., 1976.

Louis, C., "Stromungsvorgänge in Kluftigen Medien and ihre Wirkung auf die Standsicherheit von Bauwerken und Boschungen im Fells," Dissertation Universität (TH) Karlsruhe, 1967. Also published in English as: "A study of groundwater flow in jointed rock and its influence on the stability of rock masses," Imperial College Rock Mechanics Research Report No. 10, September 1969.

Nawy, E. G., "Crack Control Through Reinforcement Distribution in Two-Way Acting Slabs and Plates," ACI Journal, Proceedings, V. 69, No. 4, April 1972.

Nawy, E. G., "Crack Control, Serviceability, and Limit Design of Two-Way Action Slabs and Plates," Engineering Research Bulletin No. 53, Rutgers University, 1972.

Section 15.0 - Accident Analysis

Letter: K. Kniel to A. E. Scherer, August 2, 1976.

Letter: O. D. Parr to F. M. Stern, December 4, 1974.

Letter: O. D. Parr to F. M. Stern, NRC Staff Review of the Combustion Engineering ECCS Evaluation Model, June 13, 1975.

Letter: O. D. Parr to A. E. Scherer, NRC Review of the Combustion Engineering Proposed ECCS Evaluation Model Changes, December 9, 1975.

Letter: A. E. Scherer to R. L. Bair, June 28, 1980.

Letter: A. E. Scherer to J. R. Miller, June 29, 1980

"CEA Ejection," Combustion Engineering Topical Report, CENPD-190-A, January 1976.

Regulatory Guide 1.77, "Assumptions Used For Evaluating a Control Rod Ejection Accident For Pressurized Water Reactors," May 1974.

APPENDIX C

NUCLEAR REGULATORY COMMISSION UNRESOLVED SAFETY ISSUES

C-1 Unresolved Safety Issues

The NRC staff continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors, research results, NRC staff and Advisory Committee on Reactor Safeguards safety reviews, and vendor, architect/engineer and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to assure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to assure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue prior to making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC staff requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called "generic safety issues" because they are related to a particular class or type of nuclear facility rather than a specific plant. These issues have also been referred to as "unresolved safety issues." However, as discussed above, such issues are considered on a generic basis only after the staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer term generic review is underway.

C-2 ALAB-444 Requirements

These longer-term generic studies were the subject of a Decision by the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. The Decision was issued on November 23, 1977 (ALAB-444) in connection with the Appeal Board's consideration of the Gulf States Utility Company application for the River Bend Station, Unit Nos. 1 and 2.

In the view of the Appeal Board (pp. 25-29):

"The responsibilities of a licensing board in the radiological health and safety sphere are not confined to the consideration and disposition of those issues which may have been presented to it by a party or an "Interested State" with the required degree of specificity. To the contrary, irrespective of what matters may or may not have been properly placed in controversy, prior to authorizing the issuance of a construction permit the board must make the finding, inter alia, that there is "reasonable assurance" that "the proposed facility can be constructed and operated at the proposed location without undue risk to the health and safety of the public." 10 CFR 50.35(a) ...Of necessity, this determination will entail an inquiry into whether the staff review satisfactorily has come to grips with any unresolved generic safety problems which might have an impact upon operation of the nuclear facility under consideration."

"The SER is, of course, the principal document before the licensing board which reflects the content and outcome of the staff's safety review. The board should therefore be able to look to that document to ascertain the extent to which generic unresolved safety problems which have been previously identified in a FSAR item, a Task Action Plan, an ACRS report or elsewhere have been factored into the staff's analysis for the particular reactor -- and with what result. To this end, in our view, each SER should contain a summary description of those generic problems under continuing study which have both relevance to facilities of the type under review and potentially significant public safety implications."

"This summary description should include information of the kind now contained in most Task Action Plans. More specifically, there should be an indication of the investigative program which has been or will be undertaken with regard to the problem, the program's anticipated time span, whether (and if so, what) interim measures have been devised for dealing with the problem pending the completion of the investigation, and what alternative courses of action might be available should the program not produce the envisaged result."

"In short, the board (and the public as well) should be in a position to ascertain from the SER itself -- without the need to resort to extrinsic documents -- the staff's perception of the nature and extent of the relationship between each significant unresolved generic safety question and the eventual operation of the reactor under scrutiny. Once again, this assessment might well have a direct bearing upon the ability of the licensing board to make the safety findings required of it on the construction permit level even though the generic answer to the question remains in the offing. Among other things, the furnished information would likely shed light on such alternatively important considerations as whether: (1) the problem has already been resolved for the reactor under study; (2) there is a reasonable basis for concluding

that a satisfactory solution will be obtained before the reactor is put in operation; or (3) the problem would have no safety implications until after several years of reactor operation and, should it not be resolved by then, alternative means will be available to insure that continued operation (if permitted at all) would not pose an undue risk to the public."

This appendix is specifically included to respond to the decision of the Atomic Safety and Licensing Appeal Board as enunciated in ALAB-444 and applied to an operating license proceeding Virginia Electric and Power Company (North Anna Nuclear Power Station, Units 1 and 2), ALAB-491, NRC 245 (1978).

C-3 "UNRESOLVED SAFETY ISSUES"

In a related matter, as a result of Congressional action on the Nuclear Regulatory Commission budget for Fiscal Year 1978, the Energy Reorganization Act of 1974 was amended (PL 95-209) on December 13, 1977 to include, among other things, a new Section 210 as follows:

"UNRESOLVED SAFETY ISSUES PLAN"

"SEC. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter."

The Joint Explanatory Statement of the House-Senate Conference Committee for the FY 1978 Appropriations Bill (Bill S.1131) provided the following additional information regarding the Committee's deliberations on this portion of the bill:

"SECTION 3 - UNRESOLVED SAFETY ISSUES"

"The House amendment required development of a plan to resolve generic safety issues. The conferees agreed to a requirement that the plan be submitted to the Congress on or before January 1, 1978. The conferees also expressed the intent that this plan should identify and describe those safety issues, relating to nuclear power reactors, which are unresolved on the date of enactment. It should set forth: (1) Commission actions taken directly or indirectly to develop and implement corrective measures; (2) further actions planned concerning such measures; and (3) timetables and cost estimates of such actions. The Commission should indicate the priority it has assigned to each issue, and the basis on which priorities have been assigned."

In response to the reporting requirements of the new Section 210, the NRC staff submitted to Congress on January 1, 1978, a report describing the NRC generic

issues program (NUREG-0410).^{1/} The NRC program was already in place when PL 95-209 was enacted and is of considerably broader scope than the "Unresolved Safety Issues Plan" required by Section 210. In the letter transmitting NUREG-0410 to the Congress on December 30, 1977, the Commission indicated that "the progress reports, which are required by Section 210 to be included in future NRC annual reports, may be more useful to Congress if they focus on the specific Section 210 safety items."

It is the NRC's view that the intent of Section 210 was to assure that plans were developed and implemented on issues with potentially significant public safety implications. In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program to determine which issues fit this description and qualify as "Unresolved Safety Issues" for reporting to the Congress. The NRC review included the development of proposals by the NRC Staff and review and final approval by the NRC Commissioners.

This review is described in a report, NUREG-0510, entitled "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress" dated January 1979. The report provides the following definition of an "Unresolved Safety Issue:"

"An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants it affects."

Further the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an "Unresolved Safety Issue" is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in NUREG-0510. As a result, 17 "Unresolved Safety Issues" addressed by 22 tasks in the NRC program were identified. The issues are listed below. Progress on these issues is discussed in the NRC Annual Reports. The number(s) of the generic task(s) (e.g., A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

^{1/} NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," issued on January 1, 1978.

"UNRESOLVED SAFETY ISSUES" (APPLICABLE TASK NOS.)

1. Water Hammer - (A-1)
2. Asymmetric Blowdown Loads on the Reactor Coolant System - (A-2)
3. Pressurized Water Reactor Steam Generator Tube Integrity - (A-3, A-4, A-5)²
4. BWR Mark I and Mark II Pressure Suppression Containments - (A-6, A-7, A-8, A-39)
5. Anticipated Transients Without Scram - (A-9)
6. BWR Nozzle Cracking - (A-10)
7. Reactor Vessel Materials Toughness - (A-11)
8. Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports - (A-12)
9. Systems Interaction in Nuclear Power Plants - (A-17)
10. Environmental Qualification of Safety-Related Electrical Equipment - (A-24)
11. Reactor Vessel Pressure Transient Protection - (A-26)
12. Residual Heat Removal Requirements - (A-31)
13. Control of Heavy Loads Near Spent Fuel - (A-36)
14. Seismic Design Criteria - (A-40)
15. Pipe Cracks at Boiling Water Reactors - (A-42)
16. Containment Emergency Sump Reliability - (A-43)
17. Station Blackout - (A-44)

In the view of the staff, the "Unresolved Safety Issues" listed above are the substantive safety issues referred to by the Appeal Board in ALAB-444 when it spoke of "...those generic problems under continuing study which have...potentially significant public safety implications" (page 27). Eight of the 22 tasks identified with the above 17 "Unresolved Safety Issues" are not applicable to San Onofre 2 and 3. Six of these tasks (A-6, A-7, A-8, A-39, A-10 and A-42) are peculiar to boiling water reactors and two of the tasks (A-3 and A-5) are peculiar to pressurized water reactors with Westinghouse and Babcock & Wilcox nuclear steam supply systems.^{2/} With regard to the remaining 14 tasks that are applicable to San Onofre 2 and 3, the NRC staff has issued NUREG reports and other documents providing our resolution of five of the issues as listed below. Also listed is the section of this Safety Evaluation Report (on future supplements thereto) that addresses (or will address) each of the five issues.

<u>Task Number</u>	<u>NUREG Report and Title</u>	<u>Safety Evaluation Report Section</u>
A-2	NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems."	3.9.3.4

^{2/} Even though Tasks A-3 and A-5 address steam generator tube problems experienced in Westinghouse and B&W plants, there are many common task elements between these tasks and Task A-4 which addresses Combustion Engineering steam generator tube problems. For this reason, the Task Action Plans for all three tasks have been combined into a single Task Action Plan.

<u>Task Number</u>	<u>NUREG Report and Title</u>	<u>Safety Evaluation Report Section</u>
A-24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."	3.11, 7.9, 8.3.5
A-26	NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors," and Branch Technical Position RSB 5-2, "Reactor Coolant System Overpressurization Protection."	5.2.2
A-31	Regulatory Guide 1.139, "Guidance for Residual Heat Removal," and Branch Technical Position RSB 5-1,"	5.4.3
A-36	NUREG-0612, Control of Heavy Loads at Nuclear Power Plants	9.1.4

The remaining nine tasks that are applicable to San Onofre 2 and 3 are listed below.

GENERIC TASKS ADDRESSING UNRESOLVED SAFETY ISSUES
THAT ARE APPLICABLE TO SAN ONOFRE 2 AND 3

- (1) A-1 Water Hammer
- (2) A-4 Combustion Engineering Steam Generator Tube Integrity
- (3) A-9 ATWS
- (4) A-11 Reactor Vessel Materials Toughness
- (5) A-12 Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports.
- (6) A-17 Systems Interactions in Nuclear Power Plants
- (7) A-40 Seismic Design Criteria
- (8) A-43 Containment Emergency Sump Reliability
- (9) A-44 Station Blackout

With the exception of Tasks A-9, A-43, and A-44, Task Action Plans for the generic tasks above are included in NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants." A technical resolution for Task A-9 has been proposed by the NRC staff in Volume 4 of NUREG-0460, issued for comment. This served as a basis for the staff's proposal for rulemaking in this issue. Task Action Plans for Tasks A-43 and A-44 have been completed and will be included in the next edition of NUREG-0469. The information provided in NUREG-0469 meets most of the informational requirements of ALAB-444. Each Task Action Plan provides a description of the problem; the staff's approaches to its resolution; a general discussion of the bases upon which continued plant licensing or operation can proceed pending completion of the task; the technical organizations involved in the task and estimates of the manpower required; a description of the interactions with other NRC offices, the Advisory Committee on Reactor Safeguards, and outside organizations; estimates of funding required for contractor-supplied technical assistance; prospective dates for

completing the task; and a description of potential problems that could alter the planned approach or schedule.

We have reviewed the 10 "Unresolved Safety Issues" listed above as they relate to San Onofre 2 and 3. Discussion of each of these issues including references to related discussions in the Safety Evaluation Report and this supplement are provided below in Section C-5. Based on our review of these items, we have concluded, for the reasons set forth in Section C-5, that there is reasonable assurance that San Onofre 2 and 3 can be operated prior to the ultimate resolution of these generic issues without endangering the health and safety of the public.

New "Unresolved Safety Issues"

An in-depth and systematic review of safety concerns identified since NUREG-0510 was issued in January 1979 has been performed by the staff, and resulted in a proposed list of seven new "Unresolved Safety Issues." This proposed list was contained in a staff paper to the Commission, SECY 80-325 and supplemented by a memo of September 10, 1980 and SECY 80-325A.

The candidate issues originated from concerns identified in the TMI action plan (NUREG-0660), ACRS recommendations, abnormal occurrence reports and other operating experience. The staff's proposed list was reviewed and commented on by the ACRS, NRC's Offices of Policy Evaluation and Analysis and Evaluation of Operational Data and by the Commission. The decision by the Commission was that four candidate issues would be designated as Unresolved Safety Issues.

- (1) Shutdown Decay Heat Removal Requirements
- (2) Safety Implications of Control Systems (including steam generator and reactor overfill transients).
- (3) Seismic Qualification of Equipment in Operating Plants
- (4) Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

The staff has not yet developed Task Action Plans for these issues. During the development of the Task Action Plans, the applicability to all operating reactors will be determined and bases prepared for continued plant operation pending final resolution of the tasks. If the staff determines that any interim measures are required to assure safe operation while a task is being resolved, they will be implemented on a case by case basis.

C-5 Discussion of Tasks as they Relate to San Onofre 2 and 3

A-1 Water Hammer

Water hammer events are intense pressure pulses in fluid systems caused by any one of a number of mechanisms and system conditions. Since 1971 there have been over 100 incidents involving water hammer in pressurized water reactors and boiling water reactors. The water hammers have involved steam generator feedrings and piping,

decay heat removal systems, emergency core cooling systems, containment spray lines, service water lines, feedwater lines and steam lines. However, the systems most frequently affected by water hammer effects are the feedwater systems. The most serious water hammer events have occurred in the steam generator feedings of pressurized water reactors. These types of water hammer events are addressed in section 10.4.6 of this report. System design changes and testing requirements necessary to prevent this type of water hammer are discussed. In Section 10.4.6, we concluded that, subject to confirmation during the preoperational test program, the feedwater system and steam generator design for San Onofre 2 and 3 with respect to this potential water hammer concern is acceptable.

With regard to protection against other potential water hammer events currently provided in plants, piping design codes require consideration of impact loads. Approaches used at the design stage include: (1) increasing valve closure times, (2) piping layout to preclude water slugs in steam lines and vapor formation in water lines, (3) use of snubbers and pipe hangers, and (4) use of vents and drains. In addition, as described in Section 3.9.2.1 of this report, we discuss the preoperational vibration dynamic effects test program that the applicant will conduct in accordance with Section III of the ASME Code for all ASME Class 1 and Class 2 piping systems and piping restraints during startup and initial operation. These tests will provide adequate assurance that the piping and piping restraints have been designed to withstand dynamic effects due to valve closures, pump trips and other operating modes associated with the design operational transients.

Nonetheless, in the unlikely event that a large pipe break did result from a severe water hammer event, core cooling is assured by the emergency core cooling systems described in Section 6.3 of this report and protection against the dynamic effects of such pipe breaks inside and outside of containment is provided as described in Sections 3.6.1 and 3.6.2 of this report.

Task A-1 may identify some potentially significant water hammer scenarios that have not explicitly been accounted for in the design and operation of nuclear power plants, including San Onofre 2 and 3. The task has not as yet identified the need for requiring any additional measures beyond those already required in the short term.

Based on the foregoing, we have concluded that San Onofre 2 and 3 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-4 Combustion Engineering Steam Generator Tube Integrity

The primary concern is the capability of steam generator tubes to maintain their integrity during normal operation and postulated accident conditions. In addition, the requirements for increased steam generator tube inspections and repairs have resulted in significant increases in occupational exposures to workers. Corrosion resulting in steam generator tube wall thinning has been observed in several Westing-

house and Combustion Engineering plants for a number of years. Major changes in their secondary water treatment process essentially eliminated this form of degradation. Another major corrosion-related phenomenon has also been observed in a number of plants in recent years, resulting from a buildup of support plate corrosion products in the annulus between the tubes and the support plates. This buildup eventually causes a diametral reduction of the tubes, called "denting," and deformation of the tube support plates. This phenomenon has led to other problems, including stress corrosion cracking, leaks at the tube/support plate intersections, and U-bend section cracking of tubes which were highly stressed because of support plate deformation.

