NUREG-0857
Supplement No. 6

Safety Evaluation Report
related to the operation of Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Docket Nos. STN 50-528, STN 50-529, and STN 50-530

Arizona Public Service Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulatio

October 1984

UNITED STATES NUCLEAR REGULATORY COMMISSION

8411210379

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ABSTRACT

Supplement No. 6 to the Safety Evaluation Report for the application filed by Arizona Public Service Company, et al., for licenses to operate the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (Docket Nos. STN 50-528/529/530), located in Maricopa County, Arizona, has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. The purpose of this supplement is to update the Safety Evaluation Report by providing an evaluation of (1) additional information submitted by the applicant since Supplement No. 5 was issued and (2) matters that the staff had under review when Supplement No. 5 was issued.

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

On November 13, 1981, the Nuclear Regulatory Commission (NRC) staff issued its Safety Evaluation Report (SER) relating to the application for licenses to operate the Palo Verde Nuclear Generating Station, Unit Nos. 1, 2, and 3 (PVNGS 1-3); Supplement Nos. 1 through 5 to the SER were issued on February 4, 1982; May 17, 1982; September 23, 1982; March 15, 1983; and November 28, 1983, respectively. The application was submitted by the Arizona Public Service Company (APS or the applicant) on behalf of itself, the Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, El Paso Electric Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority.

In the SER and its supplements, the staff identified certain issues for which either further information was required of the applicant or additional staff effort was needed to complete the review of the application. The purpose of this supplement is to update the SER by providing an evaluation of (1) additional information submitted by the applicant since Supplement No. 5 to the SER was issued, and (2) matters that the staff had under review when Supplement No. 5 was issued.

Each of the following sections of this supplement is numbered the same as the section of the SER and its supplements that is being updated and, unless otherwise noted, the discussions are supplementary to and not in lieu of the previous discussions. Appendix A to this supplement is a continuation of the chronology. Appendix B, References, lists material used in preparing this supplement. Appendix C is a report by the Advisory Committee on Reactor Safeguards, dated October 18, 1983. Appendix D is a list of the milestones for implementation of inadequate core cooling instrumentation. Appendix E is a list of abbreviations used in this supplement. Appendix F is a list of principal contributors to this supplement.

1.9 Summary of Outstanding Issues

Section 1.9 of Supplement No. 5 contained a list of the outstanding issues. Several of those issues were resolved after Supplement No. 5 was issued. These are listed below, along with the section of this supplement wherein their resolution is discussed.

(1) Structural welding code (3.8.3)

(2) Seismic and loss-of-coolant (LOCA) loads for fuel assemblies (4.2.1)

(3) ACRS (Advisory Committee on Reactor Safeguards) comment on rapid depressurization capability (18)

In addition, one open issue concerning alternative shutdown capability has now become a confirmatory issue, as discussed in Section 9.5.1.6 of this supplement.

At this time, a number of outstanding issues remain to be resolved. These are listed below along with the section of the SER and/or its supplements wherein each issue is discussed. These remaining issues will be addressed in a future supplement to the SER.

(1) Foundation stability (2.5.4.3)
(2) Categorization of pressure isolation valves (3.9.7)
(3) Environmental qualification (3.11)
(4) PSI (preservice inspection) program, Units 2 and 3 (5.2.4, 6.6)
(5) Pressurizer auxiliary spray system (5.4.3)
(6) Qualification of control systems (7.7.2)
(7) Associated circuits (9.5.1.6)
(8) Organizational structure (13.1)
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(14) QA program description (17)
(15) Postaccident sampling system (II.B.3)

1.10 Confirmatory Issues

Section 1.10 of Supplement No. 5 contained a list of issues that had been essentially resolved to the staff's satisfaction, but for which certain confirmatory information was to be provided by the applicant. Subsequent to the issuance of Supplement No. 5, the applicant provided the required confirmatory information for several of those issues. These are listed below, along with the section of this supplement wherein the issue is resolved.

(1) Load limiting device testing (3.9.1)
(2) SCU (statistical combination of uncertainties) comparison (4.4)
(3) CPC software (7.2.4)
(4) Torrey Pines quality assurance (QA) evaluation (17.7.3)
(5) Emergency procedure guidelines (I.C.1)
(6) ICC (inadequate core cooling) system (II.F.2)

At this time, information on the remaining confirmatory issues is still pending or under staff review. These are listed below along with the section of the SER and/or its supplements wherein each issue is discussed. The resolution of these remaining issues will be addressed in a future supplement to the SER.

(1) Pump and valve operability, confirmation of program completion (3.9.3.2)
(2) Seismic qualification, confirmation of program completion (3.10)
(3) Guide tube wear surveillance, Unit 2 (4.2.5)
(4) Pressurized thermal shock, Units 2 and 3 (5.3.3)
(5) Cooldown testing for natural circulation (5.4.3)
(6) Relief valves for shutdown cooling system (5.4.3)
(7) Net positive suction head (NPSH) for emergency core cooling system (ECCS) pumps (6.3.1)
(8) Fiber optic data links (7.2.4)
(9) Electric system overvoltages (8.4.7)

(10) Fire protection program (9.5.1)
(11) Alternative shutdown capability (9.5.1.6)
(12) Control room design review (I.D.1)

1.11 License Conditions

Section 1.11 of the SER and Supplement Nos. 1, 2, and 5 list several issues for which a condition will be included in the operating license to ensure that NRC requirements are met during plant operations. One of the issues relates to providing an analysis of the ultimate capacity of the containment, which is identified as Item (2) in the SER. After the SER was issued, the applicant provided the ultimate capacity analysis for containment by letter dated August 26, 1984. Therefore, this condition has already been met and will not be included in the license.

Another issue relates to having administrative procedures in place prior to exceeding low-power testing to test and protect programs on the plant monitoring system computers, which is identified as Item (7) in the SER. After the SER was issued, the applicant informed the staff by letter dated September 26, 1984, that these administrative procedures are now in place. Therefore, this condition has already been met and will not be included in the license.

In addition to the 17 issues previously listed, one other issue has been identified in this supplement for which a condition will be included in the operating license. The issue is listed below, with an appropriate reference to the section of this supplement where it is addressed.

(18) ICCI system (II.F.2)

2 SITE CHARACTERISTICS

2.5 Geology and Seismology

2.5.4 Stability of Subsurface Materials and Foundations

2.5.4.3 Foundation Stability

The staff's completed evaluation of foundation stability was provided in Supplement No. 1 to the SER.

Subsequently, the applicant informed the staff that temporary construction water lines under the auxiliary building of each unit of PVNGS 1-3 had experienced leaks which resulted in erosion of backfill soil. The use of the water lines was discontinued and the lines were filled with grout to prevent further use. The applicant has provided the staff with an evaluation of the cause and effects of the water-line leakage, including an analysis of the stability of the affected buildings as a result of the soil erosion.

The staff is currently reviewing the information provided by the applicant and will report the results of its evaluation in a future supplement to the SER.

3 DESIGN CRITERIA - STRUCTURE, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.8 Design of Category I Structures

3.8.3 Concrete and Structural Steel Internal Structures

In Section 3.8.3 of Supplement No. 5 to the SER, the staff stated that the applicant was asked to provide justification for an exception taken to the American Welding Society Structural Welding Code AWS D1.1-72. The specific exception is that the governing thickness to determine preheat requirements for fillet welds was the weld throat thickness rather than the base metal thickness. Subsequently, the applicant responded to the above request, and the staff's evaluation is presented below.

In its response dated December 14, 1983, the applicant referenced a previously submitted test report, "Qualification of an Alternative Electrode Control Program for AWS D1.1-72 for the Arizona Nuclear Power Project," dated March 15, 1978. The results presented in the report demonstrated that weld procedure qualifications performed without preheat produced acceptable welds, i.e., hydrogen cracking was not present, even though some of these tests were under very high restraints. However, the maximum thickness tested was one inch and the structures in the field are significantly thicker than one inch.

Therefore, the applicant was asked to demonstrate that this exception to AWS D1.1-72 had not resulted in hydrogen cracking being present in field structures. To detect hydrogen cracking, a minimum time span between completion of welding and inspection of the welds should be specified. In the staff's judgment, 48 hours would be a reasonable time after welding to detect such cracking if it were to occur.

The applicant's response dated February 28, 1984, provided the following information. All welds are required to be visually inspected by quality control personnel. Normal plant construction practices will result in a time span longer than 48 hours between welding and inspection. Rarely would a shorter time span occur, and then probably only on tightly scheduled work. Routine inspections of no or low preheat welding of structural steels have not shown hydrogen cracking to be a factor.

Some low preheat welds on thick section steel were magnetic particle (MT) inspected in addition to routine visual inspections. The MT inspections did not reveal any cracking.

The staff has evaluated the information provided by the applicant and concludes that the applicant has demonstrated that its production operations and controls at the PVNGS site are adequate to allow the exception of the weld throat determining the preheat requirements rather than the base metal thickness. The exception is permitted within the provisions of AWS D1.1-72, Paragraph 5.2, where the engineer may qualify welding procedures which do not meet the prequalified weld-

ing procedure limits in AWS D1.1-72. Because of this provision, the staff finds the exception to be acceptable. Therefore, the issue is considered resolved.

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

In Section 3.9.1 of Supplement No. 5 to the SER, the staff identified a confirmatory item regarding the testing of the reactor vessel load limiting device. In a letter dated February 10, 1984, the applicant provided the results of its testing program. Twenty-one tests were run at various temperatures and crush velocities. The test results were found to be within the specified load deflection limits specified for PVNGS 1-3 and, therefore, are acceptable. Thus, this matter has been resolved.

4 REACTOR

4.2 Fuel System Design

4.2.1 Seismic and LOCA Loadings

In Section 4.2.1 of the SER, the staff stated that the applicant should submit the results of an analysis to demonstrate that the fuel design can withstand combined seismic and asymmetric blowdown LOCA loads at the PVNGS site. By letter dated September 26, 1983, the applicant submitted the results of such an analysis based on the models and acceptance criteria described in CENPD-178, Revision 1 (August 1981), which was approved by the staff for analyzing the fuel design for Combustion Engineering Standard Safety Analysis Report (CESSAR) System 80 plants.

The staff has reviewed the results of the analysis submitted by the applicant and concludes that the CESSAR interfaces are acceptably addressed in the analysis since the analysis is based on the approved methodology in CENPD-178, Revision 1. The staff also concludes that the results demonstrate compliance with Standard Review Plan (SRP) Section 4.2, Appendix A, and are acceptable since the peak combined loads on grids are below the prescribed limits. Therefore, this issue has been resolved.

4.4 Thermal-Hydraulic Design

In Section 4.4 of Supplement No. 5 to the Palo Verde SER, the staff stated that for each plant referencing CESSAR, the as-built error components should be compared to the generic CESSAR SCU (statistical combination of uncertainties) values (given in Enclosures 1-P and 2-P to LD-83-010, as discussed in Section 4.4.6 of Supplement No. 2 to the CESSAR SER) to verify that the generic values are bounding. The specific components are those associated with the linear heat rate, the departure from nucleate boiling ratio (DNBR) limiting safety system settings and the limiting conditions for operation.

The applicant responded to the above requirement by letter dated November 9, 1983. The response states that Combustion Engineering has reviewed the as-built error components for PVNGS 1-3 and determined that they are bounded by the generic CESSAR values. Since the error components for PVNGS 1-3 were found to be bounded by the CESSAR values, the staff finds them to be acceptable. Therefore, this matter has been resolved.

With regard to the issue of SCU values, Section 4.4.12 of Supplement No. 2 to the CESSAR SER identified two other confirmatory items for CESSAR plants. These items are (1) a review of safety analysis by Combustion Engineering (CE) to confirm that the minimum DNBR limit of 1.23 imposed as a result of the staff review for fuel burnup up to 20,000 MWD/MTU, rather than the CE-proposed 1.22, is not violated and (2) a commitment from CE to perform a test program to monitor pertinent parameters during the power ascension test of the first

CESSAR plant to determine if a hot-leg flow stratification anomaly exists in CESSAR plants.

By a letter dated August 31, 1983, CE addressed these issues. With regard to the minimum DNBR limit of 1.23, CE indicated that the DNBR limit currently installed in the COLSS (core operating limit supervisory system) and CPCs for CESSAR plants will be greater than or equal to 1.23, and that the conclusions of the CESSAR safety analyses remain valid for the installed COLSS and CPC DNBR limit. The staff, therefore, concludes that the DNBR limit issue has been properly addressed for fuel burnup not exceeding 20,000 MWD/MTU. Since the DNBR limit of 1.23 is based on a rod bow penalty of 0.8% DNBR for fuel burnup of 20,000 MWD/MTU, an additional rod bow penalty should be added to the DNBR limit for higher burnup. The PVNGS 1-3 technical specifications will incorporate a table of rod bow penalty as a function of burnup based on the approved methods described in CENPD-225, Supplement 3, "Fuel and Poison Rod Bowing," June 1979.

With regard to a possible hot-leg flow stratification anomaly, CE has committed to conduct a test program at PVNGS Unit 1, the first CESSAR System 80 reactor, in order to detect the presence or absence of a hot-leg flow stratification anomaly. The test program will consist of recording several hot-leg RTD temperature signals during the power ascension tests. The selected RTDs will provide sufficient data to determine if a hot-leg temperature transient occurs while the plant is running at equilibrium conditions. Hot-leg RTD temperatures will be recorded by a strip chart for a period of at least 24 hours at each of the power levels of 50%, 80%, and 100%. CE also committed that if a hot-leg anomaly is detected, the characteristics of the anomaly will be assessed, so that an appropriate strategy can be devised and implemented to handle the anomaly. The staff shall be notified as to how the uncertainty associated with the anomaly will be accounted for in the CPC calculation. On the basis of this commitment, the staff concludes that the possible hot-leg flow stratification anomaly issue has been properly addressed and that the tests will be included in the PVNGS Unit 1 power ascension program.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

In Sections 5.3.1.2, 5.3.1.3, and 5.3.1.4 of the SER, the staff stated that for PVNGS 1-3, exemptions would be required to Sections III.B.5 and III.C.2 of Appendix G, 10 CFR Part 50, and to Section II.B of Appendix H, 10 CFR Part 50. Subsequently, Appendices G and H were revised effective July 16, 1983.

The revised Appendix G requires that, in lieu of the requirements in Sections III.B.5 and III.C.2 of Appendix G, the fracture toughness program meet the ASME edition and addenda, as permitted by Paragraph 50.55a, 10 CFR Part 50. As discussed in the SER, the fracture toughness test program for PVNGS 1-3 does comply with the ASME Code fracture toughness requirements of Paragraph 50.55a. Hence, exemptions to the requirements of Appendix G are no longer required.

The revised Appendix H permits the use of the earlier editions (e.g., 1970 edition) of ASTM E-185 for the materials surveillance program, rather than the 1973 edition which was used in the evaluation of PVNGS 1-3 presented in the SER. Since PVNGS 1-3 does comply with the 1970 edition of the ASTM E-185, exemptions to the requirements of Appendix H are no longer required.

5.4 Component and Subsystem Design

5.4.3 Shutdown Cooling (Residual Heat Removal) System

In Section 5.4.3 of the SER, the staff stated that the applicant was required to reevaluate the sizing of the safety-grade nitrogen accumulators (which operate the steam generator atmospheric dump valves) after the natural circulation cooldown analysis for CESSAR System 80 is completed. Subsequently the required natural cooldown analysis and reevaluation of the accumulator sizing was completed. The staff's evaluation of this issue is presented below.