Specific measures such as steam generator design features, a secondary water chemistry control and monitoring program, condensate demineralization and condenser tubing material selection, that the applicant has employed to minimize the onset of steam generator tube problems are described in Section 5.4.2.1 of this report. In addition, Section 5.4.2.2 of this report discusses the inservice inspection requirements for steam generator tubes. As described in these sections, the applicant has met all current requirements regarding steam generator tube integrity. The Technical Specifications will include requirements for actions to be taken in the event that steam generator tube leakage occurs during plant operation.

Task A-4 is expected to result in improvements in our current requirements for inservice inspection of steam generator tubes. These improvements will include a better statistical basis for inservice inspection program requirements and consideration of the cost/benefit of increased inspection. Pending completion of Task A-4, the measures taken at San Onofre 2 and 3 should minimize the steam generator tube problems encountered. Further the inservice inspection and Technical Specification requirements will assure that the applicants and the NRC staff are alerted to tube degradation should it occur. Appropriate actions such as tube plugging, increased and more frequent inspections and power derating could be taken if necessary. Since the improvements that will result from Task A-4 will be procedural, i.e., an improved inservice inspection program, they can be implemented by the applicant at San Onofre 2 and 3 after operation begins, if necessary.

Based on the foregoing, we have concluded that San Onofre 2 and 3 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-9 Anticipated Transients Without Scram (ATWS)

Nuclear plants have safety and control systems to limit the consequences of temporary abnormal operating conditions or "anticipated transients." Some deviations from normal operating conditions may be minor; others, occurring less frequently, may impose significant demands on plant equipment. In some anticipated transients, rapidly shutting down the nuclear reaction (initiating a "scram"), and thus rapidly reducing the generation of heat in the reactor core, is an important safety measure. If there were a potentially severe "anticipated transient" and the reactor shutdown

system did not "scram" as desired, then an "anticipated transient without scram," or ATWS, would have occurred.

The ATWS issue and the requirements that must be met by the applicants prior to operation of San Onofre 2 and 3 are discussed in Section 15.3.7 of this report. The requirements set forth are for the interim period pending completion of Task A-9 and implementation of additional requirements if found to be necessary.

A-11 Reactor Vessel Materials Toughness

Resistance to brittle fracture, a rapidly propagating catastrophic failure mode for a component containing flaws, is described quantitatively by a material property generally denoted as "fracture toughness." Fracture toughness has different values and characteristics depending upon the material being considered. For steels used in nuclear reactor pressure vessels, three considerations are important. First, fracture toughness increases with increasing temperature. Second, fracture toughness decreases with increasing load rates. Third, fracture toughness decreases with neutron irradiation.

In recognition of these considerations, power reactors are operated within restrictions imposed by the Technical Specifications on the pressure during heatup and cooldown operations. These restrictions assure that the reactor vessel will not be subjected to that combination of pressure and temperature that could cause brittle fracture of the vessel if there were significant flaws in the vessel material. The effect of neutron radiation on the fracture toughness of the vessel material is accounted for in developing and revising these Technical Specification limitations over the life of the plant.

For the service times and operating conditions typical of current operating plants reactor vessel fracture toughness for most plants provides adequate margins of safety against vessel failure under operating testing, maintenance, and anticipated transient conditions over the life of the plant. In addition, conservative analyses indicate that adequate safety margins are available during accident conditions until after many years of operation. However, results from a reactor vessel surveillance program and analyses performed using currently available methods indicate that the reactor vessels for up to 20 older operating pressurized water reactors and those for some more recent vintage plants will have marginal toughness after comparatively short periods of operation. The principal objective of Task A-11 is to develop an improved engineering method and safety criteria to allow a more precise assessment of the safety margins that are available during normal operation and transients in older reactor vessels with marginal fracture toughness and of the safety margins available during accident conditions for all plants.

Our review of this issue is still incomplete, as is discussed in Sections 5.2 and 5.3 of this report. We will report on the resolution of this issue in a supplement to this report.

A-12 Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports

NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," was issued for comment in November 1979. This report summarizes work performed by the NRC staff and its contractor, Sandia Laboratories, in the resolution of this generic activity. The report describes the technical issues, the technical studies performed by Sandia Laboratories, the NRC staff's technical positions based on these studies, and the NRC staff's plan for implementing its technical positions. As a part of initiating the implementation of the findings in this report, letters were sent to all applicants and licensees on May 19 and 20, 1980. In these letters a revised proposed implementation plan was presented and specific criteria for material qualifications were defined.

Many comments on both the draft of NUREG -0577 and the letters of May 19 and 20 have been received by the NRC staff and detailed consideration is presently being given to these comments. After completing our review and analysis of the comments provided, we will issue the final revision of NUREG-0577 which will include a full discussion and resolution of the comments and a final plan for implementation.

We estimate that our implementation review will require approximately two years. Failure of critical primary system supports would be dependent on first, an initiating event such as a large LOCA coupled with low fracture toughness of a support member, low operating temperature and the existence of a large flaw. We have, therefore, determined that licensing for pressurized water reactors should continue during the implementation phase of Task A-12. Our conclusions regarding licensing and subsequent operation are not sensitive to the estimated length of time required for this work.

With regard to the lamellar tearing issue, the results of an extensive literature survey by Sandia revealed that, although lamellar tearing is a common occurrence in structural steel construction, virtually no documentation exists describing inservice failures due to lamellar tearing. Nonetheless, additional research is recommended to provide a more definitive and complete evaluation of the importance of lamellar tearing to the structural integrity of nuclear power plant support systems.

A-17 Systems Interactions In Nuclear Power Plants

The licensing requirements and procedures used in our safety review address many different types of systems interactions. Current licensing requirements are founded on the principle of defense-in-depth. Adherence to this principle results in requirements such as physical separation and independence of redundant safety systems, and protection against events such as high energy line ruptures, missiles, high winds, flooding, seismic events, fires, operator errors, and sabotage. These design provisions supplemented by the current review procedures of the Standard Review Plan (NUREG-75/087) which require interdisciplinary reviews and which account, to a large

extent, for review of potential systems interactions, provide for an adequately safe situation with respect to such interactions. The quality assurance program which is followed during the design, construction, and operational phases for each plant is expected to provide added assurance against the potential for adverse systems interactions.

In November 1974, the Advisory Committee on Reactor Safeguards requested that the NRC staff give attention to the evaluation of safety systems from a multi-disciplinary point of view, in order to identify potentially undesirable interactions between plant systems. The concern arises because the design and analysis of systems is frequently assigned to teams with functional engineering specialties--such as civil, electrical, mechanical, or nuclear. The question is whether the work of these functional specialists is sufficiently integrated in their design and analysis activities to enable them to identify adverse interactions between and among systems. Such adverse events might occur, for example, because designers did not assure that redundancy and independence of safety systems were provided under all conditions of operation required, which might happen if the functional teams were not adequately coordinated. Simply stated, the left hand may not know or understand what the right hand is doing in all cases where it is necessary for the hands to be coordinated.

In mid-1977, Task A-17 was initiated to confirm that present review procedures and safety criteria provide an acceptable level of redundancy and independence for systems required for safety by evaluating the potential for undesirable interactions between and among systems.

The NRC staff's current review procedures assign primary responsibility for review of various technical areas and safety systems to specific organizational units and assign secondary responsibility to other units where there is a functional or interdisciplinary relationship. Designers follow somewhat similar procedures and provide for interdisciplinary reviews and analyses of systems. Task A-17 will provide an independent investigation of safety functions--and systems required to perform these functions--in order to assess the adequacy of current review procedures. This investigation is being conducted by Sandia Laboratories under contract assistance to the NRC staff.

The contract effort, Phase I of the task, began in May 1978 and is nearing completion. The Phase I investigation is structured to identify areas where interactions are possible between and among systems and have the potential of negating or seriously degrading the performance of safety functions. The investigation will then identify where NRC review procedures may not have properly accounted for these interactions. Preliminary results of the Phase I contracted effort indicate that, within the limitations of the study, there are only a few areas where the review procedures are weak from a systems interaction standpoint. These results are being finalized by the contractor and the staff is considering whether, and if so what changes in the Standard Review Plan are needed. Finally, a follow-on Phase II of the task will be scoped based on the results of Phase I and the status and scope of other related NRC activities.

The NRC staff believes that its review procedures and acceptance criteria currently provide reasonable assurance that an acceptable level of system redundancy and independence is provided in plant designs. Although some changes to the review procedures will likely result, the preliminary results of the Phase I effort appear to confirm this belief. Therefore, we conclude that there is reasonable assurance that San Onofre 2 and 3 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-40 Seismic Design Criteria - Short-Term Program

NRC regulations require that nuclear power plant structures, systems and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are provided in the NRC regulations and in Regulatory Guides issued by the Commission. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance were in place. For this reason, rereviews of the seismic design of various plants are being undertaken to assure that these plants do not present an undue risk to the public. Task A-40 is, in effect, a compendium of short-term efforts to support such reevaluation efforts of the NRC staff, especially those related to older operating plants. In addition, some revisions to SRP sections and Regulatory Guides to bring them more in line with the state-of-the-art will result.

As discussed in Sections 2.5.2 and 3.7 of this report, the seismic design basis and seismic design of San Onofre 2 and 3 have been reevaluated at the operating license stage and have been found acceptable. We do not expect the results of Task A-40 to affect these conclusions because the techniques under consideration were essentially utilized in the San Onofre review. Accordingly, we have concluded that San Onofre 2 and 3 can be operated prior to ultimate resolution of this generic issue without endangering the health and safety of the public.

A-43 Containment Emergency Sump Reliability

Following a postulated loss-of-coolant accident, i.e, a break in the reactor coolant system piping, the water flowing from the break would be collected in the emergency sump at the low point in the containment. This water would be recirculated through the reactor system by the emergency core cooling pumps to maintain core cooling. This water would also be circulated through the containment spray system to remove heat and fission products from the containment. Loss of the ability to draw water from the emergency sump could disable the emergency core cooling and containment spray systems. The consequences of the resulting inability to cool the reactor core or the containment atmosphere could be melting of the core and/or loss of containment integrity.

One postulated means of losing the ability to draw water from the emergency sump could be blockage by debris. A principal source of such debris could be the thermal insulation on the reactor coolant system piping. In the event of a piping break, the

subsequent violent release to the high pressure water in the reactor coolant system could rip off the insulation in the area of the break. This debris could then be swept into the sump, potentially causing blockage.

Currently, regulatory positions regarding sump design are presented in Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and Containment Spray Systems," which address debris (insulation). The Regulatory Guide recommends, in addition to providing redundant separated sumps, that two protective screens be provided. A low approach velocity in the vicinity of the sump is required to allow insulation to settle out before reaching the sump screening; and it is required that the sump remain functional assuming that one-half of the screen surface area is blocked.

A second postulated means of losing the ability to draw water from the emergency sump could be abnormal conditions in the sump or at the pump inlet such as air entrainment, vortices, or excessive pressure drops. These conditions could result in pump cavitation, reduced flow and possible damage to the pumps.

Currently, regulatory positions regarding sump testing are contained in Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," which addresses the testing of the recirculation function. Both in-plant and scale model tests have been performed by applicants to demonstrate that circulation through the sump can be reliably accomplished.

As indicated in Section 6.3.3.2 of this report, the applicants are conducting out-of-plant scale model tests of the San Onofre 2 and 3 containment sump design. The test identified the need for several design modifications that were subsequently incorporated into the plant design. We will report on our evaluation of the results of these tests in a supplement to this report.

A-44 Station Blackout

Electrical power for safety systems at nuclear power plants must be supplied by at least two redundant and independent divisions. The systems used to remove decay heat to cool the reactor core following a reactor shutdown are included among the safety systems that must meet these requirements. Each electrical division for safety systems includes an offsite alternating current (ac) power connection, a standby emergency diesel generator ac power supply, and direct current (dc) sources.

Task A-44 involves a study of whether or not nuclear power plants should be designed to accommodate a complete loss of all ac power, i.e., a loss of both the offsite and the emergency diesel generator ac power supplies. A loss of all ac for an extended period of time in pressurized water reactors accompanied by loss of the auxiliary feedwater pumps (usually one of two redundant pumps is a steam turbine driven pump that is not dependent on ac power for actuation or operation) could result in an inability to cool the reactor core, with potentially serious consequences. This particular accident sequence was a significant contributor to the overall risk associated with the PWR analyzed in the Reactor Safety Study (WASH-1400). The steam

turbine driven auxiliary feedwater pump for the PWR analyzed in WASH-1400 had no ac dependencies. If the auxiliary feedwater pumps are dependent on ac power to function, then a loss of all ac power could of itself result in an inability to cool the reactor core and accordingly, this event sequence would be expected to be more important to the overall risk posed by the facility.

A loss of all ac power was not a design basis event for San Onofre 2 and 3. Nonetheless, the combination of design, operation, and testing requirements that have been imposed on the applicants will assure that these units will have substantial resistance to a loss of all ac and that even if a loss of all ac should occur there is reasonable assurance that the core will be cooled. These are discussed below.

A loss of offsite ac power involves a loss of both the preferred and backup sources of offsite power. Our review and basis for acceptance of the design, inspection, and testing provisions for the offsite power system are described in Section 8.2 of the this report. In addition, the applicants conducted a grid stability analysis. Our review of this analysis is also described in Section 8.2.

If offsite ac power is lost, two independent and redundant onsite diesel generators and their associated distribution systems will deliver emergency power to safety-related equipment. Our review of the design, testing, surveillance, and maintenance provisions for the San Onofre 2 and 3 onsite emergency diesels are described in Section 8.3.1 of this report.

Even if both offsite and onsite ac power are lost, cooling water can still be provided to the steam generators by the auxiliary feedwater system by employing a steam turbine driven pump that does not rely on ac power for operation. Our review of the auxiliary feedwater system design and operation is described in Section 10.4.2 of this report.

Based on the foregoing, we conclude that there is reasonable assurance that San Onofre 2 and 3 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

APPENDIX D

EVALUATION OF ONSHORE ATMOSPHERIC DISPERSION AT THE SAN ONOFRE NUCLEAR GENERATING STATION

During the review of the sphere enclosure project for San Onofre Unit 1, we concluded that without additional information the data collected on the permanent site meteorological tower during 1973 and 1974 could not be used to estimate atmospheric diffusion conditions for the San Onofre vicinity. The data characteristics were anomalous compared to data from other sites we had reviewed. Differences included a very high occurrence of the unstable stability classes and a decrease in average wind speed with height.

To explain these anomalies, the applicants presented several hypotheses concerning the relationships among the site meteorology, the complex local topography, and the site data collection system. However, the applicants did not provide any supporting onsite data. Thus, we could not conclusively determine whether the anomalies were real or whether the permanent tower data could be used to estimate the site atmospheric diffusion conditions as described in Section 2.3.4 of NUREG-75/087 (the Standard Review Plan).

In our review of the sphere enclosure project for San Onofre Unit 1 we recommended that the applicants install additional towers to aid in defining the atmospheric diffusion characteristics of the site. Until they presented information that substantiated site diffusion characteristics, we concluded that our diffusion estimates for short-term releases in the onshore directions should be based upon the atmospheric conditions described in Regulatory Guide 1.4 (Revision 2), "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors." For time periods less than eight hours, this condition is equivalent to Pasquill Stability Class F with a windspeed of one meter per second. We judged that this condition would overestimate the relative concentrations that would be calculated using Section 2.3.4 of NUREG-75/087 and representative site data. Table D.1 lists this diffusion estimate for San Onofre Units 2 and 3.

In response, the applicants told us they were designing an onsite atmospheric tracer program to meet the following objectives (Septoff, et al., 1976):

- "(1) To measure and characterize atmospheric dispersion to permit realistic calculations of short-term accident dispersion factors;

TABLE D.1

SHORT-TERM RELATIVE CONCENTRATION VALUES
CALCULATED FOR SAN ONOFRE NUCLEAR GENERATING STATION
UNITS 2 AND 3 BY FOUR METHODS

The values are short-term (0-2 hour) relative concentration (X/Q) values calculated for releases from San Onofre Units 2 and 3. The values are for a distance of 580 meters from the buildings. The four models are: (1) that described in Regulatory Guide 1.4; (2) that described in Regulatory Guide 1.145; (3) that described in Regulatory Guide 1.145, but with Figure 3 of the draft guide replaced with the site-derived plume concentration reduction credits of Figure D-4; and (4) that described in Appendix C of Septoff, et al. (1977).

<u>Model</u>	<u>X/Q (seconds per cubic meter)</u>
1. Regulatory Guide 1.4	8.7×10^{-4}
2. Regulatory Guide 1.145 (0.3 percentile value)	4.0×10^{-4}
3. Regulatory Guide 1.145 amended (0.3 percentile value)	1.9×10^{-4}
4. Appendix C	3.9×10^{-5}

"(2) To demonstrate the appropriateness of using bluff tower meteorology to estimate dispersion; and .

"(3) To characterize dispersion under less restrictive atmospheric conditions representative of routine release meteorology."

In the program, the tracer gas was released under meteorological dispersion conditions which ranged from the "moderately restrictive" (moderate windspeeds and/or neutral atmospheric stability which produce average dilution) to "least restrictive" (high windspeeds and/or unstable atmospheric stability which produce the most dilution). (Tests were also to have been run during "most restrictive" conditions (low windspeeds and/or stable atmospheric stability which produce little dilution); however, these periods were not successfully sampled.) Tracer gas concentrations were sampled on arcs 300 meters and 700 meters from the release points (at San Onofre Units 1 and 2).

Meteorological measurements were made at eight towers within the vicinity of the plant. Primary test measurements of wind speed and direction, standard deviation of wind direction, and temperature difference were made at the permanent onsite 40-meter bluff tower and at a 40-meter tower located 700 meters inland. Atmospheric stability was determined by the vertical temperature gradient in accordance with Regulatory Guide 1.23, "Onsite Meteorological Programs."

In our review for San Onofre Units 2 and 3, we concluded that our evaluation procedures for this site should provide estimates of the variations in atmospheric dispersion that occur as a function of wind direction and distance from the source to receptor. Certain air flow directions can exhibit substantially more or less favorable diffusion conditions than others, and the wind can transport effluents in certain directions more frequently than others. Section 2.3.4 of NUREG-75/087 procedures involve the use of onsite meteorological data in a direction-independent model to estimate atmospheric diffusion conditions which occur no more than 5 percent of the time (438 hours per year) around the site at a distance equal to the minimum exclusion area boundary distance. An interim staff Branch Technical Position, approved by the Regulatory Requirements Review Committee at their May 2, 1978 meeting, allowed the use of either this direction-independent approach or the direction-dependent approach as outlined in Regulatory Guide 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," August 1979. The direction-dependent approach considers reduction of plume concentration due to enhanced lateral plume spread, variation of meteorological conditions by direction, and variable exclusion area boundaries. The draft version of this guide, dated September, 1977, considered an 0.3 percentile value rather than the current 0.5 percentile value.

In our evaluation of short-term diffusion estimates, we modified the calculational procedures described in Section 2.3.4 of NUREG-75/087 by using the approach outlined in Regulatory Guide 1.145, with the exception that an 0.3 percentile

value was used rather than the 0.5 value considered by the Guide. The applicants also used this direction-dependent approach as outlined in Appendix C of Septoff, et al. (1977). One objective of our independent evaluation of the site tests was to determine whether a reduction of concentration equivalent to the enhanced lateral plume spread factors of the draft guide could be used for the site short-term diffusion evaluation.

We thus evaluated the test data, attempting to correlate the bluff tower data to the measured tracer concentration data. Our National Oceanic and Atmospheric consultant also reviewed the test data and his conclusions are in Attachment D-1. Nearly 40 test runs were successful; these ranged over the unstable and neutral Stability Classes (A-D). Unfortunately, during the testing period stable onshore flow occurred much less frequently than observed historically, and no successful test run was made during stable atmospheric diffusion conditions (E, F, G). For near-ground level releases, these conditions generally produce the poorest atmospheric dispersion, and are the conditions of prime interest for short-term (Section 2.3.4 of NUREG-75/087) diffusion estimates.

Due to this shortcoming of the tests, we attempted to extrapolate concentration estimates for the stable classes from the measured data. Looking at the data as a function of atmospheric stability alone (Figure D-1) indicated that normalized peak concentrations measured during Class D stability were within the same range as those in Class A. (Normalized concentration, $\chi u/Q$, is a measure of the atmospheric dilution and is concentration, χ , normalized for source strength, Q , and the average 10-meter windspeed, u .) Classically, as stability increases (i.e., going from Class A to G), normalized concentrations for a ground-level release should increase. However, no pattern was evident from which we could conclusively extrapolate concentrations for the stable classes from the onsite tracer data measured during unstable and neutral conditions.

Because the San Onofre site data alone were not sufficient to predict onsite diffusion during stable atmospheric conditions, we compared the available onsite tracer data to data obtained in other tracer tests. Over the past few years, other atmospheric tracer tests were run at various locations in the United States. Van der Hoven (1976) summarized several tests series conducted during periods of poorest atmospheric dispersion (low windspeeds and stable atmospheric conditions). These tests were run at inland sites in varied terrain, but without the presence of buildings. In 1975, tests were conducted at the Rancho Seco Nuclear Station to determine the effect buildings would have on concentrations (Start, et al., 1977).

The staff evaluation of the Rancho Seco tests were included in the development of Regulatory Guide 1.145. These tests demonstrated that during periods of low wind speeds and a stable or neutral atmosphere, measured concentrations were lower than those predicted using traditional Pasquill-Gifford dispersion coefficients (Gifford, 1968). The tests reviewed by Van der Hoven (1976) also support this conclusion.

FIGURE D-1

To account for this observation, one facet of the guide allows reductions of calculated concentrations. But in developing the guide, only that amount of extra dispersion (above the traditional coefficient values) attributed to the lateral plume spread dispersion coefficients was used to reduce the traditionally derived concentrations. (Plume concentration is a function of both lateral and vertical plume spread.) In the guide, we did not include the extra mixing attributable to the vertical plume spread, because we could make no specific generic conclusions. This issue is still under review by the staff. Due to this potential extra vertical mixing, predicted concentrations using the guide will tend to overpredict measured concentrations.

Inherent in the reduced values are the contributions of both thermal and mechanical turbulence. The amount contributed by each cannot be readily separated from the test data. Simply expressed, little mixing of the air occurs when cooler (heavier) air underlies warmer (lighter) air, i.e., when the air is thermally stable. Mixing occurs when the air is thermally unstable, with rising warm (lighter) air displacing cooler (heavier) air aloft. As air flows over an obstacle (such as a building or a bluff), mechanical turbulence is generated that will better mix an effluent released near the obstacle compared to an effluent released in an open area. This is often called the "building wake" effect. At the San Onofre site, both the coastal bluff and the plant structures contribute to the mechanical turbulence. At Rancho Seco, the plant structures are the primary mechanical turbulence generators.

Figures 1-4 of Attachment D-1 show the comparison between the Rancho Seco data and the San Onofre data. The solid line on the figures represents traditionally-derived values for a ground-level release using the Pasquill-Gifford dispersion coefficients for the given stability class. We concluded that there was a general agreement between the normalized concentration data from the two sites.

We analyzed the San Onofre data in a manner similar to our analysis of the Rancho Seco data for Regulatory Guide 1.145, evaluating only the lateral plume spread component. Figure D-2 shows the ratio of observed lateral plume spread (Σy_{obs}) to Pasquill-Gifford lateral plume spread (Σy_{PG}) versus the 10-meter wind speed. The solid line is the concentration reduction factor developed from the Rancho Seco tests for the draft guide. No reduction was justifiable for Stability Class A. For most cases of Stability Class D, the draft guide allows less concentration reduction than observed in the San Onofre tests. More reduction was apparent as stability increases (from Class A to Class D).

We conclude that using Regulatory Guide 1.145 reduction factors would produce a conservative assessment for our short-term (Section 2.3.4 of NUREG-75/087) diffusion estimates. We based this on the following:

- (1) For the unstable and neutral stability classes for which we could compare San Onofre and Rancho Seco data, the normalized concentrations and lateral plume spread parameters were similar.

FIGURE D-2

- (2) More concentration reduction is apparent as stability increases for the Rancho Seco tests and those at other sites; this is true for the unstable and neutral cases for the San Onofre site and we expect this pattern to occur in the stable classes for San Onofre.
- (3) Because we had not considered reduction for the total plume concentration (both vertical and lateral), we would still overestimate plume concentrations using only a lateral plume spread reduction factor.

In December 1977, we met with the applicants to discuss our assessment of the tests and application to short-term diffusion estimates. Their analysis of the tests and application to short-term diffusion estimates is described in Appendix C of Septoff, et al. (1977). For the exclusion area boundary distance (580 meters) for San Onofre Units 2 and 3, our assessment using the draft guide methodology resulted in an estimated relative concentration (χ/Q) value 10 times greater than the applicants' estimate (see Table D.1). The applicants claimed that our analysis was overly conservative. A basic difference existed in the statistical techniques we each had used to evaluate the test data: the applicants based their results on the mean of the data, whereas we used an enveloping technique that encompassed most of the data. Further, the applicants had considered the full plume, whereas we had limited our analysis to the lateral plume spread. Because in past case reviews of tracer tests we had considered the full plume, we agreed to reanalyze the data using our enveloping technique to consider the full plume and to allow full plume reduction if we determined it justifiable.

We reanalyzed the data using the ratio of traditionally-predicted normalized concentration to measured normalized concentration (thus analyzing the full plume). Figure D-3 shows these ratios versus wind speeds. Again, no reduction was considered justifiable for Stability Class A. For Stability Class D, a reduction of concentration by a maximum of a factor of 10 appeared reasonable, yet enveloped the data.

To account for the lack of onsite tracer data during stable conditions, we assumed that the total reduction factor for Stability Classes E, F and G would be the same as we observed for Class D. As noted above, this ratio increased with increasing stability for test data at other sites, again meaning that the traditional methodology overestimated concentrations more for Class G than Class D. But by keeping this ratio constant, we concluded that application of our evaluation should still overpredict actual concentrations in the site vicinity.

Figure D-4 shows the total plume reduction factor we derived for the San Onofre site; the figure also shows the reduction factors used in Regulatory Guide 1.145 (Figure 3 of the guide). We consider that using the total plume reduction factor is meteorologically reasonable for the San Onofre site. However, because test data during stable cases are not available to verify this conclusion,

FIGURE D-3

FIGURE D-4

it is our position that for short-term diffusion estimates the guide reduction factors be used. If the applicants present additional data that substantiate the diffusion at the San Onofre site during stable atmospheric conditions with onshore flow, we would consider using total plume reduction factors with the draft guide methodology.

Table D.1 lists the short-term (0-2 hour) relative concentration values estimated using the techniques we have described. These models were: (1) Regulatory Guide 1.4; (2) Regulatory Guide 1.145 with an 0.3 percentile value; (3) Regulatory Guide 1.145 with an 0.3 percentile value, but with Figure 3 of the guide replaced with the site-derived total plume reduction factors of Figure D-4; and (4) Appendix C of Septoff, et al. (1977).

In our evaluation in Sections 2.3.4 and 2.3.5 of this report, we used the onsite meteorological tower data provided by the applicants. The tracer program led to our conclusion that using these data to calculate diffusion estimates with the Regulatory Guide 1.145 model with or without site-derived reduction factors would overpredict concentrations for neutral and stable conditions. Likewise, assuming a ground-level release, the model described in Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," would also overpredict annual/average ground-level concentrations. Thus, we conclude that, although the onsite meteorological data appeared anomalous compared to other sites, it can be used to estimate site atmospheric diffusion conditions using the Regulatory Guide 1.145 and Regulatory Guide 1.111 models.

APPENDIX F

Letter from Robert H. Morris, USGS, to
Robert Jackson, NRC, dated August 13, 1980



United States Department of the Interior

GEOLOGICAL SURVEY
RESTON, VA. 22092


Mail Stop 908
August 13, 1980

Mr. Robert Jackson
Geosciences Branch
Division of Site Safety & Environmental
Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Bob:

In response to your request of July 2, 1980, we are transmitting to you under separate cover the Administrative Report entitled "Review of Offshore Seismic Reflection Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California". The review is a joint collaboration by H. Gary Greene of the USGS and Michael P. Kennedy of the California Division of Mines and Geology and provides data pertinent to the San Onofre Nuclear Generating Station.

Sincerely,


Robert H. Morris
Deputy Chief for Reactor Programs
Office of Environmental Geology



One Hundred Years of Earth Science in the Public Service

REVIEW OF OFFSHORE SEISMIC REFLECTION PROFILES IN
THE VICINITY OF THE CRISTIANITOS FAULT,
SAN ONOFRE, CALIFORNIA

by

H. Gary Greene¹ and Michael P. Kennedy²

INTRODUCTION

The purpose of this investigation is to review offshore seismic-reflection profile data that have been acquired by Southern California Edison (SCE) industry, and government during the past 10 years in the vicinity of the San Onofre Nuclear Generating Station (SONGS). These data were examined and interpreted by us to determine the seaward extension and structural relationship (if any) of the Cristianitos fault and the "Offshore Zone of Deformation" "(OZD)" of Woodward-Clyde (1979). Although many studies have been undertaken and numerous reports have been written regarding the offshore geological structure of this area (Woodward-Clyde, 1979; Ehlig, 1979; Greene and others, 1979, and many others), new data used in conjunction with a recently developed regional tectonic model of the Gulf of Santa Catalina have led to the re-evaluation of the character of faulting in this area (Greene and others, 1979). The present report gives the results of this re-evaluation. We have described the method of the analysis, the interpretation of the data, and have discussed regional tectonics in conclusions.

The report includes new data, items 1 through 4 (table 1) which were supplied by SCE and the remainder were obtained from our files. Interpretive line drawings were made for most Woodward-Clyde, Marine Advisors, Western Geophysical, and USGS 1978-1979 SEA SOUNDER profiles, however, few were made of the others.

1. U.S. Geological Survey, Menlo Park, Calif.

2. California Division of Mines and Geology, La Jolla, Calif.

Analysis of the data was accomplished in three steps: (1) all of the seismic profile data were examined to determine the location of major geological structures; (2) line drawings were then constructed showing those features of which we were confident and geological structure was plotted on a 1:24,000 scale planimetric map; (3) the data set was evaluated for its quality and weakly defined or questionable parts were removed from the map. Plate 1 presents only those geologic features that are well defined. Correlation of geological structure on the final map was made with a high degree of confidence.

INTERPRETATION OF DATA

Standard interpretive methods were used in the analysis of the seismic reflection data. For a description of basic seismic reflection techniques and inherent problems in studying reflectors see Moore (1969), Tucker and Yorston (1973), Greene and others (1974), and Payton (1977). Criteria for the interpretation of faults from acoustic profiles are as follows:

Well-defined faults: (1) distinct displacement of prominent reflectors, (2) abrupt discontinuity of prominent reflectors, (3) juxtaposition of an interval of prominent reflectors with an interval having different acoustic characteristics, or (4) abrupt changes in the dips of prominent reflectors along distinct boundaries.

Poorly defined faults: (1) inferred displacement of prominent reflectors, in which the upper or shallow reflectors may be bent rather than broken, (2) discontinuity of prominent reflectors combined with a change in acoustic character, or (3) apparent changes in dip.

Questionable faults: (1) non-instrumental phase shift of reflectors, (2) bent or broken reflectors that can be correlated with known faults on

other profiles, (3) discontinuity of poorly defined reflectors, or (4) any other zone of acoustic contrast, especially where the zone appears similar to and aligns with a fault identified on an adjacent profile.

The orientation of faults was determined by the correlation of faults having similar characteristics from one seismic profile to another. Geologic structures have been projected between adjacent profiles on the basis of their overall spatial relationships to one another. Faults that could not be correlated between two or more adjacent profiles are not shown on the map.

Where fault planes dip more than $\sim 35^{\circ}$, vertical exaggeration precludes the determination of the dip of that fault. Such faults are shown to be vertical on the line drawings. Ordinarily, only an apparent vertical component (vertical separation) of slip can be determined on seismic reflection profiles, whereas the apparent horizontal component (strike separation) is generally impossible to determine. The sense of displacement has not been shown on faults mapped in this review because no stratigraphic control was available or observable.

Data Voids

Areas in which good quality data are lacking or the density of seismic profiles are insufficient to map and correlate structures at a scale of 1:24,000 are designated as "Data Voids" (Plate 1). It must be emphasized that the notation "data void" does not mean that no data are available, only that we felt the data are insufficient for correlation with confidence between lines. The data in some areas are of sufficient quality to permit the extension of geologic structures by inference across expanses mapped as data voids; in such cases, these structures are mapped as inferred or questionably inferred.