By a letter dated August 12, 1983, CE submitted a reanalysis of a full natural circulation cooldown for a CESSAR System 80 plant. The analysis was performed using only safety-related equipment concurrent with a loss of offsite power and an assumed single active failure. The results of this analysis indicate that a total of approximately 10.5 hours is required to maintain a System 80 plant at hot standby for 4 hours followed by cooldown from hot standby conditions to temperatures and pressures that permit use of the shutdown cooling system. Cold shutdown is achieved with a controlled steam void in the reactor vessel upper head. The maximum size of the steam void is about 1000 ft^3 during the cooldown process and it does not extend into the hot legs. The auxiliary pressurizer spray and charging systems are used for depressurization during cooldown of the reactor coolant system.

By a letter dated January 27, 1984, the applicant then reevaluated the design of the nitrogen accumulators for the atmospheric dump valves (ADVs) and concluded that they are sized for 4 hours at hot standby plus 6.5 hours of operation to reach cold shutdown under conditions of natural circulation. Therefore, the staff concludes that the nitrogen accumulators provide sufficient capacity to support ADV operation. This issue is now closed.

As a result of the staff's further review of the shutdown cooling system (SDCS) for PVNGS 1-3, two new issues have been identified which require resolution. These are discussed below.

(1) The relief valves in the SDCS are used to provide low-temperature overpressure protection for the reactor vessel as well as for SDCS. These valves are larger by an order of magnitude than those found in other PWR plants. At the time the valves were manufactured, the ASME Code permitted such valves to be certified based solely on calculations performed by the manufacturer. However, recent tests performed by the Electric Power Research Institute (EPRI) on large valves suggest that manufacturers cannot obtain a complete understanding of valve performance without some full-size testing or operational experience. Therefore, the staff has requested information to confirm that the large SDCS relief valves can provide the required pressure relief capacity and will subsequently reclose.

(2) A potential single failure has been identified in the auxiliary pressurizer spray (APS) system that may render the system unable to supply charging fluid to the pressurizer spray nozzle. The loop charging valve (CH-240) is manually operated and must be closed for charging flow to be diverted to the pressurizer for spray flow. Failure of the loop charging valve to close may cause insufficient flow to the pressurizer spray nozzle. The staff requires that this potential single failure be addressed in the context of Branch Technical Position RSB 5-1, Position A.3, as it relates to Class 2 plants.

The staff has advised the applicant of both of these issues, by letters dated April 3 and 18, 1984, and will report on the resolution of the concerns in a future supplement to the SER.

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protection System

7.2.4 Confirmatory Items

In the SER, the staff stated that it would audit the core protection calculator (CPC) software modifications after the modifications were completed. Subsequently the modifications were completed and the staff conducted the audit. The staff's evaluation of this matter is presented below.

Before the audit, the staff questioned the applicant regarding CEN-251(V)-P, Revision 0 - "PVNGS-1 Cycle 1, CPC and CEAC Data Base Listing," June 1983, which provided data base values for CPC and CEAC for PVNGS. The BERR values (addressable constants) were not consistent with the approved CESSAR System 80 values described in Enclosure 1-P tc LD-83-010, "Statistical Combination of Uncertainties Part II," January 1983. The applicant responded by letter dated April 17, 1984, that the current PVNGS BERR values do not differ from the CESSAR System 80 values. Since the BERR values are calculated toward the end of the CPC software testing, they are not available at the time the CPC/CEAC data base is generated. The BERR values given in CEN-251(V)-P were only preliminary values which were required in order to generate and certify a data base for use in Phase I and Phase II testing. In addition, certain outputs of the CPC/CEAC software testing were required as inputs to the uncertainty analysis which determines the correct BERR values for plant power operations. Since the BERR values are addressable constants, the final values are loaded when the software is loaded. The staff concludes that the information provided resolves the above concern.

The staff reviewed the "CPC/CEAC System Phase I Software Verification Test Report" and "CPC/CEAC System Phase II Software Verification Test Report" submitted by the applicant by letter dated July 27, 1983. The staff performed the CPC implementation audit on March 2, 1984. The audit items follow.

(1) Calculation for the PVNGS Unit 1 CPC addressable constants BERR0, BERR1, BERR2, BERR3, and BERR4

(2) PVNGS CPC/CEAC software changes from the San Onofre CPC/CEAC

(3) Procedures for transmittal of the CPC/CEAC-related documentation from Combustion Engineering (CE) to Arizona Public Service Co. (APS)

(4) QA procedures to avoid an undetected CPC/CEAC software error

(5) Exercise of the PVNGS Unit 1 CPC Phase II tests

The findings of the audit are summarized as follows:

(1) The values of the PVNGS addressable constants, BERR0 to BERR4, are the same as those reported in the CESSAR System 80 submittal, Enclosure 1-P to LD-83-010, "Statistical Combination of Uncertainties, Part II." The calculation of the BERR values is contained in the calculation file, Analysis No. 14273-TM-025, by S. H. Kim, dated May 23, 1983. The values reported in the CEN-251(V)-P, Revision 0, "PVNGS-1 Cycle 1, CPC and CEAC Data Base Listing," are the preliminary default values. The correct values had been transmitted to the applicant via a letter dated September 7, 1983.

(2) The software changes have been done in accordance with the approved procedure described in CEN-39(A)-P, Revision 2. The changes require a functional design specification for a CEAC, a functional design specification for a CPC, a software change request, and a computer code certification.

(3) The "Core Protection Calculation System Addressable Constants and Software Media Transfer Form" in the CE Document Control Package requires that an acknowledgement of receipt of the CPC Addressable Constants/Software media be signed by APS personnel. The staff suggested that (a) the PVNGS Station Manual Procedure No. 720P-95B01, Revision 0, "CPC Addressable Constants," be modified to include a provision to ensure that actions be taken for implementation of the CE transmittal of the addressable constants, or (b) the acknowledgement of receipt be changed to the acknowledgement of implementation. The applicant responded by a letter dated July 12, 1984, that it will add a statement to the PVNGS Station Manual Procedure No. 72AC-0ZZ03, Revision 0, "Control of Reactor Engineering and Operations Engineering Computer Software," requiring implementation of all the CPC software changes and addressable constants transmitted by CE, and return of the proper acknowledgement sheet for such changes to CE. The staff finds this acceptable.

(4) No QA procedures have been changed to avoid an undetected CPC/CEAC software error. However, the software design personnel have received additional training in the QA procedure to avoid such errors.

(5) An exercise of the Phase II test was performed by running the test cases in the single channel test facility. About 50% of the test cases were run for the dynamic software Verification Test and live input single parameter test. The results agreed completely with the results listed in CEN-219(V)-P, Revision 1, "CPC/CEAC System Phase II Software Verification Test Report."

On the basis of the audit and the fact that the results of all the test cases are within the acceptance criteria established for the initial DNBRs and trip times, the staff concludes that the CPC/CEAC Phase I and Phase II verification reports are acceptable. This matter is closed.

In Amendment No. 12 to the FSAR, the applicant stated that the CPC and CEAC provide their outputs and a number of their inputs to the plant-monitoring system (PMS) by means of fiber-optic data links isolation devices. In order to ensure that any electrical failure applied to the isolation device output will not degrade the operation of the circuit to the input below an acceptable level, the staff asked the applicant (letter dated July 25, 1984) to provide additional confirmatory information to address this matter. The applicant has responded by letter dated September 7, 1984. The staff is reviewing this information and will address this matter further in a future supplement to the SER.

8 ELECTRIC POWER SYSTEMS

8.4 Other Electrical Features and Requirements for Safety

8.4.7 Adequacy of Station Electric Distribution System Voltages

The staff's completed evaluation of the adequacy of station electric distribution system voltages was presented in Supplement No. 5 to the SER. Subsequently in Amendment No. 12 to the FSAR, the applicant revised its response in Appendix A concerning the results of an analysis of maximum voltages for safety-related motors. In its revised response, the applicant stated that under certain plant conditions the maximum voltage to the motors can be 118% of rated voltage, whereas previously the maximum voltage was less than 113%. As a result, the staff requested that the applicant provide additional information to confirm that the higher voltage does not adversely affect motor performance. After the applicant has responded, the staff will address this issue further in a future supplement to the SER.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

In Section 9.5.1.1 of the SER, the staff stated that a fire protection audit would be conducted at the PVNGS site to ensure the adequacy of the installed measures for the fire protection program. The fire protection site audit was conducted between February 1 and 4, 1983. As a result, the staff expressed a number of concerns pertaining to previous applicant commitments and the degree of compliance of the program with the fire protection criteria delineated in Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 and Appendix R to 10 CFR Part 50. In addition, certain features of the fire protection program, which required further review by the staff, were found acceptable. All these issues were addressed in the site audit summary report, dated April 11, 1983 (February 1-4, 1983, site audit).

By letters dated June 15, September 29, and December 1, 1983, the applicant provided additional information in response to the staff's concerns. Sections 9.5.1.2 through 9.5.1.6 of the SER have been supplemented and amended to reflect the results of the staff's evaluation of this information and the staff's further review of certain features of the fire protection program. The supplemental evaluation is presented below.

9.5.1.2 Fire Protection Systems Description and Evaluation

Sprinkler and Standpipe Systems

In the SER, the staff identified those areas for which the applicant committed to provide sprinkler and deluge fire suppression systems. During the site audit, the staff observed that sprinklers were missing from the main steam support structure at elevation 140 feet. By letter dated June 15, 1983, the applicant committed to install a sprinkler system both above and below elevation 140 feet before fuel load. On the basis of this commitment, this area conforms with Section C.3 of BTP APCSB 9.5-1 and is, therefore, acceptable.

The sprinkler system for the low-pressure safety injection (LPSI) and containment spray pump rooms features sprinkler nozzles positioned below the grating in the center of the room and none at the ceiling. Although this design concept does not achieve complete areawide sprinkler protection, it provides coverage for those locations where combustible materials would be present. Therefore, reasonable assurance exists that if a fire should occur, it would be extinguished by the sprinkler system or controlled until the plant's fire brigade arrived. The staff finds that an areawide sprinkler system is not necessary to limit fire damage, and therefore, the existing system is acceptable.

Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety-related area. During the site

audit, the staff became concerned that the location of hose stations would not permit an effective hose line to be deployed in the following areas:

(1) Diesel generator engine room and control room (zones 21/22)
(2) Main steam support structure (zone 74)
(3) Diesel generator air intake filter room (zone 24)
(4) Auxiliary building (zone 37)

By letter dated September 29, 1983, the applicant committed to install another hose station with 125 feet of hose in the control building near the exit to the diesel building. The installation of this hose station will achieve complete coverage for zones 21 and 22.

The applicant has conducted hose stretch tests to verify that the main steam support structure (MSSS) (zone 74) can be protected from the existing hose stations at elevations 100 feet and 140 feet of the turbine building. To reach the 120-foot level of the MSS, hose streams will be directed through the open steel gratings of the floor and ceiling above. This information resolves the staff's concern.

The existing standpipe stations at the air intake filter room (zone 24) and auxiliary building (zone 37) will be equipped with 125-foot lengths of hose line. The applicant has verified that no significant hydraulic degradation will occur with the use of this length of hose. Because these areas are easily accessible, the fire brigade will be able to deploy these hose lines to provide complete protection for the above referenced areas.

The staff, therefore, concludes that the installation of 125-foot lengths of hose line in the above zones is an acceptable deviation from Section C.3.d of Appendix A to BTP APCSB 9.5-1.

Fire Detection System

In the SER, the staff evaluated the design of the fire alarm system. During the site audit, the staff became concerned that a single break or ground fault condition would cause the loss of power to the multiplex system remote terminal concentrators (RTCs). This would represent a deviation from the guidelines of National Fire Protection Association (NFPA) Standard No. 72D.

The RTCs are powered from the plant security electrical distribution system. The security electrical distribution system supplies power to the RTCs through an uninterruptible power supply and parallel circuits to each unit. The loss of a power circuit will not affect more than two RTCs, and in most cases only one RTC. Loss of power to an RTC would be alarmed in the control room of each unit and in the guardhouse. The plant technical specifications require that a fire watch be established for the affected fire zone. The loss of power to an RTC does not prevent the actuation of fire protection systems. In addition, the loss of power to an RTC does not affect the operation of the local fire alarm panels since these are powered separately from the essential lighting system, with battery backup for areas required to be manned for safe shutdown. This design feature of the fire alarm system conforms to the guidelines of NFPA Standard No. 72D and Section C.1 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

The staff was also concerned that a trouble or fire alarm signal would not be continuously displayed on the cathode-ray tube (CRT) until the condition is rectified. This could result in an alarm being unacknowledged, with no corresponding response or corrective action. By letter dated June 15, 1983, the applicant verified that trouble/fire alarm signals remain displayed on the CRT until the condition is rectified and cleared by an operator. This information resolves the staff's concern and is, therefore acceptable.

In the SER, the staff stated that the fire alarm system supervision conforms to the requirements of NFPA Standard No. 72D for class A systems in the containment building and is class B supervised in the remainder of the plant. In actuality, for those areas provided only with fire detection systems, all wiring from the detectors to the local fire alarm panels is class A supervised. The wiring from the local panels to the security system is class B. The security system itself is class A.

The carbon dioxide system detector and initiating device circuits are class B supervised to the local fire alarm panels and from the panels to the security system remote terminal concentrator. There are two independent fire detection zones (circuits) associated with the carbon dioxide systems. If one zone experienced a trouble condition and was rendered inoperable, the zone would still be able to transmit a fire alarm signal to the control room.

The water suppression systems are class A supervised from the local panel to the security system. The signals that are wired class A are the "AC Power On," "Water Flow," "Alarm," and "Trouble" as appropriate to the type of system.

The diesel fire pumps have class A circuits for indication to the control room. These are "Pump Running," "Controller Switch Off" or "Manual Position," and "Controller Trouble." The class A circuits for the motor-driven fire pump are motor running and loss of power. This design feature conforms with the guidelines of Section C.1 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

During the site audit, the staff observed that the following areas, which contain safety-related equipment, were not equipped with fire detectors as recommended by Section C.1 of the guidelines:

(1) Condensate transfer pump room (zone 83)
(2) Elevation 131 feet, diesel generator building (zone 25)
(3) Above the auxiliary control cabinets (control room)
(4) Charging pump rooms (zone 46)
(5) Spray chemical accumulator room
(6) Spray chemical storage tankroom (zone 51B)
(7) Emergency cooling water (ECW) heat exchanger rooms (zone 43)

In Amendment No. 13 to the FSAR, the applicant committed to install fire detectors prior to fuel load in all of the above areas, except the ECW heat exchanger rooms. The staff's evaluation of the ECW heat exchanger rooms is presented below. For the remaining areas, the staff concludes that, with the installation of the detectors, the remaining areas are in conformance with Section C.1 guidelines.

The fire load in the ECW heat exchanger rooms is low, and combustible materials are widely dispersed. Consequently, a fire of any significant magnitude or duration is not expected to occur. If a fire were to occur in these areas, it would be detected by fire detectors in adjoining locations or by plant operators who would summon the fire brigade. The safety-related equipment in these locations consists of the heat exchanger shell which is not significantly prone to fire damage. Therefore, pending arrival of the brigade and eventual extinguishing of the fire, no loss of safety function would result. On the basis of its evaluation, the staff concludes that the absence of fire detectors in the ECW heat exchanger rooms is an acceptable deviation from Section C.1 of BTP APCSB 9.5-1.