DISCUSSION

The interpretive geological structure map shows two zones of deformation (Plate 1). The most prominent and well-defined zones lies along the western edge of the map and is a segment of the "OZD." The other zone is less well-defined but is nevertheless distinctive in its character and extends southward offshore from a position a short distance south of SONGS. Between these zones, the stratigraphic succession is only moderately deformed and consists of very gently folded or homoclinal beds.

"Offshore Zone of Deformation"

The "OZD" of Woodward-Clyde (1979) has been referred to in earlier literature as: (1) the South Coast Zone of Deformation, (2) "Newport-Inglewood offshore zone of deformation," and (3) the Newport-Inglewood-Rose Canyon fault zone. This fault zone is generally continuous and well-defined in the seismic profiles examined for this study (Figs. 1, 2, 3, 5, 7, 8, and 9). It is located on the distal part of the nearshore shelf approximately 7 km from SONGS at its closest point. The OZD trends northwest through the area studied; it is narrow (less than 1 km wide) in the northwest part of the area and broadens to over 2 km wide in the southeast where it is less clearly defined (Plate 1).

The OZD is typically characterized in the seismic reflection profiles by abrupt truncation of well-defined reflectors (Figs. 1 and 2). Between the truncated reflectors are tightly folded, incoherent and locally displaced reflectors. A well-developed syncline lies sub-parallel to the "OZD" along its length in the area studied (Figs. 1, 2, 3, 5, and 7; Plate 1). Many of the faults that bound the "OZD" extend upward to the sea floor where they

questionably offset Holocene sediment.

"Cristianitos Zone of Deformation"

The "Cristianitos Zone of Deformation" "CZD", trends north in this area, and lies oblique to the "OZD." This zone is less well-defined and more complex in pattern than the "OZD" (Figs. 2, 5, 6, 8, and 10). The "CZD" consists of en echelon faults and folds that extend offshore from SONGS and the zone appears to connect with the "OZD" 16 km southeast of the site, although the area of probable intersection is not well surveyed ("Data Void," Plate 1). The "CZD" appears to be a relatively narrow zone, averaging approximately 0.5 km in width. It narrows to less than 0.5 km about 10 km southeast of SONGS.

The "CZD" is an extensively faulted structure that is grossly manifested as a complex asymmetrical anticline (Figs. 2, 3, and 6). The nearshore end of the "CZD" is dominated by a well-defined fault that cuts near-surface sedimentary rocks and is continuous for nearly 3 km (Plate 1).

Structure landward (east) of the "CZD" is a little more complex than that seaward (west) of the zone (Plate 1). The structure consists primarily of short en echelon folds that are oriented north-south and intersect both the "CZD" and a poorly defined fault zone (A on Plate 1) to the east at an angle of $\sim 30^\circ$. The western boundary of this structural zone is composed of en echelon, short, deep-seated faults trending parallel to the "CZD" in the nearshore area (Figs. 2, 4, 6, and 7; Plate 1).

CONCLUSIONS

Interpretation of marine continuous seismic-reflection profiles in the vicinity of SONGS and concentrated along the projected, offshore trace of the Cristianitos fault indicates to us that two structural zones of

deformation are present in this area. The first and most well defined zone is a segment of the "OZD," a recognized Quaternary fault zone (Greene and others, 1979; Hileman, 1979; Legg and Kennedy, 1979). The second is less well defined but nevertheless exhibits characteristics similar to those of the "OZD." This second zone, the "CZD," consists principally of a highly fractured and faulted asymmetrical anticlinal structures.

The "CZD" and associated folds to the east combine to form a broad structural zone (up to 3 km in width) which projects onshore to the north. The southeast end of the "CZD" could become incorporated with a major syncline of the "OZD", however, the structural relationship of the "CZD" with the "OZD" is unconfirmed because of a "data void" (Plate 1).

The age of most recent faulting along the "CZD" is unknown. All seismic profiles examined show that faults associated with the "CZD" end at or near the surface of an apparent wave-cut platform that is overlain by acoustically transparent sediment. Nowhere within the "CZD" is there evidence of seafloor displacement.

It is our conclusion that a structurally deformed zone consisting of correlatable en echelon faults and folds, many extending into shallow subsurface strata (probably Neogene in age), is present along the expected offshore extension of the "CZD." The seismic reflection data reviewed here show that a fairly continuous fault zone extends south to southeastward offshore from SONGS to within 1 km of the "OZD," where a projected connection is possible.

REFERENCES

- Ehlig, Perry, 1979, The Late Cenozoic evolution of the Capistrano embayment, in Fife, D. L., ed., Geologic guide of San Onofre Nuclear Generating Station and adjacent regions of southern California: Pacific Section, American Association of Petroleum Geologists Guide Book 46, p. A-38-A-46.
- Greene, H. G., Lee, W. H. K., McCulloch, D. S., and Brabb, E. E., 1974, Faults and earthquakes in Monterey Bay region, California: U.S. Geological Survey Miscellaneous Field Studies MF-518, 14 p.
- Hileman, J. A., 1979, Seismicity of the San Diego region, in Abott, P. L. and Elliott, W. J., eds., Earthquakes and other perils, San Diego region: Geological Society of America Annual Meeting, San Diego, California, 1979, Field Trip Guidebook, p. 11-20.
- Legg, M. R., and Kennedy, M. P., 1979, Faulting offshore San Diego and northern Baja California, in Abbott, P. L., and Elliott, W. J., eds., Earthquakes and other perils, San Diego region: Geological Society of America Annual Meeting, San Diego, California, 1979, Field Trip Guidebook, p. 29-46.
- Moore, D. G., 1969, Reflection profiling studies of the California continental borderland: Structure and Quaternary turbidite basins: Geological Society of America, Special Paper 107, 142 p.
- Payton, C. E., 1977, ed., Seismic stratigraphy--applications to hydrocarbon exploration: American Association of Petroleum Geologists, Memoir 26, 516 p.

Tucker, P. M., Yorston, H. J., 1973, Pitfalls in seismic interpretation:
Society of Exploration Geophysicists Monograph Series Number 2, 50 p.
Woodward-Clyde Consultants, 1979, Report of the evaluation of maximum
earthquake and site ground motion parameters associated with the off-
shore zone of deformation San Onofre Nuclear Generating Station:
Prepared for Southern California Edison.

TABLE 1*
DATA EXAMINED

1. Marine Advisors intermediate penetration sparker profiles 5-9, 11, 12, 13, 14, 16, 18, 20, 25, and 26.
2. Woodward-Clyde intermediate penetration sparker and high-resolution UNIBOOM profiles numbers 801 to 807, 809-812, 814, 816, 818, 819, 821, 822, 825, 828, 830, 832, 834, 836, 839, 841, 843, 845, 847, 849, 850, and 852.
3. Fugro Sonia profile SNO-5.
4. Western Geophysical deep-penetration CDP profiles numbers 106 (S. P. 359-191), 117 (S. P. 231-270), 119 (S. P. 65-290), 121 (S. P. 165-330), 123 (S. P. 171-270), and 145 (S. P. 195-390).
5. USGS, 1970 POLARIS intermediate penetration sparker and high-resolution mini-sparker profiles numbers 18, 23F, 24, and 25.
6. USGS, 1978 and 1979 SEA SOUNDER (S2-78-SC and S2-79-SC) intermediate to deep-penetration and high-resolution UNIBOOM profiles: S2-78-SC lines 27, 28, 31, and 33; S2-79-SC lines 56 and 58.

*See Plate 2 for location of profiles.

ILLUSTRATIONS

Plate 1. Geologic structure map - San Onofre offshore

2. Composite geophysical trackline map of San Onofre offshore

Figure 1. Line drawing Marine Advisor's seismic reflection profile S-22 showing location of the OZD and CZD. See Plates 1 and 2 for location.

Figure 2. Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 845 showing OZD and CZD. See Plates 1 and 2 for location.

Figure 3. Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 836 showing OZD and CZD. See Plate 1 and 2 for location.

Figure 4. Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 822 showing CZD and inshore fault. See Plate 1 and 2 for location.

Figure 5. Line drawing and seismic reflection profile of USGS SEA SOUNDER Line 58 (S2-79-SC) showing OZD, CZD, and other faults seaward of the study area. See Plates 1 and 2 for location.

Figure 6. Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 816 showing CZD and deep faults nearshore. See Plates 1 and 2 for location.

Figure 7. Line drawing of marine Advisor's seismic reflection profile S-16 showing OZD, CZD, and other structure in study area. See Plates 1 and 2 for location.

Figure 8. Line drawing of USGS seismic reflection profile 33 (S2-78-SC)

showing OZD and CZD. See Plates 1 and 2 for location.

Figure 9. Line drawing and seismic reflection profile of USGS SEA SOUNDER

(S2-79-SC) Line 56 showing OZD. See Plates 1 and 2 for location.

Figure 10. Line drawing of USGS seismic reflection profile 57 (S2-79-SC)

showing fault inshore of CZD. See Plates 1 and 2 for location.

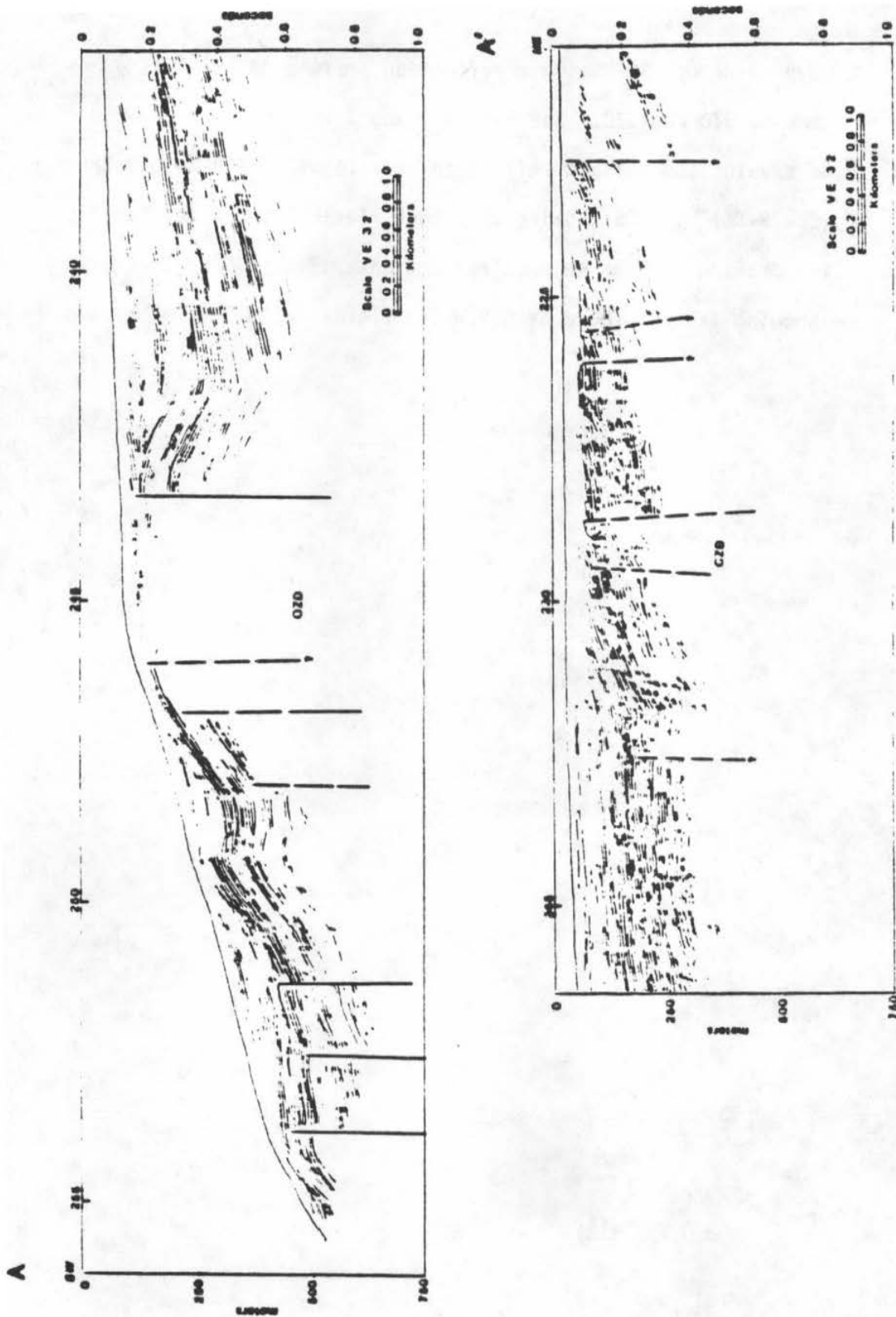


Figure 1.--Line drawing Marine Advisor's seismic reflection profile S-22 showing location of the OZD and CZD. See Plates 1 and 2 for location.

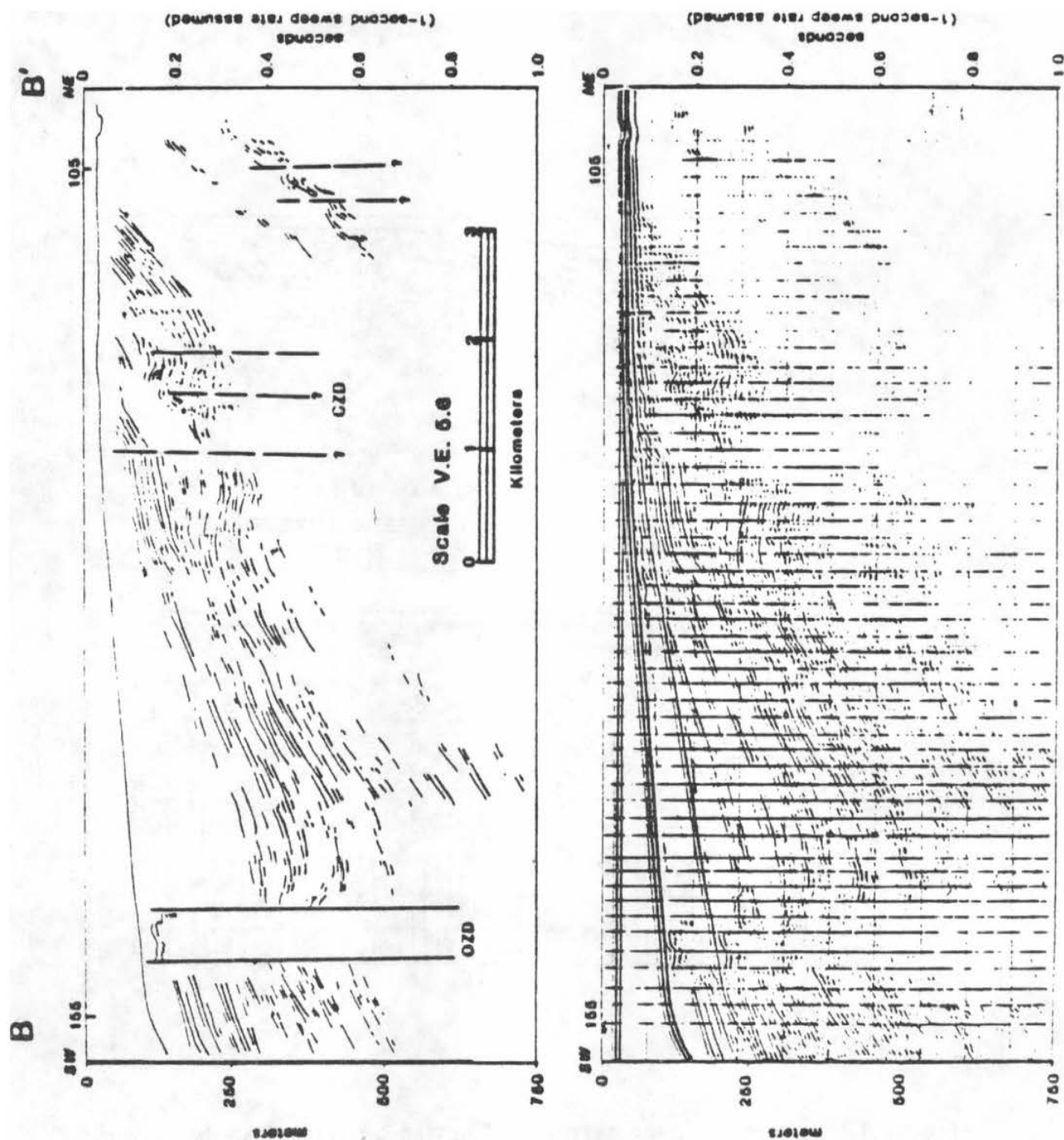


Figure 2.--Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 845 showing OZD and CZD. See Plates 1 and 2 for location.

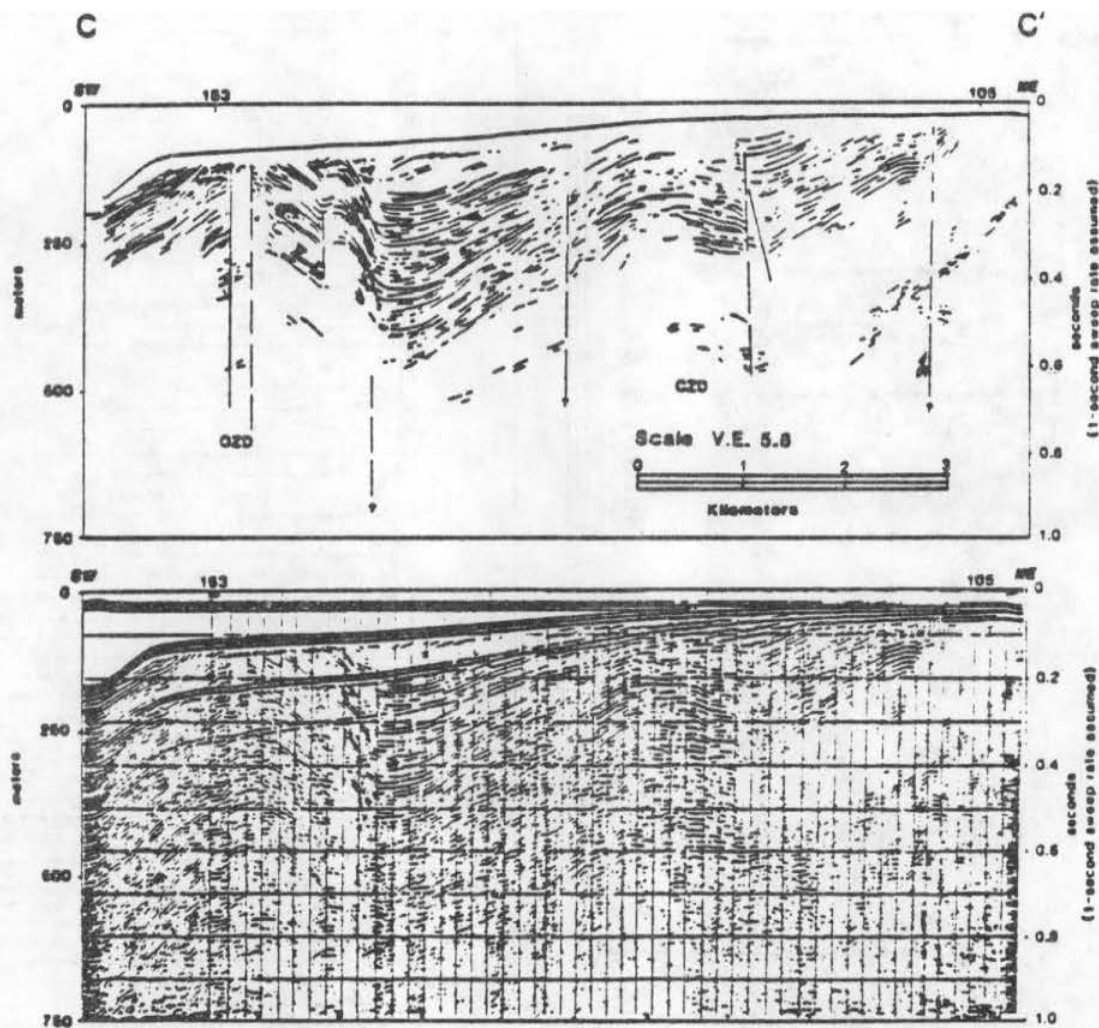


Figure 3. Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 836 showing OZD and CZD. See Plate 1 and 2 for location.

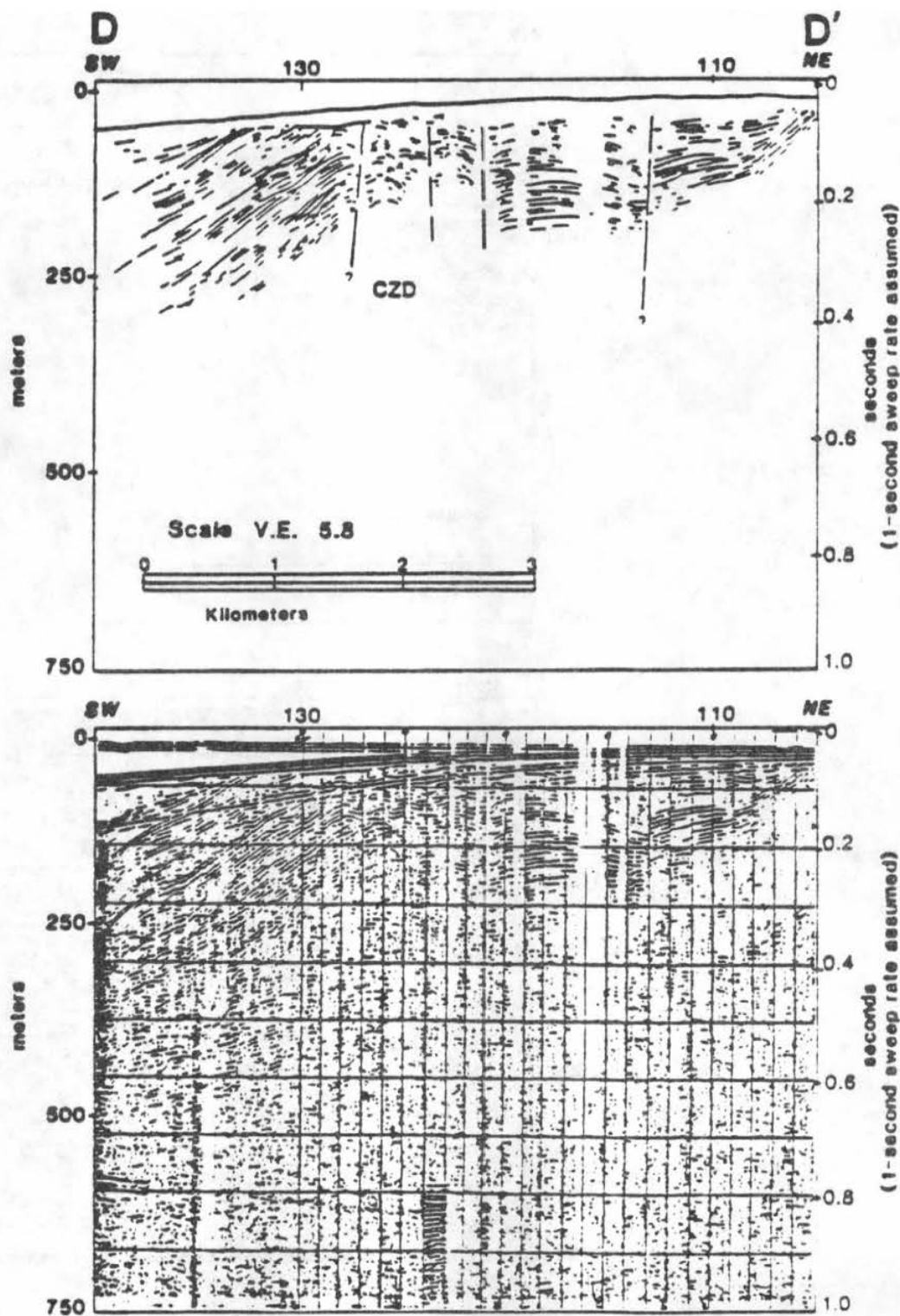


Figure 4.--Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 822 showing CZD and inshore fault. See Plate 1 and 2 for location.

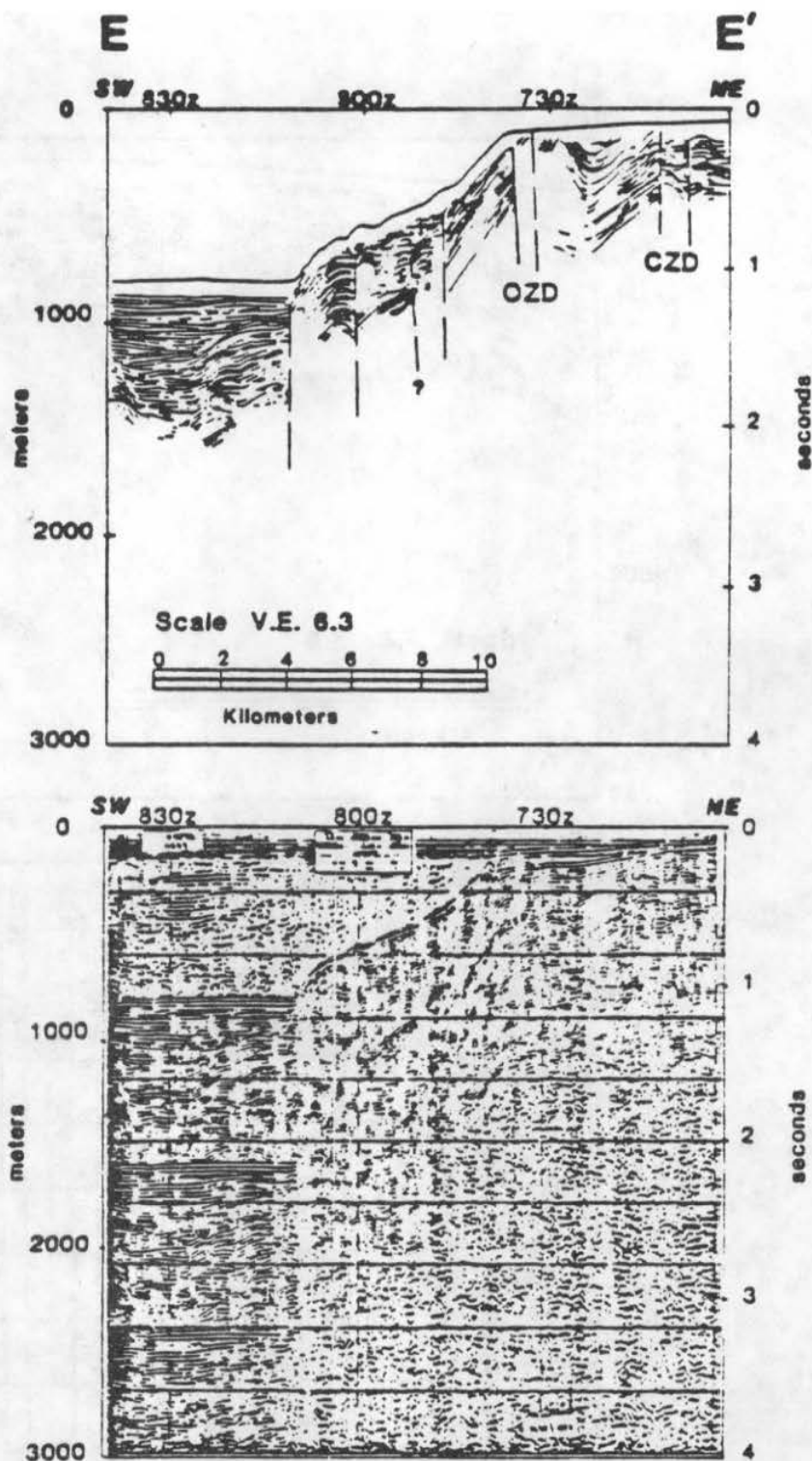


Figure 5.--Line drawing and seismic reflection profile of USGS SEA SOUNDER Line 58 (S2-79-SC) showing OZD, CZD, and other faults seaward of the study area. See Plates 1 and 2 for location.

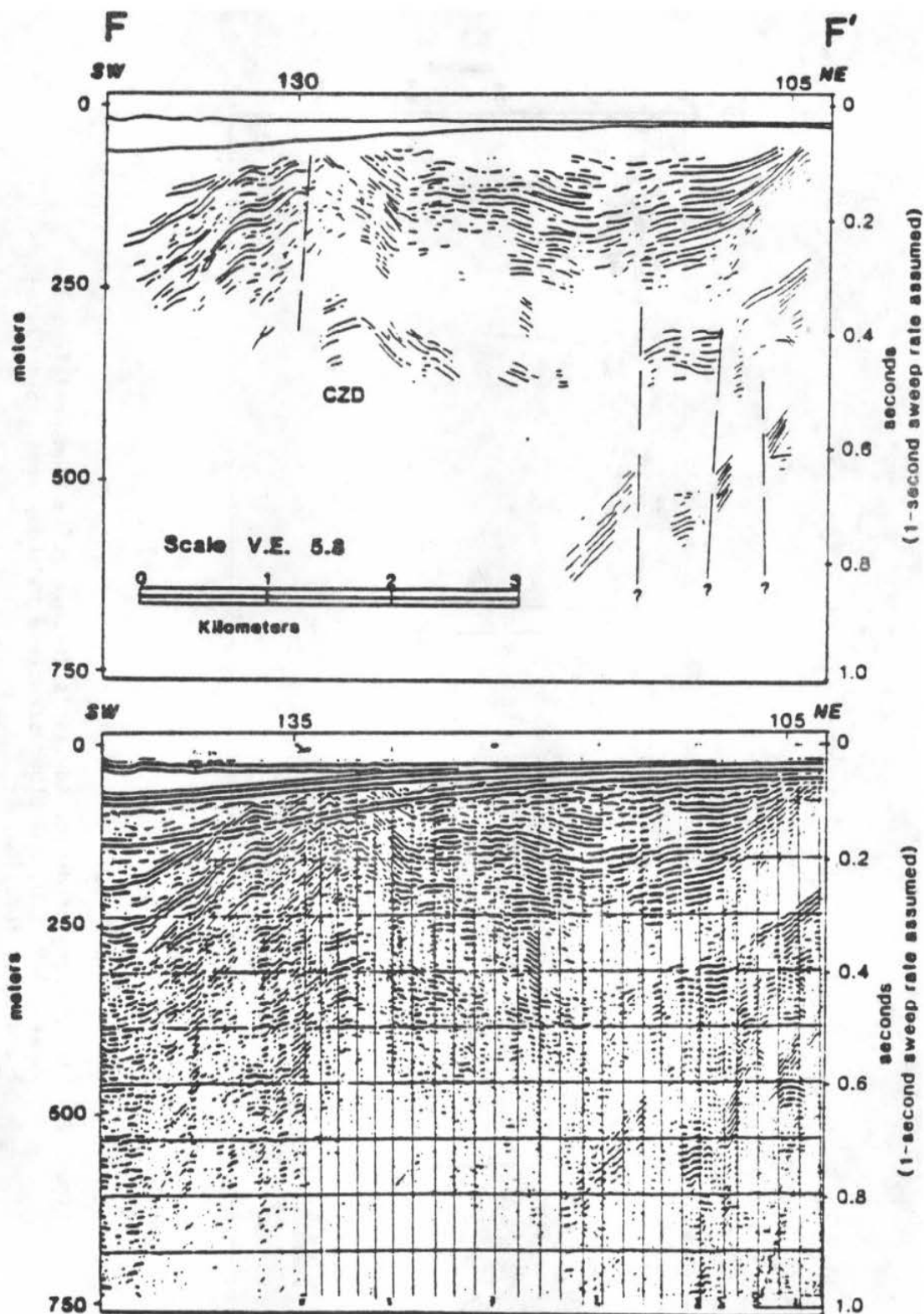


Figure 6.--Line drawing and seismic reflection profile of Woodward-Clyde Consultant's Line 816 showing CZD and deep faults nearshore. See Plates 1 and 2 for location.