During the site audit, the staff became concerned that no procedures existed to restrict the use of the emergency radio communications frequency to authorized personnel. Also, sufficient information was unavailable to ascertain the need for a radio repeater. By letter dated June 15, 1983, the applicant verified that emergency radio procedures are contained in the station Fire Response Procedure and that fixed repeaters are not necessary. This information resolves the staff's concern and is, therefore, acceptable.

9.5.1.3 Other Items Related to Fire Protection Programs

Fire Barrier and Fire Barrier Penetrations

Walls that separate buildings and walls between safe shutdown systems are 3-hour fire rated. During the site audit, information was not available to independently verify the fire rating of the drywall, metal lath and plaster, and hollow concrete block partitions. By letter dated December 1, 1983, the applicant provided additional information which confirmed the 3-hour rating for those items. Along with this information, the applicant identified a number of metal lath and plaster walls that will be reclassified as 1-hour fire-rated and non-fire-rated because their design cannot achieve a higher rating. The unrated walls do not separate fire areas. Also the walls do not separate redundant shutdown divisions. As such, these walls are in conformance with Section D.1 of BTP APCSB 9.5-1 and are, therefore, acceptable.

During the site audit, the staff observed that in several areas of the plant the walls are formed by removable concrete blocks. This design is intended to facilitate equipment servicing. The staff was concerned that these block walls may not be able to withstand the effects of a fire. However, a typical block wall is equal in thickness to the surrounding masonry wall (in excess of 24 inches). The blocks are staggered both horizontally and vertically and contain no penetrations which would facilitate the propagation of hot gases. In the staff's opinion, the block walls will achieve an acceptable level of fire safety equivalent to that provided by 3-hour fire-rated walls. Therefore, these walls are an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

During the site audit, the staff observed a number of unprotected openings in the following fire barriers:

(1) Wall separating zones 1 and 2 (control building elevation 74 feet) from the adjoining pipe chase

(2) Wall opening between elevation 88 feet of the auxiliary building and the radwaste building

(3) Seismic gap (both horizontal and vertical) at the containment building/auxiliary building interface (zones 42A and B, and 47A and B)

(4) Wall opening between elevation 120 feet of the main steam support structure (zone 74) and the turbine building

(5) PVC (polyvinyl chloride) drain pipe through a fire-rated floor assembly above the essential chiller room

The staff was concerned that if a fire occurred in one area, it would spread to other areas through these openings.

By letter dated September 29, 1983, the applicant committed to seal all openings in the wall separating zones 1 and 2 from the pipe chase and the wall between elevation 88 feet of the auxiliary building and the radwaste building with materials having a fire-resistance rating of 3 hours. The staff finds this commitment acceptable.

The applicant committed to install areawide automatic sprinkler systems in auxiliary building zones 42A and B and 47A and B. These systems will provide reasonable assurance that fire damage will be limited to the area of origin. A small amount of smoke and hot gases may pass through the existing gap but these products of combustion will represent no significant threat to safety-related systems in adjoining areas. Therefore, the staff finds this commitment acceptable.

The fire load at the opening between the main steam support structure (MSSS) (zone 74) and the turbine building, as well as in the essential chiller room, is low. Combustible materials are limited and widely dispersed. Therefore, a fire in either of these areas is not expected to propagate rapidly or with a high rate of heat release. The fire would be detected by fire detectors or plant operators and would be suppressed manually by the plant's fire brigade before significant damage occurred. Because these openings are not sealed with a fire-rated material, some smoke and hot gases would be expected to pass through the openings. However, the products of combustion would be so dissipated and cooled as to represent no significant threat to safety-related equipment on the other side of the barrier. The staff, therefore, concludes that the unprotected openings in the MSSS/turbine building wall and the PVC drain pipe penetration in the ceiling above the essential chiller room represent an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

In the SER, the staff stated that structural steel members were protected by spray-on fireproofing. During the site audit, the staff observed in a number of locations in the plant that the original fireproofing had been damaged by construction activities.

By letter dated June 15, 1983, the applicant committed to reapply the fireproofing to all sections of structural steel that were damaged. This work will be completed before fuel load. The staff finds this commitment acceptable.

The staff also observed that in the following locations, protection of steel members was not contemplated. The staff was concerned that, as a result of a fire, structural integrity may be compromised in

(1) Floors and roof of the diesel generator building
(2) Main steam support structure at elevation 140 feet
(3) Auxiliary building zones: 42A and 42B, 47A and 47B, 55 and 56B

In the diesel generator building, the applicant has verified that the floors and roof are self-supporting and are not dependent upon the unprotected steel members for structural integrity. Hence, the possible failure of these steel members in a fire will not result in the collapse of the floors, walls, or roof. This resolves the staff's concern and is, therefore, acceptable.

By letter dated December 1, 1983, the applicant committed to provide areawide sprinkler protection for auxiliary building zones 42A and 42B and 47A and 47B. The main steam support structure and auxiliary building zones 55 and 56B are presently protected by sprinkler systems. If a fire should occur in these areas, it would be detected by the existing fire-detection systems or plant operators who would summon the fire brigade. The fire would then be extinguished using portable fire-fighting equipment. If a fire propagated rapidly and caused a significant increase in room temperature, the fire-suppression systems would activate automatically to control the fire and reduce temperatures. Hence, there is reasonable assurance that the steel structural members would not be subjected to such temperatures as to cause their failure. Therefore, the staff concludes that unprotected steel in the main steam support structure and in the previously identified zones in the auxiliary building is an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

In Revision 2 to the fire-protection program reevaluation and fire hazards analysis, the applicant committed to provide 3-hour fire-rated sealant material in penetrations of fire barriers. During the site audit, the staff observed that bus duct penetrations of fire walls were not sealed. Also, sufficient information was not available to independently verify that lead powder/iron powder-type penetration seals were fire rated. By letter dated June 15, 1983, the applicant committed to seal bus-duct penetrations of fire walls by the time of fuel load. The applicant also verified that the dual-purpose penetration seals have been tested and rated for 3 hours. On the basis of the results of the seal test and the applicant's commitment, the staff concludes that this design feature is acceptable.

The staff was also concerned that in those locations where cable trays penetrate fire walls, a fire-induced tray collapse could cause the penetration seal to fail. By letter dated December 1, 1983, the applicant committed to protect the first tray support nearest the fire wall whenever the support is in excess of 24 inches from the face of the wall. The staff concludes that this protection provides reasonable assurance that the section of tray nearest the wall will remain in place during a fire, along with the penetration seal. Therefore, this design feature is acceptable.

Fire Doors and Dampers

In the SER, the staff stated that door openings in fire-rated barriers are provided with UL (Underwriters Laboratories)-listed fire doors. During the site

audit, the staff observed that there is a non-fire-rated watertight door in the wall separating the auxiliary feedwater pump rooms. With this arrangement, the staff was concerned about whether the steel, submarine-type, watertight door will protect the pump room contents from direct flame impingement, heat, and smoke until the fire self-extinguishes or is suppressed by the plant's fire brigade.

The fire load in this area of the plant is low. If totally consumed, the combustibles would produce a fire which corresponds to a fire severity on the ASTM E-119 time temperature curve of approximately 3 minutes. It is the staff's judgment that a fire in this area, if one should occur, would not be of significant magnitude or duration. It would be discovered early by the smoke detection system and extinguished by the fire brigade using manual fire-fighting equipment. Because the door is watertight, smoke would not pass through it. Since it is constructed of steel, the door would act as an effective radiant heat shield. The door, in conjunction with the ventilation system, would prevent convective heat from increasing to a significant level so as to damage safety systems. As a result, a 3-hour fire-rated door is not necessary to provide reasonable assurance that one safety division would remain free of fire damage. Therefore, the staff concludes that the watertight door is an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

During the site audit, the staff observed a number of door assemblies which protect openings in fire barriers that are not UL listed. By letter dated December 1, 1983, the applicant supplied a complete list of those doors. The door in the concrete block wall separating the auxiliary building, zone 48, from the radwaste building, zone 61C, contains a monorail passing through the upper transom door along with a removable piece in the monorail. This removable piece is to allow the double swinging transom door to close when the rail is not in use. The fire load on both sides of the wall is low. Also, the wall does not separate redundant shutdown divisions. In the same letter, the applicant committed to provide automatic sprinkler protection on both sides of the door to prevent the possibility of fire passing from one zone to another. The staff finds this commitment acceptable.

Door C 111 is a non-rated door in the main steam support structure. The door is not in a fire area boundary; it does not separate redundant shutdown divisions and it does not segregate significant fire hazards. Therefore, the lack of a fire rating has no safety significance.

All of the other door assemblies are unlisted because the doors, removable transoms, louvers, and glass view plates exceed listed sizes. By letter dated December 1, 1983, the applicant submitted the manufacturer's certification that the component materials which are used in these assemblies comply with UL and FM (Factory Mutual) construction requirements for a fire-rated assembly. It is the staff's judgment that these doors will provide an equivalent level of fire protection to listed fire doors. Therefore, the installation of unlisted doors, which are identified in the applicant's letter of December 1, 1983, is an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

During the site audit, the staff observed a number of swinging fire doors with fusible-link-type hold-open devices. The staff was concerned that, in the event of a fire, smoke and hot gases would propagate through the doorway before the

link fused and the door closed automatically. By letter dated June 15, 1983, the applicant committed to remove the fusible links in all swing-type fire doors by the time of fuel load. The doors will be maintained in a closed position continuously. The staff finds this commitment acceptable.

During the site audit, insufficient information was available to independently verify that fire dampers installed in the plant are listed by UL for the following uses:

(1) Grouped dampers at floor/wall penetrations
(2) Single dampers at 3-hour fire-rated wall/floor penetrations
(3) Dampers in drywall and metal lath and plaster partitions

By letter dated December 1, 1983, the applicant verified that the above dampers have been subjected to a fire test in accordance with the test method in ASTM E-119 and are either 1-1/2-hour or 3-hour fire rated, which is consistent with the rating of the walls in which they are installed. This information resolves the staff's concern and is, therefore, acceptable.

Because of the inaccessibility of some HVAC (heating, ventilating, and air conditioning) ducts and the absence of access panels, the staff was unable to visually confirm that dampers were installed wherever ducts penetrate fire barriers. By letter dated June 16, 1983, the applicant confirmed that every duct which penetrates a fire barrier has a fire damper. This is in conformance with Section D.1 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

Curbs are not provided at the entrance to the diesel generator rooms. The staff was concerned that if a diesel oil fire occurred, it would spread to other adjoining areas through the entryway. However, each diesel engine room contains a pipe trench with a sump and two sump pumps. Each trench is approximately 21 feet long, 4 feet wide, and 6 feet deep. The sumps are approximately 5 feet deep x 4 feet square (with about 48 ft^3 of usable volume above the pump low level cutoff). The floors are sloped to floor drains which run to the sumps. The total volume in the trench and sump for each room is approximately 550 ft^3, or 4400 gallons.

Each diesel generator contains approximately 1000 gallons of oil, and each sprinkler system is designed for approximately 350 gpm. Therefore, there is capacity in the sump for all the oil and approximately 10 minutes of sprinkler flow. This conforms with Section D.1 of the fire protection guidelines and is, therefore, acceptable.

9.5.1.4 Emergency Lighting

In Amendment 3 to the Fire Protection Evaluation, the applicant committed to provide 8-hour, battery-powered, emergency-lighting units in all areas needed for operation of safe-shutdown equipment. During the site audit, the staff noticed that an emergency light was not installed in the emergency cooling water (ECW) pump room (zone 34).

By letter dated June 15, 1983, the applicant committed to provide 8-hour battery-powered emergency lights in the above area before the time of fuel load. With this commitment, the ECW pump room will conform with Section D.5 of BTP APCSB 9.5-1 and is, therefore, acceptable.

9.5.1.5 Fire Protection for Specific Areas

Containment Building

In Amendment 3 to the Fire Protection Evaluation, the applicant committed to comply with Section III.O of Appendix R to 10 CFR Part 50 concerning an oil-collection system for the reactor coolant pumps. The staff was concerned that the piping, oil-collection tank, and protection for the lift pumps would not collect oil from leakage after a safe shutdown earthquake. By letter dated September 29, 1983, the applicant submitted design details of the oil-collection system.

The pressurized and unpressurized portions of reactor coolant pump (RCP) lube oil system (for pump and motor) have been analyzed to determine whether the components would survive a safe shutdown earthquake (SSE) without pressurized spray or leakage. On the basis of that analysis, the applicant identified various mechanical joints (e.g., flanges), RTD (resistance temperature detector) connections, and sight glasses in the unpressurized section as potential leakage paths.

The lift pump discharge connection flange is considered subject to failure and is shrouded with a silicon-treated, glass-cloth shield. The shroud is seismic Category I and provides an envelope for the oil spray, and serves to collect and direct the oil to the collection system like any other oil leakage. The shroud will be inspected annually as part of the RCP in-service inspection (ISI) program. Leakage points are provided with open "cans" or catch trays, or are enclosed in shields. These devices drain by gravity to a piping system. The interface point between the RCP collection devices and the piping system is an open funnel. The piping system drains by gravity to two collection tanks. Each tank can contain all the oil from two RCPs, plus 10%, and is equipped with a flame arrestor and sight glass.

On the basis of its evaluation of the design concept, the staff concludes that the RCP oil-collection system conforms with the requirements of Section III.O of Appendix R to 10 CFR Part 50 and is, therefore, acceptable.

In Amendment 3 to the Fire Protection Evaluation, the applicant proposed to utilize administrative controls to prevent fire damage to redundant shutdown divisions inside containment.

The staff was concerned that if a lapse in the controls occurred and a fire resulted, redundant shutdown divisions would be damaged. By letter dated December 1, 1983, the applicant committed to protect the train A pressurizer auxiliary spray circuitry from the train B circuitry by a radiant-energy shield. The shield consists of a metallic reflectorized insulation for the solenoid valves and a fire-rated barrier material for cables and conduit. The staff finds that the shield will provide protection and, therefore, the design is acceptable.

In the same letter, the applicant requested approval for a deviation from the requirement of Section III.G of Appendix R to the extent that it requires that redundant shutdown divisions be separated by 20 feet, free of intervening combustibles. Shutdown divisions not conforming to the separation criteria are physically separated within containment by a horizontal distance of more

than 67 feet, with the presence of intervening combustible materials. The intervening combustibles consist of a limited quantity of IEEE 383-qualified cable. The amount of combustible material within containment varies depending on the elevation. Existing fire protection includes ionization-type smoke detectors and line-type heat detectors, manual hose stations, and portable fire extinguishers. Because the combustibles are widely dispersed and sources of ignition are limited, the staff does not expect a fire of significant magnitude or duration to occur. Smoke and hot gases from a postulated fire would be dissipated and cooled through the large open areas of containment. It is the staff's judgment that, under these conditions, a fire would, at most, cause damage to systems from one shutdown division, but would not be able to propagate horizontally and damage the redundant division before self-extinguishing or being suppressed by the plant fire brigade. Therefore, the presence of intervening combustible materials within containment is an acceptable deviation from Section III.G of Appendix R.