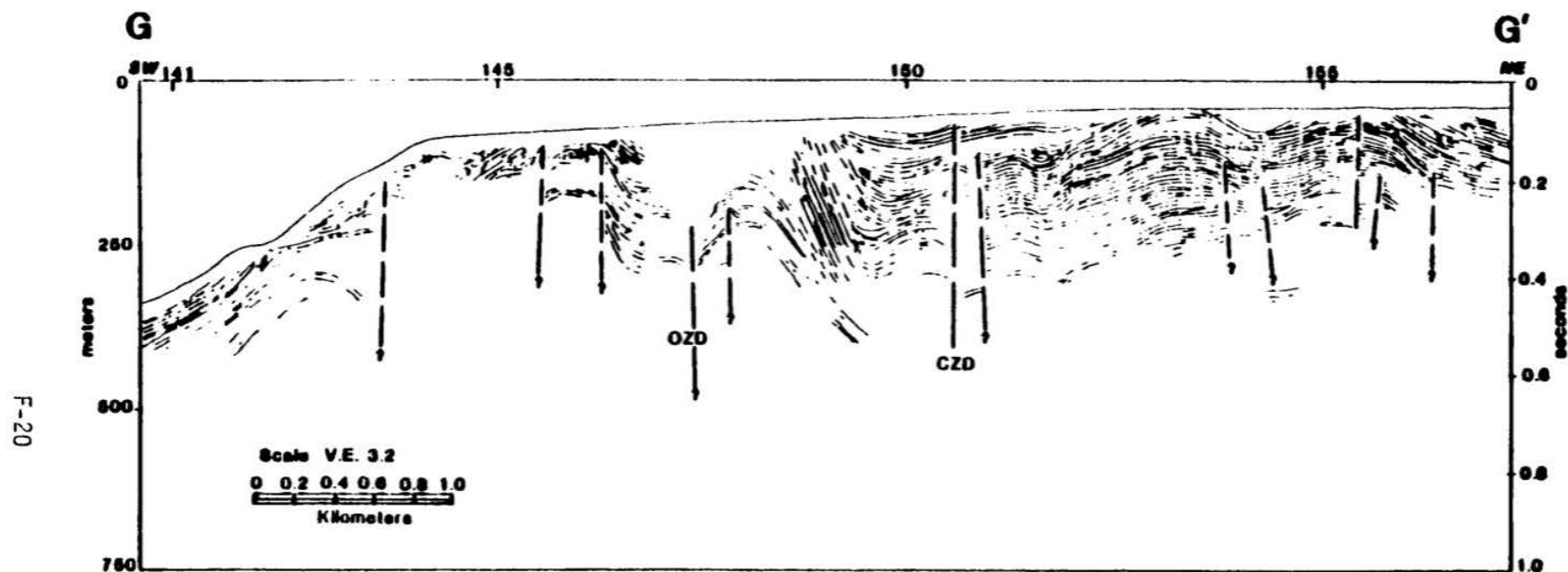


Figure 7.--Line drawing of Marine Advisor's seismic reflection profile S-16 showing OZO, CZD, and other structure in study area. See Plates 1 and 2 for location.

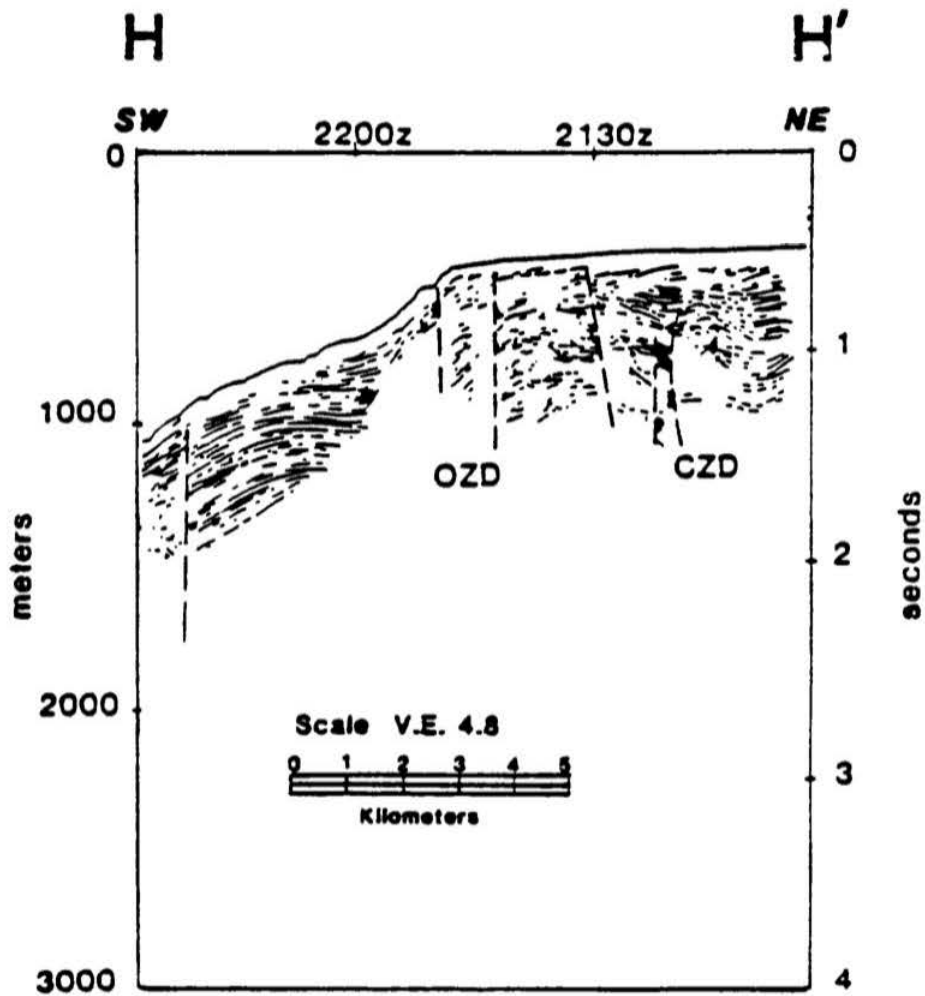


Figure 8.--Line drawing of USGS seismic reflection profile 33 (S2-78-SC) showing OZD and CZD. See Plates 1 and 2 for location.

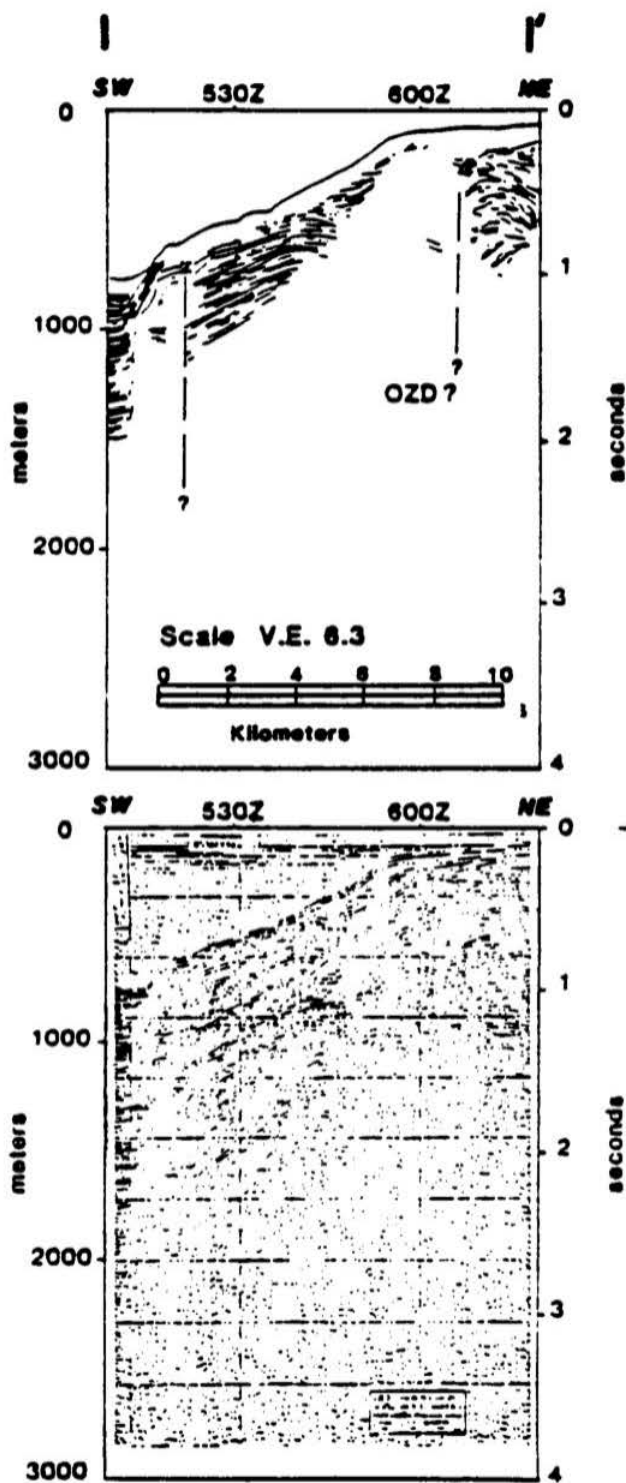


Figure 9.--Line drawing and seismic reflection profile of USGS SEA SOUNDER (S2-79-SC) Line 56 showing OZD. See Plates 1 and 2 for location.

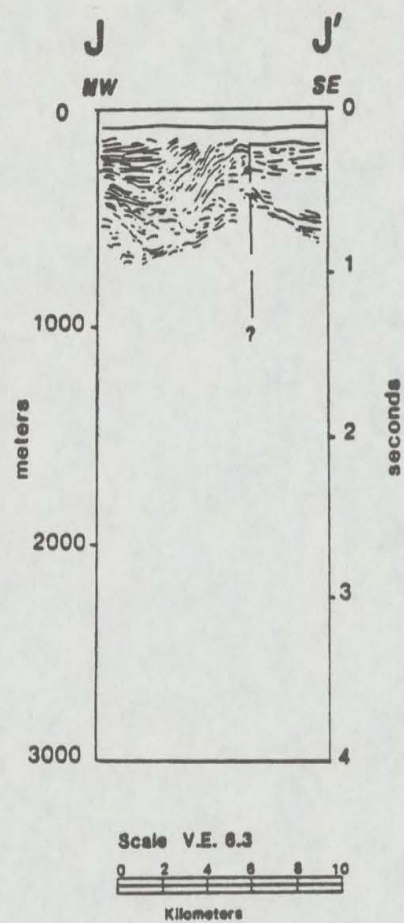
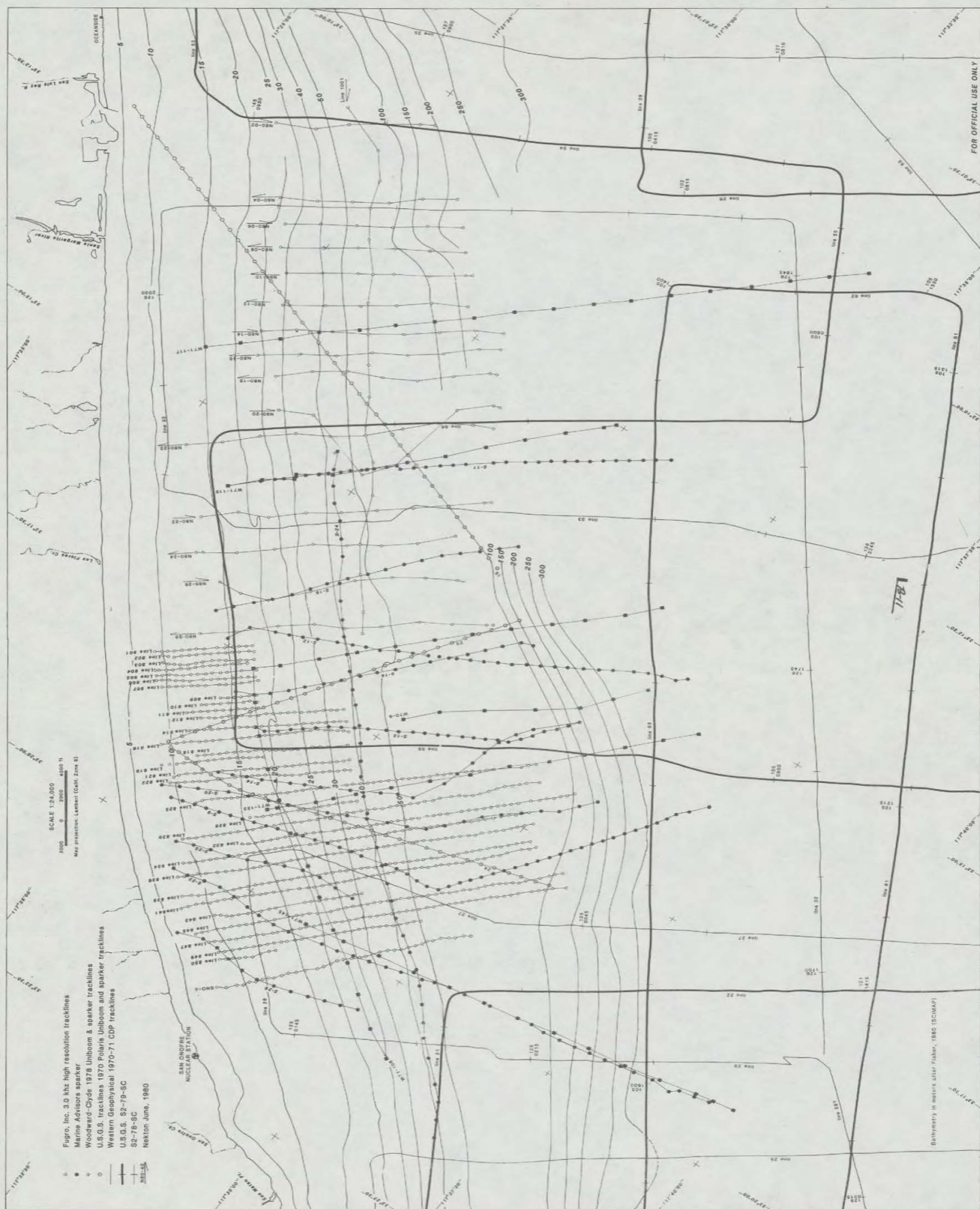
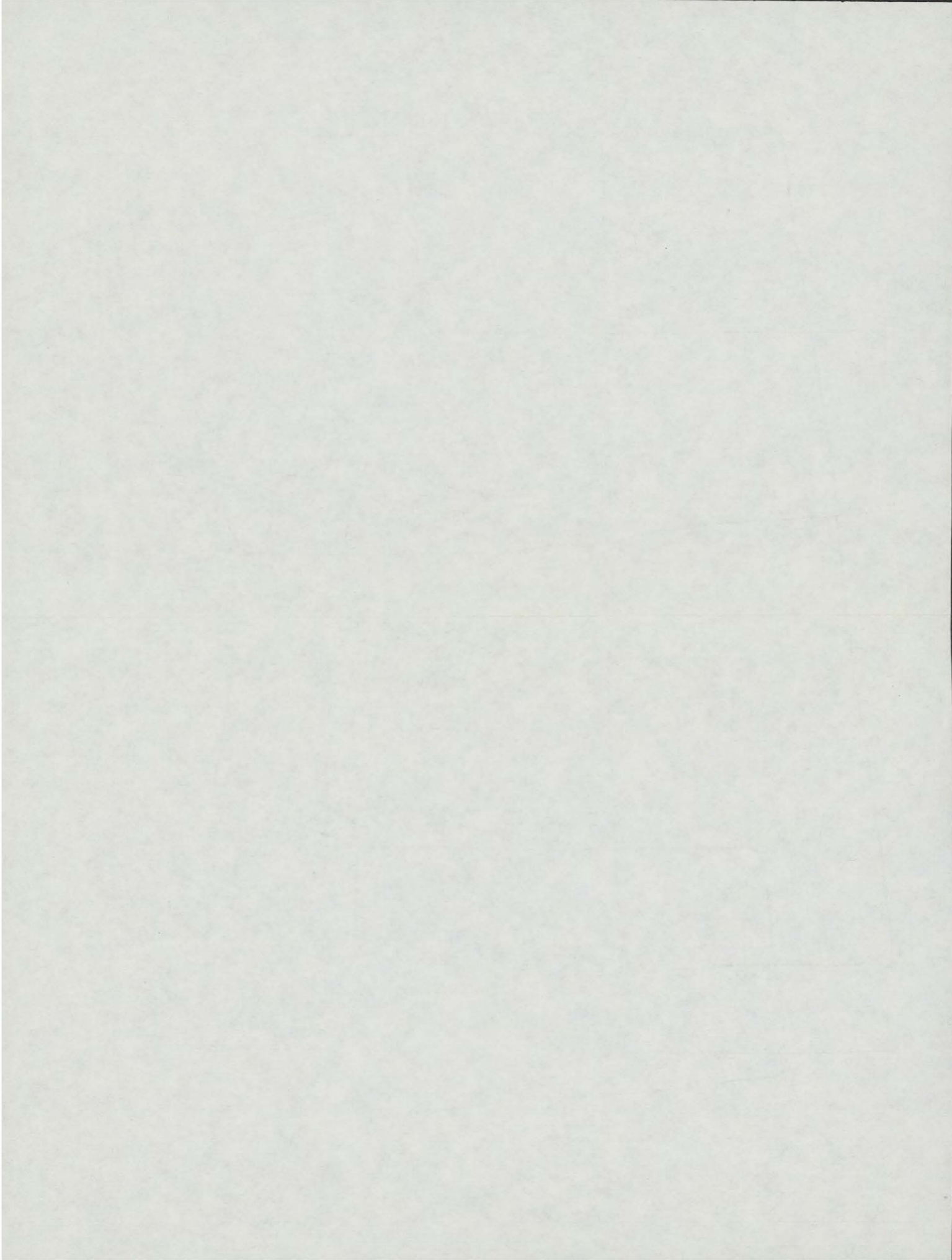


Figure 10.--Line drawing of USGS seismic reflection profile 57 (S2-79-SC) showing fault inshore of CZD. See Plates 1 and 2 for location.





APPENDIX G

Letter from H. William Menard, USGS, to
Harold R. Denton, NRC, dated November 26, 1980



United States Department of the Interior

GEOLOGICAL SURVEY
RESTON, VA. 22092

OFFICE OF THE DIRECTOR

In Reply Refer To:
EGS-Mail Stop 106

NOV 26 1980

Mr. Harold R. Denton, Director
Office of Nuclear Reactor
Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

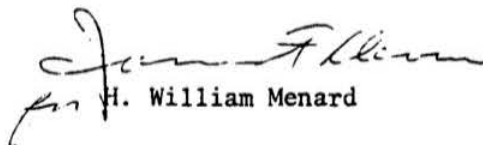
Dear Mr. Denton:

Transmitted herewith, in response to the requests of your staff, is a review of the geologic and seismologic data submitted by the Southern California Edison Company in support of its position concerning the San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2 and 3).

This review was prepared by Mr. Robert H. Morris and Mr. James F. Devine. Assistance was provided by Dr. H. Gary Greene and Dr. Joseph S. Andrews.

We have no objection to your making this review part of the public record.

Sincerely yours,


H. William Menard

Enclosure

Review of Geologic and Seismologic Data Relative to the
San Onofre Units 2 and 3 Operating License Application

On August 13, 1980, the U.S. Geological Survey (USGS) transmitted to Dr. Robert E. Jackson in response to his request dated July 2, 1980, an Administrative Report entitled "Review of Offshore Seismic Reflections Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California" by H. G. Greene, USGS, and Mr. M. P. Kennedy, California Division of Mines and Geology (CDMG). Since that transmittal, additional reflection profiles have been submitted by the applicant for the San Onofre Nuclear Generating Station Units 2 and 3 (SONGS). On September 23, 1980, a meeting was conducted in Menlo Park, California, during which the applicant, Southern California Edison (SCE), presented their interpretation of the Nekton survey. The USGS, in collaboration with M. P. Kennedy of the CDMG, has completed review of the Nekton data. This review constitutes an addendum to their earlier report and is being made available as an Administrative Report with the title "Addendum to Review of Offshore Seismic Reflections Profiles in the Vicinity of the Cristianitos Fault, San Onofre, California" by H. G. Greene and M. P. Kennedy (attached). In this addendum, Greene and Kennedy conclude that the Cristianitos Zone of Deformation (CZD) merges with or is truncated by the Offshore Zone of Deformation (OZD) and that generally faults within the CZD, with few exceptions, displace shallow stratified sedimentary rock that lies beneath a prominent unconformity and younger, poorly stratified sediments.

The significance of the above described studies on the earthquake potential at the SONGS site has been studied extensively by the applicant. On October 8, 1980, the USGS received edited transcriptions of some of the September 23, 1980, presentations made by SCE and its consultants. Included were the following:

1. Discussion of Geologic Setting, SONGS area, September 23, 1980, Dr. Perry Ehrlig.
2. Discussion of Offshore Recent Seismic Reflection Profiles, September 23, 1980, Dr. David Moore.
3. A description of the A, B, C, and D features at the site.
4. Amended response to NRC question 361.54.

The full set of these presentations represent the most complete summary of the applicant's analysis of this earthquake potential. The transcriptions of September 23, 1980, did not include the discussion by Dr. Roy Shleman, consultant to SCE, whose interpretation of the geomorphology and Holocene history of the area contributed significantly to the interpretation of the ages represented by various marine terrace sequences. The importance of this information is demonstrated by the application of these data to the interpretation of the marine profiles described by Dr. David Moore, and this, in turn, reflects the manner in which projection of the Cristianitos Fault to the south has been made. In assessing the conclusions drawn by the applicant's consultants in contrast with those by Greene and Kennedy, there emerges a difference in the use of

certain named structures. Apparently, the applicant's consultants restrict the use of the term "Cristianitos Fault" to a single fault structure, i.e., a west-dipping normal fault. However, Greene and Kennedy use the terms "Cristianitos Zone of Deformation" (CZD), to refer to a zone of short discontinuous faults and folds. The applicant's consultants conclude that the Cristianitos fault dies out to the south whereas Greene and Kennedy project the Cristianitos Zone of Deformation southward to the OZD. SCE recognizes the southward projection by Greene and Kennedy but state in their conclusion that it does not represent an interconnection between the Cristianitos fault and the OZD. Both parties recognize younger undeformed, probably marine terrace, deposits capping the structures near shore. The range in age of these capping deposits is stated by Dr. Shleman (oral discussion, September 23, 1980, and viewgraph) to be from 80,000 years before present (YBP) to 8,500 YBP. The 8,500 YBP date was obtained by C14 method and the 80,000 YBP was inferred based upon geomorphology and late Pleistocene history. Assuming the inferred age is a reasonable conclusion, then the applicant's contention that the Cristianitos Fault (restricted use) is not capable is permissive. On land, the Cristianitos Fault is capped by the 125,000 year-old marine terrace, and the above conclusion then is consistent with that evidence.

Applicant's consultant, Dr. Perry Ehlig, discussed the origin of the Cristianitos Fault (restricted use) and concluded that the fault originated from 10 to 4 million years ago during a period of crustal extension and that the present stress regime of generally northeast-southwest compression represents a significant change; therefore, movement on the OZD would not trigger movement on the Cristianitos Fault.

The USGS, in general, concurs with the conclusions stated by the applicant and its consultants regarding the history and age of last movement of the Cristianitos Fault, its relation as one of several faults of the CZD of Greene and Kennedy, and its apparent lack of potential for movement in response to movement on the OZD.

The extensive investigations and studies by the applicant and its consultants to develop an estimate of the proper magnitude of the Safe Shutdown Earthquake have been reviewed. The techniques discussed in these studies have value but also limitations and shortcomings. Consequently, uncertainty still remains as to just which magnitude number is the "correct" one. Some of this uncertainty results not from the tools for deriving a specific magnitude number but from the limited relevance of such a number as a primary avenue through which ground motion values are estimated for sites near to the earthquake source structures. It is our judgment that a single magnitude value alone is an insufficient basis for assessing the consequence of the occurrence of an earthquake. Instead, it is necessary to include the entire tectonic package in three dimensions and in time sequence and the engineering considerations in order to develop appropriate seismic design numbers. Continued efforts to define a specific "magnitude" have, in our judgment, rapidly diminishing returns.

One could argue even today that reasoned judgment of the amount of ground shaking from many large earthquakes as indicated by the observed response at or near the fault structure may still be the most useful tool for estimating future ground motions very near to the fault. To the extent that that is the case, the previous estimates of shaking "intensity" and resulting estimated seismic design values, as used in the process leading to the seismic design of the SONGS facilities, still appear to be valid and appropriate to the SONGS 2 and 3 facilities.

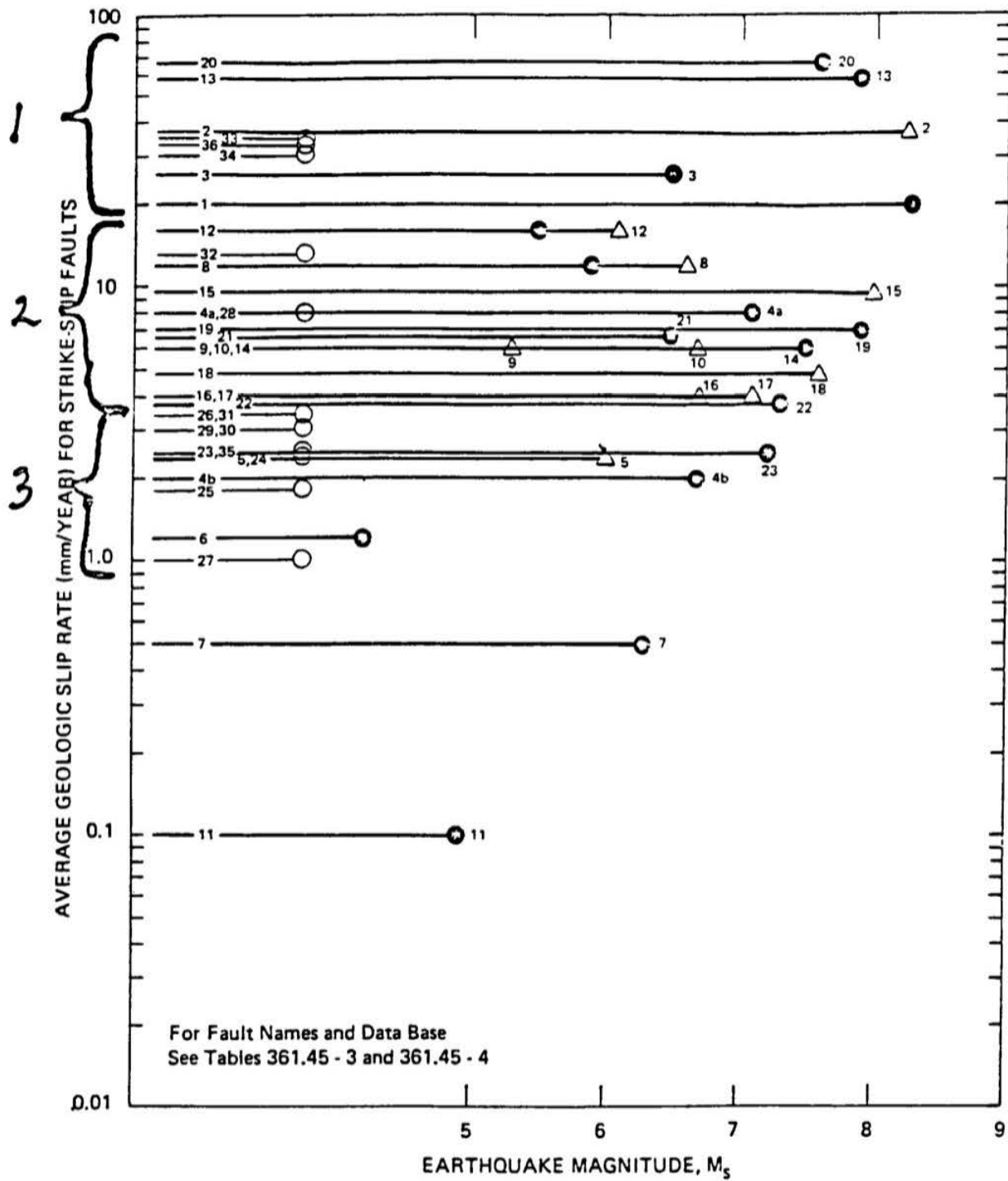
However, in an effort to be responsive to your requests to review the material submitted by the applicant, we offer the following comments concerning the primary technique discussed by the applicant, slip-rate versus magnitude study.

On the question of the statistical significance of the slope of a line bounding points on the log slip-rate versus magnitude plot, the applicant's consultants point out that while a single fault with low slip-rate is unlikely to have a "maximum" earthquake in historic time, a group of low-slip-rate faults has a significance proportional to their moment-rate sum. This same reasoning can be applied quantitatively.

There are 14 faults in Group 2 (see attached figure) with slip-rates ranging from 3.5 to 17.5 mm/yr. Seven of these faults have had historic earthquakes within one magnitude unit of the proposed "maximum earthquake limit" (MEL) line, and two have had earthquakes within 1/2 magnitude unit of the proposed MEL line.

There are 11 faults in Group 3 with slip-rate of 0.7 to 3.5 mm/yr. It is stated on p. 361.51-2 of the SCE report of February 1980 that "The total moment rate for group 3 is roughly equal to the average rate for group 2." Therefore, the faults of group 3 collectively have the statistical weight of a single fault of group 2. The probability that any earthquake in group 3 is within one magnitude unit of a properly-drawn "maximum earthquake limit" line is $7/14 = 0.5$, and the probability that any earthquake on any fault in group 3 is within 1/2 magnitude unit of the MEL is $2/14 = 0.14$. Therefore, there is a substantial probability that the MEL line should be steeper than shown in Figure 361.45-4, and earthquake magnitudes at smaller geologic slip-rates could be larger. During discussion the applicant made the observation that there are probably many faults with small geologic slip-rates and no historic earthquakes which are not shown on the plot and that these should be included in an estimate of statistical significance. It remains to be shown that the number of such faults increases inversely with decreasing geologic slip-rate. Consequently, an imperical technique based on such limited data cannot be considered definitive in assessing maximum magnitude. However, this technique is helpful, when considered along with other procedures for estimating earthquake size to assess the potential impact of earthquakes on the SONGS site.

A comment is in order relative to other regional and areal studies prepared for a variety of uses that have listed estimates of the magnitude of the maximum earthquake on the various faults in southern California and elsewhere. Such studies are based on a variety of generalized geologic and seismologic assumptions that may be adequate for the purposes for which those reports are intended but quite inappropriate for other purposes such as the development of the seismic design criteria for a specific site. Such specific site design criteria usually require detailed studies with the particular needs and requirements for that site as a basis for the studies. Consequently, the very extensive studies and evaluations accomplished for the particular purpose of assessing the earthquake safety at the SONGS site should provide the bases upon which seismic safety issues relative to that site are resolved.



EXPLANATION

- Maximum instrumental recording
- △ Maximum pre-instrumental estimates
- Range over which smaller earthquakes occur
- No maximum magnitude from instrumental or pre-instrumental data.

Figure 361.45 - 1 Empirical Plot
Geologic Slip Rate VS Historical
Magnitude for Strike-Slip Faults

ADDENDUM TO:
REVIEW OF OFFSHORE SEISMIC REFLECTION PROFILES IN
THE VICINITY OF THE CRISTIANITOS FAULT,
SAN ONOFRE, CALIFORNIA

by

H. Gary Greene¹ and Michael P. Kennedy²

INTRODUCTION

On May 8, 1980 the U.S. Nuclear Regulatory Commission (NRC) requested that a comprehensive review be made of all marine geophysical data relevant to the character and recency of faulting along the offshore extension of the Cristianitos fault in the vicinity of the San Onofre Nuclear Generating Station (SONGS) in northwestern San Diego county, California. This request was made to the U.S. Geological Survey (USGS) and was concerned specifically with a proposed structural relationship between the Cristianitos zone of deformation (CZD) and the Newport-Inglewood-Rose Canyon fault zone (Greene et al., 1979) or the Offshore Zone of Deformation (OZD) of Southern California Edison (SCE) Company. H. G. Greene of the U.S.G.S. suggested to the NRC that this review be made jointly by himself and M. P. Kennedy of the California Division of Mines and Geology. This suggestion was made because of the extensive joint research effort then underway between Greene and Kennedy on aspects of the structural geology of the southern California borderland. The NRC agreed to Greene's suggestion and a review and report were completed on July 18, 1980.

¹U.S. Geological Survey, Menlo Park, California

²California Division of Mines and Geology, La Jolla, California

Following the completion of this review and report an additional data set was forwarded for the authors consideration. This data set was collected in June 1980 by NEKTON Inc. for SCE. It consists of about 90 km of high resolution water gun and 3.5 kHz seismic reflection profiles and side-scan sonographs collected within the area of earlier studies (plate 2). The 3.5 kHz data is generally good to moderately good and the penetration is on the order of 10-20 ms. The side-scan data is generally poor and for the most part unuseable for our purpose.

PURPOSE OF NEKTON DATA COLLECTION

The June 1980 NEKTON survey was aimed specifically at collecting data in the vicinity of the proposed intersection of the CZD and the Newport-Inglewood-Rose Canyon fault zone (Greene et al., 1979) or OZD. This relationship was explained in detail by H. G. Greene in a meeting with the NRC and SCE held May 21, 1980. The objectives of the survey as defined by NEKTON, Inc. (1980) were (1) to identify, if possible, the seaward extension of the Cristianitos fault that is mapped onshore 0.8 kilometers southeast of SONGS within our Cristianitos zone of deformation, (2) to determine if the Cristianitos fault connects with the OZD, (3) to identify and map other faults and folds in the area, and (4) to determine whether any faults show evidence of Holocene movement.

DISCUSSION

Although no seismic lines collected by NEKTON in the June 1980 survey actually cross the proposed CZD-OZD intersection of Greene and Kennedy (1980) the CZD can be extended by way of this data (June 1980

NEKTON data) to an area where we interpret it to merge with a synclinal fold and adjoining fault associated with the OZD.