Other Plant Areas

During the site audit, the staff observed that propane piping in the corridor at elevation 140 feet of the auxiliary building was vulnerable to damage. By letter dated June 15, 1983, the applicant committed to reroute the piping to above the structural framework of the drop ceiling to protect the piping from impact. This work is to be completed before the time of fuel load. The staff finds this commitment acceptable.

The staff also observed that there was no forced ventilation in the flammable gas storage room at elevation 140 feet of the auxiliary building. The staff was concerned that a hazardous concentration of gas could occur with a resulting fire or explosion. By letter dated June 15, 1983, the applicant committed to provide ventilation for this room in accordance with NFPA Standard No. 51. The staff finds this commitment acceptable.

9.5.1.6 Fire Protection for Safe Shutdown Capability

During the site audit, the staff observed that complete areawide automatic fire suppression was not provided in zone 42C at elevation 100 feet of the auxiliary building. The area is equipped with a complete smoke detection system; a cable-tray fire-suppression system; portable fire extinguishers; manual hose stations; and a 1-hour fire barrier around one shutdown division. If a fire were to occurr in this area, it would be detected in its initial stages by the smoke-detection system. The fire brigade would then be summoned and would extinguish the fire using portable fire-fighting equipment. If room temperatures rose significantly, the cable-tray sprinkler system would activate. Water from this system would protect vulnerable cables and would limit further temperature rise and fire spread. During the time delay between the advent of a fire and its eventual control, damage would be confined to this area by the fire-rated perimeter construction. Also, because one shutdown division is protected by a fire barrier, there is reasonable assurance that safe shutdown could still be achieved and maintained. Therefore, complete areawide sprinkler coverage is not necessary to limit fire damage. The staff concludes that the absence of areawide sprinkler protection in zone 42C at elevation 100 feet of the auxiliary building is an acceptable deviation from Section III.G of Appendix R.

The staff also observed that the 3-hour fire-rated wall at elevation 70 feet of the auxiliary building is not continuous, because it does not completely separate redundant shutdown divisions in the separate piping penetration rooms (zone 37). However, the wall is so located that if a fire were to occur in one penetration room, it would have to propagate through more than 150 feet of intervening plant areas in order to affect the redundant division. Because of the smoke-detection systems in these areas, the limited fire hazard, and the availability of manual firefighting equipment, it is the staff's opinion that damage would, at most, be limited to one shutdown division. With the other division, the plant would be able to achieve and maintain safe shutdown conditions. The staff, therefore, concludes that the lack of a continuous fire wall between the piping penetration rooms at elevation 70 feet of the auxiliary building is an acceptable deviation from Section III.G of Appendix R.

The staff's evaluation of the applicant's electrical separation study, for ensuring that at least one safe shutdown train is available in the event of a fire, is presented in Supplement No. 5 of the SER.

Subsequently, the applicant informed the staff that it is reassessing its electrical separation study to consider circuits that are associated with the safe shutdown train either because of (1) a common power source, (2) a common enclosure case, or (3) a spurious signal. After the applicant submits results of the associated-circuits review, the staff will evaluate those results and will provide its assessment in a future supplement to the SER.

In Supplement No. 5 to the SER, the staff stated that the completion of the review of the remote shutdown panel was subject to the resolution of the issue relating to the need for a source-range neutron flux monitor for the panel.

Subsequently, the applicant provided additional information on the subject by letter dated February 14, 1984 and in a meeting held on May 31, 1984. In its response, the applicant stated that in the event that the control room needs to be evacuated, a source-range neutron flux monitor is not necessary on the remote shutdown panel since a recriticality occurrence would be very unlikely because of the following considerations:

(1) Before leaving the control room area, the operator will ensure that the control rods are in by tripping the scram breakers.

(2) The initial hot shutdown margin for PVNGS 1-3 (CESSAR System 80) with the control rods in is approximately 14%, which is about twice the margin for other typical pressurized-water reactor (PWR) designs. This negative reactivity worth is sufficient to maintain the core subcritical in hot shutdown even with unborated water in the reactor.

(3) The operator will verify that makeup water to the reactor comes from a borated source.

(4) In the event of an inadvertent boron dilution incident (addition of unborated water to the core), and assuming a maximum cooldown rate of 60°F per hour, there still would be a shutdown margin of 4% nine hours after the start of the incident.

(5) The operator will check the boron concentration in the reactor coolant by taking samples every hour starting at two hours after the control room is evacuated.

The applicant also stated that the direct indication being provided at the remote shutdown panel for other primary process variables (e.g., temperature, pressure, and water level) can assist the operator in determining whether a boron dilution event is occurring. In addition, the remote shutdown panel instrumentation includes a log power meter, and the line downstream of the letdown isolation valve includes a boron concentration meter. Furthermore, to provide added confidence that a source-range neutron flux monitor is not necessary to provide the required indication of plant functions outside the control room, the applicant stated that it will perform a confirmatory probabilistic risk assessment (PRA) analysis regarding postfire recriticality.

The staff has reviewed the above design features for PVNGS 1-3. On the basis of these design features and subject to the confirmatory results of the PRA analysis being performed by the applicant, the staff concludes that the current design of the remote shutdown panel is acceptable and that the alternative shutdown capability complies with the requirements of Section III.L of Appendix R. Therefore, this matter now becomes a confirmatory item.

9.5.1.11 Summary of Deviations From Appendix A to BTP APCSB 9.5-1 and Appendix R to 10 CFR 50

The following deviations from the fire-protection guidelines have been evaluated and found acceptable. The section of this supplement in which each deviation is evaluated is shown after each item.

(1) The use of 125-foot lengths of fire hose (9.5.1.2)

(2) No fire detectors in areas containing safety-related equipment as delineated in Section (9.5.1.2)

(3) Removable block fire walls (9.5.1.3)

(4) Unprotected penetrations in fire barriers as identified (9.5.1.3)

(5) Unprotected structural steel as delineated (9.5.1.3)

(6) Unlisted watertight door in the fire barrier as listed (9.5.1.3)

(7) Equivalent fire doors in fire barriers as delineated (9.5.1.3)

(8) Intervening combustible materials between shutdown divisions in containment (9.5.1.5)

(9) Lack of areawide fire suppression at elevation 100 feet of the auxiliary building (9.5.1.6)

(10) Discontinuous fire wall at elevation 70 feet of the auxiliary building (9.5.1.6)

In addition to the above deviations, the applicant has recently revised its fire-protection program description in Amendment No. 13 to the FSAR, which identifies other deviations. The staff is currently reviewing this information and will provide its evaluation in a future supplement to the SER.

11 RADIOACTIVE WASTE MANAGEMENT

11.3 Process and Effluent Radiological Monitoring System

The staff's completed evaluation of the process and effluent radiological monitoring system was presented in Section 11.3 of the SER. Subsequently during the review of the PVNGS technical specifications, the staff determined that the plant design did not provide for flow monitors for determining gaseous effluent flow rates through the vents of the fuel building, condenser evacuation system, and the plant.

As a result, by letter dated January 16, 1984, the staff asked the applicant to document the method for determining gaseous flow rates through the vents discussed above. In its response dated June 14, 1984, the applicant stated that it will install flow sensors in the fuel building exhaust, condenser vacuum pump/gland seal exhaust, and plant vent for PVNGS 1-3. These sensors will be installed before Unit 1 fuel load with the following exception.

Installation of the flow sensors for the fuel building exhaust and the condenser vacuum pump/gland seal exhaust for PVNGS Unit 1, will be completed before exceeding 5% power operation. In the interim, until these flow sensors are installed, the applicant will utilize the maximum design flow rates through these vents for determining offsite doses. Since the maximum flow rates to be used by the applicant will provide a conservative estimate of the doses, the staff finds this compensating measure to be acceptable.

On the basis of the above evaluation, the staff reaffirms its conclusion that the process and effluent radiological monitoring systems and the sampling provisions for PVNGS 1-3 meet GDC 60, 63, and 64 of 10 CFR Part 50, Appendix A and the guidelines of Regulatory Guide 1.21.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure and Qualifications

In Section 13.1 of the SER, the staff provided its completed evaluation of the applicant's organizational structure and qualifications. Subsequently in Amendment No. 13 to the FSAR, the applicant updated the discussion on organizational structure to reflect the changes made since then. The staff is currently reviewing these changes and will provide its completed evaluation in a future supplement to the SER.

13.2 Training Program

13.2.1 Training Program for Licensed Plant Staff

The staff's completed evaluation of the applicant's training program for the licensed plant staff is presented in Supplement No. 1 to the SER.

Subsequently, by letter dated June 29, 1984, the applicant proposed changes to the training program in Section 13.2.1 of the FSAR. The proposed changes are to delete the course, Advanced Engineering Training, from the training program for subsequent senior reactor operator license candidates and to revise the FSAR to ensure that additional training for senior reactor operator license candidates, as specified in Paragraph 5.2.2, "Related Technical Training," of ANSI/ANS 3.1-1978, be included in the PVNGS training program.

The Advanced Engineering Training course, which is academic in nature, included instruction in differential calculus, integral calculus, materials science, corrosion chemistry, advanced reactor physics, thermodynamics, heat transfer, fluid mechanics, and human behavior. These topics now will be taught in depth in Nuclear Fundamentals, the training program course provided for reactor operator and senior reactor operator license candidates. The applicant has indicated that the heat transfer, fluid flow, and thermodynamics to be taught in this course were established in accordance with the guidance as outlined in Enclosure 2 of H. R. Denton's March 28, 1980, letter to all power reactor applicants and licensees.

On the basis of its review of the proposed changes to the training program, the staff has determined that the training program will be in accordance with the requirements of 10 CFR Parts 50 and 55. Therefore, the staff concludes that the proposed changes to the FSAR are acceptable.

14 INITIAL TEST PROGRAM

The staff's completed evaluation of the PVNGS 1-3 initial test program description was provided in Supplement No. 2 to the SER.

Subsequently, the applicant updated the test program description in Amendment No. 12 to the FSAR. As a result of the staff's review of the changes in Amendment No. 12, the staff requested additional information, relating to startup test procedures, organizational responsibilities and testing of the dc power system, by letter dated April 20, 1984. The applicant's response was submitted by letters dated July 3 and August 1, 1984. The staff is currently reviewing the information submitted on the Amendment No. 12 changes and will report on the results of its evaluation in a future supplement to the SER.

At this time the staff is also reviewing the resolution of problems encountered during preoperational testing with the following components:

(1) RCS pumps
(2) Control element shroud assembly
(3) Thermowelds
(4) Thermal sleeves
(5) LPSI pumps

The staff will report on the results of its evaluation of the above components in a future supplement to the SER.

15 ACCIDENT ANALYSES

15.3 Limiting Accidents

15.3.9 Anticipated Transients Without Scram

In Section 15.3.9 of the SER, the staff stated that the applicant had committed to develop emergency procedures for and train operators to respond to anticipated transients without scram (ATWS). As discussed in Section 22, Item I.C.1, in this supplement, the staff has approved the Combustion Engineering Owners Group (CEOG) Emergency Procedure Guidelines, and the applicant has committed to implement a program for developing plant-specific emergency operating procedures (EOPs) based on those guidelines.

Since the guidelines include appropriate actions for mitigating an ATWS, the staff concludes that the applicant has adequately responded to the guidance, in NUREG-0460, for having EOPs for mitigating an ATWS. Therefore, this matter is considered resolved.

15.4 Radiological Consequences of Design-Basis Accidents

15.4.5 Steam Generator Tube Rupture Accident

In Section 15.4.5 of Supplement No. 5 to the SER, the staff stated that it was reviewing the applicant's evaluation of the steam generator tube rupture (SGTR) accident. Results of the staff's review are presented below.

In the applicant's analysis, the dynamic response of the plant parameters for the first 460 seconds of the SGTR transient, i.e., from the time of tube rupture until the operator takes control of the plant, is the same as that described in CESSAR FSAR Section 15D. At 460 seconds the operator would take control of the plant and open one atmospheric dump valve (ADV) on each steam generator to cool down the plant at the maximum cooldown rate of 75°F/hr allowed by procedures. This cooldown rate translates into a 10.5% opening of one ADV of each steam generator. At 2700 seconds the reactor coolant system (RCS) would be cooled to 550°F.

In accordance with the procedures, the analysis then assumes that the operator isolates the auxiliary feedwater to the affected generator, closes the main steam isolation valves of both steam generators, and attempts to close the ADV of the affected generator. However, the analysis assumes that the damaged steam generator ADV fails to close and stays open for the remainder of the transient. The analysis assumes that the operator then initiates an orderly cooldown and depressurization using the ADVs and auxiliary feedwater (AFW) flow to the unaffected steam generator, auxiliary pressurizer spray, pressurizer heaters and safety injection flow. Thirty minutes after attempting to isolate the affected steam generator, it is assumed that the operator reduces the cooldown rate to 30°F/hr by throttling the intact steam generator ADV flow.

The applicant's analysis indicates that for the first two hours following the initiation of the SGTR event, approximately 488,000 lb of steam would be released to the environment through the ADVs and for the 2- to 8-hr cooldown period, an additional 982,000 lb of steam would be released via the ADVs from both steam generators. The maximum RCS and secondary pressures would not exceed 110% of design pressure throughout the transient.

The auxiliary pressurizer spray (APS) system was assumed operable for plant depressurization following an SGTR event. The staff will allow credit for only safety-related systems in the analysis of design-basis events. Since the applicant has assumed the operation of the APS in the analysis, the staff requires the applicant to address the potential deficiency of the APS system discussed in Section 5.4.3 of this supplement.

The backup pressurizer heaters are assumed to operate in the SGTR analyses to reflect the Combustion Engineering (CE) emergency response guidelines. These heaters are not fully safety related, but are powered from Class 1E power supplies. Because the use of the heaters results in a more conservative analysis (i.e., a slower RCS depressurization), the staff concludes that assuming the use of backup pressurizer heaters in the recovery period following an SGTR is acceptable.

Independent staff assessments of a postulated SGTR for PVNGS 1-3 with a stuck-open ADV at 10.5% indicated that the potential radiological consequences would be less than the 10 CFR Part 100 guideline values. However, the results are strongly dependent on the particular degree of opening for the ADVs during the postaccident operations. If the ADV should fail in the full-open position, or in a position greater than the 10.5% assumed for PVNGS 1-3, or if the cooldown rate is greater than 30°F/hr 30 minutes after attempting to isolate the failed ADV, preliminary calculations show that the offsite radiological consequences could exceed the 10 CFR Part 100 guideline values.

The ADVs at PVNGS 1-3 do not have upstream block valves. Hence, there would be virtually no way of isolating a stuck-open ADV. Only local, manual operator action, if at all possible, would terminate the leakage. The staff notes that the ADVs have no device to limit their opening to the assumed 10.5%, and other calculations have shown that an opening of slightly less than 12% would result in exceeding the 10 CFR Part 100 values. Also, there are no specific limits in either the technical specifications or procedures to restrict opening of the ADV to less than 10.5%. There is only the maximum cooldown rate limit of 75°F/hr, a value that the staff believes is difficult for the operator to determine during a complicated event like the SGTR.

In conclusion, the acceptability of the offsite radiological consequences of an SGTR accident is heavily dependent upon the instructions to the operators for maintaining a specific cooldown rate, and the ability of the operators to recognize the conditions when the cooldown rate exceeds the assumed values for this analysis. To resolve this issue, the staff finds that, from an overall plant safety standpoint, the applicant should install block valves at PVNGS 1-3 upstream of the ADVs, per the interface requirement stated in the CESSAR System 80 FSAR. Alternately, the applicant should either assume an ADV stuck in the full-open position, or provide positive assurance that the ADV cannot be opened beyond the assumed 10.5%.