With the exception of minor and consistent navigational errors between the earlier data studied and the June, 1980 NEKTON data nearly all of the geological structures identified correlate with those noted previously (Greene and Kennedy, 1980). Several faults that were inferred and shown in areas labeled "data void" have been confirmed with the June 1980 NEKTON data set. As in the original review no geological features have been shown on plate 1 that cannot be correlated between two or more lines.

The June 1980 NEKTON data suggest that the CZD narrows to the south and merges with a syncline that marks the landward boundary of the OZD. This syncline in turn is truncated by a fault that lies parallel or subparallel to this syncline (plate 1).

In the area of the proposed CZD-OZD intersection the OZD is wide (6.4 km) but appears on the bases of the June 1980 NEKTON data to narrow or trend out onto the continental slope southeast of the intersection (plate 1). Components of the OZD southeast of the proposed CZD-OZD intersection consist primarily of a single continuous fault. At the locality where the OZD is represented by a single fault a scarp on the seafloor suggests recent fault movement. The seafloor scarp is at the intersection of two very continuous faults within the central part of the OZD (plate 1).

Structure noticeably changes southeast of the OZD-CZD intersection. Northwest of this intersection structural components mapped on the shelf are plentiful and relatively complex while southeast of the intersection the structural components are reduced in number and complexity (plate 1).

The geological structure mapped from the total review process, with

by a few exceptions are confined to a section of well stratified sedimentary rock that lies wholly beneath a prominent unconformity and a thin sequence of poorly stratified, locally acoustically transparent (poorly consolidated and possibly water saturated) sediment. The exceptions noted are faults that displace near surface bedrock or sediment in the vicinity of (1) the proposed intersection of the CZD and OZD, (2) along the eastern margin of the CZD at a single locality and (3) centrally in the CZD at four separate localities that lie between approximately 4.5 - 6 km south of SONGS (plate 1).

CONCLUSIONS

The CZD merges with or is truncated by the OZD in the area offshore from SONGS (plate 1). Generally faults within the CZD with few exceptions (plate 1) displace shallow stratified sedimentary rock that lies beneath a prominent unconformity and younger poorly stratified sediments. The June 1980 NEKTON data support the conclusions reported previously by Greene and Kennedy (1980).

APPENDIX H

PRESERVICE INSPECTION REQUIREMENTS OF 10 CFR 50.55a(g)(2)

I. Introduction

For nuclear power facilities whose construction permits were issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) specifies that components shall meet the preservice examination requirements set forth in editions of Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code and Addenda in effect of six months prior to the date of the issuance of the construction permit. The provisions of 10 CFR 50.55a(g)(2) also state that components (including supports) may meet the requirements set forth in subsequent editions of this code and addenda which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In a letter dated October 6, 1980, the applicants submitted their preservice inspection program for San Onofre 2 and 3. Additional information was provided in response to questions 121.33 through 121.38 in the FSAR. This Appendix evaluates the extent to which the San Onofre 2 and 3 comply with the requirements of the 1974 Edition through Summer 1975 Addenda of Section XI. As a result of our review of the preservice inspection program, we have determined that certain examinations are impractical and that performing these examinations would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Our basis for this conclusion is discussed in the subsequent paragraphs of this Appendix.

II. Technical Evaluation Considerations

San Onofre 2 and 3 received construction permits on October 18, 1973. In accordance with 10 CFR 50.55a, the preservice inspection must comply with the 1971 Edition through Winter 1972 Addenda of the Code.

The ASME first published rules for inservice inspection in the 1970 Edition of Section XI. No preservice or inservice inspection requirements existed prior to that date. Since the plant system design and ordering of long lead time components were well underway by the time the Section XI rules became effective, full compliance with the exact Section XI access and inspectability requirements of the Code was not always practical. The applicants elected to base the preservice inspection program on the requirements of the 1974 Edition through Summer 1975 Addenda, as permitted by 50.55a(g)(2) in 10 CFR 50.

Verification of the as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction

codes to which the San Onofre 2 and 3 primary pressure boundary were fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations the primary pressure boundary full penetration welds were volumetrically inspected (radiographed) and the system was subjected to hydrostatic pressure tests.

The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examinations can then be compared to the original condition to determine if changes have occurred. If review of the inservice inspection results shows no change from the original condition, no action is required. In the case where baseline data are not available, all indications must be treated as new indications and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which can be used as the basis for evaluating the acceptability of such indications. Therefore, conservative disposition of defects found during inservice inspection can be accomplished even though preservice information is not available.

Other benefits of preservice examination include providing redundant or alternative volumetric inspection of the primary pressure boundary using a test method different from that employed during the components fabrication. Successful performance of a preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of San Onofre 2 and 3, a large portion of the ASME Code requiring preservice examination was performed. We have concluded that failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, we will require that these or supplemental examinations be conducted as a part of the inservice inspection program. We have concluded that requiring these supplemental examinations to be performed at this time (before plant startup) would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current inspection technique limitations, we will continue to evaluate the development of new or improved volumetric examination techniques. As improvements in these areas are achieved, we will require that these new techniques be made a part of the inservice examination requirements of those components or welds which received a limited preservice examination.

III. Evaluation Of Relief Requests

We have reviewed the information supplied by the applicants in the October 6, 1980 submittal and in response to our questions in the FSAR. Based on this information and our review of the design, geometry, and materials of construction of components, certain preservice inspection requirements identified below have been determined to be impractical, and imposing these requirements would result in hardships or unusual difficulties without a compensating increase in quality and safety.

Therefore, pursuant to 10 CFR Part 50, paragraph 50.55a(g)(2), our conclusions that these preservice requirements are impractical is justified as follows:

- (1) Pressurizer and Steam Generator Nozzle -To-Vessel Weld Examinations (Relief Request B-1 and C-1).

Code Requirements:

Examination Category B-D, Item Numbers B2.2 and B3.2 (applies to pressurizer and primary side nozzles of steam generators): volumetrically examine 100% of the volume shown in Figure IWB-25000 of Section XI, including, weld, adjacent base metal and inside radiused section.

Examination Category C-B, Item Number C1.2 (applies to secondary side of steam generators): volumetrically examine 100% of the nozzle-to-vessel attachment weld.

Code Deviation Request:

Perform ultrasonic examination from only the vessel side of the nozzle.

Reason for Request:

The nozzle design on the San Onofre steam generators and pressurizer has limited access on the nozzle forging side for conducting ultrasonic examination. Because of this restricted access, the volumetric examination can be performed only from the vessel side and not from the piping side.

Staff Evaluation:

The geometric configuration of the nozzle-to-vessel weld prevents ultrasonic examination from the nozzle side of the weld. The applicant has estimated that 60% of the code required volume can be examined with a 0° ultrasonic scan, 84% with a 45° scan, and 87% with a 60° scan. The ASME Code requires that three different scanning angles be used in the examination. Hence, only a limited portion of the code required volume cannot be examined during the preservice inspection by ultrasonic techniques. As part of the construction code examinations, these welds were volumetrically examined by radiography and received a surface examination.

The weld identifications for which this request for relief applies are as follows:

<u>Nozzle</u>	<u>Weld No.</u>	<u>Examination Category</u>
S/G Inlet	02-003-010	B-D
S/G Outlet @ 45°	02-003-011	B-D
S/G Outlet @ 315°	02-003-012	B-D
S/G Inlet	02-004-010	B-D
S/G Outlet @ 45°	02-004-011	B-D
S/G Outlet @ 315°	02-004-012	B-D
Pressurizer Surge	02-005-009	B-D
Pressurizer Spray	02-005-010	B-D
Pressurizer Safety @ 45°	02-005-011	B-D
Pressurizer Safety @ 225°	02-005-012	B-D
Pressurizer Safety @ 315°	02-005-013	B-D
S/G Steam	02-042-007	C-B
Feedwater	02-042-008	C-B
S/G Steam	02-043-007	C-B
Feedwater	02-043-008	C-B

We have determined that the design of the nozzle-to-vessel welds prevents the applicant from examining 100% of the code required volume, and the imposition of this requirement would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. We conclude that the limited ultrasonic examinations, the volumetric examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

- (2) Reactor Pressure Vessel Studs and Nuts; Reactor Coolant Dump Studs (Relief Request B-2).

Code Requirement:

Volumetric and surface examinations, when removed. (Examination Category B-6-1, Item B1.8).

Code Deviation Request:

For the preservice inspection, the volumetric and surface examination requirements have been met under ASME Section III and no relief is required. For the inservice examinations, relief is requested from performing a surface examination.

Reason for Request:

It can be shown that the chemical cleaning used to remove the protective coating on the studs and nuts will have a deleterious effects. Because of this harmful situation, only a volumetric examination will be conducted on these components.

Staff Evaluation:

The applicants have indicated that the Code required preservice examinations were performed. Hence, relief is not required for the preservice inspection. For the inservice inspection review, we will require additional information concerning the nature of the protective coating, the deleterious effects which may result from chemical cleaning, and the feasibility of substituting alternate materials before relief can be granted.

- (3) Piping Branch Connections in Reactor Coolant, Safety Injection, and Shutdown Cooling Systems (Relief Request B-4).

Code Requirement:

Piping branch connections exceeding six inches in diameter require a volumetric examination from both sides of the weld. (Examination Category B-1, Item B4.6).

Code Deviation Request:

Perform only a limited volumetric examination.

Reason for Request:

Restricted access and weld and nozzle design configurations prohibit a volumetric examination from the nozzle forging side of the pipe. A volumetric examination can only be performed from the reactor coolant piping side.

Staff Evaluation:

The geometric configuration of the branch pipe connections prevents ultrasonic examination from the nozzle forging side of the pipe. The applicant has estimated that 60% of the code required volume can be examined with a 0° scan, 84% with a 45° scan, and 87% with a 60° scan. The ASME Code, Section XI, requires that three different scanning angles be employed in ultrasonic

examinations. Hence, relief is required from only a limited portion of the volume specified by the code. As part of the fabrication code examinations, these welds were examined by radiography and received a surface examination.

The weld identifications for which this request for relief applies are as follows:

<u>Nozzle</u>	<u>Weld No.</u>
RC Surge	02-006-008
RC Drain	02-006-009
Shutdown Cooling	02-007-009
RC Drain	02-008-018
Safety Injection	02-009-009
RC Spray	02-009-010
Charging	02-009-011
RC Drain	02-010-018
Safety Injection	02-011-009
RC Spray	02-011-010
RC Drain	02-012-018
Safety Injection	02-013-009
Charging	02-013-010
RC Drain	02-014-018
Safety Injection	02-015-009

We have determined that the design of these branch pipe connection welds prevents the applicant from examining 100% of the code required volume, and the imposition of this requirement would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. We conclude that the limited ultrasonic examinations, the volumetric examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

- (4) All ASME Class 1 and 2 Piping Systems (Relief Request B-6).

Code Requirement:

Ultrasonic examinations of Class 1 or 2 ferritic steel piping systems shall be conducted in accordance with ASME Section V, Article 5.

Code Deviation Request:

Use an ultrasonic recording sensitivity of 50% in lieu of 20%, as specified in Article 5 of Section V.

Reason for Request:

ASME Section XI, Subarticle IWB-3121 states that inservice nondestructive examination results shall be compared with recorded results of the preservice and prior inservice examinations. In keeping with the interest of the code, San Onofre's first inservice examination results will be compared to the preservice examination results. Since the 1977 Edition through Summer 1978 Addenda requirements of IWA-2232 only requires recording of reflectors that

produce a response greater than 50%, SCE saw no value in recording indications between 20% and 50%.

The present San Onofre 2 and 3, Preservice Examination Program for recording of reflectors is verbatim identical to the Code which will be used inservice.

Staff Evaluation:

The applicant may update to the provisions of the 1977 Edition through Summer 1978 Addenda, which are approved in 10 CFR 50.55a(b), as permitted by Paragraph 50.55a(g)(2). The Summer 1978 Addenda requires that reflectors which produce a response greater than 50% of the reference level shall be recorded, and reflectors with a response greater than 100% of the reference level to be investigated to the extent that the operator can determine the shape identity, and location of all such reflectors in terms of the acceptance-rejection standards. The applicable provisions for the 1974 Edition of Section XI are in Article 5 of Section V, and require indications which produce a response greater than 20% of the reference level to be investigated.

As an alternative examination, we will require the following for the inservice inspection program:

- a. Indications of 50% of DAC or greater shall be recorded.
- b. An indication 100% of DAC or greater shall be investigated by a Level II or Level III examiner to the extent necessary to determine the shape, identity, and location of the reflector.
- c. Non-geometric indications 20% of DAC or greater discovered during the ultrasonic examination shall be recorded and investigated by a Level II or Level III examiner to the extent necessary to determine the shape identity, and location of the reflector.

IV. Additional Relief Requests

In addition to the relief requests evaluated in Section III, the applicant submitted three relief requests which involved updating examination requirements to the 1977 Edition through Summer 1978 Addenda of Section XI of the ASME Code. Updating to the requirements of later NRC approved editions and addenda is permitted by 50.55a(g)(2), subject to the limitations and modifications in 50.55a(b). We have evaluated the following relief requests submitted by the applicant and have found them to be acceptable. Thus, relief is not required.

<u>Relief Request Identification</u>	<u>Examination Category</u>	<u>Component</u>
1. B-3	B-I-1 and B-I-2	Cladding on RV, steam generator, and pressurizer

<u>Relief Request Identification</u>	<u>Examination Category</u>	<u>Component</u>
2. B-5	B-K-1	Integrally welded attachments
3. C-2	C-D	Class 2 bolting

V. Conclusions

Based on the foregoing, we have determined, pursuant to 10 CFR Part 50, paragraph 50.55a(a)(2), that certain Section XI required preservice examinations are impractical, and compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

Our technical evaluation has not identified any practical method by which San Onofre 2 and 3 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are steam generator nozzles, pressurizer nozzles, and piping support systems. Even after the redesign effort, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on our review and evaluation we conclude that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(2), we have allowed deviations from these requirements which are impractical to implement and would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. We conclude that the San Onofre 2 and 3 preservice examinations meet the requirements of the 1974 Edition through Summer 1975 Addenda of Section XI of the ASME Code to the extent practical and is in compliance with 10 CFR 50.55a(g)(2).

Further we have determined that the granting of these deviations does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. We have concluded that this action would be insignificant from the standpoint of environmental impact and pursuant to 10 CFR 51.5(d)(4) that an environmental impact statement, or negative declaration and environmental impact appraisal, need not be prepared in connection with this action.

NRC FORM 335 (7-77)		U.S. NUCLEAR REGULATORY COMMISSION BIBLIOGRAPHIC DATA SHEET		1. REPORT NUMBER (Assigned by DDC) NUREG-0712	
4. TITLE AND SUBTITLE (Add Volume No., if appropriate) Safety Evaluation Report Related to the Operation of San Onofre Nuclear Generating Station, Units 2 and 3, Southern California Edison Company, et al.				2. (Leave blank)	
7. AUTHOR(S)				3. RECIPIENT'S ACCESSION NO.	
9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Office of Nuclear Reactor Regulation U.S. Nuclear Regulatory Commission Washington, D.C. 20555				5. DATE REPORT COMPLETED MONTH YEAR February 1981	
12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Same as 9. above				DATE REPORT ISSUED MONTH YEAR February 1981	
				6. (Leave blank)	
				8. (Leave blank)	
				10. PROJECT/TASK/WORK UNIT NO	
				11. CONTRACT NO.	
13. TYPE OF REPORT			PERIOD COVERED (Inclusive dates)		
15. SUPPLEMENTARY NOTES Docket Nos. 50-361 and 50-362				14. (Leave blank)	
16. ABSTRACT (200 words or less) The Safety Evaluation Report for the application filed by Southern California Edison Company, et al for licenses to operate the San Onofre Nuclear Generating Station, Units 2 and 3 (Docket Nos. 50-361 and 50-362) located in San Diego County, California has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. A Safety Evaluation Report on geological and seismological matters for San Onofre 2 and 3 was issued in December 1980 (NUREG-0712). The December 1980 report is incorporated into this February 1981 report as Section 2.5. Subject to favorable resolution of the items discussed in the Safety Evaluation Report, the staff concludes that the plant can be operated by the Southern California Edison Company without endangering the health and safety of the public.					
17. KEY WORDS AND DOCUMENT ANALYSIS			17a. DESCRIPTORS		
17b. IDENTIFIERS/OPEN-ENDED TERMS					
18. AVAILABILITY STATEMENT Unlimited			19. SECURITY CLASS (This report) Unclassified		21. NO. OF PAGES
			20. SECURITY CLASS (This page) Unclassified		22. PRICE \$



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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, \$300

POSTAGE AND FEES PAID
U.S. NUCLEAR REGULATORY
COMMISSION