The staff will report the resolution of this matter in a future supplement to the SER.

17 QUALITY ASSURANCE

The staff's completed evaluation of the applicant's quality assurance program was presented in Supplement No. 5 to the SER. Subsequently, in Amendment No. 13 to the FSAR and by letter dated August 30, 1984, the applicant revised its quality assurance program description. The staff is currently reviewing these changes and will provide its completed evaluation in a future supplement to the SER.

17.3 Quality Assurance Program

Subsequent to the issuance of Supplement No. 5 to the SER, by letter dated February 24, 1984, the applicant clarified its commitment to Regulatory Guides 1.28 and 1.33, as stated in Section 1.8 of the FSAR, to specify which of these regulatory guides will be applied during prerequisite and startup testing. As clarified, the applicant's commitment is that Regulatory Guide 1.28, "Quality Assurance Program Requirements (Design and Construction)," will be used during prerequisite and Phase I (preoperational) startup testing, and that Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)," will be used during Phase II through Phase V Startup Testing. Thus, the Phase I (preoperational) Startup Testing will be conducted in accordance with Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plant," instead of Section 5.2.1.9.1, "Preoperational Tests," of ANSI 18.7. This clarification is acceptable to the staff.

17.7 Independent Quality Assurance Evaluation

17.7.3 Assessment by NRC Staff

In Section 17.7.3 of Supplement No. 5 to the SER, the staff presented its assessment of (1) the findings identified by the Torrey Pines Technology (TPT) independent quality assurance evaluation of PVNGS 1-3 and (2) the applicant's corrective action plans (CAPs) for resolving the issues identified. In Supplement No. 5, the staff identified four areas, relating to PFRs 012, 027, 050, and 065, for which the applicant was asked to provide additional information to respond to TPT recommendations made for the applicant's corrective action plans in those areas.

Subsequently, the applicant provided the requested information by letters dated November 30, 1983 and February 6, 1984. The staff's completed assessment of this matter is presented in the following discussion.

Task C (Evaluation of QA Activities)

The applicant's CAP for potential finding report (PFR) 012 (improperly torqued instrument mounting bolts) only addressed undertorqued bolts. TPT recommended that questionable bolts be loosened and retorqued to the proper level. In its response, the applicant stated that for the bolts in question (i.e., those conforming to the specifications of ASTM A307) which are not undertorqued, once

such bolts are preloaded and do not fail during installation, they are considered good bolts. Since the bolts in question did not fail, the applicant concluded that they are acceptable. The staff concurs with the applicant and concludes that retorquing is not required. Therefore, this matter has been resolved.

The applicant's CAP for PFR 027 (lack of assurance that inspection of instrument panel welds did occur) stated that a sample of the affected welds would be reinspected. TPT recommended that all of the affected welds be reinspected. In its response, the applicant stated that documentation was reviewed to identify those instrument installations which involved welding (114 were identified). Then a sample of about 10% were reinspected and all welds on these installations were found to be acceptable. As a result, the applicant concluded that additional reinspection is not warranted since the results of sample reinspection provide adequate confidence that all affected welds are acceptable. Since all of the welds that were reinspected were found acceptable, the staff concludes there is reasonable assurance that the welds on the remaining installations are also acceptable. Therefore, the staff concurs with the applicant that additional reinspection is not warranted. Hence, this matter has been resolved.

Task D (Design Verification Review)

The applicant's CAP for PFR 050 (improperly specified stiffness or frequency for pump support structures) only addressed the containment spray pumps. Since the safety injection pumps were supplied to the same generic specification by the same vendor who provided the containment spray pumps, TPT recommended that the safety injection pumps be evaluated in a similar manner (i.e., either validating the frequency analysis of the pump/support combined response, or performing vibration testing during pump startup). In its response, the applicant stated that vibration testing of the safety injection pumps and containment spray pumps was performed during startup testing and that the measured amplitudes satisfy the specified acceptance criteria. Therefore, the staff considers this matter closed.

The applicant's CAP for PFR 065 (release of a design specification without internal interface design review) did not explicitly state that the interface review would be performed. As a result, TPT recommended that the interface review be done. In its response, the applicant stated that the required internal interface review of the specification was performed and that completion of the action is indicated by signature on the cover page of the specification. Therefore, the staff considers this matter closed.

18 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In Supplement No. 1 to the SER, the staff stated that it was evaluating the comments and recommendation made by the Advisory Committee on Reactor Safeguards (ACRS) regarding a need for a rapid depressurization capability for CESSAR System 80 plants. The following discussion presents the staff's completed evaluation of this matter.

The PVNGS 1-3 reactor coolant system is designed without power-operated relief valves (PORVs) on the pressurizer. As a result, capability to remove decay heat ultimately relies on removing heat via steam generators using emergency feedwater and atmospheric steam dump valves.

In its review of this matter, the ACRS had asked that the staff consider the potential for adding valves sized to facilitate rapid depressurization of the PVNGS 1-3 reactor coolant system to allow more direct methods of decay heat removal.

The staff evaluation of the need for a rapid depressurization capability for the current 3410 MWt and 3800 MWt classes of plants designed by Combustion Engineering (CE) without PORVs consisted of reviewing licensee, applicant, and vendor responses to staff questions, supplemented by independent analyses. The overall evaluation was grouped into four topic areas. First, the staff determined if the CE plants met current regulatory requirements without PORVs. Second, the staff determined the extent to which the existing design without PORVs can mitigate events that are beyond the design basis, and whether a PORV would substantially improve the ability of the plant to mitigate or reduce the severity of these events. Third, a probabilistic risk assessment was performed to estimate the change in core-melt probability if a PORV were installed. And fourth, the costs and benefits were assessed and compared.

The results of the staff review led to the conclusion that, based on risk reduction and cost/benefit considerations, the installation of PORVs in CE plants that currently do not have them could not be justified. However, when other considerations regarding the potential benefit of a PORV are factored into the evaluation, more-substantial benefits could be realized. Given the high degree of uncertainty in the evaluation results, along with the qualitative nature upon which any decision would have to be made, the staff concluded that the decision regarding PORVs for these CE plants should be deferred and incorporated into technical resolution of Unresolved Safety Issue A-45, "Shutdown Decay Heat Removal Requirements." Since part of the benefit of the PORVs was predicated on their ability to provide an alternate decay heat removal path ("feed and bleed"), any improvements in decay heat removal capability that might be promulgated as a result of the A-45 assessment could reduce the net benefit of PORVs. Finally, the events for which PORVs could prove to be a benefit are of low probability, and the staff is aware of no immediate safety concerns associated with deferring the PORV decision until the A-45 decision is made.

The staff has briefed the ACRS Subcommittee on Decay Heat Removal Requirements (on October 4, 1983) and the full ACRS in an executive session (on October 13-15, 1983) on the status of the staff's evaluation of this matter. Subsequently, the ACRS issued a letter report dated October 18, 1983, included as Appendix C to this supplement, which stated that the Committee agreed with the NRC staff's recommendation to integrate any new requirements for rapid depressurization into the more comprehensive evaluation of the need for improvements to decay heat removal systems, expected to be forthcoming from Task Action Plan A-45. The Committee saw no need for earlier resolution of the PORV issue. Previously, in Appendix C to the SER, the staff had provided the basis for permitting operation of PVNGS 1-3 prior to ultimate resolution of Task A-45. Therefore, this issue regarding the need for a PORV has been resolved for licensing purposes.

22 TMI-2 REQUIREMENTS

22.2 Evaluation of TMI Requirements

I.C.1 Guidance for the Evaluation and Development of Procedures for Transients and Accidents

In the SER, the staff reported that the applicant would implement a program of emergency operating procedures (EOPs) based on revised Combustion Engineering Owners Group (CEOG) Emergency Procedure Guidelines in accordance with the schedule of NUREG-0737. On July 29, 1983, the staff issued a safety evaluation which approved the CEOG Emergency Procedure Guidelines for implementation.

Staff guidance for upgrading EOPs was provided in NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures." The schedule and review requirements for TMI-2 Task Action Plan (TAP) Item I.C.1 have been modified by Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability" (Generic Letter No. 82-33), dated December 17, 1982. Supplement 1 to NUREG-0737 requires that each applicant and licensee submit a procedures generation package (PGP) at least three months before the date it plans to begin formal operator training on the upgraded procedures. The PGP must include:

(1) Plant-specific technical guidelines
(2) A writer's guide
(3) A description of the program for validation/verification of EOPs
(4) A description of the program for training operators on the upgraded EOPs

On June 8, 1982, and April 7, 1983, meetings were held with representatives of Arizona Public Service Co. (APS) and the staff to discuss their program for preparing EOPs for PVNGS 1-3 and for developing a PGP.

On July 15, 1983, the PGP for PVNGS 1-3 was formally submitted for staff review. The submitted PGP was separated into five parts as follows:

(1) A plant-specific technical guideline
(2) A plant-specific writer's guide
(3) A description of the program for EOP verification
(4) A description of the program for EOP validation
(5) A description of the program for training operators on the upgraded EOPs

The staff's review was conducted to determine the adequacy of the applicant's program for preparing and implementing EOPs. Criteria developed from NUREG-0899 and Supplement 1 to NUREG-0737 were used as the basis for the review.

The review of the plant-specific technical guidelines for PVNGS 1-3, which referenced the approved CEOG Emergency Procedure Guidelines, included an evaluation of the description of the process for preparing the EOPs from these guidelines, as well as the identified deviations (with related justification) from the guidelines.

As a result of the review of the identified deviations from CE generic guidelines, by letter dated November 8, 1983, the staff asked the applicant for the following additional information:

(1) Provide assurance that dividing the LOCA into two guidelines (one for small LOCA and one for large LOCA) would not result in the operator being directed to the incorrect procedure;

(2) Justify removal of the pressure restriction for isolation of the safety injection tanks for a LOCA; and

(3) Provide sufficient information to show that the function recovery guidelines have been combined in such a manner that they reflect CEN-152, Revision 1, generic guidelines, or provide the technical basis, including supporting analysis, for the differences from the generic guidelines.

The applicant's response was provided in a letter dated January 10, 1984. After reviewing the additional information submitted by the applicant, the staff concluded that plant-specific technical guidelines for PVNGS 1-3:

(1) Would provide adequate checks within the procedures to ascertain whether the operator is using the correct procedures either for the small LOCA or large LOCA, or direct the operator to the correct procedure if he had misdiagnosed the event;

(2) Will establish isolation pressure criteria for safety injection tanks that will be incorporated into the plant-specific technical guidelines and recovery procedures by the time the procedures are issued; and

(3) Include the CEOG success path criteria for the safety function.

On the basis of its review, the staff has concluded that the deviations from PVNGS 1-3 plant-specific technical guidelines identified by the applicant are acceptable.

Although not identified by the applicant as a deviation from CEOG generic technical guidelines, during discussions with the applicant, the staff had noted that the PVNGS 1-3 EOPs will be initiated whenever a reactor trip is required, a valid plant protection system signal exists, or the reactor is manually tripped. The applicant had stated that the control room staff can implement the EOPs for any unusual condition that occurs in the plant during any mode of operation. However, the CEOG generic emergency procedure guidelines do not cover conditions other than off-normal events which require a reactor trip from power operation (letter from D. G. Eisenhut to R. W. Wells dated July 29, 1983, page 4-3). Therefore, the staff had asked the applicant to provide confirmatory information documenting the technical bases for extending the plant-specific technical guidelines to all operational modes. In its letter response dated August 1, 1984, the applicant stated that this deviation will be removed from the PGP.

It should be noted that in its July 29, 1983, evaluation of the CEOG generic technical guidelines, the staff identified open issues. The applicant will be required to appropriately update the plant-specific technical guidelines and EOPs to reflect any changes made to the CEOG generic technical guidelines as a result of resolving those open issues.

The staff reviewed the Palo Verde Writer's Guide to determine if it provided acceptable methods for meeting the objectives of NUREG-0899. Assuming the EOPs were written in accordance with the Writer's Guide, the staff concludes that all the objectives of NUREG-0899 would be met and, therefore, the PVNGS 1-3 Writer's Guide is acceptable.

The PVNGS 1-3 validation and verification (V&V) programs were also reviewed to determine if the V&V objectives of NUREG-0899 were adequately addressed. On the basis of a review of the V&V program description, it was not clear that the applicant's program would evaluate the adequacy of the existing instrumentation and controls. The applicant submitted a modification to the PGP in a letter dated September 2, 1983, which described the process for evaluation of the control room instrumentation and controls. The staff found the process adequate, with the exception that the PGP still did not address operator information and control requirements. Supplement 1 to NUREG-0737 specifically calls for the identification of "information and control requirements" as part of the reanalysis of transients and accidents. The need for such analyses is to ensure that the instrumentation and controls called out in the EOPs, and available in the control room for emergency operations, are based on operator information and control requirements (derived from the functions and systems as defined by the technical guidelines), rather than on what is already available.

At a September 27, 1983 meeting, the applicant stated that it had conducted the necessary analysis as part of its detailed control room design review (DCRDR), but that the DCRDR Summary Report did not include a description of the task analysis process. At the meeting and by letter dated January 10, 1984, the staff requested that the applicant modify the DCRDR Summary Report, or the PGP, to include a description of the analysis effort. The applicant's response, dated April 9, 1984, is currently under staff review.

The staff has evaluated the impact of not having the task analysis completed. In the PGP, the applicant indicated that it would evaluate the parameters currently available in the control room to determine how best to use those parameters in implementing the EOPs. This process does provide an effective means of identifying the existing control room instrumentation and controls to be used during execution of the EOPs, but is not adequate for evaluating whether the instrumentation and controls meet the information and control requirements of the operators. However, on the basis of its review of the technical bases for the EOPs and on its evaluation of the EOP develoment process, the staff has reasonable assurance that the Palo Verde EOPs are adequate to allow interim operation of PVNGS 1-3. The staff will require that the applicant complete the task analysis efforts, as required by Supplement 1 to NUREG-0737, to further reduce the risk to public health and safety.

The applicant's description of the EOP training program was reviewed using the objectives in NUREG-0899 and was found to be adequate.

On the basis of its review, the staff concludes that the applicant's program provides reasonable assurance that the PVNGS 1-3 EOPs will be consistent with approved technical guidelines and an appropriate writer's guide, that the EOPs will be verified and validated, and that the operators will be adequately trained before the implementation of EOPs.

On the basis of the above evaluations, the staff concludes that the applicant's program for preparing and implementing emergency operating procedures is acceptable for issuance of a full-power operating license.

As noted in the above evaluations, the following two areas will require resolution to complete the review of the PGP for PVNGS 1-3:

(1) Update of PGP for PVNGS 1-3 to reflect any changes made to the CEOG generic guidelines as a result of resolving open issues in the CEOG,

(2) Completion of a suitable task analysis effort by either (a) providing a detailed description of the function and task analysis effort (addressing the issue of information and control requirements) in the PGP, or referencing an acceptable analysis description in the DCRDR, or (b) referencing an acceptable generic function and task analysis in the PGP.

If the above areas are not resolved before a license is issued, the actions required for resolution will be made a condition of the license. With the above exceptions, the staff finds the applicant's response to TMI-2 Task Action Plan Item I.C.1 to be acceptable.

I.C.7 NSSS Vendor Review of Procedures

In the SER, the staff stated that a decision on whether a specific review of the applicant's EOPs by the NSSS vendor will be required would be made at a later date. The requirement for vendor review of EOPs has been satisfied by the involvement of Combustion Engineering in the development of the CEOG Emergency Procedure Guidelines, as discussed in Item I.C.1, above. Therefore, this matter is considered resolved.

I.C.8 Pilot Monitoring of Selected Emergency Procedures for NTOL Applicants

In the SER, the staff stated that, on the basis of expectation that the applicant would develop EOPs in accordance with TMI-2 Task Action Plan Item I.C.1, the staff did not anticipate conducting a pilot monitoring review of selected EOPs. Having reviewed the applicant's PGP, described in Item I.C.1, above, the staff has determined that a pilot monitoring review of selected EOPs is not required for licensing. Therefore, this matter is considered resolved.

I.D.1 Control Room Design Review

The status of the staff's review of control room design was presented in Supplement No. 1 to the SER. By letter dated May 11, 1982, the staff provided the applicant with a report giving a further status of the review. In this supplement the staff updates the status of review of the control room preliminary design assessment (PDA) which is required for licensing, and provides the status of the detailed control room design review (DCRDR) which is required for ultimate resolution of control room design.

In Supplement No. 1 to the SER, the staff identified 13 systems and items which were not available, in whole or in part, for staff review during its site visit in September 1981. Subsequently through various submittals, the applicant has provided the staff with additional information in those areas. As a result of these submittals the staff has closed out a number of items.

The following issues remain open and need resolution to complete the staff's review for the PDA:

(1) Confirmation of correction of human engineering discrepancies (HEDs),

(2) Clarification of the status of the environmental survey including the lighting survey,

(3) Clarification of the applicant's review of the remote shutdown panel.

A detailed discussion of these issues is presented below.

In its status report of May 11, 1982, the staff identified 157 HEDs relating to the PDA review of the control room. The applicant's actions regarding these HEDs were provided by letters dated June 30, 1983 and March 14, 1984. During May 1984, the staff conducted a confirmatory audit on a sample of 28 of the HEDs. Of this sample, all except four of the HEDs were found to be acceptably corrected. The corrective actions for the remaining four were in progress; the HEDs concern specular glare on Foxboro displays (Item A.1.3), inconsistent abbreviations on alarm legends (Item A.3.13), green light intensity change for faulted from normal status on the electrical bus panel (Item A.5.16), and logic for selecting correct pairs of pushbutton controls to initiate manual reactor trip (Item A.6.1).

The applicant has committed to complete action on the above four HEDs before fuel loading. In addition, the staff requires that the applicant provide confirmation, prior to fuel load, that all other corrections required for licensing have been completed.

In its letter of June 30, 1983, the applicant committed to provide the NRC with the corrective action and implementation date required as a result of reviewing its control room lighting problems (Item A.1.2); that review was to be completed by July 31, 1983. To date, the staff has not received the results of the applicant's control room lighting review, about its proposed corrective actions. With regard to the remainder of the environmental review, in its March 14, 1984 letter, the applicant committed to complete the control room environmental study and provide a report of corrective actions for NRC review before the plant exceeds 5% power.

It is not clear from the applicant's submittals what portion of the environmental study will be completed before licensing and what corrective actions will be completed. The applicant should submit the results of the environmental study, including the control room lighting survey, 30 days before licensing. The submittal should include the HEDs identified, the proposed corrections and implementation schedule, and justification for HEDs not to be corrected. Also, any portions of the environmental study which will not be completed before licensing should be identified and justified.

By letter dated May 4, 1984, the applicant submitted a summary of its human factors evaluation of the remote shutdown panel. However, the submittal contained a list of just the HEDs which would be corrected, provided no basis for the proposed corrective actions, and provided no basis for delaying the evaluation of panel layout and functional grouping beyond fuel loading. Thirty days

before licensing, the staff requires that the applicant submit a discussion of the results of the remote shutdown panel human factors evaluation, including all HEDs identified, the proposed corrective actions correlated with the HEDs, and the justification for not correcting HEDs or for delaying corrective actions beyond fuel load.

With regard to the applicant's DCRDR, the staff has reviewed the information submitted by the applicant by letters dated June 17, 1983, June 30, 1983, and April 9, 1984. On the basis of that review, the staff has concluded that the nine elements for completing a DCRDR, as defined in NUREG-0700, September 1981, "Guidelines for Control Room Design Reviews," have been satisfactorily addressed by the applicant, except for the following. In its April 9, 1984 submittal, the applicant did not provide a description of a task analysis which was based on generally accepted human-factors standards, principles, and guidelines as required by NUREG-0737, Supplement 1. In addition, although the submittal described how the DCRDR was coordinated and integrated with development of the EOPs, it did not address how the DCRDR activity was coordinated and integrated with other emergency response facility initiatives as required by NUREG-0737, Supplement 1.

To complete the review of the DCRDR, the applicant is required to perform a task analysis to determine (1) operator information and control needs, (2) display and control characteristics independent of the existing control room instrumentation, and (3) to coordinate the DCRDR with other emergency response capability initiatives. Resolution of these two items is not required for PVNGS 1-3 before licensing, as permitted by Supplement 1 to NUREG-0737. However, if these items are not resolved before licensing, appropriate conditions will be included in the operating license for resolution at a specified time.

II.B.3 Postaccident Sampling Capability

In the SER, the staff identified five conditions that the applicant needed to satisfy in order to demonstrate the capability of the postaccident sampling system (PASS). At that time, the staff stated that the required actions for the conditions should be completed before exceeding 5% power operation, consistent with time constraints resulting from procurement, installation, testing, and training. Since February 1984, the staff has advised the applicant that more than two years have passed since the SER was issued, so that operability of PASS could have been demonstrated. On September 27, 1984, the applicant submitted information on the status of efforts to satisfy the five conditions relating to the PASS. The staff is currently reviewing this information and will report on this matter in a future supplement to the SER.

II.F.2 Instrumentation for Detection of Inadequate Core Cooling

In Supplement No. 5 to the SER, the staff stated that it was reviewing information submitted by the applicant on inadequate core cooling instrumentation (ICCI). As a result of that review, the staff had requested additional information by letter dated December 20, 1983. The applicant's responses were subsequently submitted by letters dated February 23, and May 18, 1984. The staff's evaluation of ICCI for PVNGS 1-3 is presented below.

The ICCI system to be implemented for PVNGS 1-3 is a CESSAR System 80 package which consists of hot-leg and cold-leg resistance temperature detectors (RTDs), pressurizer pressure sensors, core exit thermocouples (CETs), and reactor vessel level monitoring system (RVLMS) probes employing the heated junction thermocouple (HJTC) concept. The Palo Verde RVLMS design is identical to the CESSAR System 80 design which is discussed in Supplement No. 2 to the CESSAR SER.

These sensor inputs have been integrated into the emergency response facility (ERF) computer system which is similar to the accident monitoring system (AMS) used in CESSAR System 80 as the ICCI display system. The ERF computer system consists of three major subsystems as follows: (1) emergency response facility data acquisition and display system (ERFDADS) which is identical to the CESSAR System 80 critical function monitoring system (CFMS); (2) qualified safety parameter display system (QSPDS) which is identical to the CESSAR System 80 QSPDS; and (3) chemical and radiological analysis computer system (CRACS) which provides postaccident sampling and dose projection. The QSPDS provides a two-channel, seismically qualified Class 1E display of safety parameters including the ICC processing information. The ERFDADS is a non-Class 1E system and provides primary safety parameter display system/inadequate core cooling (SPDS/ICC) displays in the control room, technical support center (TSC), and emergency operations facility (EOF).

The ICC instrument outputs appear on a single display and can be viewed on either of the two QSPDS screens or on the ERFDADS cathode-ray tube (CRT) display system. Primary or secondary designations are not used on the various system displays. The various displays will be used to fit the situation that the operators are responding to. These displays are designed according to good principles of human-factors engineering, in order to give the operator clear unambiguous indications.

In addition to the trend capability in the ERFDADS for ICC, the applicant has installed postaccident monitoring trend recorders (strip charts) on the main control board.

The applicant has provided a schedule for installation, testing, and calibration of the ICCI system. Installation of the loop pressure transmitters and RTDs, QSPDS, ERFDADS, and cabling has already been completed. Installation of the HJTC and the CETs will be completed 4 weeks after the start of fuel load (prior to initial criticality).

Testing of the QSPDS computer, the ERFDADS computer, and the integration test will be completed before fuel load. Calibration and preoperational testing of the ICCI system (sensor to display) will begin 6 weeks after the start of fuel load and will be completed before the plant exceeds 5% power operation. At that time, the system will be fully operational.

The CE Owners Group (CEOG) has incorporated the RVLMS information into the emergency procedure guidelines (EPGs) as Revision 2 to CEN-152 which was submitted to the NRC by letter dated May 8, 1984.

On the basis of its review of CEN-152, Revision 2, the NRC staff has concluded that use of the ICC instrumentation specified in CEN-152, Revision 2, at PVNGS 1-3 is acceptable provided that the following items are appropriately addressed in the PVNGS emergency operating procedures (EOPs) using the ICC instrumentation specified in CEN-152, Revision 2.

(1) At numerous points throughout the CEN-152 guidelines, an acceptable criterion is indicated as reactor coolant system 20°F subcooled. Initially, the subcooling margin was measured using the reactor vessel pressure and the hot-leg coolant temperature (TH), usually with an RTD. It is presumed that the indicated acceptance margin refers to the TH measurement of subcooling margin. For near-normal conditions or slowly proceeding transients, particularly with main coolant pumps running, this measurement is adequate. A statement to this effect appears on page 4-12 of the CEN-152 guidelines.

The procedures encompass a wide range of emergency conditions which include pumps on or off and slow to rapid transients. Under most conditions, there is typically a significant temperature difference between the hot-leg, core-exit, and upper-head thermocouples. Since the hot areas are where voiding is likely to occur first and the subcooling margin will be the least, it would seem advisable to include in the procedures appropriate reference to subcooling margin as calculated by core-exit thermocouples (CETs) and upper head (UH) thermocouples when they are limiting. However, the CEN-152 guidelines include only two or three instances in the Functional Recovery Guidelines where CET calculated subcooling margin is to be used.

CE plants using heated junction thermocouples (HJTC) also have the capability to calculate UH subcooling margin. Where significant differences between UH, CET, and hot-leg coolant temperatures are expected, it is recommended that the most conservative indication of low subcooling margin and potential voiding be used where appropriate in the CEN-152 guidelines.

(2) When the CEN-152 guidelines refer to CET temperatures, they should identify which and how many of the CETs should be used. The use of "representative CET temperature" per the display would be acceptable.

(3) The HJTC systems have generally been accepted by the NRC for RVLMS on a generic basis; however, additional guidance is needed on interpreting the level information display, particularly where dynamic conditions (e.g., pumps running) may cause difficulty of interpretation. "Important information concerning reactor vessel liquid trending" (in the CEN-152 guidelines, see page 6-15, Item 14; page 9-11, Item 8; etc.) requires additional guidance for interpretation of indications. The guidance should be applicable to both split and single HJTC probe.

(4) The following phrases which are used repeatedly in the EPGs require considerable interpretation of indications and should be consistently defined:

- "voiding is present" or "no voiding is present": No guidance is given for this interpretation, including no advice of selection of the most conservative indicator (see Item (1) above).

- "core is covered": This guidance should be further defined in relation to actual instrument indications, especially with regard to allowing margin for approach to core uncovery.

- "follow inventory trend": (See Item (3) above).

- "indication of unacceptable RCS voiding": A definition of "unacceptable voiding" should be included.

Assessment of ICC indicators and the response actions are contained in the Palo Verde emergency operating procedures. These actions are performed initially at the start of an event and continuously throughout plant recovery as part of safety function maintenance, and are verified through independent checks performed by a supervisor.

Key operator actions include (1) assessment actions to verify subcooling in the primary system (greater than 28°F), vessel water level, core ΔT (less than 57°F), and adequate core cooling (e.g., CETs less than 700°F) and (2) response actions to stabilize RCS pressure, cycle pressurizer heaters as necessary, and initiate or restore safety injection flow when required.

On the basis of the review of the above information, the staff finds that

(1) The responses to the plant-specific information required by the CESSAR SER are acceptable.

(2) The schedule for implementing a fully operational final ICCI system for PVNGS Unit 1 prior to exceeding 5% power operation is acceptable. However, the staff's review of the final design for acceptability will not be completed until after the installation and preoperational testing of the RVLMS are complete. To complete the review, an Implementation Letter Report, as described in Appendix D to this supplement, must be provided by the applicant before exceeding 5% power operation.

(3) Before reaching initial criticality on PVNGS Unit 1, those PVNGS EOPs which incorporate the use of the RVLMS shall be modified to reflect the previously discussed staff comments on the generic EPGs (CEN-152, Revision 2). Where deviations to the approved EPGs exist, they shall be identified and justified.

(4) Before fuel load on PVNGS Unit 1, the technical specifications shall include operability limits for the ICCI system.

On the basis of the staff's evaluation of the PVNGS ICCI system, the staff finds that the ICCI system for PVNGS 1-3 conforms to the design requirements of NUREG-0737, Item II.F.2, and is acceptable for issuance of an operating license. Items (2) and (3), above, will be included as conditions of the Unit 1 license.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW

September 29, 1983	Letter from applicant transmitting revised responses to fire protection issues previously submitted on June 15, 1983.
October 19, 1983	Generic Letter 83-33 - NRC Positions on Certain Requirements of Appendix R
October 21, 1983	Letter from applicant advising that response to September 20, 1983 letter will be provided by November 27, 1983
October 27, 1983	Letter from applicant transmitting replacement for attachment submitted with October 17, 1983 letter
October 31, 1983	Generic Letter 83-38 - NUREG-0965, "NRC Inventory of Dams"
November 2, 1983	Generic Letter 83-35 - Clarification of TMI Action Plan Item II.K.3.31
November 3, 1983	Letter from applicant providing response to Generic Letter 83-28
November 7, 1983	Letter from applicant commenting on NRC evaluation of need for rapid depressurization capability for Combustion Engineering plants
November 8, 1983	Letter to applicant transmitting request for additional information
November 8, 1983	Letter from applicant commenting on NRC review of environmental qualification of equipment
November 9, 1983	Letter from applicant advising that for as-built components the error components are bounded by generic CESSAR values
November 9, 1983	Letter from applicant forwarding information on mechanical equipment qualification program
November 14-16, 1983	Visit to CE pump test facility
November 15, 1983	Letter from applicant advising that information requested by June 20, 1983, letter will be submitted December 30, 1983

November 16, 1983	Letter from applicant forwarding information on impact of high-energy-line breaks on control systems
November 18, 1983	Letter to applicant regarding schedule for completion of review
November 23, 1983	Letter from applicant regarding monitoring source-range neutron flux
November 23, 1983	Letter to applicant advising that commitment to Regulatory Guide 1.88 is acceptable
November 30, 1983	Letter from applicant regarding evaluation of possible overtorquing of ¼-inch bolts
December 1, 1983	Letter from applicant forwarding information on fire protection
December 1, 1983	Letter from applicant transmitting information related to site audit for environmental qualification
December 2, 1983	Letter from applicant transmitting Amendment 5 to security plan
December 2, 1983	Letter from applicant forwarding supplemental information in response to clarification of Supplement 1 to NUREG-0737
December 2, 1983	Generic Letter 83-32 - NRC Staff Recommendations Regarding Operator Action for Reactor Trip and ATWS
December 2, 1983	Letter from applicant forwarding information on environmental/seismic qualification of Class 1E equipment
December 5, 1983	Letter to applicant transmitting Supplement 5 to SER
December 5, 1983	Letter from applicant requesting certification of pollution control facilities
December 6, 1983	Letter to applicant forwarding facility staffing survey
December 6, 1983	Letter to applicant regarding its conformance to Regulatory Guide 1.97
December 7, 1983	Letter from applicant forwarding information requested about the security plan
December 14, 1983	Letter to applicant regarding staff evaluation of the need for a rapid depressurization capability for Combustion Engineering plants
December 14, 1983	Letter from applicant forwarding information regarding exception taken in FSAR to structural welding code AWS D1.1-72

December 19, 1983	Generic Letter 83-42 - Clarification of Generic Letter 81-07 Regarding Response to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants"
December 19, 1983	Generic Letter 83-43 - Reporting Requirements of 10 CFR Part 50, Sections 50.72 and 50.73 and Standard Technical Specifications
December 20, 1983	Generic Letter 83-44 - Availability of NUREG-1021, "Operator Licensing Examiner Standards"
December 20, 1983	Letter to applicant forwarding request for additional information on TMI Item II.F.2
December 20, 1983	Letter from applicant forwarding information on environmental qualification program
December 23, 1983	Letter from applicant forwarding revision to December 5, 1983, letter
December 23, 1983	Letter from applicant forwarding list and response schedule for open and confirmatory items
December 29, 1983	Letter to applicant forwarding certificate for pollution control facilities
December 29, 1983	Issuance of Order extending construction completion date for Unit 1 to December 31, 1984
January 3, 1984	Letter from applicant regarding meteorological conditions
January 5, 1984	Board Notification 84-004 - Environmental Qualification Briefing of Chairman by Sandia
January 5, 1984	Generic Letter 84-01 - NRC Use of the Terms, "Important to Safety" and "Safety-Related"
January 6, 1984	Generic Letter 84-02, Notice of Meeting Regarding Facility Staffing
January 10, 1984	Letter to applicant requesting response to staff comments on control room design review
January 10, 1984	Letter from applicant transmitting responses to November 8, 1983, letter
January 13, 1984	Generic Letter 84-03 - Availability of NUREG-0933, "Prioritization of Safety Issues"
January 16, 1984	Letter to applicant regarding monitoring of gaseous effluents

January 16, 1984	Letter from applicant advising of its reorganization
January 17, 1984	Letter to applicant providing estimate of schedule for operator licensing examinations for FY84-FY87
January 20, 1984	Letter from applicant transmitting description of "Off-site Protective Action Decision Process" and "Activation of the Technical Support Center (TSC) and Satellite Technical Support Center (STSC)"
January 24, 1984	Letter from applicant documenting telephone conference regarding justification for interim operation for unqualified safety-related equipment
January 24, 1984	Letter from applicant transmitting "Safety Injection Nozzle Thermal Liner" and "Resistance Temperature Detector Thermowell"
January 24, 1984	Letter from applicant transmitting "Evacuation Time Analysis, 10-Mile Emergency Planning Zone"
January 25, 1984	Letter from applicant in response to December 6, 1983, letter transmitting facility staffing survey
January 27, 1984	Letter from applicant concerning requirements for atmospheric dump valve accumulators
January 27, 1984	Letter from applicant transmitting corrected copy of September 13, 1983, submittal on steam generator tube rupture accident analysis
January 27, 1984	Letter from applicant transmitting list of onsite emergency organization
January 31, 1984	Letter to applicant advising of approval of location for backup emergency operations facility
January 31, 1984	Letter from applicant forwarding "Interim Report on Performance Evaluation of Palo Verde Control Element Assembly Shroud"
January 31, 1984	Letter from applicant advising of revision of organizational structure
February 1, 1984	Generic Letter 84-04 - Safety Evaluation of Westinghouse Topical Reports Dealing With Elimination of Postulated Pipe Breaks in PWR Primary Main Loops
February 6, 1984	Letter from applicant advising of revision in organization structure
February 6, 1984	Letter from applicant forwarding additional information on potential finding - Reports 027, 050, and 065

February 6, 1984	Letter to applicant transmitting request for additional information
February 10, 1984	Letter from applicant forwarding information on tests performed by Combustion Engineering on load-limiting devices in reactor vessel lower key horizontal supports
February 13, 1984	Board Notification 84-032 - Additional Information on Environmental Qualification
February 13, 1984	Letter from applicant advising that response to information regarding control room design review will be submitted by March 30, 1984
February 14, 1984	Letter from applicant providing information on independent source range neutron flux monitor at remote shutdown panel
February 14, 1984	Letter from applicant forwarding information regarding impact of high-energy-line breaks on control systems
February 14, 1984	Letter to applicant regarding deletion of home telephone numbers, unlisted utility numbers, etc. from emergency plans
February 16, 1984	Board Notification 84-30 - Combustion Engineering Auxiliary Pressurizer Spray Systems
February 16, 1984	Board Notification 84-33 - Task Action Plan for USI A-17 "Systems Interaction Program"
February 17, 1984	Letter from applicant transmitting revision to pump and valve testing program
February 17, 1984	Letter from applicant forwarding press release, "Palo Verde Unit 1 Fuel Loading To Be Rescheduled"
February 21, 1984	Letter from applicant transmitting Amendment 12 to FSAR
February 23, 1984	Letter from applicant forwarding response to request for information on TMI-2 Task Action Plan Item II.F.2, Instrumentation for Detection of Inadequate Core Cooling
February 24, 1984	Letter from applicant forwarding response to request regarding missing thermal liner in safety injection system line
February 24, 1984	Letter from applicant advising of upcoming revision to proposed changes to program categorizing reactor coolant system pressure isolation valves
February 24, 1984	Letter from applicant forwarding information on missing thermal liner in the safety injection system line

February 24, 1984	Letter from applicant forwarding preliminary description for reactor coolant system demonstration test
February 24, 1984	Letter from applicant forwarding information concerning Regulatory Guides 1.28 and 1.33
February 24, 1984	Letter from applicant forwarding clarifications and justifications made to revisions included in FSAR Amendment 12
February 27, 1984	Letter to applicant transmitting request for information on environmental qualification program
February 27, 1984	Letter to applicant transmitting request for information on reactor coolant pumps
February 28, 1984	Letter from applicant forwarding information on low preheat fillet welding
February 29, 1984	Letter from applicant transmitting "High Pressure Safety Injection Pump"
February 29, 1984	Letter to applicant transmitting request for additional information
March 1, 1984	Letter to applicant regarding January 26, 1984, meeting concerning limited operating experience of operating crews and development of acceptable experience profile
March 1, 1984	Letter to applicant regarding leak rate acceptance criteria for pressure isolation valves
March 2, 1984	Audit of results of Phase I and Phase II testing for core protection calculator
March 14, 1984	Letter from applicant forwarding status update of Human Engineering Discrepancies and Audit Findings resulting from detailed control room design review
March 14, 1984	Letter from applicant advising that information on electrical equipment environmental qualification program will be submitted by March 26, 1984
March 14, 1984	Board Notification 80-050 - Environmental Qualification: Commission Policy Statement and Proposed Rulemaking
March 14, 1984	Letter from applicant transmitting updated preliminary description for reactor coolant system demonstration test
March 19, 1984	Letter from applicant regarding Generic Letter 81-27 concerning information to be withheld from emergency plans

March 20, 1984	Meeting with applicant on its presentation of proposed testing program (and results of testing at Combustion Engineering facilities) to demonstrate adequacy of modifications to reactor coolant system pumps, thermowells, thermal sleeves and control element assembly shrouds and presentation of status of evaluation on low-pressure safety-injection pump problems
March 21, 1984	Letter to applicant regarding Kaman instrumentation
March 23, 1984	Letter from applicant forwarding operations experience base
March 26, 1984	Letter from applicant forwarding press release regarding revised fuel load dates: first quarter of 1985 for Unit 1; last quarter of 1985 for Unit 2; first quarter of 1987 for Unit 3
March 27, 1984	Letter from applicant advising that safety parameter display system installation is complete
March 29, 1984	Letter from applicant transmitting résumés of Operations Manager and Maintenance Manager
April 2, 1984	Generic Letter 84-05 - Change to NUREG-1021, "Operator Licensing Examiner Standards"
April 3, 1984	Letter to applicant forwarding request for additional information on process control program
April 3, 1984	Letter to applicant forwarding request for additional information on reactor system components
April 3, 1984	Letter to applicant transmitting request for additional information on auxiliary pressurizer spray system
April 4, 1984	Generic Letter 84-08 - Interim Procedures for NRC Management of Plant-Specific Backfitting
April 6, 1984	Letter from applicant regarding potential affect of Palo Verde Hills on local meteorological conditions
April 9, 1984	Letter from applicant forwarding information on qualification and structure of detailed control room design room review team
April 13, 1984	Letter from applicant forwarding revised responses to questions on fire protection
April 17, 1984	Letter from applicant forwarding draft responses concerning Unit 1 data base values for core protection calculators and control element assembly calculators

April 18, 1984	Letter to applicant transmitting request for information on shutdown cooling system relief valves
April 18, 1984	Letter to applicant transmitting request for information on organizational structure
April 20, 1984	Letter to applicant transmitting request for information on initial test program
April 26, 1984	Generic Letter 84-10 - Administration of Operating Tests Prior to Initial Criticality
April 27, 1984	Letter to applicant forwarding request for additional information on steam generator tube rupture analysis
April 30, 1984	Generic Letter 84-12 - Compliance With 10 CFR Part 61 and Implementation of the Radiological Effluent Technical Specifications (RETS) and Attendant Process Control Program (PCP)
May 3, 1984	Generic Letter 84-13 - Technical Specifications for Snubbers
May 3, 1984	Letter from applicant in response to April 3, 1984, request for information on process control program
May 4, 1984	Letter from applicant forwarding corrective actions with implementation dates of human factors problems identified during equipment evaluation
May 7, 1984	Letter from applicant requesting license term be 40 years from date of issuance of license
May 7, 1984	Letter from applicant advising that guide tube wear surveillance program for Unit 2 should be ready for NRC review six months before first refueling outage for Unit 2
May 7, 1984	Letter from applicant advising that information on auxiliary pressurizer spray system will be addressed on CESSAR docket
May 8, 1984	Meeting with applicant to discuss staff request for information on disturbed backfill
May 10, 1984	Letter from applicant regarding installation of high-range noble-gas monitors
May 18, 1984	Letter from applicant forwarding revised response to request for information on instrumentation for detection of inadequate core cooling

May 23, 1984	Letter from applicant transmitting responses to questions regarding reactor coolant pump report
May 24, 1984	Letter from applicant advising that information on organizational structure will be provided by June 29, 1984
May 24, 1984	Letter from applicant advising that information on organizational structure will be provided by June 29, 1984
May 25, 1984	Letter from applicant forwarding information on environmental qualification
May 29, 1984	Letter to applicant regarding operating shift staffing
May 31, 1984	Appeal meeting with applicant regarding source range neutron flux monitor for remote shutdown panel
June 5, 1984	Letter to applicant advising of acceptability of procedure generation package
June 7, 1984	Letter from applicant requesting partial exemption from provisions of General Design Criterion 4
June 7, 1984	Letter from applicant forwarding information on organization realignment
June 7, 1984	Letter from applicant transmitting Amendment 6 to security plan
June 7, 1984	Meeting with applicant to discuss potential deviations in fire protection program
June 14, 1984	Letter from applicant regarding monitoring of gaseous effluents
June 15, 1984	Letter to applicant regarding augmented shift staffing for emergency planning
June 18, 1984	Letter from applicant forwarding information on temporary water lines and noting that fuel load is scheduled for November 1984
June 20, 1984	Letter from applicant advising that information on shutdown cooling system relief valves will be submitted by the Combustion Engineering Owners Group approximately August 1984
June 21, 1984	Letter from applicant forwarding proprietary information regarding removal of surge line thermal liner
June 27, 1984	Letter to applicant forwarding request for information on CEA shroud assembly

June 29, 1984	Letter from applicant transmitting proposed change to FSAR Chapter 13.2
July 2, 1984	Letter to applicant forwarding request for information on engineered safety features actuation system
July 2, 1984	Generic Letter 84-15 - Proposed Staff Actions To Improve and Maintain Diesel Generator Reliability
July 2, 1984	Letter from applicant transmitting information on organizational structure
July 3, 1984	Letter from applicant transmitting information concerning the initial test program
July 5-6, 1984	Early readiness review management meeting with applicant
July 6, 1984	Letter from applicant concerning augmented shift staffing for emergency planning
July 6, 1984	Generic Letter 84-18 - Filing of Applications for Licenses and Amendments
July 6, 1984	Letter from applicant forwarding information which justifies FSAR change concerning IEEE Standard 450 and maintenance activity of adding water to the battery
July 9, 1984	Letter from applicant transmitting revised fire protection evaluation report
July 12, 1984	Letter from applicant regarding reactor coolant system demonstration test description
July 12, 1984	Letter from applicant advising of change to be made to station manual procedure concerning CPC software changes and addressable constants
July 19, 1984	Letter from applicant providing updated information on augmented shift staffing for emergency planning
July 25, 1984	Letter to applicant transmitting request for additional information relating to isolation devices used within reactor protection system
July 27, 1984	Letter to applicant forwarding request for additional information on evacuation time estimate analysis for emergency plan
July 30, 1984	Letter to applicant confirming telephone discussion regarding results of May 31, 1984, appeal meeting on alternate shutdown capability (remote shutdown panel)

July 30-31, 1984	Meeting with applicant to discuss open issues concerning onsite emergency planning
July 31, 1984	Letter from applicant advising that response to July 2, 1984, letter will be provided by September 1, 1984
August 1, 1984	Submittal of Amendment 13 to FSAR
August 1, 1984	Letter from applicant forwarding information regarding compliance with Regulatory Guide 1.97, Revision 2
August 1, 1984	Letter from applicant forwarding information on initial test program
August 1, 1984	Letter from applicant responding to comments in June 5, 1984, letter on procedure generation package
August 2, 1984	Letter from applicant forwarding information on development of setpoint methodology used in technical specifications
August 2, 1984	Letter to applicant regarding September 22-24, 1984, audit of emergency operating procedures
August 2, 1984	Letter from applicant advising that response to June 27, 1984, letter will be forwarded by August 15, 1984
August 6, 1984	Generic Letter 84-19 - Availability of Supplement 1 to NUREG-0933, "A Prioritization of Generic Safety Issues"
August 7, 1984	Letter from applicant forwarding revised process control program
August 7, 1984	Letter from applicant transmitting report providing description of test program relative to Branch Technical Position RSB 5-1 and report, "Evaluation of Natural Circulation Cooldown Test Performed at San Onofre Nuclear Generating Station"
August 10, 1984	Meeting with ACRS
August 13, 1984	Letter from applicant forwarding information on organizational structure
August 14, 1984	Letter to applicant transmitting proof and review copy of technical specifications
August 15, 1984	Letter from applicant forwarding Revision 4 to Emergency Plan
August 15, 1984	Letter from applicant transmitting information on CEA Shroud Assembly Designation

August 16, 1984	Letter from applicant transmitting revised Evacuation Time Analysis
August 16, 1984	Letter from applicant forwarding Revision 5 to Emergency Action Levels
August 16, 1984	Letter to applicant transmitting request for additional information on environmental qualification of equipment
August 20, 1984	Letter from applicant requesting approval of two temporary deviations in emergency response plan
August 20, 1984	Letter from applicant transmitting information on containment ultimate capacity analysis
August 20, 1984	Generic Letter 84-20 - Scheduling Guidance for Licensee Submittals of Reloads That Involve Unreviewed Safety Questions
August 21, 1984	Letter from applicant forwarding modification to deviation request related to fire protection
August 21, 1984	Letter from applicant concerning categorization of reactor coolant system pressure isolation valves, forwarding Revision 2 to "Pump and Valve Inservice Testing Program"
August 22-23, 1984	Meeting with applicant to discuss evaluation of effects of water leaks on foundation stability
August 26, 1984	Letter from applicant transmitting ultimate capacity analysis of containment
August 30, 1984	Letter from applicant transmitting proposed changes to Chapter 17 of FSAR
August 30, 1984	Letter to applicant confirming request for documents related to water leakage from temporary lines
September 4, 1984	Letter from applicant advising that response to August 16 letter will be provided by September 14
September 4, 1984	Letter from applicant transmitting supplemental information regarding overvoltage conditions on Class 1E busses during periods of light loading, specifically duration basis for stated duration
September 5, 1984	Letter from applicant regarding probability of occurrence of a double-ended guillotine break in the primary coolant piping
September 7, 1984	Letter from applicant forwarding information on isolation devices used within the reactor protection system and information on control failures due to high-energy-line breaks

September 10, 1984	Letter from applicant forwarding justification for interim operation for items not expected to be completed before fuel load and updated equipment qualification status sheets
September 11, 1984	Letter from applicant transmitting Revision 5 to Emergency Plan
September 11, 1984	Letter from applicant forwarding clarification for information on reactor coolant pump report
September 12, 1984	Letter from applicant forwarding Revision 1 to operating shift experience tables
September 19-20, 1984	Meeting with applicant to discuss status of equipment qualification program and resolution of pump problems
September 20, 1984	Meeting with applicant to discuss reactor systems portion of the technical specifications
September 22-24, 1984	Audit of emergency operating procedures
September 26, 1984	Letter from applicant concerning administrative procedures for plant protection system

APPENDIX B

REFERENCES

Combustion Engineering reports

CEN-39(A)-P, "CPC Protective Algorithm Software Change Procedure," Rev. 2.

CEN-152, "Combustion Engineering Emergency Procedure Guidelines," Rev. 1, November 22, 1982.

CEN-152, "Combustion Engineering Emergency Procedure Guidelines," Rev. 2, May 8, 1984.

CEN-219(V)-P, "CPC/CEAC System Phase II Software Verification Test Report," Rev. 1, June 1983.

CEN-217(V)-P, "CPC/CEAC System Phase I Sofeware Verification Test Report," Rev. 1, June 1983.

CEN-251(V)-P, "PVNGS-1 Cycle 1, CPC and CEAC Data Base Listing," Rev. 0, June 1983.

CENPD-178, "Structural Analysis of Fuel Assemblies for Combined Seismic and Loss-of-Coolant Accident Loading," Rev. 1, August 1981.

CENPD-225, "Fuel and Poison Rod Bowing," Suppl. 3, June 1979.

U.S. Nuclear Regulatory Commission reports

NUREG-0460, "Anticipated Transients Without Scram for Light Water Reactors," April 1978.

NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

NUREG-0737, Suppl. 1, "Requirements for Emergency Response Capability," December 17, 1982 (Generic Letter 82-33).

NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," August 1982.

APPENDIX C

LETTER REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OCTOBER 18, 1983

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

October 18, 1983

Honorable Nunzio J. Palladino
Chairman
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Dr. Palladino:

SUBJECT: NEED FOR RAPID DEPRESSURIZATION CAPABILITY IN NEWER COMBUSTION ENGINEERING, INC. PLANTS

During its 282nd meeting, October 13-15, 1983, the Advisory Committee on Reactor Safeguards (ACRS) reviewed analyses of the NRC Staff and of a Combustion Engineering Owners Group (CEOG) regarding the need for addition of power operated relief valves (PORVs) to certain nuclear power plants designed by Combustion Engineering, Inc. (CE). This matter had been reviewed previously by a Subcommittee of the ACRS on October 4, 1983, and earlier on January 27, 1983 and March 16, 1982. PORVs are automatic and remotely operable valves installed on the reactor coolant system (RCS) pressurizer in most PWRs. The valves were originally intended to intercept overpressure challenges to code safety valves. These latter valves are prone to failure to automatically reclose tightly following pressure relieving actuation. The PORVs were perceived to be more manageable in this respect in that they can be closed on demand and can be isolated by a block valve.

Analysis and experience have shown RCS pressure to be more easily controlled than had been recognized earlier so that the need for PORVs in avoiding code safety valve actuation is not now believed to be an important consideration. For that reason, CE, in its most recent plant designs, has not included PORVs in the RCS. Their reasoning is that leakage and the potential for spurious actuation of PORVs (creating, in effect, a small or medium break LOCA) are detrimental to both safety and operating efficiency.

However, within the past few years the PORV has come to be seen as offering other advantages. For one, it is a means to rapidly depressurize the RCS when desired, for example, to minimize leakage to the secondary side following failure of a steam generator tube. A second advantage is as a controlled means to remove steam or hot water from the RCS so that cooler water can be injected by the high pressure safety injection (HPSI) pumps. This is the so-called "feed and bleed" cooling process by which heat can be removed from the RCS and hence the reactor core. Because these advantages must be weighed against the disadvantages mentioned above and the cost of installing PORVs, the NRC Staff and CEOG each have made an extensive analysis of the pros and cons.

The NRC Staff has concluded that the CE plants without PORVs meet all regulatory requirements, with some minor exceptions which can be rather easily corrected. Further, they have concluded that these CE plants, which are equipped with reliable, auxiliary pressurizer sprays (APS) can effect moderate rates of depressurization to accommodate certain transients more effectively than can be done in other PWRs which have PORVs, but which do not have APS. The NRC Staff has also analyzed on a probabilistic basis accidents beyond the design basis accidents, including:

- multiple steam generator tube failures,
- total loss of feedwater,
- small break LOCA without HPSI,
- pressurized thermal shock, and
- ATWS.

The NRC Staff has concluded that addition of PORVs could be advantageous in permitting "feed and bleed" heat removal following loss of all feedwater, and that there would be some advantage in having PORVs provide additional pressure relief for ATWS, and in the case of failure of a large number of steam generator tubes. For the other accident sequences, they conclude that PORVs would provide no improvement over existing systems in the CE plants. The NRC Staff's overall cost-benefit analysis concludes there would be a slight advantage in adding PORVs over not adding PORVs. They acknowledge that the advantage is small compared with uncertainty in the analysis. However, the Staff also states it is their judgment that PORVs will provide an additional margin of safety in providing an effective, alternative means for depressurizing the RCS and thus provide greater flexibility in means for emergency core cooling.

Based on this judgment, the NRC Staff has concluded that PORVs should be required to be backfitted to the CE plants in question. However, they have also concluded that implementation of this requirement need not be hurried, and should be integrated with new requirements for decay heat removal systems that evolve from Task Action Plan A-45.

Analysis by the CEOG has produced results similar to those of the NRC Staff. They conclude the plants meet all regulatory requirements with the minor exceptions alluded to above. Their cost-benefit analysis shows a very small disadvantage in adding PORVs. Several differences in assumptions and data used by CEOG and those used by the NRC Staff apparently account for this conclusion, opposite from that of the NRC Staff. These differences have not been resolved. However, as with the cost-benefit analysis by the NRC Staff, the calculated margin is small compared with uncertainties.

Although the CEOG acknowledges that PORVs could provide an emergency means to depressurize the RCS, they have concluded that depressurization by the APS or by rapid secondary side cooldown is much to be preferred. It is their judgment that PORVs should not be added.

The Committee believes there is so nearly a standoff between costs and benefits that extensive efforts to resolve differences or improve assumptions in the analyses are not warranted. A decision to require or not to require addition of PORVs must hinge on largely nonquantitative judgments.

Under some circumstances there might be significant safety advantage in having available an effective backup means to depressurize the RCS. On the other hand, maintaining integrity of the primary pressure boundary and removing heat through systems designed for that purpose, i.e., the steam generators, is generally preferable, even in emergency situations.

The Committee agrees with the NRC Staff's recommendation to integrate any new requirements for rapid depressurization into the more comprehensive new requirements for improvements to decay heat removal systems expected to be forthcoming from Task Action Plan A-45 within one year. We see no need for earlier resolution of the PORV issue.

Sincerely,

J. J. Ray
Chairman

APPENDIX D

MILESTONES FOR IMPLEMENTATION OF INADEQUATE CORE COOLING INSTRUMENTATION

1. Submit final design description (by licensee) (complete the documentation requirements of NUREG-0737, Item II.F.2, including all plant-specific information items identified in applicable NRC evaluation reports for generic approved systems).

2. Approval of emergency operating procedure (EOP) technical guidelines - (by NRC).

   Note: This EOP technical guideline which incorporates the selected system must be based on the intended uses of that system as described in approved generic EOP technical guidelines relevant to the selected system.

3. Inventory Tracking Systems (ITS) installation complete (by licensee).

4. ITS functional testing and calibration complete (by licensee).

5. Prepare revisions to plant operating procedures and emergency procedures based on approved EOP guidelines (by licensee).

6. Implementation letter* report to NRC (by licensee).

7. Perform procedure walkthrough to complete task analysis portion of ICC system design (by licensee).

8. Turn on system for operator training and familiarization.

9. Approval of plant-specific installation (by NRC).

10. Implement modified operating procedures and emergency procedures (by licensee).

    - System Fully Operational -

*Implementation Letter Report Content

(1) Notification that the system installation, functional testing, and calibration is complete and test results are available for inspection.

(2) Summary of licensee conclusions based on test results, e.g.:

  (a) the system performs in accordance with design expectations and within design error tolerances, or

(b) description of deviations from design performance specifications and basis for concluding that the deviations are acceptable.

(3) Description of any deviations of the as-built system from previous design descriptions with any appropriate explanation.

(4) Request for modification of technical specifications to include all ICC instrumentation for accident monitoring.

(5) Request for NRC approval of the plant-specific installation.

(6) Confirm that the EOPs used for operating training will conform to the technical content of NRC-approved EOP guidelines (generic or plant specific).

APPENDIX E

ABBREVIATIONS

ACRS	Advisory Committee on Reactor Safeguards
ADV	atmospheric dump valve
AFW	auxiliary feedwater
ANSI	American National Standards Institute
APS	Arizona Public Service Company
APS	auxiliary pressurizer spray
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	Anticipated transient without scram
AWS	American Welding Society
BTP	branch technical position
CAP	corrective action plan
CE	Combustion Engineering
CEA	control element assembly
CEAC	control assembly element calculator
CENPD	designation of combustion engineering report
CEOG	Combustion Engineering Owners Group
CESSAR	Combustion Engineering Standard Safety Analysis Report
CET	core exit thermocouple
CFMS	critical function monitoring system
CFR	Code of Federal Regulations
COLSS	core operating limit supervisory system
CPC	core protection calculator
CRACS	chemical and radiological analysis computer system
CRT	cathode ray tube
DCRDR	detailed control room design review
DNBR	departure from nucleate boiling ratio
ECCS	emergency core cooling system
ECW	emergency cooling water
EOF	emergency operations facility
EOP	emergency operating procedure
EPG	emergency procedure guidelines
EPRI	Electric Power Research Institute
ERF	emergency response facility
ERFDADS	emergency response facility data acquisition and display system
FM	Factory Mutual
GDC	General Design Criteri(on)(a)

HED	human engineering discrepancy
HJTC	heated junction thermocouple
HVAC	heating, ventilating, and air conditioning
ICC	inadequate core cooling
ICCI	inadequate core cooling instrumentation
ISI	in-service inspection
ITS	Inventory Tracking System
LOCA	loss-of-coolant accident
LPSI	low-pressure safety injection
MSSS	main steam support structure
MT	magnetic particle testing
MTU	metric ton of uranium
MWD	megawatt days
NFPA	National Fire Protection Association
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NTOL	near-term operating license
PASS	postaccident sampling system
PCP	process control program
PDA	preliminary design assessment
PFR	potential finding report
PGP	Procedures Generation Package
PMS	plant monitoring system
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PSI	preservice inspection
PVC	polyvinyl chloride
PVNGS	Palo Verde Nuclear Generating Station
PWR	pressurized-water reactor
QA	quality assurance
QSPDS	qualified safety parameter display system
RCP	reactor coolant pump
RCS	reactor coolant system
RETS	Radiological Effluent Technical Specifications
RTC	remote technical concentrator
RTD	resistance temperature detector
RVLMS	reactor vessel level monitoring system
SCU	statistical combination of uncertainties
SDCS	shutdown cooling system
SER	Safety Evaluation Report
SGTR	steam generator tube rupture
SPDS	safety parameter display system
SRP	Standard Review Plan
SSE	safe shutdown earthquake

TAP	Task Action Plan
TPT	Torrey Pines Technology
TSC	technical support center
UH	upper head
UL	Underwriters Laboratory
V&V	validation and verification

APPENDIX F

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NRC FORM 335 (6-83)

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any)
NUREG-0857
Supplement No. 6

2. Leave blank

3. TITLE AND SUBTITLE
Safety Evaluation Report Related to the Operation of Palo Verde Nuclear Generating Station, Units 1, 2 and 3

4. RECIPIENT'S ACCESSION NUMBER

5. DATE REPORT COMPLETED

MONTH	YEAR
October	1984

6. AUTHOR(S)

7. DATE REPORT ISSUED

MONTH	YEAR
October	1984

8. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

9. PROJECT/TASK/WORK UNIT NUMBER

10. FIN NUMBER

11. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Same as 8. above

12a. TYPE OF REPORT

12b. PERIOD COVERED (Inclusive dates)

13. SUPPLEMENTARY NOTES
Docket Nos. STN 50-528, STN 50-529 and STN 50-530

14. ABSTRACT (200 words or less)
Supplement No. 6 to the Safety Evaluation Report for the application filed by Arizona Public Service Company, et al, for licenses to operate the Palo Verde Nuclear Generating Station, Units 1, 2 and 3 (Docket Nos. STN 50-528/529/530), located in Maricopa County, Arizona has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The purpose of this supplement is to update the Safety Evaluation Report by providing an evaluation of (1) additional information submitted by the applicants since Supplement No. 5 was issued and (2) matters that the staff had under review when Supplement No. 5 was issued.

15a. KEY WORDS AND DOCUMENT ANALYSIS

15b. DESCRIPTORS

16. AVAILABILITY STATEMENT
Unlimited

17. SECURITY CLASSIFICATION (This report)
Unclassified

18. NUMBER OF PAGES

19. SECURITY CLASSIFICATION (This page)
Unclassified

20. PRICE
$

431-02-0483
Box 19

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

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WASH. D.C.
PERMIT No. G-67

NUREG-0857, Supp. 6 SER RELATED TO THE OPERATION OF PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 OCTOBER 1984